The Transmission Provider shall operate the Day-Ahead Energy and Operating Reserve Market and Real-Time Energy and Operating Reserve Market to develop for all Market Participants' Day-Ahead Schedules, Dispatch Targets and Setpoint Instructions for Resources during the Operating Day. The Day-Ahead Schedules, Dispatch Targets and Setpoint Instructions will be developed to maximize the combined economic value of Transmission Service, Energy, Operating Reserves, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve, based on the Bids and Offers submitted. The Transmission Provider shall also make available Financial Transmission Rights (FTRs), which provide the FTR Holder with a hedge against Costs of Congestion.

The Transmission Provider shall provide all market services for the Energy and Operating Reserve Markets and Market Activities in accordance with the terms of this Tariff, the Business Practices Manuals, and related agreements.

The Transmission Provider shall be the sole point of application for all Energy and Operating Reserve Markets, Markets Activities, and all Transmission Services provided in the Transmission Provider Region. Notwithstanding the foregoing, nothing herein is intended to alter in any way the existing rights and obligations of the Transmission Provider or other parties, including Transmission Customers, Transmission Owners, and/or Market Participants, under the ISO Agreement, Appendix I Agreements, and related protocols, other provisions of this Tariff or any other agreement.

Section 38.1.6 of this Tariff sets forth the responsibilities of the Transmission Provider in its role as Reliability Coordinator, Balancing Authority, Energy and Operating Reserve Market operator, Transmission Service provider, and Planning Coordinator. Transmission Owner responsibilities are also set forth in the ISO Agreement and in Other Agreements. The Local Balancing Authorities' rights and responsibilities relating to implementation of the markets are set forth in the Balancing Authority Agreement.

Certain of the responsibilities described below are set forth in more detail in the ISO Agreement, the Balancing Authority Agreement, and Other Agreements. In the event of any conflict between this Section 38 of this Tariff and the ISO Agreement, the Balancing Authority Agreement, and/or the Other Agreements, then the ISO Agreement, the Balancing Authority Agreement and/or Other Agreements will control.

The Transmission Provider shall, on behalf of the Market Participants, perform the services pertaining to the Energy and Operating Reserve Markets specified in this Tariff, including but not limited to, the following.

a. Develop and maintain rules, practices and procedures for the Energy and Operating Reserve Market.

b. Operate a Day-Ahead and Real-Time Energy and Operating Reserve Market and manage Financial Transmission Rights.

c. Administer the Energy and Operating Reserve Markets, including: (i) identifying Reserve Zones within the Transmission Provider Region through Reserve Zone Studies; (ii) calculating Transmission Provider Region Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve requirements; (iii) procurement of Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve products; (iv) scheduling and development of Dispatch Targets and Setpoint Instructions; (v) accounting for Market Activities (vi) rendering bills to Market Participants; (vii) receiving from or disbursing to Market Participants credits or debits; (viii) maintaining appropriate records; and (ix) assisting in the independent monitoring for compliance of Market Participants' actions in accordance with the provisions of Module D.

d. Review and evaluate the qualification of entities seeking status as Market Participants pursuant to Section 38.2.2.

e. Coordinate maintenance schedules for Generation Resources and approve, coordinate and reschedule as necessary, Planned Transmission Outages operated within the Transmission Provider Region.

f. Determine and declare that an Emergency is expected to exist, exists, or ceases to exist, in all or any part of the MISO Balancing Authority Area, consistent with Good Utility Practice and serve as a primary point of contact for interested local, state, or federal agencies concerning such Emergencies.

g. Direct and coordinate arrangements for (i) the transfer of Energy during conditions constituting an Emergency in the MISO Balancing Authority Area or in an adjacent Balancing Authority, and the mutual provision of other support in such Emergency conditions with other interconnected Balancing Authorities; and (ii) coordinate and direct purchases of Emergency Energy offered by Market Participants during conditions constituting an Emergency in the MISO Balancing Authority Area.

h. Coordinate the Curtailment of Load, instruct Load Shedding, or other measures appropriate to alleviate an Emergency, to preserve reliability in the MISO Balancing Authority Area in accordance with ERO standards, or applicable Regional Entity standards, and to ensure the operation of the facilities within the MISO Balancing Authority Area in accordance with Good Utility Practice, this Tariff and the Business Practices Manuals.

i. Protect Confidential Information as specified in Section 38.9.

j. Implement and maintain the Commercial Pricing Nodes for Load and Generation Resources that comprise Hubs, Zones and Interfaces, and modify each to meet the needs of Market Participants.

k. Receive and maintain data and information relating to the operations of generation, demand response, and transmission facilities in the Transmission Provider Region as may be necessary or appropriate to operate the Energy and Operating Reserve Markets.

l. Maintain records of all transmission facility ratings. The Transmission Provider may review any submitted change or any submitted procedure for pre-established transmission facility rating changes.

m. Develop and maintain the Network Model.

n. Develop and maintain the Commercial Model.

o. Coordinate with Local Balancing Authority operators to implement the dispatch of Resources reliably

p. Manage physical and Financial Schedules submitted by Market Participants.

q. Coordinate and interface with the Independent Market Monitor.

r. Develop and manage the Market Portal.

s. Respond to and resolve inquiries by Market Participants regarding Market Activities.

t. Conduct inter-regional coordination.

u. Develop, maintain and manage procedures for credit risk exposure.

v. Ensure the Transmission Provider's Security Constrained Economic Dispatch and the Security Constrained Unit Commitment processes manage the Transmission System within reliability constraints and make a good faith effort to mitigate congestion within the Transmission Provider Region.

w. Perform a regional Security Constrained Economic Dispatch that dispatches Resources to simultaneously balance Load, generation and schedules, and manage congestion at five (5) minute intervals.

x. Issue Day-Ahead Schedules resulting from the Day-Ahead Energy and Operating Reserve Market clearing process, pursuant to Section 39.2.9, and Setpoint Instructions resulting from its Real-Time Energy and Operating Reserve Market clearing, pursuant to Section 40.2.7.

y. Develop and send Dispatch Targets for each Resource to Market Participants based on Offers to the Real-Time Energy and Operating Reserve Market.

The Transmission Provider shall prepare and maintain such records and prepare such reports, including, but not limited to, quarterly budget reports, as are required to document the performance of its obligations to Market Participants, Transmission Customers, and Local Balancing Authority operators hereunder in a form adopted by the Transmission Provider. The Transmission Provider shall also produce special reports reasonably requested by Market Participants and consistent with the Commission's standards of conduct; provided, however, an entity requesting any such special reports shall reimburse the Transmission Provider for the costs of producing such reports. Notwithstanding the foregoing, the Transmission Provider shall comply with the confidentiality provisions of Section 38.9 with respect to Confidential Information contained in any such report.

A. Zonal Uplift Report

The Transmission Provider shall prepare a monthly Zonal Uplift Report. The monthly Zonal Uplift Report must be posted by the Transmission Provider within 20 calendar days from the end of the month. The Transmission Provider shall post the Zonal Uplift Report on the public website, in a machine-readable format.

The Zonal Uplift Report shall utilize Local Resource Zones for geographic reporting. In the event that a Local Resource Zone may have less than four Resources in a given day, the Zonal Uplift Report may include an aggregation of Local Resource Zones. The aggregation, to the extent necessary, would be to one or more neighboring Local Resource Zones, should a Local Resource Zone have less than four Resources.

Notwithstanding the foregoing, resources with dispatchable Import Schedules into MISO will be reported on an Interface basis, rather than a Local Resource Zone basis.

The Zonal Uplift Report must identify the cause of Day-Ahead Revenue Sufficiency Guarantee Credits, Real-Time Revenue Sufficiency Guarantee Credits, Day-Ahead Margin Assurance Payments, and Real-Time Offer Revenue Sufficiency Guarantee Payments. The Transmission Provider shall identify the cause of Day-Ahead Revenue Sufficiency Guarantee Credits, Real-Time Revenue Sufficiency Guarantee Credits, Day-Ahead Margin Assurance Payments, and Real-Time Offer Revenue Sufficiency Guarantee Payments by utilizing existing Resource commitment reasons. The Zonal Uplift Report will identify total daily Day-Ahead Revenue Sufficiency Guarantee Credits, Real-Time Revenue Sufficiency Guarantee Credits, Day-Ahead Margin Assurance Payments, and Real-Time Offer Revenue Sufficiency Guarantee Payments, in dollars, in each category paid to the Resources in each Local Resource Zone.

B. Resource-Specific Uplift Report

The Transmission Provider shall prepare a monthly Resource-Specific Uplift Report. The monthly Resource-Specific Uplift Report must be posted by the Transmission Provider within 90 calendar days from the end of the month. The Transmission Provider shall post the Resource-Specific Uplift Report on the public website, in a machine-readable format.

The Resource-Specific Uplift Report shall include the Resource name and the corresponding amount of Day-Ahead Revenue Sufficiency Guarantee Credits, Real-Time Revenue Sufficiency Guarantee Credits, Day-Ahead Margin Assurance Payments, and Real-Time Offer Revenue Sufficiency Guarantee Payments paid, summed together for the month, to the Resource.

C. Operator-Initiated Commitment Report

The Transmission Provider shall prepare a monthly Operator-Initiated Commitment Report. The monthly Operator-Initiated Commitment Report must be posted by the Transmission Provider within 30 calendar days from the end of the month. The Transmission Provider shall post the Operator-Initiated Commitment Report on the public website, in a machine-readable format.

The Operator-Initiated Commitment Report shall include any commitments made after the Day-Ahead Market (e.g. Forward Reliability Assessment Commitments, Intra-Day Reliability Assessment Commitments, and Look-Ahead Commitments), including both manual and automated commitments that occur for any reason other than minimizing the total production costs associated with serving load.

Each Operator-Initiated Commitment Report shall include the size of each commitment and the commitment start time. The size will be measured by using a Resource’s economic maximum, which reflects the upper economic operating limit of a committed

Resource. The commitment will be measured in megawatts. The Operator-Initiated Commitment Report shall utilize Local Resource Zones for geographic reporting. The Operator-Initiated Commitment Report must include one of the following reasons for each Resource commitment:

- System-wide capacity
- Constraint management
- Voltage Support

The Transmission Provider shall operate and maintain a Market Portal and an internet webpage that will facilitate: (i) the submission of Offers and Bids by Market Participants; and (ii) the posting, by the Transmission Provider, of LMPs, MCPs and market clearing results for accepted Bids and Offers. The Market Portal or internet webpage shall provide historical data regarding market clearing activities, in accordance with Commission policies. The Market Portal or internet webpage shall also provide a platform for Market Participants to purchase and sell FTRs, submit FTR Bids and FTR Offers, and shall report the results of FTR Auctions pursuant to sections 44.1 and 45.1 of this Tariff.

Subject to the provisions of applicable local, state, or federal law, all voice communications with the Transmission Provider may be recorded by the Transmission Provider. By qualifying as a Market Participant, a Market Participant expressly consents to such recordings. Further, any entity acting on behalf of a Market Participant, by virtue of undertaking action on behalf of one (1) or more Market Participants, including but not limited to, a Scheduling Agent or Meter Data and Management Agent (MDMA), expressly consents to such recordings.

The Transmission Provider shall prepare, maintain, promulgate, and update the Business Practices Manuals as they relate to the operation of the Energy and Operating Reserve Markets. The Business Practices Manuals shall conform and comply with this Tariff, and the Applicable Reliability Standards. The Business Practices Manuals shall be designed to facilitate administration of efficient Energy and Operating Reserve Markets within industry reliability standards and the physical capabilities of the facilities located within the Transmission Provider Region. The Business Practices Manuals are available for reference, through the Transmission Provider's internet website.

The Transmission Provider, in its role as the Reliability Coordinator, Balancing Authority, Transmission Service provider, and Planning Coordinator, shall act in compliance with and perform the functions required by the Applicable Reliability Standards.

An entity may qualify as a Market Participant pursuant to the requirements specified herein.

A Market Participant may participate in all Market Activities. The Market Participant shall settle with the Transmission Provider for all credits and debits associated with these Market Activities. A Market Participant may designate a Scheduling Agent to conduct scheduling activities and/or a MDMA to conduct metering activities and/or Billing Agent to conduct settlement activities on its behalf. The Market Participant, however, ultimately remains financially liable for, and shall settle, all such Market Activities with the Transmission Provider.

To qualify as a Market Participant, a Market Participant Applicant shall fulfill the following requirements.

a. Submit a duly executed Market Participant Application to the Transmission Provider, in such form as shall be established by the Transmission Provider.

   i. A Market Participant Applicant shall not qualify as a Market Participant until the Transmission Provider has duly executed a Market Participant Agreement that has previously been duly executed by the Market Participant Applicant.

   ii. Notwithstanding any information provided to the Transmission Provider prior to the submission of the Market Participant Application, the Market Participant Applicant must provide all information required in the Market Participant Application.

b. Demonstrate to the Transmission Provider that it or its Designated Agent complies with all applicable metering, telemetry, data storage and transmission, and other reliability, operation, planning and accounting standards and requirements for operating in the Transmission Provider Region as set forth in this Tariff.

   i. A Market Participant Applicant that intends to assign to a Scheduling Agent, an MDMA, or other Market Participant certain Markets Activities shall demonstrate to the Transmission Provider’s satisfaction that it has assigned these responsibilities to a qualified Designated Agent by forwarding to the Transmission Provider a certificate that represents the underlying relationship between the Market Participant and the Designated Agent. In the event an entity other than the Local Balancing Authority is designated as an MDMA, the Local

Balancing Authority must still receive the metered data. If a Market Participant designates another entity as a Scheduling Agent or MDMA, the Market Participant remains financially responsible for all Market Activities represented by the Scheduling Agent or MDMA.

ii. A Market Participant Applicant that, as a Market Participant, intends to make purchases and sales of Energy, Operating Reserves, Up Ramp Capability, and/or Down Ramp Capability, or Other Ancillary Services, or FTRs on behalf of other entities shall so inform the Transmission Provider. The Market Participant shall remain financially responsible and liable for all Market Activities in the Energy and Operating Reserve Markets in which it engages regardless of on whose behalf it has arranged to make purchases and sales. The Market Participant's purchases and sales for other entities may, however, impact its own creditworthiness assessment.

c. Inform the Transmission Provider of its intent to submit Self-Schedules, Bilateral Transactions, Bids, Offers, including Virtual Bids and Offers, or hold FTRs.

i. Market Participant Applicants that are party to Grandfathered Agreement(s) and intend to terminate such agreements and provide or receive Transmission Service under this Tariff shall so inform the Transmission Provider pursuant to procedures established by the Transmission Provider. Such Market Participants that intend to maintain service under such agreements should inform the Transmission Provider in accordance with the process set forth by the Transmission Provider of its selection of the optional treatment of transactions pursuant to such agreements under the Energy and Operating Reserve Markets as described in Section 38.8.3. In addition, the Market Participant Applicant shall provide the information listed in Section 38.2.3.a.

d. A Market Participant Applicant seeking to submit Demand Bids into the Day-Ahead Energy and Operating Reserve Market shall demonstrate to the Transmission Provider that the end-users to be served by Energy purchased in the Energy and Operating Reserve Markets are located within the Transmission Provider Region or will be brought within the Transmission Provider Region prior to any purchases from the Energy and Operating Reserve Markets.

e. A Market Participant Applicant seeking to submit Generation Offers, Stored Energy Resource Offers, or Electric Storage Resource Offers, including Self-Schedules, to sell in the Energy and Operating Reserve Markets shall demonstrate to the Transmission Provider that such Market Participant Applicant: (i) has exclusive rights through ownership, operational control, or other contractual arrangements to the output of Resources capable of responding to the Dispatch Target and, if applicable, Setpoint Instructions; (ii) meets any applicable requirements pursuant to RAR; and (iii) complies with all metering, telemetry, data storage and communication protocols, and other reliability, operation, planning and accounting standards and requirements for operating in the Transmission Provider Region necessary to allow the Transmission Provider to validate the ability of the Generation Resource, Stored Energy Resource, or Electric Storage Resource to respond to the Dispatch Targets, and, if applicable, Setpoint Instructions.

f. A Market Participant Applicant seeking to engage in Market Activities shall demonstrate to the Transmission Provider that it meets all of the requirements established by the Transmission Provider and included in this Tariff for each activity as to which Market Participant seeks to participate, including, without limitation, executing a credit agreement in a form acceptable to the Transmission Provider, providing any Financial Security required by the Transmission Provider and otherwise complying with the Credit Policy.

g. A Market Participant Applicant seeking to submit Demand Response Resource–Type I Offers or Demand Response Resource–Type II Offers in the Energy and Operating Reserve Markets shall: (i) demonstrate to the Transmission Provider that it has exclusive rights through ownership, operational control, or other contractual rights to the output of such Resources, (ii) that such Resources are capable of responding to the Dispatch Target for Energy and Operating Reserve and Setpoint Instructions if a Demand Response Resource–Type II or that such Resources are capable of responding to commitment instructions to supply Energy or responding to deployment instructions associated with Dispatch Targets for Contingency Reserve in the case of a Demand Response Resource–Type I; (iii) designate those Resources as either a Demand Response Resource–Type I or Demand Response Resource–Type II with the Transmission Provider; (iv) demonstrate to the Transmission Provider that it complies with all metering, telemetry, data storage, and communication protocols, and other reliability, operation, planning, and accounting standards and requirements for operating in the Transmission Provider Region necessary to allow the Transmission Provider to validate the ability of the Resource to respond as described under (ii) above; and (v) verify to the Transmission Provider during the asset registration process that it has received any required approvals from all applicable state regulatory agencies to enable such Resources to participate in the Energy and Operating Reserve Markets.

h. Transmission Provider Evaluation of Application. Upon submission of a complete Market Participant Application, and such other information as shall be requested by the Transmission Provider, and a signed written representation that the Market Participant Applicant will be able to execute the Market Participant Agreement as provided in Attachment W of this Tariff upon approval of the Application, the Transmission Provider shall investigate and evaluate whether the Market Participant Applicant meets the criteria specified in Section 38.2.2. As soon as practicable, but in any event not later than sixty (60) Days after submission of the requested information, the Transmission Provider shall notify the Market Participant Applicant of its determination, along with a written summary of the basis for the determination. The Transmission Provider shall grant the sought for status upon a reasonable showing by the Market Participant Applicant that it meets the criteria specified in Section 38.2.2, subject to its execution of the applicable Market Participant Agreement and upon approval of the Application.

Subsequent to submission of a Market Participant Application, a Market Participant Applicant shall be subject to the obligations specified below.

a. **Submission of Information.** A Market Participant Applicant shall furnish all information reasonably requested by the Transmission Provider that the Transmission Provider believes is necessary to evaluate the Market Participant Application. Upon request, the Transmission Provider may waive the submission of particular provisions of the Market Participant Application to the extent the information in the Transmission Provider's possession is sufficient to evaluate the Market Participant Application.

b. **Duty to Notify Transmission Provider of Changed Circumstances.** Subsequent to the submission of the Market Participation Application, the Market Participant Applicant shall notify the Transmission Provider within twenty-four (24) Hours of learning of any unexpected material adverse change(s) in circumstances that would affect: (i) the information provided in the Market Participant Application; (ii) its status as a Market Participant; or (iii) the status of its Designated Agent(s). The Transmission Provider reserves the right to re-evaluate the Market Participant Application in light of any such new information. Failure to duly notify the Transmission Provider of such a change in information may result in the termination of the Market Participant Application. The Market Participant Applicant shall notify the Transmission Provider of any material adverse change in circumstances within seventy-two (72) Hours of learning of such changed circumstance(s) that would affect: (i) the information provided in the Market Participant Application; (ii) its status as a Market Participant; or (iii) the status of its Designated Agent(s). These notification provisions shall continue to apply to Market Participants after qualification as Market Participants.

A Market Participant may terminate its status as a Market Participant by providing the Transmission Provider at least five (5) Business Days written notice. Such termination shall not relieve the Market Participant of: (i) its obligation to follow the Dispatch Instructions during an Emergency; (ii) any obligation to deliver Energy or Operating Reserves or related services to the Energy and Operating Reserve Markets pursuant to an Offer made prior to such termination; (iii) any obligations pursuant to a Bid made prior to such termination; (iv) any obligations incurred or assessed by the Transmission Provider prior to the date of such termination; (v) any credits or debits related to FTR Obligations held by the Market Participant, until the Market Participant has sold or otherwise divested itself of the FTR; or (vi) any obligation to provide indemnification for the consequences of acts, omissions, or events occurring prior to such termination. A Market Participant that has terminated its Market Participant status may reapply to become a Market Participant no earlier than one (1) Month after the effective date of termination, and only provided that the Market Participant is not in Default of any obligation incurred under this Tariff.

a. **Standards.** In performing its obligations under this Tariff, a Market Participant shall, at all times, conduct its operations pursuant to the following standards.

i. Each Market Participant shall at all times: (i) follow Good Utility Practice; (ii) comply with all applicable laws and regulations; (iii) comply with the applicable principles, guidelines, standards and requirements of the Commission, ERO and the applicable Regional Entities; (iv) comply with the procedures established for operation by the Transmission Provider; and (v) cooperate with the Transmission Provider as necessary pursuant to the terms of this Tariff, for the operation of the facilities in the Transmission Provider Region in a safe, reliable manner, consistent with Good Utility Practice.

ii. Each Market Participant shall operate, or shall cause to be operated, any Resources supplying Energy and/or Operating Reserve owned or controlled by such entity within the Transmission Provider Region or otherwise supplying Energy to, through, or out of, the Transmission Provider Region in a manner consistent with the standards, requirements or directions of the Transmission Provider, pursuant to the terms of this Tariff. Such standards and requirements shall be established in accordance with industry standards, Applicable Reliability Standards, Commission regulation, Good Utility Practice and applicable law. The directions of the Transmission Provider shall be consistent with those directions authorized under this Tariff; provided, however, no Market Participant shall be required to take any action inconsistent with Good Utility Practice or applicable law.

iii. Each Market Participant shall notify the Transmission Provider of any changes to the availability of, changes in quantity of, and/or changes in the Resources it has committed for Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve as the Operating Day approaches in accordance with timing specified in Business Practices Manuals.

iv. Each Market Participant shall obtain and maintain all permits, licenses, or approvals required for it to participate in the Energy and Operating Reserve Markets in the manner contemplated by this Tariff.

v. Any Market Participant that seeks to transfer control of its generating unit or load to (or from) the MISO Balancing Authority Area from (or to) a specified external Balancing Authority Area on or after September 1, 2018 must execute and abide by the terms of the Pseudo-tie Agreement included as Attachment FFF-1 or Attachment FFF-2 to this Tariff prior to transferring control of the generating unit or load specified. The Market Participant shall conform to all standards, specifications, and requirements of Attachment FFF-1 or Attachment FFF-2, as applicable, at all times the Pseudo-tie Agreement is in effect for that Market Participant.

b. Scheduling. Each Market Participant shall provide, or cause to be provided to the Transmission Provider, scheduling and other information specified in this Tariff, and such other information as the Transmission Provider reasonably requires. Such information shall be provided in accordance with the deadlines established by this Tariff or by the Transmission Provider. Any Market Participant that executes the Pseudo-tie

Agreement in Attachment FFF-1 or Attachment FFF-2 shall conform to all standards, specifications, and requirements regarding scheduling and providing information to MISO as outlined in Attachment FFF-1 and Attachment FFF-2, as applicable.

The Transmission Provider shall abide by appropriate requirements for the non-disclosure and protection of any Confidential Information given to the Transmission Provider by a Market Participant as specified in Section 38.9. Each Market Participant shall maintain, or cause to be maintained, compatible information and communications systems, as specified by the Transmission Provider, required to transmit scheduling, dispatch, or other time-sensitive information to the Transmission Provider in a timely manner. Any Market Participant that executes the Pseudo-tie Agreement in Attachment FFF-1 or Attachment FFF-2 shall maintain or cause to be maintained all communications and other systems necessary to convey data to the MISO Balancing Authority and external Balancing Authority as required under Attachment FFF-1 or Attachment FFF-2, as applicable.

c. **Fees and Charges.** Each Market Participant shall be responsible for all fees and charges to the Transmission Provider for operation of the Energy and Operating Reserve Markets as determined by the Transmission Provider and allocated to the Market Participant in accordance with Schedule 17 of this Tariff.

In addition, each Market Participant shall be responsible for all fees and charges of the Transmission Provider for administration of Financial Transmission Rights as determined by the Transmission Provider and allocated to the Market Participant in accordance with Schedule 16 of this Tariff.

d. Communications.

i. Each Market Participant shall have, or shall arrange to have: (i) its operations staffed and equipped with communications systems capable of real-time communication with the Transmission Provider during normal and Emergency conditions; and (ii) systems to permit the Market Participant to control its Load or facilities sufficient to meet the requirements of its Market Activities.

ii. A Market Participant selling Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve from Resources within the Transmission Provider Region shall: (a) report to the Transmission Provider sources of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve available for operation; (b) supply to the Transmission Provider all applicable Offer data; (c) report to the Transmission Provider those Resources that are Self-Scheduled Resources; (d) confirm with the Transmission Provider any Interchange Schedules; (e) respond to the Transmission

Provider's directives to start, shutdown, or change output levels of Resources, in accordance with the terms specified in the Offer or change scheduled voltages or reactive output levels; (f) continuously maintain all Offers consistent with the Offer rules and obligations for Market Participants in the Day-Ahead Energy and Operating Reserve Market, as specified in Section 39, and/or Real-Time Energy and Operating Reserve Market, as specified in Section 40 concurrently with on-line operating information; and (g) ensure that, where so equipped, Resources are operated with control equipment, functioning as specified in the Business Practices Manuals.

iii. A Market Participant selling Energy from Resources outside the Transmission Provider Region shall comply with the Transmission Provider's requirements for Interchange Schedules provided herein.

iv. The Market Participant shall furnish the Transmission Provider with the information specified in the Offer as set forth in Section 39 and Section 40 of this Tariff for new Resources including default unit ratings, default Start-Up Offers or Shut-Down Offers, time parameters, and default No-Load Offers or Hourly Curtailment Offers. The information must be furnished no less than thirty (30) days before a Market Participant's initial Offer to sell Energy from a given Resource in the Day-Ahead Energy and Operating Reserve Market or the Real-Time Energy and Operating Reserve Market.

v. A Market Participant that is a Load Serving Entity or is purchasing on behalf of a Load Serving Entity shall respond to Transmission Provider directives as set forth in Section 40.2.20 this Tariff.

vi. To make purchases in the Energy and Operating Reserve Markets, a Market Participant that is not a Load Serving Entity or purchasing on behalf of a Load Serving Entity shall provide to the Transmission Provider requests to purchase specified amounts of Virtual Energy for each Hour of the Day-Ahead Energy and Operating Reserve Market.

vii. Any Market Participant that executes the Pseudo-Tie Agreement included as Attachment FFF-1 or Attachment FFF-2 to this Tariff shall provide the Transmission Provider information and data in the manner and form specified in Attachment FFF-1 or Attachment FFF-2, as applicable.

e. Metering.

i. Market Participants shall meet the minimum metering specifications and standards described in this Section 38.2.5.e for all meters that are used as a data source by the Transmission Provider, and the Transmission Provider shall make these specifications and standards available in the Business Practices Manuals.

ii. A Market Participant shall either install and operate, or otherwise arrange for, appropriate metering and related equipment capable of recording and transmitting all data communications, as specified in this Section 38.2.5.e, reasonably necessary for the Transmission Provider to perform the services specified in this Tariff.

iii. Where available, a Market Participant or MDMA shall provide the Transmission Provider with Metered data that meets the Transmission Provider's requirements by one of the following means: (a) direct transmission to the Transmission Provider; (b) direct transmission to the Transmission Provider through the Local Balancing Authority, Transmission Owner, ITC or LSE within whose area the Load is located; or (c) indirectly through metering provided by the Local Balancing Authority, Transmission Owner, ITC or LSE within whose area the Load is located. The Transmission Provider shall make this data available to the

Local Balancing Authority upon request. The Market Participant or MDMA shall also provide its Metered data to the Transmission Owner, Local Balancing Authority, ITC or LSE within whose area the Load is located to the extent such information is needed to implement the Transmission Provider's system operation and planning functions, to provide billing services to the Market Participant, to allow for data to be verified and agreed to by Transmission Owner, Local Balancing Authority, ITC, or LSE, or to permit the performance of calculations required by the Transmission Provider.

iv. A Market Participant whose metering services are provided by an MDMA shall itself be responsible for ensuring that all data described in this Section 38.2.5 are provided accurately.

v. All Market Participants must use their best efforts to provide the Transmission Provider with Metered values for purposes of settlement in the form requested by the Transmission Provider.

(a.) Market Participants shall report injection and withdrawal of Energy at each Commercial Pricing Node where they have injections or withdrawals. If the Market Participant does not have available actual meter data at these locations, the Market Participant is required to estimate Hourly injections and withdrawals based on their possible information and make the data available to the Transmission Provider by submitting the meter data according to the timeline established in the Business Practices Manuals. If no meter data is provided to the Transmission Provider by the Market

Participant, or the submitted data is unreasonable or erroneous, the Transmission Provider shall estimate the Hourly injections and withdrawals based on the information it has available to be used in Settlements for the Market Participant.

(b.) Market Participants must register any Internal Commercially Pseudo-Tied Load, identifying for each such Load: (1) the Commercial Pricing Node representing such Load, (2) the Local Balancing Authority where the Load is physically located, and (3) the Elemental Pricing Node(s) comprising the Internal Commercially Pseudo-Tied Load. Market Participants shall report injection and withdrawal of Energy for each Internal Commercially Pseudo-Tied Load where they have injections or withdrawals. If the Market Participant does not have available actual meter data at these locations, the Market Participant is required to estimate Hourly injections and withdrawals based on its possible information and make the data available to the Transmission Provider by submitting the meter data according to the timeline established in the Business Practices Manuals. If no meter data is provided to the Transmission Provider by the Market Participant, or the submitted data is unreasonable or erroneous, the Transmission Provider shall estimate the Hourly injections and withdrawals for an Internal Commercially Pseudo-Tied Load as the product of: (i) the sum of the weighting factors for the Elemental Pricing Node(s) comprising the Internal Commercially Pseudo-Tied Load that were used in the calculation of the Day-Ahead and Real-Time LMPs of the Commercial Pricing Node representing such Load; and (ii) the Meter data submitted or estimated for that Commercial Pricing Node.

vi. Market Participants shall submit withdrawal data for each Commercial Pricing Node where they represent Load, including consumption information for Commercial Pricing Nodes defined as Aggregate Load Zones. The Transmission Provider will, for Settlement purposes apply any calculated Residual Load in each Local Balancing Authority to the withdrawal data for the Load Zone applicable to the Residual Load in that Local Balancing Authority.

vii. All Market Participants shall maintain metering equipment that meets the following minimum standards:

a. All metering equipment must use megawatt-hour (MWh) as the standard unit of service measurement. Service may be measure in kilowatt-hours (kWh) if required by specific service, local or state regulations, host utilities, service providers, or as are mutually agreed upon by the parties involved, provided that KWh information is converted to fractional MWh information before it is transmitted to the Transmission Provider.

b. All metering equipment must have bi-directional capability (the ability to measure power flows in both directions).

c. All metering equipment must be capable of storing a minimum of 35-days of hourly intervals for each measured value.

d. Test switches or other means must be used to allow independent testing and/or replacement of each meter or transducer using a secondary circuit so as not to interrupt the operation of other devices using the same secondary circuit.

e. Current transformers and voltage transformers used for metering shall meet or exceed an accuracy class of 0.3%, and secondary connected burdens shall not exceed rated burdens of any voltage transformer. The same accuracy standards shall apply to optical metering transducers.

f. Metering equipment shall be tested periodically in accordance with the ANSI Standard requirement for the particular meter type as stated in ANSI C12.1 Appendix D – Periodic Testing Schedules. If any such test identifies any deficiency or inaccuracy in any metering equipment, the deficient or inaccurate equipment must be restored to correct operation as soon a reasonably possible, but in no case any later than 30 days from the date of discovery.

g. All Market Participants must maintain meter and equipment records, and associated documentation that demonstrates compliance with the requirements of this Section (including documentation of the appropriate periodic testing of metering equipment). Such records must be maintained for a period of seven years and be made available for inspection by the Transmission Provider upon request.

h. All Market Participants must maintain all meter and equipment records, and associated documentation in a form that insures the Transmission Provider's ability to obtain the metering data it needs to reliably and efficiently operate the Transmission System. The Transmission Provider must file all additional metering standards proposed by the Metering Standards Working Group unless, in its own independent judgment, the Transmission Provider determines that the additional standards proposed by the Metering Standards Working Group, if implemented, could adversely impact the reliable or efficient operation of the Transmission System.

f. **Energy Delivery Outside of the Transmission Provider Region.**

i. An Interchange Schedule for delivery outside of the Transmission Provider Region shall be priced at and delivered to an Interface. Any transmission service required on transmission systems beyond the Transmission Provider Region shall be the responsibility of the Parties to the transaction. External resources can supply Energy through Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and Real-Time Energy and Operating Reserve Market.

ii. A Market Participant may enter into a transaction for the purchase or sale of Energy to or from another Market Participant or any other entity, outside of the Energy and Operating Reserve Markets, subject to the obligations of the Market Participant pursuant to RAR. Market Participants shall report to and coordinate with the Transmission Provider in accordance with this Tariff all Interchange

Schedules, and Pseudo-Tie transactions, that include a physical transfer of Energy to or from an entity external to the Transmission Provider Region. All sales of Energy, Capacity, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve from resources located in Canada and all purchases of Energy, Capacity, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve under this Tariff to serve load in Canada shall be deemed to have a point-of-delivery at the U.S/Canada border. Sales of Operating Reserve from resources located in Canada may be provided from qualified Pseudo-tied External Resources or qualified External Asynchronous Resources. Pseudo-Tie transaction may utilize Day-Ahead Virtual Transactions to align the Transmission Usage Charge and available congestion hedges, i.e. FTRs and ARRs.

iii. A Market Participant may Pseudo-tie all or part of its generation or load as specified in the Pseudo-tie Agreement included as Attachment FFF-2 to this Tariff, as applicable, subject to the approval of the Transmission Provider. The Market Participant shall be subject to all the standards, specifications, and requirements of Attachment FFF-2, as applicable, for the generation and load identified as subject to any executed Pseudo-tie Agreement under Attachment FFF-2.

g. **Generation Outage Schedule.** The Transmission Provider shall coordinate all Generator Planned Outages of a Market Participant’s Generation Resource within the

Transmission Provider Region, as appropriate, to the extent such Generator Planned Outage impacts the Transmission Provider Region, as follows:

i. All Market Participants owning or controlling Generation Resource(s) within the Transmission Provider Region affecting transmission capability or reliability shall submit their Generator Planned Outage schedules to the Transmission Provider for a minimum of a rolling two (2) Year period, however Market Participants with nuclear Generation Resources shall submit nuclear Generator Planned Outage schedules for a minimum of a rolling three (3) Year period. Outages schedules submitted within these parameters will be considered by the Transmission Provider as timely submitted. The Generator Planned Outage schedules shall be presumed to be current unless updated. Market Participants may modify previously submitted planned outages at any time up until twelve (12) months prior to the time of the previously scheduled outage for non-nuclear Generation Resources and twenty-four (24) months prior to the outage for nuclear Generation Resources.

   If a Market Participant modifies a previously submitted planned outage, then the queue position in which the Generator Planned Outage schedule was received will be reset to the time such modified planned outage schedule is received by the Transmission Provider.

ii. The Transmission Provider shall analyze a Generator Planned Outage schedule to determine its effect on Available Transfer Capability (ATC), the reliability of the facilities within the Transmission Provider Region, and any other relevant material effects. The Transmission Provider shall inform a Market Participant if its schedule is expected to have a material impact on the reliability of the facilities within the Transmission Provider Region within three (3) Months after Generator Planned Outage schedules are submitted.

iii. As part of the review process, the Transmission Provider shall identify opportunities and associated costs for rescheduling the Generator Planned Outage to enhance the reliability of the facilities within the Transmission Provider Region. Prior to making any rescheduling decision, the Transmission Provider shall attempt to minimize the economic consequences of rescheduling including direct costs (excluding Opportunity Costs), to consider physical feasibility, and to coordinate with the affected Market Participants.

The Transmission Provider will re-schedule outages consistent with Good Utility Practice when faced with, in real-time or in any time horizon for which NERC standards require planning, a documented reasonable expectation of an Emergency, or a documented reasonable expectation of any of the following circumstances that compromise the reliability of the Transmission System, as determined by the Transmission Provider: (a) the inability to maintain voltage required by nuclear Generation Resources, or to meet any other Nuclear Plant Interface Requirement, as that term is defined by NERC, including the provision of off-site power supply; (b) the inability to maintain the Transmission System within System Operating Limits using normal (non-emergency) operating procedures or restore the Transmission System to normal operating conditions following a single contingency with the use of normal (non-emergency) operating procedures; or (c) the potential for contingencies to significantly affect Transmission System reliability of metropolitan areas.

The Transmission Provider will coordinate with affected Market Participants to attempt to voluntarily reschedule Generator Planned Outages to minimize direct costs, which do not include Opportunity Costs, of such outages. If the Transmission Provider is unable to resolve scheduling conflicts voluntarily with the affected Market Participants, the Transmission Provider will assign priority to Generator Planned Outage schedules based upon the chronological order in which the Generator Planned Outage schedules were received to reschedule the outage. Provided that the Generator Planned Outage is timely submitted, no rescheduling will occur within twelve (12) Months of a Generator Planned Outage (twenty-four (24) Months for nuclear Generation Resources), except where there is a documented reasonable expectation of an Emergency or a documented reasonable expectation of any of the circumstances (a)-(c) described supra in Subsection 38.2.5.g.iii that compromise the reliability of the Transmission System, due to the following unexpected conditions: (1) severe weather; or (2) unplanned (urgent, emergency, or forced) outages.

Market Participants whose Generator Planned Outage(s) have been rescheduled shall be compensated for reasonable and explicit additional costs associated with rescheduling such Generator Planned Outage pursuant to Attachment BB of this

Tariff and will be applied on a non-discriminatory basis to all Market Participants assuming the following conditions:

(1) the Generator Planned Outage was timely submitted; or (2) the Generator Planned Outage was not timely submitted and the following occurred: (a) the Transmission Provider approved (accepted) the Generator Planned Outage in the outage scheduling application; and (b) the Transmission Provider was forced to re-schedule such planned outage within twelve (12) Months of the planned outage (twenty-four (24) Months for nuclear Generation Resources) date due to a documented reasonable expectation of an Emergency or a documented reasonable expectation of any of the circumstances (a)-(c) described supra in Subsection 38.2.5.g.iii that compromise the reliability of the Transmission System, that were caused by the following unexpected conditions: (1) severe weather; or (2) unplanned (urgent, emergency, or forced) outages.

The Market Participant shall not be compensated for any opportunity costs associated with such rescheduling.

iv. The Transmission Provider shall be responsible for documenting all Generator Planned Outage schedules, all schedule changes, and all studies and services performed with respect to any Generator Planned Outage. If a Generator Planned Outage has been rescheduled, the Transmission Provider shall issue a report to a stakeholder group, after the date that the originally scheduled outage has passed.

v. For Market Participants who are operators of nuclear Generation Resources within the Transmission Provider Region, the Transmission Provider shall enter into written agreements that define scheduling criteria, limitations and restrictions necessary to ensure the safety and reliability of such facilities.

vi. The Transmission Provider may not reschedule Generator Planned Outages, if doing so would contravene applicable laws, regulations, judicial orders, agency orders, or where rescheduling is not feasible (voided warranty or equipment damage).

vii. If: (1) a Market Participant does not provide the Transmission Provider with at least one year advance notice of a Proposed Generator Planned Outage for Generation Resources located within the Transmission Provider Region; (2) the Transmission Provider determines that the proposed outage would cause a scheduling conflict as specified in this Section 38.2.5.g; and (3) the Market Participant refuses to reschedule the proposed Generator Planned Outage as requested by the Transmission Provider, then during the next Planning Year, the Transmission Provider shall calculate the $XEFOR_d$ used to determine the Unforced Capacity value for such Generation Resource under RAR by (1) adding to the numerator of the $XEFOR_d$ equation a number equal to three times the duration of the outage, and (2) adding to the denominator of the $XEFOR_d$ equation a number equal to the duration of the outage.

viii. In addition to the provisions set forth in Section 38.2.5.g.vii, a Market Participant providing notice of a Proposed Generator Planned Outage for a Generation

Resource located within the Transmission Provider Region will be subject to the forced outage rate adjustment described below unless the Market Participant provides Transmission Provider with: (1) at least one hundred and twenty (120) Calendar Days' advance notice; or, (2) between fourteen (14) and one hundred and nineteen (119) Calendar Days' advance notice of a Proposed Generator Planned Outage to occur entirely during a time of adequate projected margin, at the time the outage is provided to the Transmission Provider. There is adequate projected margin when the Maintenance Margin is at or above zero (0) MW after subtracting the MW of the requested Proposed Generator Planned Outage. The forced outage rate adjustment applies if the Generator Planned Outage occurs during a period when the Transmission Provider has declared a Maximum Generation Emergency, as set forth in the Transmission Provider's emergency operating procedures, in the area where the Generation Resource is located. The forced outage rate adjustment shall be applied in the next applicable Planning Year as follows: the forced outage rate used to determine the Unforced Capacity value for such Generation Resource under RAR and the Generator Forced Outage rates used in the PRM analysis outlined in Section 68A.2 will be adjusted by adding to the forced outage hours in both the numerator and denominator of the forced outage rate equations a number equal to the greater of (1) the period during which the outage overlaps with the Maximum Generation Emergency or (2) one Day. Further, the outage will increase the number of forced outage occurrences by one in the forced outage rate equations. If the Generator Planned Outage is a derate, the greater of the period during which the derate overlaps with the Maximum Generation Emergency or one Day will be converted into equivalent forced derated hours.

ix. A Market Participant will be able to make changes to its Generator Planned Outage and be exempt from the forced outage rate adjustment set forth in Section 38.2.5.g.viii by submitting a new outage request for any increased outage duration provided: (1) the schedule change is requested not less than fourteen (14) Calendar Days prior to the start of such outage; and, (2) the increased duration must occur entirely during a time of adequate projected margin, at the time the change is submitted. Any schedule change(s) made one hundred and twenty (120) Calendar Days in advance or more will not be subject to the forced outage rate adjustment described in Section 38.2.5.viii.

x. If a Market Participant provides at least one hundred and twenty (120) Calendar Days' notice for more than one Generator Planned Outage for the same unit to be taken in whole or in part within the same one hundred and twenty (120) Calendar Day period, the first request submitted will be eligible for exemption from the forced outage rate adjustment set forth in Section 38.2.5.g.viii without further review. The 120 Calendar Day period begins with the end date of the higher queued request. Any subsequent Generator Planned Outage requests for the same unit to be taken in whole or in part within the same one hundred and twenty (120) Calendar Day period will be granted an exemption from the forced outage rate adjustment only if there is adequate projected margin, at the time the request is submitted.

xi. If the Market Participant reschedules its Generator Planned Outage at the Transmission Provider's request, the outage will not be subject to the forced outage rate adjustment set forth in Section 38.2.5.g.viii.

h. **Continuing Creditworthiness.** Market Participants shall continue to comply with the Credit Policy and creditworthiness criteria established by the Transmission Provider.

i. **Grandfathered Agreements**. A Market Participant that is party to a Grandfathered Agreement(s) may choose to terminate such contracts and receive or provide Transmission Service under this Tariff. Market Participants that intend to maintain service under Grandfathered Agreements shall inform the Transmission Provider of their selection of the treatment of transactions pursuant to such agreements under the Energy and Operating Reserve Markets as described in Section 38.8. Market Participants may request a change of treatment of such agreements annually as provided under those options available to parties under Grandfathered Agreements described in Section 38.8.3; provided, that, only Market Participants that settled the initial treatment of the Grandfathered Agreement with the Transmission Provider prior to July 28, 2004, may request such a change of treatment to any of Option A, Option B or Option C; and provided, further, that Market Participants that did not settle the initial treatment of the Grandfathered Agreement with the Transmission Provider prior to July 28, 2004, may request such a change of treatment only to select either Option A or Option C. Requests for such change of treatment may be made and granted only during the period designated by the Transmission Provider for the annual redistributions of FTRs. In addition, the Market Participants shall provide the information listed below. Information to be provided to the Transmission Provider includes:

i. The GFA Responsible Entity.

ii. The GFA Scheduling Entity.

iii. The source and sink points applicable under the Grandfathered Agreement(s).

iv. The maximum MW Capacity permissible under the Grandfathered Agreement(s).

a. Market Participants shall perform the following functions for all Resources for which the Market Participant is qualified to submit Offers.

i. Two days prior to the Operating Day and on the day prior to the Operating Day, provide operating and availability status of Resources to the Transmission Provider for reliability analysis;

ii. On the day prior to the Operating Day, report the status of automatic voltage regulators to Transmission Operators;

On the day prior to the Operating Day, submit Interchange Schedule requests in accordance with process and procedures established by the Transmission Provider.

b. During the Operating Day, Market Participants shall perform the following functions for all Resources for which the respective Market Participant is qualified to submit Offers:

i. Implement Reactive Supply and Voltage Control schedules provided by Transmission Operators; and

ii. Implement Dispatch Targets and Setpoint Instructions and commitment instructions provided by the Transmission Provider.

38.2.7 Generation Suspension, Generation Retirement, and System Support Resources

a. Generator or SCU Notification of Change in Status.

(i) Notification Procedures for Units.

An owner of a Generation Resource, Synchronous Condenser Unit (SCU), or a Generator that is directly interconnected to the Transmission System but is Pseudo-tied out of the Transmission Provider's Balancing Authority Area that is planning to Suspend operations of all or any portion of that resource must notify the Transmission Provider of such a plan by submitting a completed Attachment Y Notice to the Transmission Provider. This notification provision also applies to a Generation Resource connected to the underlying lower voltage facilities within Transmission Provider region and to Generation Resources that are not directly interconnected to the Transmission System, but are External Resources that are Pseudo-tied into the Transmission Provider's Balancing Authority Area. The Transmission Provider shall coordinate with the entity to which the External Resource is directly connected to determine whether the External Resource is necessary for reliability of the Transmission System, in accordance with applicable coordinated planning provisions between the Transmission Provider and the regional planning entity to which the External Resource is interconnected.

The owner of a Generation Resource or SCU shall submit an Attachment Y Notice to the Transmission Provider at least twenty-six (26) weeks prior to changing to Suspend status, unless the Generation Resource or SCU is inoperable due to Forced Outage in which case Attachment Y Notice must be submitted to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. The owner of a Pseudo-tied out Generator shall submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to the anticipated effective date of change of status.

A Generation Resource or SCU that is inoperable due to Forced Outage or a Pseudo-tied out Generator shall not be designated as an SSR Unit. The provisions for time limitations on suspension within Section 38.2.7 shall apply to a Generation Resource or SCU that is inoperable due to Forced Outage and a Pseudo-tied out Generator.

A Generation Resource that is designated as a Blackstart Unit by a Transmission Operator in its System Restoration Plans shall not be designated as an SSR Unit to solely provide Blackstart Service. However, the Transmission Provider may determine that SSR Unit status is justified if such Generation Resource is required to maintain the reliability of the Transmission System based on its Attachment Y Reliability Study. Section 38.2.7 shall not modify or alter a Transmission Operator’s obligations under the Tariff to identify Blackstart Units that are included in its System Restoration Plans, or a Blackstart Unit Owner's obligations to comply with the terms of any Blackstart Service agreement, in accordance with Schedule 33, or the requirements of Commission approved reliability standards.

The following exception applies to the Generation Suspension, Generation Retirement and System Support Resource (SSR) provisions in Section 38.2.7: The owner of a Generation Resource or SCU that requests a Generator Planned Outage or submits a Generator Forced Outage through the Transmission Provider’s outage scheduling system (Control Room Operations Window – CROW or its successor) does not need to submit an Attachment Y Notice to the Transmission Provider if the request does not involve a change of status to Suspend.

An owner of a Generation Resource, SCU, or a Pseudo-tied out Generator certifies by submitting an Attachment Y Notice that it has elected to Suspend such resource and the

Attachment Y Notice shall be executed by an officer of such owner attesting to that claim. The decision to Suspend may be modified by rescission as specifically provided in this Section 38.2.7.

An owner may not submit a new Attachment Y Notice to Suspend that supersedes a prior notification unless the prior Attachment Y Notice is rescinded. The new Attachment Y Notice requires at least twenty-six (26) weeks prior notice to the Transmission Provider.

(ii) Confidentiality of Attachment Y Notice.

The Transmission Provider shall treat all Attachment Y Notices as Confidential Information unless the Attachment Y Reliability Study is complete and any of the following occurs: 1) the owner has elected to waive its rescission rights; 2) the resource fails to return to operation before the period for rescission has lapsed; 3) public release is required under Section 38.2.7.b in order to evaluate the need for an SSR Agreement; or 4) the information is otherwise publicly disclosed by the owner of a Generation Resource, SCU, or a Pseudo-tied out Generator. The Transmission Provider shall promptly post on OASIS that an Attachment Y Notice was submitted, along with the effective date of retirement, under the first three of these circumstances.

(iii) Notification of the Outage Scheduler After Submittal of Attachment Y Notice.

After receipt of an Attachment Y Notice, the Transmission Provider shall schedule such outage notification through the Transmission Provider's Control Room Operations Window ("CROW") outage scheduling system, or successor system, to coordinate the outage planning of a Generation Resource or SCU through CROW, on behalf of the owner.

b. SSR Unit Procedures.

System Support Resource (SSR) procedures provide a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain reliability of the Transmission System, if all or a specified portion of the capacity of such Generation Resources or SCUs would otherwise either Retire or Suspend. SSR Agreements are a last-resort measure to address a reliability issue on the Transmission System facilities under the functional control of the Transmission Provider and shall only be entered into once all potential SSR Agreement alternatives have been examined.

An owner of a Generation Resource or SCU must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU. If, after completing a reliability study (Attachment Y Reliability Study) and analyzing potential alternatives (Attachment Y Alternatives Study), the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, that is not subject to an exception under Section 38.2.7.a, then the Transmission Provider and Market Participant of such Generation Resource or SCU shall enter into an SSR Agreement, in accordance with the Attachment Y-1 form of agreement. The SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU. The Transmission Provider shall periodically review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended.

The Transmission Provider shall use reasonable efforts to respond to the owner within 75 Calendar Days after receipt of the Attachment Y Notice, regarding whether the subject of an Attachment Y Notice appears to be required for transmission system reliability, unless an alternative date is agreed to by the owner and the Transmission Provider.

If the Attachment Y Reliability Study determines that a reliability concern exists, and a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly post on OASIS: (1) that an Attachment Y Notice was submitted; (2) that the Transmission Provider's Attachment Y Reliability Study concluded that the Generation Resource or SCU was required for the reliability of the Transmission System; (3) the draft report on the Attachment Y Reliability Study with the CEII information redacted from the report; and (4) how the associated SSR Unit costs would be allocated in the event that the Generation Resource or SCU is required to provide service under an SSR designation.

The Transmission Provider shall discontinue Confidential treatment of an Attachment Y Notice and Attachment Y Reliability Study in the event that the Attachment Y Reliability Study results determine that the Generation Resource or SCU is required to maintain system reliability and would be eligible for treatment as an SSR Unit. The Transmission Provider may use information related to Retire or Suspend status in its Transmission Planning processes (pursuant to Attachment FF and the Transmission Planning BPM) and in its Generator Interconnection process (pursuant to Attachment X and the Generation Interconnection BPM), provided that recipients of the information have signed appropriate Non-Disclosure Agreements with the Transmission Provider.

c. Evaluation of Need for the SSR Designation.

The Transmission Provider will perform an Attachment Y Reliability Study to determine whether the Generation Resource or SCU is necessary for the reliability of the Transmission System based on the analyses described in this section and the criteria set forth in the Business Practices Manuals, but will not determine in this initial analysis the available alternatives to designating the Generation Resource or SCU as an SSR Unit.

In collaboration with the affected Transmission Owners, the Transmission Provider will cause an evaluation to be performed of transmission system conditions (an Attachment Y Reliability Study) that result from the change in status of the unit(s) subject to Attachment Y notification requirements. The evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable NERC Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online. The scope of this evaluation will include a steady state analysis, and may require analyses of stability and import limitations for the particular study area. Study cases will be derived from approved MTEP models that are representative of the period of time for which the suspension of the unit(s) is requested, and will include models that represent near-term and/or longer-term scenarios as appropriate for the study period. Models that are developed to reflect both the online and offline status of the unit being evaluated will be analyzed to compare the differences in results to determine the impact of the unit on the transmission system. The results of the evaluation will be reviewed with the participating Transmission Owners to verify the Transmission Provider’s findings and to evaluate proposed solutions that should be considered to address the reliability issues. The need to retain a unit(s) as a System Support Resource, absent implementation of a feasible alternative, shall be determined by the presence of unresolved reliability violations on the Transmission System that is under the functional control of the Transmission Provider.

The Transmission Provider shall post the determination of reliability need on the Transmission Provider's OASIS and shall: (1) begin negotiations of a potential SSR Agreement with the Market Participant owning or operating the Generation Resource or SCU; and (2) use reasonable efforts to hold a stakeholder meeting pursuant to Attachment FF within thirty (30) Calendar Days to review alternatives to the potential SSR Unit designation or designations (if multiple Attachment Y Notices apply). The Transmission Provider will schedule subsequent stakeholder meetings as needed. The Transmission Provider shall complete the Attachment Y Alternatives Study within 26 weeks after receipt of an Attachment Y Notice, if the Attachment Y Notice provides only 26 weeks of advance notification, unless otherwise agreed to by the owner of the potential SSR Unit. If no alternative is identified as available by the Attachment Y Notice date to Suspend, then the Transmission Provider shall file the SSR Agreement with an effective date as of the Attachment Y Notice date to Suspend.

Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess, in an open and transparent planning process in accordance with the provisions of the Transmission Expansion Planning Protocol Attachment FF to the Tariff, feasible alternatives to the proposed SSR Agreement. The list of alternatives to SSR Unit status that the Transmission Provider shall consider and expeditiously approve as applicable include (depending upon the type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated upon Generation Resource trips or unplanned Transmission Outages; (iv) contracted demand response or Generator alternatives; and (v) transmission expansions. Consistent with Section B.1.b of Attachment FF, the Transmission Provider will review and evaluate alternatives to an SSR Agreement on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to require contractual assurances that the party who provides the alternative solution will implement the solution before the Generation Resource or SCU with the Attachment Y Notice is permitted to Retire or Suspend. The executed contractual arrangements must provide a binding arrangement that obligates the Market Participant who provides the alternative solution to complete any required infrastructure changes that are needed to avoid the reliability issues that would otherwise be addressed by transmission upgrades. While the contractual arrangements will vary based on the particular solution, the terms of the contractual arrangements must further obligate the party who provides the alternative solution to implement actions when required by the Transmission Provider to provide necessary relief. A Generator alternative may be a new Generator, an existing Generator that is made available after the Attachment Y Reliability Study is completed, or an increase to existing Generator capacity that has an executed Generator Interconnection Agreement pursuant to Attachment X for a Commercial Operation Date that is prior to the commencement of the change of status date of the Generation Resource or SCU that has submitted an Attachment Y Notice and must be registered as a Generation Resource that is obligated to offer into the market and respond to instructions from the Transmission Provider. Contractual commitments associated with demand-side resource alternative solutions shall require demonstration to the Transmission Provider of an executed contract between LSE or ARC and Energy Consumers as well as necessary procedures and protocols for responding to Transmission Provider instructions. Such demand-side contracts must be in place by the time that the SSR Agreement alternative solution would otherwise need to be committed in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable alternative solution can be assured. In assessing applicability for SSR status, the Transmission Provider will not require continued operation when the continued operation of a portion or all of Generation Resources or SCUs would be contrary to applicable law, regulations, or court or agency orders (such as a settlement with an environmental agency or a consent decree approved by a court). In performing the Attachment Y Reliability Study and the Attachment Y Alternatives Study to an SSR Agreement, the Transmission Provider shall collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, may consult with a retained consultant. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend before the Transmission Provider transfers such information to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, to comply with any confidentiality obligations owed to Transmission Provider under the Tariff or pursuant to a related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner of the Generation Resource or SCU subject to review under this section shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental or other regulatory requirements that would necessitate improvements to the potential SSR Unit. The Transmission Provider will reasonably assist the owner of a potential SSR Unit in working with regulatory agencies to obtain environmental or other waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System. For purposes of determining whether a Generation Resource or SCU qualifies as an SSR Unit, the Transmission Provider will process multiple Attachment Y Notices in the order in which the Attachment Y Notices are received. If a subsequent Attachment Y Notice is received before a determination is made for a Generation Resource or SCU that is the subject of a prior Attachment Y Notice, the Generation Resource or SCU that is the subject of a prior Attachment Y Notice will not be the subject of an SSR Agreement to avoid reliability issues caused by the subsequently noticed suspension of another Generation Resource or SCU.

The filing of a SSR Agreement with FERC shall be accompanied by a corresponding report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study that details the methodologies used, study assumptions, Transmission Owner planning criteria used (including when the criteria became effective and the approving regulatory body, if any), analysis results, an evaluation of alternatives and the conclusion of the study (including a short explanation of the proposed solution to any reliability issue identified and estimated timetables for implementing the preferred solution). An affirmation that the results, in whole or in part, from a previously filed report remain applicable may substitute for filing an entirely new report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study.

d. Modification or Rescission of an Attachment Y Notice.

(i) Rescission of an Attachment Y Notice Prior to the Transmission Provider's Reliability Study Response.

The Transmission Provider shall notify the owner prior to publicizing the Attachment Y Notice and Attachment Y Reliability Study results that the Attachment Y Reliability Study is complete. However, the Transmission Provider shall not provide any information related to the

Attachment Y Reliability Study results to the owner at that time. The owner may rescind its Attachment Y Notice by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention, not more than fifteen (15) Business Days after receiving notice from the Transmission Provider that the Attachment Y Reliability Study is complete. In the event of such rescission, the confidentiality of the Attachment Y Notice shall be preserved.

(ii) Modification or Rescission of an Attachment Y Notice After the Owner of Generation Resource or SCU Receives the Results of Attachment Y Reliability Study, but Prior to Commencing Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is not necessary for the reliability of the Transmission System, may rescind its decision to Suspend any time prior to the end of the period for rescission following the effective date or may modify the start of the suspension any time prior to the original effective date by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention. If the revised date for suspension is prior to the original date specified in the Attachment Y Notice, a new Attachment Y Notice shall be submitted to the Transmission Provider at least twenty-six (26) weeks prior to the effective date of suspension.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice. After the owner has waived the right to both rescind and modify the Attachment Y Notice, the requested status of the Generation Resource will change to Retire, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive its right to both rescind and modify the Attachment Y Notice and committed to retirement of the Generation Resource or SCU.

(2) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is required as an SSR Unit may rescind its decision to Retire or Suspend or modify the date of suspension at any time while designated as an SSR Unit by submitting an amended Attachment Y Notice specifying the modified effective date or stating its decision to rescind.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

(iii) Modification or Rescission of an Attachment Y Notice After Commencing a Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the resource has not been designated as an SSR Unit or is not continuing to operate pursuant to an SSR Agreement, may rescind its decision to Suspend by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention to rescind any time during the period for rescission following the effective date.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to rescind and modify the Attachment Y Notice. After the owner has waived the right to rescind, the Generation Resource will have a Retire status, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive their right to rescind and committed to retirement of the Generation Resource or SCU.

(2) An owner of an SSR Unit may rescind its decision to Suspend or to Retire or modify the effective date prior to the termination date of the SSR Agreement by submitting an amended Attachment Y Notice specifying the modified effective date or stating its intention to rescind. After receiving an amended Attachment Y Notice from an owner of an SSR Unit to rescind or modify its decision to Suspend or to Retire, the Transmission Provider will then exercise the termination provisions of the SSR Agreement.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

e. Refund of Costs.

(i) If the owner of a Generation Resource or SCU that notifies the Transmission Provider of a decision to Suspend and for which the Transmission Provider has not determined the Generation Resource or SCU is needed for reliability rescinds an Attachment Y Notice prior to commencing suspension, then such owner shall pay the Transmission Provider all of the costs that the Transmission Provider incurred in conducting an Attachment Y Reliability Study.

(ii) The Market Participant that owns or operates an SSR Unit must refund to the Transmission Provider with interest at the FERC-approved rate, all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the Generation Resource or SCU and to meet applicable regulations and other requirements (including environmental) while the Generation Resource or SCU was subject to an SSR Agreement if the owner: (1) rescinds its decision to Suspend or to Retire the unit while it is designated a SSR; (2) rescinds its decision to Suspend following its previous designation as an SSR Unit; or (3) returns a unit to service following its previous designation as an SSR Unit and later retirement of the unit.

(iii) An owner of a Generation Resource or SCU that returns the unit to service upon failure to Retire or Suspend according to an Attachment Y Notice (*i.e*. returns from retirement or rescinds the Attachment Y Notice, including a Generation Resource or SCU that was not a SSR Unit, a former SSR Unit that no longer operates pursuant to an SSR Agreement, or an SSR Unit) will be allocated the total costs of Network Upgrades incurred or financially committed to as of the date of the notification of modification of the decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in an Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such an owner will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by the Attachment Y Notice to Suspend.

In the event that multiple Attachment Y studies identified reliability issues that required the Network Upgrades and the owners of the units subject to the studies return their units to operation upon failure to Retire or Suspend (*i.e*. return from retirement or rescind the Attachment Y Notices, including Generation Resources and/or SCUs that were not SSR Units, former SSR Units that no longer operate pursuant to an SSR Agreement, or SSR Units), the owners will be allocated the total costs of such Network Upgrades incurred or financially committed to as of the date of notification of the last modification of a decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in the Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such owners will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by an Attachment Y Notice to Suspend.

Except as provided in this Section, cost responsibility is assigned only for Network Upgrades that are identified to fully alleviate the violations identified in the Attachment Y Reliability Study in connection with a change in a plan to Retire or Suspend a Generation

Resource or SCU. Costs of Network Upgrades that have been identified in the MTEP to address Transmission issues other than the issues identified in the Attachment Y Reliability Study of a unit that requests suspension will not be allocated to the owner of that unit if such costs of construction were not expedited as the result of an Attachment Y Notice to Suspend. In accordance with Attachment FF of the Tariff, the estimated costs of such Network Upgrades are included in the MTEP when it is approved by the Board of Directors of the Transmission Provider for inclusion in the MTEP. The Transmission Provider will solicit from the constructing Transmission Owner the actual costs (including the costs of expediting construction, and pre-construction costs, if any) incurred or committed to as of the date of notification for the last modification of a decision to Retire or Suspend. Each owner shall pay its pro rata share of the incurred or committed Network Upgrade costs, based on the relative Generation Verification Test Capacity of each resource whose operation causes the assignment of Network Upgrade costs to its owner. The Transmission Provider will promptly notify the responsible owner of their share of the total costs once actual costs are determined.

f. Execution and Filing of SSR Agreement.

The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating a Generation Resource or SCU that is needed for SSR purposes based on the *pro forma* Attachment Y-1. The SSR Agreement shall state that it incorporates by reference the compensation authorized by the Commission. Resources that are ineligible to continue operating for legal or regulatory reasons, however, shall not be required to enter into an SSR Agreement. If a potential SSR Unit is ineligible or an existing SSR Unit becomes ineligible to continue operation, then the Transmission Provider shall seek to minimize the impact to Load by operating the Transmission System in the same manner as for any Resource that becomes ineligible to continue operation due to Forced Outage.

The Transmission Provider will file an SSR Agreement with the Commission for approval if the Transmission Provider's analysis determines that the Generation Resource or SCU is required for reliability of the Transmission System. All potentially affected parties will receive notification of such Commission filing. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for a term of twelve (12) months, unless the Transmission Provider requires a different term. The Transmission Provider must have available the entire capacity specified in the SSR Agreement of each SSR Unit.

g. Operation of SSR Unit.

Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit for reliability purposes. The Transmission Provider will commit the SSR Unit when conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic commitment of the SSR Unit. The SSR Agreement found in Attachment Y-1 to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched by the Transmission Provider.

h. Scheduling Rules for SSR Units.

The Transmission Provider shall notify Market Participants with SSR Units as to the time period of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term

Reserve, and/or Other Ancillary Services required from each SSR Unit in accordance with Section 39.1.5 for the Day-Ahead Energy and Operating Reserve Markets, Section 40.1 for Reliability Assessment Commitment processes, and Section 40.1.A.3 Look Ahead Commitment processes.

i. SSR Unit Participation in Markets.

A Market Participant may offer Energy or Ancillary Services from SSR Units into the Day-Ahead Energy and Operating Reserve Market, RAC, or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has not requested the Market Participant to run the SSR Unit at full capacity unless this would impair the ability of the SSR Unit to provide the Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, or Other Ancillary Services when requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; or (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section.

j. SSR Unit Compensation.

(**i**) The Market Participant will be compensated for only costs incurred for the extended operation as an SSR Unit that do not exceed the full cost-of-service (including the fixed cost of existing plant). The hourly component of compensation will be provided as stated in this Tariff. For the determination of any additional compensation, the Market Participant shall submit a filing to the Commission under Section 205 of the FPA that states the additional compensation the Market Participant deems appropriate that is associated with the SSR Agreement filed by the Transmission Provider, but the Market Participant shall not separately file an SSR Agreement. The Market Participant shall provide the Transmission Provider and the Independent Market Monitor with a copy of all compensation-related filings regarding a SSR-designated unit.

(ii) Any compensation for the SSR Unit will be reduced by payments for operation of the SSR Unit, according to the provisions in this Tariff. Monthly compensation under Schedule 2 of this Tariff and payments under resource adequacy programs (a percentage of such payments to a Market Participant whose generating unit designations are not made) shall be identified in the filing for compensation submitted by the Market Participant.

Hourly compensation will be provided for those hours in which the SSR Unit has Actual Energy Injections and the SSR Unit is committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or committed by the Transmission Provider in any of the RAC processes, or in the Look Ahead Commitment ("LAC") process, including any Reliability Assessment Commitment ("RAC") process conducted prior to the Day-Ahead Energy and Operating Reserve Market, in which hours the Transmission Provider shall calculate the Market Participants' Production Cost and Operating Reserve Cost. For the purposes of this calculation, "Production Cost" means the Energy output cost pursuant to Section 39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments of the Tariff for commitments by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or the Energy output cost pursuant to Section 40.2.19 Real-Time Sufficiency Guarantee of the Tariff for commitments by the Transmission Provider in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, of each SSR Unit based upon Start Up, No Load, and Energy Offer cost components that reflect the actual costs of physically operating the SSR Unit(s). "Operating Reserve Cost" mean the actual cost to provide Operating Reserves. All Production Costs and Operating Reserve Costs will be subject to audit by the Transmission Provider, and will be subject to audit and enforcement by the Independent Market Monitor.

Through the Transmission Provider settlement process, the Transmission Provider will compare the "SSR Unit Compensation," which (for each SSR Unit) is equal to the sum of Production Cost and Operating Reserve Cost, to the SSR Unit Energy, Operating Reserve Credit, and Short-Term Reserve. The SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit are those charges and credits calculated pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market, 40.3 Real Time Energy and Operating Reserve Market Settlement and 40.7 Determination of Inadvertent Energy of the Tariff, plus any revenues from Schedule 2 associated with the SSR Unit or from Planning Resource designation and any charges assessed through Schedule 17 and Schedule 24. In those hours where the SSR Unit Compensation is greater than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit for that SSR Unit, the Transmission Provider will make the applicable make-whole payment to Market Participant (such make-whole payment to be equal to the difference between the SSR Unit Compensation and the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit). In those hours where the SSR Unit Compensation is less than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit, the Transmission Provider will debit from Market

Participant (such debit to be equal to the difference between the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit and the SSR Unit Compensation). If the SSR Unit receives revenue pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market and 40.3 Real Time Energy and Operating Reserve Market Settlement of the Tariff in hours other than those described above, the Transmission Provider will debit those revenues from the Market Participant.

(iii) The Market Participant shall file with the Commission for a Monthly SSR Payment for compensation not covered by the hourly compensation stated in the previous sub-section. The Market Participant's filing shall state the requested Monthly SSR Payment along with its sub-components (including amounts for monthly Schedule 2 payments for each SSR Unit) and applicable cost support, including an affidavit executed by an officer of the Market Participant attesting to the accuracy of the submitted cost information. The Market Participant shall provide the Monthly SSR Payment information for each SSR Agreement, including any renewals of an SSR Agreement, and may update the information in a Section 205 filing to revise such Monthly SSR Payment following any material, unforeseen circumstances affecting the SSR Unit that changes the costs incurred by the Market Participant. The Transmission Provider shall pay the Market Participant the Monthly SSR Payment as directed by the Commission, commencing on the effective date established by the Commission.

The filing for the additional compensation should evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (1) operations and maintenance labor expenses directly related to the SSR Unit; (2) administrative expenses directly related to employees at the SSR Unit, including employee expenses environmental fees, safety and operator training, office supplies, communications, and plant inspection/testing expenses; (3) non-labor maintenance expenses, including chemical and materials consumed during maintenance of the SSR Unit and rental expenses for maintenance equipment used to maintain the SSR Unit; (4) taxes, permit and licensing fees, site security expenses, and insurance; (5) carrying charges**,** including charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operating unit decisions based on Good Utility Practice; (6) corporate expenses, including those incurred for legal services, environmental reporting, and procurement; (7) costs associated with capitalized projects; (8) depreciation, and (9) return on the undepreciated plant costs for the SSR Unit.

k. Termination of Interconnection Service.

Except as provided in Attachment X, the Transmission Provider shall file with the Commission to terminate the interconnection service to the Transmission Provider's system held by an owner of a Generation Resource or SCU or Pseudo-tied out Generator, that certifies by submitting an Attachment Y Notice that it plans to Suspend a Generation Resource or SCU or Pseudo-tied out Generator, upon the latter of: (1) the termination of an SSR Agreement; (2) the effective date for which the owner has elected to convert the Attachment Y Notice to retirement by waiving the right to rescind the decision; or (3) the end of the period for rescission for which the owner has not waived the right to rescind. Such termination of interconnection service shall be contained in a filing with the Commission and also posted by the Transmission Provider on its OASIS to the extent that such interconnection service was filed with the Commission, and shall otherwise be terminated by the Transmission Provider by a posting on its OASIS. If the owner rescinds or modifies the Attachment Y Notice in accordance with Section 38.2.7.d, the owner of such resource may retain its interconnection service and continue to operate after the conclusion of an SSR Agreement or the date specified in the Attachment Y Notice.

l. Allocation of SSR Unit Costs.

The costs pursuant to the SSR Agreement shall be allocated to the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes.

m. Annual Review of SSR Unit Status.

On at least an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider's annual regional transmission expansion plan in accordance with Attachment FF. If an SSR Unit continues to be required for reliability of the Transmission System, then the Transmission Provider will have the unilateral right to negotiate and enter into a subsequent SSR Agreement by providing the Market Participant at least ninety (90) days advance notice prior to the termination date of the existing SSR Agreement and by negotiating and filing a new SSR Agreement at the Commission. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will resume suspension in accordance with the Attachment Y Notice or Retire. Any subsequent SSR Agreement also shall be filed with the Commission.

n. Time Limitations on Suspension.

An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator may request suspension pursuant to the provisions of this Section 38.2.7 and remain for a maximum of thirty-six (36) cumulative months during any five (5) year period under any combination of suspended and SSR-designated statuses. An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator that had not exhausted its maximum period may request an additional suspension period by submitting a new Attachment Y Notice twenty-six (26) weeks prior to the effective date of the extension period, provided that the combined period is not greater than thirty-six (36) months in a five (5) year period. If a Generation Resource or a SCU or a Pseudo-tied out Generator does not return to service at the end of the thirty-six (36) month maximum suspension period, the Transmission Provider will terminate interconnection service of the resource pursuant to Section 38.2.7.

o. Non-Binding Informational Studies.

An owner of a Generation Resource or a SCU may complete an Attachment Y-2 to request that the Transmission Provider conduct a study to determine whether it is likely that a portion or all of such Generation Resource of SCU would qualify as an SSR Unit. The Transmission Provider will collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, will consult with a retained consultant to evaluate whether the facility is required for the reliability of the Transmission System. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend that the Transmission Provider transfers to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, or to any confidentiality obligations owed to Transmission Provider under the Tariff or related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner will not be bound to the change of status indicated in an Attachment Y-2 request. Along with a completed Attachment Y-2, such owner shall submit a study deposit of

$70,000 to the Transmission Provider for the reasonable costs and expenses of such study. The Transmission Provider shall invoice such owner for all costs and expenses incurred in addition to the deposit amount, or shall refund any unused portion of such deposit upon completion of the study.

The Transmission Provider will process multiple Attachment Y-2 requests in the order in which the Attachment Y-2 requests are received. The Transmission Provider shall use reasonable efforts to submit the results of such study to the owner upon its completion within 75 days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to. The Transmission Provider shall treat Attachment Y-2 as Confidential Information. If an owner rescinds an Attachment Y-2 study request, then such owner shall not receive the results of the study and the owner shall pay the Transmission Provider all of the costs incurred in conducting the study up until the date of such rescission.

Once a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly notify the Independent Market Monitor of any Resource that may qualify as an SSR Unit. The results of such study will provide the owner with the outcome if the owner elects to submit an Attachment Y Notice to request SSR status in the future and does so in accordance with Section 38.2.7.p.

The Transmission Provider shall maintain regional power flow models pursuant to Section I.C of Attachment FF, for use by the owner of a Generation Resource or a SCU choosing to conduct a study.

p. Submission of Attachment Y Notice Following Non-Binding Reliability Studies Under Y-2.

The Attachment Y Notice following a non-binding Y-2 request must be submitted at least 26 weeks prior to the date of the planned change of status. The Transmission Provider shall conduct the subsequent Attachment Y process consistent with timeline and milestones in Section 38.2.7.

q. Transition to New Attachment Y Framework.

The Attachment Y Conversion Period shall not apply to an Attachment Y Notice submitted prior to the effective date of the revision of the term “Suspend.” A subsequent decision to Suspend operation or Retire after the end date stated in such notice shall require a new Attachment Y Notice at least 26 weeks prior to the effective date of the new change of status.

The provisions contained in Section 38.2.7.e (“Refund of Costs”) that shall apply are those stated in the Tariff at the time an Attachment Y Notice was submitted to MISO.

Failure to comply with any of the requirements and/or provisions of this Tariff shall subject a Market Participant to such reasonable charges, penalties, or other remedies or sanctions for non-compliance as may be recommended by the Transmission Provider and implemented through appropriate Commission proceedings.

Generation Owners, Load Serving Entities, ARCs, and Electric Storage Resource Owners shall not be authorized to engage in Market Activities unless these entities are qualified as Market Participants. Generation Owners that do not intend to qualify as Market Participants, but intend to have the output of their Generation Resources available to the Transmission Provider, shall enter into agreements with Market Participants who will employ the output of the Generation Resources in support of the Market Participant's Generation Offers. Such Market Participant shall remain financially, and in all other respects liable, to the Transmission Provider for service(s) provided by the Generation Resource through the Energy and Operating Reserve Markets, pursuant to such arrangements. Load Serving Entities that do not intend to qualify as Market Participants, but intend to have their Load served through purchases in the Energy and Operating Reserve Markets, shall enter into agreements with Market Participants who may submit Demand Bids supported by the Load Serving Entities' Load. The Market Participant shall remain financially, and in all other respects, liable for any service(s) received pursuant to such arrangements. Load Serving Entities and ARCs that intend to Offer as Demand Response Resources shall fulfill the appropriate requirements of this Tariff. Generation Owners or Load Serving Entities that seek to Pseudo-tie generating units or load to an external Balancing Authority must execute the Pseudo-tie Agreement included as Attachment FFF-1 or Attachment FFF-2 to this Tariff, as applicable. Any executed Pseudo-tie Agreement must be approved by the Transmission Provider before it may be effective. An Electric Storage Resource Owner that does not intend to qualify as a Market Participant, but intends to have the output of its Electric Storage Resource available to the Transmission Provider, shall enter into agreements with a Market Participant who will employ the output of the Electric Storage Resources in support of the Market Participant's Electric Storage Resource Offers. Such Market Participant shall remain financially, and in all other respects, liable to the Transmission Provider for service(s) provided by the Electric Storage Resource through the Energy and Operating Reserve Markets, pursuant to such arrangements.

Market Participants may designate Scheduling Agents to conduct for them scheduling and scheduling support services. A Scheduling Agent shall not be authorized to settle with the Transmission Provider on the underlying transactions for which it provides scheduling or scheduling support services. Market Participants may designate MDMA to perform metering and metering data management services. An MDMA shall not be authorized to settle with the Transmission Provider on the underlying transactions for which it is providing support services. Market Participants may designate a Billing Agent to receive and make credits and debits for Settlement Statements issued by the Transmission Provider. The Market Participant shall remain financially, and in all other respects, liable for all statements received by the Billing Agent on behalf of the Market Participant. If a Market Participant is designated to serve as a Scheduling Agent, MDMA, and/or Billing Agent for another, or a group of other Market Participants, the Market Participant will be required to indicate which Market Participants shall settle with the Transmission Provider, and shall remain financially, and in all other respects, liable for the submitted transaction.

A Market Participant may submit Bids for its Load at its Commercial Pricing Node. The Commercial Pricing Node can include an aggregation of Elemental Pricing Nodes or a portion of Elemental Pricing Nodes all within a single Local Balancing Authority Area. The Transmission Provider will maintain a list of defined Elemental Pricing Nodes that comprise Customer Load Aggregations for the purpose of forming the aggregated Load Zone. Customer Load Aggregations will be settled using Ex Post LMPs for the associated Load Zone. Market Participants must submit Energy withdrawal data for Loads to the Transmission Provider using the same aggregations that were used in definition of the Load Zone. Market Participants can establish Customer Load Aggregations pursuant to the provisions set forth in the Business Practices Manuals and must schedule using the established Customer Load Aggregations Load Zone. Day-Ahead Schedules for Customer Load Aggregation shall be settled using the same Load Zone for the Customer Load Aggregation.

Market Participants submitting Demand Bids at the Load Zone for the Customer Load Aggregation must submit the same information in the same form as described in Section 39.2.2. Market Participants are responsible for submitting withdrawal data for each Commercial Pricing Node where they represent Load including consumption information for Commercial Pricing Nodes defined as Load Zones for Customer Load Aggregation. The Transmission Provider will, for Settlement purposes apply any calculated Residual Load in each Local Balancing Authority Area to the withdrawal data for the Residual Load Zone in that Local Balancing Authority Area.

ARCs can register DRR, LMR, and/or EDRs. The resource represented by an ARC will be associated with a Commercial Pricing Node.

A. Registration

i. <u>Information Requirements</u>

Market Participants can establish resources pursuant to the provisions set forth in the Business Practices Manuals. An end use customer account shall be registered as a DRR, LMR, or EDR by only one Market Participant. The Transmission Provider will maintain a list of defined Elemental Pricing Nodes making up the Commercial Pricing Node that comprise injections of customer demand response. Any initial registration of or changes to a DRR, LMR, or EDR that an ARC manages, will require the ARC to provide information to the Transmission Provider and may be subject to LSE and LBA confirmation and RERRA approval.

ARC registration will include but not be limited to the following information, for each resource:

- LSE serving the Load, with relevant contact information as set forth in the Business Practices Manuals.
- Applicable RERRA(s), with relevant contact information as set forth in the Business Practices Manuals.
- Local Balancing Authority Area where the Load is located, with relevant contact information as set forth in the Business Practices Manuals.
- Measurement and Verification procedures selection as specified in Attachment TT or Schedule 30.
- List of end use customer account number(s) and other relevant customer information,

including the Electric Distribution Company and/or LSE and related account number to identify the unique end use customer(s) comprising each demand asset to be offered by the ARC, as set forth in the Business Practices Manuals.

- Maximum level of participation (MW) and location of the DRR, LMR, or EDR being registered.

ii. <u>Process to identify double-counting</u>

The Transmission Provider will coordinate with relevant parties to assist in the review of information provided to determine whether such end use customer is currently registered in the Transmission Provider's markets as part of an existing resource, to avoid the potential of double-counting of such end use customer, as set forth in the Business Practices Manual. Proposed resources that include one or more end use customers already included in a registered resource with the Transmission Provider will be rejected.

iii. <u>Notifications and Approvals</u>

1. RERRA

(a) ARC certification

To establish eligibility for registration, the ARC must certify the following for each end use customer included in the DRR, LMR, or EDR.

a. Where the relevant utility distributed more than four million MWh in the prior fiscal year, an ARC must certify that the laws, regulations, or order(s) of the RERRA do not preclude the end use customer from participating directly in the Transmission Provider's Energy and Operating Reserve Markets, providing Capacity under RAR of the Tariff, or being used as an EDR resource. The ARC may also state whether the RERRA specifically permits such participation by the end use customer; or

b. Where the relevant utility distributed four million MWh or less in the prior fiscal year, an ARC must certify that the laws, regulations, or order(s) of the RERRA specifically permit the end use customer to participate directly in the Transmission Provider's Energy and Operating Reserve Markets, to provide Capacity under RAR of the Tariff, or to be used as an EDR resource.

If an ARC proposes to register the same end use customer(s) as multiple resource types, the Transmission Provider shall review each registration independently.

(b) RERRA notification and approval

The Transmission Provider will notify the RERRA(s) following the submission of a DRR, LMR, or EDR registration by an ARC. Such notification shall include the following information as relevant to each resource type: the ARC name, LSE name(s), resource type, end use customer account number(s), effective date and termination date and their maximum level of participation, subject to the appropriate protection of any Confidential Information. The Transmission Provider will wait ten (10) Business Days before approving such DRR, LMR, or EDR registration to allow an opportunity for the RERRA(s) to contest the ARC registration provided, however, a RERRA will be able to contest an ARC registration at any time.

RERRA(s) may elect to notify the Transmission Provider if applicable laws or regulations expressly prohibit (for A.iii.1.(a) above) or do not explicitly permit (for A.iii.1.(b) above) an end use customer's participation in the Transmission Provider's markets. Upon receipt of such a notification from the RERRA(s) for ARC registrations subject to section

A.iii.1(a) above, the Transmission Provider will reject the ARC's registration. In the event that Transmission Provider receives no such notification from the RERRA(s), the relevant section A.iii.1(a) ARC registration will not be rejected by Transmission Provider as a result. With respect to ARC registrations subject to section A.iii.1(b) above, the Transmission Provider will deem the ARC's registration rejected if the relevant RERRA(s) do not affirmatively notify Transmission Provider of acceptance within ten (10) days.

The Transmission Provider may continue to accept offers from the ARC, unless and until the Transmission Provider receives a notification from the RERRA that either (a) rejects the certification provided by the ARC, or (b) claims loss of eligibility of one or more end use customers included in a resource registered with the ARC. Upon receipt of such a notification, the Transmission Provider shall inform the ARC, which shall immediately cease to offer the portion of the resources based on end use customers deemed ineligible by the applicable RERRA. The ARC shall only be allowed to include in its offer such previously disqualified end use customers if the RERRA subsequently notifies the Transmission Provider that the ARC and relevant end use customers are eligible to participate. Offers tendered and cleared before the RERRA provides the Transmission Provider with notice of contested certification will be honored. Offers tendered and cleared after the RERRA provides the Transmission Provider with notice will not be honored by the Transmission Provider. For offers involving the PRA, once the PRA offer window closes all offers tendered will be deemed accepted by the Transmission Provider.

2. LBA and LSE or EDC

The LSE or EDC, and LBA will have access to relevant information used by the

Transmission Provider, subject to the appropriate protection of any Confidential Information. The DRR, LMR, or EDR information accessible to the LSE and LBA includes, but is not limited to, the following information as relevant to each resource type: ARC name, resource type, effective date, termination date, LBA name, LSE name(s), CPNode name, EPNodes that comprise the resource, Load Zone CPNode name, end use customer account number(s), meter identification number(s), maximum level of participation, Measurement and Verification methodology, coincident peak dispatch information for use in Peak Load Contribution calculations, and RERRA name.

Upon the submission of a new or change to a DRR, LMR or EDR for approval, the contact person(s) identified for the relevant LBA and LSE will receive notification requesting them to access the information provided and review their pending tasks. The Transmission Provider will provide the LBA and LSE ten (10) Business Days in total to take any necessary action(s). In the event that the LBA or LSE does not take action within ten (10) Business Days of being notified, the registration will be deemed approved by default. The tasks to be performed by the LSE and/or LBA shall be set forth in the Business Practices Manuals.

LBAs will work with the Transmission Provider to review the composition of CPNodes proposed by ARCs. The Transmission Provider will provide LBAs with access to the electrical location and magnitude of each resource registered by an ARC to perform operational planning studies. If the LBA takes no action, the EPNode will be assigned by the Transmission Provider. If the LBA confirms the DRR, then the LBA shall identify the EPNode assignment.

If the LSE takes no action, the Load Zone associated to the DRR, LMR, or EDR will be assigned by the Transmission Provider. If the LSE confirms the DRR, LMR, or EDR, then the

LSE shall identify or approve the Load Zone associated with the DRR, LMR, or EDR.

During the time that spans the date the ARC submits an addition of or change to a DRR, LMR, or EDR, and the time that the addition of or change to a DRR, LMR, or EDR is confirmed by both the LSE and LBA, whether explicit or by default, the addition of or change to a DRR, LMR, or EDR will be considered unapproved and therefore incapable of participating in the applicable Transmission Provider Markets.

If the LSE or LBA objects to the accuracy of relevant information provided in a new or updated DRR, LMR, or EDR registration, then the ARC may work with the relevant LSE or LBA to resolve the objection and re-submit the registration for the appropriate registration deadline. If the ARC and the LSE or LBA are unable to reach resolution, then the ARC may pursue Alternative Dispute Resolution in accordance with Attachment HH.

B. Market Activities

i. Demand Response Resources

Market Participants must participate using the established Commercial Pricing Node. The Transmission Provider will communicate the quantities of the DRRs cleared in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market to the ARC and the applicable LBA. The Transmission Provider will communicate the quantities of the DRRs cleared in the Planning Resource Auction to the ARC and the applicable LBA.

The Transmission Provider will provide the LBA in which a DRR has a Day-Ahead Schedule information including, but not limited to, the following: the name of the DRR CPNode and the MW quantity of the Day-Ahead Schedule for each DRR CPNode.

ii. Load Modifying Resources

The Transmission Provider will communicate the quantities of the LMRs cleared in the Planning Resource Auction to the ARC and the applicable LBA. The Transmission Provider will communicate the quantities of LMRs issued Scheduling Instructions to the applicable Local Balancing Authority when instituting Emergency procedures.

iii. Emergency Demand Response Resources

The Transmission Provider will communicate the quantities of EDR resources offered through Schedule 30 protocols to the applicable Local Balancing Authority when instituting Emergency procedures.

C. Metering

DRRs, LMRs, and/or EDR resources registered by ARCs must meet the metering requirements specified in Module C, Module E-1, Schedule 30, or Attachment TT, as applicable.

D. Settlements

i. Demand Response Resources

The ARC's day-ahead and real-time transactions will be settled using LMP and/or MCP, as applicable, for the Resource's Commercial Pricing Node, in accordance with Module C. ARCs must submit meter data for the DRR to the Transmission Provider using the same aggregations that were used in the definition of the asset.

The DRR settlement information can be viewed by the LSE and LBA via the Market Portal once the Hourly Ex Post LMPs are approved. The DRR settlement information accessible to the LSE and LBA via the Market Portal includes but is not limited to the: meter data, calculated baseline, MW reduction and hourly Dispatch Target for Energy.

The Transmission Provider shall review the participation of an ARC in the Energy and Operating Reserve Markets when the ARC's settlements are successfully disputed more than ten percent (10%) of the time by a relevant LSE.

The Transmission Provider shall have thirty (30) days to conduct a review pursuant to this Section. The Transmission Provider shall refer the matter to the RERRA, and may refer the matter to the Independent Market Monitor, if the review indicates the relevant ARC and/or LSE is engaging in activity that is inconsistent with the Energy and Operating Reserve Markets.

DRRs that clear the PRA will be settled in accordance with Module E-1.

ii. **<u>Load Modifying Resources</u>**

LMRs that clear the PRA will be settled in accordance with Module E-1.

iii. **<u>Emergency Demand Response Resources</u>**

EDRs will be settled as described in Schedule 30.

When Demand Response Resources are unable to provide demand response output telemetry to the Transmission Provider within specific submission deadlines, their participation in the Energy and Operating Reserve Markets will be subject to the provisions set forth for such Resources in Section 40.3.4.g.

The Transmission Provider will, for each Month, determine the Net Benefits Price Threshold in accordance with the following procedure.

1. The Transmission Provider will initially use historical hourly Real-Time Offers from all available Resources, excluding Demand Response Resources, to create price-quantity offer pairs reflective of the Transmission Provider's Aggregate Power Supply Curve using these offers in conjunction with an index to reflect Outages, and coal and natural gas fuel price data.

(i) Explanatory Variables

The Transmission Provider will develop a mathematical model based upon the econometric approach to determine the Net Benefits Supply Curve. The Transmission Provider will consider explanatory variables in determining the Net Benefits Supply Curve that affect short-term power supply. These variables shall include, but are not limited to, any variable that significantly impacts wholesale electricity prices, such as: fuel prices, the Resource Outage Index, environmental compliance costs, and the quantity of supply.

(ii) Exclusion of Explanatory Variables

The Transmission Provider may not include potential explanatory variables that are not statistically significant in the determination of Net Benefits Supply Curve if a statistical analysis results in the Transmission Provider being unable to reject the null hypothesis that the coefficient resulting from the econometric analysis is not significantly different from zero, at the five percent significance level.

(iii) Aggregate Power Supply Curve

The Transmission Provider will obtain price and quantity data by aggregating the Energy Offers made by Market Participants for their Resources. The Transmission Provider accepts

Energy Offers in pairs that include a given amount of Energy (MWh), and the minimum price for providing that amount of Energy. The Transmission will combine these Energy Offers to determine an Energy Offer curve for each Resource. After the Transmission Provider has determined an Energy Offer curve for each Resource, the Energy Offer curves for all Resources are combined to determine the aggregate amount of Energy offered to the market at any given price which represents the hourly Aggregate Power Supply Curve. The hourly Aggregate Power Supply Curves are averaged across the Operating Day to determine the daily Aggregate Power Supply Curve.

(iv) Net Benefits Supply Curve

The set of daily Aggregate Power Supply Curves and explanatory variables selected, as described above, are analyzed using econometric techniques. The result of this analysis is a mathematical representation of the relationship between Energy, LMP and the selected explanatory variables. This mathematical representation, when provided with input values for the selected explanatory variables and modeled graphically, is a Net Benefits Supply Curve in the Cartesian plane of wholesale electricity prices (LMP) and Energy offered. As such, the Net Benefits Supply Curve can then be examined to solve for the Net Benefits Price Threshold. Each month, updated values reflecting the most recent available information for the selected explanatory variables are input to the econometric results described above, resulting in a new representation of the Net Benefits Supply Curve. From each month's Net Benefits Supply Curve, the Net Benefits Price Threshold is determined.

2. The Transmission Provider will determine, prior to the 15th of each Month, the Net Benefits Price Threshold by using the Net Benefits Supply Curve. The Transmission Provider

shall post prior to the 15th of each Month: (1) the Aggregate Power Supply Curve analysis described in (1)(iv) above that is updated each Month; (2) the method used to determine the Net Benefits Price Threshold; (3) the Net Benefits Price Threshold for the next Month and the previous 12 Months; and (4) supporting documentation on its website.

An LSE that is a Market Participant that intends to submit Offers for demand response on behalf of eligible end use customers must register the asset. The demand response represented by a Market Participant shall be deemed an asset for which a Commercial Pricing Node will be established. The Transmission Provider will maintain a list of defined Elemental Pricing Nodes that comprise injections of customer demand response.

Market Participants can establish resources pursuant to the provisions set forth in the Business Practices Manuals and must schedule using the established Commercial Pricing Node. DRR registration by the LSE serving the Load will include but not be limited to the following information, for each resource: (i) LSE serving the Load; (ii) Local Balancing Authority Area where the Load is located; (iii) Measurement and Verification procedures; (iv) list of end use customer accounts that are part of the Demand Response Resources being registered, including names and addresses of such end use customers; and (v) maximum level of participation of each registered asset.

DRR information will be made available to the LBA as soon as an addition of or change to a DRR is submitted for approval. The DRR information will be provided by the LSE and accessible to the LBA including, but is not limited to, the following type of information: resource type, DRR owner name, DRR effective date, DRR termination date, LBA name, LSE name, DRR Commercial Pricing Node name, LSE Commercial Pricing Node name, address, load reduction capability, Measurement and Verification methodology, EPNodes that comprise the DRR, and the load reduction method.

The DRR settlement information can be viewed by the LSE and/or LBA via the Market Portal once the Hourly Ex Post LMPs are approved. The DRR settlement information accessible to the LSE and LBA via the Market Portal includes but is not limited to the: meter data, calculated baseline, MW reduction and hourly Dispatch Target for Energy.

Process to identify double-counting: The Transmission Provider will coordinate with relevant parties to assist in the review of information provided to determine whether such retail customer is currently registered as part of an existing demand asset, to avoid the potential of double-counting of such demand asset, as set forth in the Business Practices Manual. Proposed demand assets that are already registered with the Transmission Provider will be rejected.

The Transmission Provider will reject demand assets that are double-counted.

The Transmission Provider will provide the LBA in which a DRR has a Day-Ahead Schedule information including, but will not be limited to, the following information: the name of the DRR CPNode and the MW quantity of the Day-Ahead Schedule for each DRR CPNode.

All parties to Grandfathered Agreements that choose to maintain such agreements and not convert to Transmission Service under this Tariff shall be subject to the following provisions. Carved-Out GFAs shall be subject to Section 38.8.4 of this Tariff.

a. Parties to Grandfathered Agreements shall inform the Transmission Provider who will be the GFA Responsible Entity, within the time frame set forth in Section 38.2.5.i.

b. The GFA Responsible Entity must be a fully qualified Market Participant under this Tariff.

c. The GFA Responsible Entity shall be financially responsible pursuant to the applicable GFA for:

   i. All Market Activities charges, as well as all charges under Schedules 16 and 17;

   ii. All Transmission Usage Charges caused by the applicable transactions; and

   iii. Any debits or credits associated with ARRs or FTRs held by the GFA Responsible Entity.

a. All entities operating pursuant to Grandfathered Agreements shall designate a GFA Scheduling Entity within the time frame set forth in Section 38.2.5.i. The GFA Scheduling Entity shall submit GFA Schedules consistent with the provisions set forth herein for any sales and/or purchases of Energy pursuant to the Grandfathered Agreement.

b. The GFA Scheduling Entity responsible for submitting such GFA Schedules shall either be the GFA Responsible Entity or a Scheduling Agent designated by the GFA Responsible Entity.

Market Participant Applicants that are party to Grandfathered Agreement(s) and intend to maintain service under such agreements shall select one of three options for scheduling and settlement of Costs of Congestion and Costs of Losses resulting in the Day-Ahead Energy and Operating Reserve Market and shall so notify the Transmission Provider in writing:

a. Option A.

i. Treatment of ARRs and FTRs: The GFA Responsible Entity shall be entitled to nominate the Capacity under the Grandfathered Agreement(s) for allocation of ARRs pursuant to the procedures set forth in Section 43.1.2. The GFA Responsible Entity shall be allocated ARRs, shall hold the ARRs and shall be responsible for all credits, debits, rights, and responsibilities associated with the ARR(s) as set forth in Section 42. The GFA Responsible Entity may self-schedule the ARRs in the annual FTR Auction to convert the ARRs to FTRs.

ii. Treatment of Transmission Congestion: The Transmission Provider shall charge the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to Dispatch Instruction or Day-Ahead Schedules based on the designated Internal Delivery Points or GFA Schedule Receipt Points and GFA Schedule Delivery Points for the Grandfathered Agreement(s), as set forth in Section 39.3.3 and 40.4.

iii. Treatment of Transmission Losses: The GFA Responsible Entity shall be assessed the Cost of Losses for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Points or GFA Schedule Receipt Point and GFA Schedule Delivery Point, as set forth in Section 39.3.3 and 40.4.

b. Option B.

i. Treatment of ARRs and FTRs. The GFA Responsible Entity will not nominate or receive ARRs nor be eligible for conversion of FTRs in the annual FTR Auction for the Capacity under the GFA, but will instead receive a refund of the Cost of Congestion resulting from the Day-Ahead Schedules cleared in the Day-Ahead Energy and Operating Reserve Market. The GFA Responsible

Entity shall be responsible for the Transmission Provider's administrative costs associated with accounting for the ARRs and FTRs under this option as set forth in Schedule 16 of this Tariff.

ii. Treatment of Transmission Congestion. The Transmission Provider shall charge the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Point or the GFA Schedule Receipt Point and the GFA Schedule Delivery Point under the Grandfathered Agreement(s) but shall credit back the full amount of the Cost of Congestion resulting from Day-Ahead Schedules cleared in the Day-Ahead Energy and Operating Reserve Market to the GFA Responsible Entity. This refund will only be provided if the GFA Scheduling Entity submits a GFA Schedule according to the procedures specified in Section 39.1.4 for the Day-Ahead Energy and Operating Reserve Market for the Grandfathered Agreement transaction(s) prior to the closing of the Day-Ahead Energy and Operating

Reserve Market, consistent with the Internal Delivery Point or, the GFA Schedule Receipt Point and the GFA Schedule Delivery Point, and within the maximum MW Capacity permissible under the Grandfathered Agreement. In the event that there results a revenue inadequacy, the Transmission Provider shall fully compensate the GFA Responsible Entity for the Costs of Congestion. The revenue inadequacy shall be funded through an assessment of debits on all Market Participants on a *pro-rata* basis, based on their Market Load Ratio Share. The Transmission Provider shall account for Grandfathered Agreements under Option B in the Annual ARR Allocation and annual FTR Auction processes, but shall not actually allocate ARRs or assign FTRs to the GFA Responsible Entity. The Transmission Provider shall not provide a preference to ARRs or FTRs associated with Option B Grandfathered Agreements held by the Transmission Provider.

iii. Treatment of Transmission Losses. The Transmission Provider shall charge the GFA

Responsible Entity the Cost of Losses for all transactions under the Grandfathered Agreement based on the designated Internal Delivery Point or GFA Schedule Receipt Point and GFA Schedule Delivery Point, as set forth in Section 39.3.3 and 40.4. The Transmission Provider shall credit back to the GFA Responsible Entity the difference between Marginal Losses and System Losses at the designated Internal Delivery Points or GFA Schedule Receipt Point and GFA Schedule Delivery Point. The difference between Marginal Losses and System Losses shall be determined by dividing the amount of Marginal Losses for a transaction by two (2), consistent with the procedures described in the Business Practices Manuals. This refund will only be provided if the GFA Scheduling Entity submits a transaction for the Grandfathered Agreement transaction(s) the day prior to the Operating Day, consistent with the source and sink point and within the maximum MW Capacity permissible under the Grandfathered Agreement. GFA Responsible Entities that receive such reimbursement for GFA transactions shall not receive an allocation of the Local Balancing Authority Marginal Losses Surplus Share.

c. **Option C.**

i. Treatment of ARRs and FTRs. The GFA Responsible Entity will not nominate nor receive an allocation of ARRs nor be eligible for conversion to FTRs in the annual FTR Auction for the Capacity under the GFA.

ii. Treatment of Transmission Congestion. The Transmission Provider shall charge the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Points, or GFA Schedule Receipt Point and GFA Schedule Delivery Points for the Grandfathered Agreement(s), as set forth in Section 39.3.3 and 40.4.

iii. Treatment of Transmission Losses: The GFA Responsible Entity shall be assessed the Marginal Losses Component for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Points, or the GFA Schedule Receipt Point and GFA Schedule Delivery Point, as set forth in Section 39.3.3 and 40.4. GFA Responsible Entities receiving such assessment for Marginal Losses shall receive an allocation of excess marginal losses revenue based on the Marginal Losses Surplus Share.

Treatment of Grandfathered Agreements Added to Attachment P of the Tariff:

Grandfathered Agreements added to Attachment P of the Tariff after September 16, 2004 shall be subject to the following treatment:

a. Grandfathered Agreements subject to a just and reasonable standard of review must choose:

   i. Option A or Option C treatment under the Tariff; or

   ii. Full conversion to service under the Tariff.

b. Grandfathered Agreements shall be carved out of the Energy and Operating Reserve Markets, and shall be subject only to Section 38.8.4 of the Tariff, to the extent that:

   i. They are subject to the public interest standard of review;

   ii. They are silent on the applicable standard of review; or

   iii. They provide for transmission service by an entity that is not a public utility.

However, parties to Carved-Out Grandfathered Agreements may voluntarily choose Option A or Option C treatment under the Tariff, or fully convert to service under the Tariff, as described in Section 38.8.3A.a above. Parties that make such a choice or conversion cannot revert to carved-out status. Notwithstanding the foregoing, carved-out treatment under this paragraph b shall not be available to Grandfathered Agreements added to Attachment P of the Tariff effective on or after November 1, 2009, that involve service to an Affiliate or an owner-member of the Transmission Owner. Option A or Option C treatment shall be available to parties to such Grandfathered Agreements.

Carved-Out GFAs shall be subject to the following requirements and be entitled to the following treatment.

The parties to Carved-Out GFAs shall provide the Transmission Provider with the data required to administer and implement the terms of this Section 38.8.4, including information with respect to the billing entity, the entity responsible for providing scheduling of Energy, the entity responsible for providing scheduling of Operating Reserve, if applicable, the specific Resources that will be providing Regulating Reserve, Spinning Reserve and/or Supplemental Reserve to meet the Carved-Out GFA Operating Reserve obligations, if applicable, GFA number, OASIS page and OASIS Transmission Service Reservation number, maximum Capacity, Commercial Pricing Node source(s), and sink(s), total Capacity for each such Carved-Out GFA and any other necessary information required by the Transmission Provider. All LSEs located in the Transmission Provider's Balancing Authority Area, including the parties to Carved-Out GFAs, and agreements administered as Carved-Out GFAs, shall comply with all RAR. Unless otherwise agreed by the parties to a Carved-Out GFA, the billing entity is the Transmission Owner or ITC Participant.

The maximum Capacity associated with each Carved-Out GFA shall be reflected in Transmission Provider's FTR allocation model in a manner that reflects expected transmission usage under Carved-Out GFAs. The Transmission Provider shall not provide a preference to ARRs or FTRs associated with Carved-Out GFAs.

The parties to Carved-Out GFAs shall provide the Transmission Provider with non-binding Day-Ahead Schedules under such Agreements and non-binding Day-Ahead Schedules for Regulating Reserve, Spinning Reserve and/or Supplemental Reserve under such Agreements, if applicable, in accordance with the Day-Ahead Energy and Operating Reserve Market close timelines set forth in Section 39.2.9 of the Tariff. The information provided shall include: Generation Offer, Regulating Capacity Offer or Self-Schedule, Regulating Mileage Offer, Spinning Reserve Offer or Self-Schedule and/or Supplemental Reserve Offer or Self-Schedule, and Demand Bid information as well as relevant data on transactions involving Carved-Out GFAs in the form of a tag entered into the Transmission Provider's schedule system and into the Interchange Distribution Calculator. Carved-Out GFA schedules and Generation Offers, Regulating Capacity Offers or Self-Schedules, Regulating Mileage Offer, Spinning Reserve Offers or Self-Schedules and/or Supplemental Reserve Offers or Self-Schedules submitted in the Day-Ahead Energy and Operating Reserve Market may be updated in the Real-Time Energy and Operating Reserve Market according to the provisions set forth in Section 40.2.3 of the Tariff. The difference between the Day-Ahead and Real-Time schedules associated with Carved-Out GFAs shall be excluded from the Real-Time energy and Operating Reserve imbalance settlement of the pertinent generation or load asset. Where necessary, tags shall be curtailed using applicable TLR procedures.

Carved-Out GFA schedules and related Offers and/or Self-Schedules shall be incorporated into the RAC and the LAC processes in the same manner as other schedules.

Carved-Out GFAs must observe Real-Time scheduling requirements established in Section 40.2.3. Where generation schedules, Load and cleared Operating Reserve schedules are balanced in Real-Time, deviations from Day-Ahead Schedules resulting in Real-Time transmission schedule imbalance and/or real-time Operating Reserve schedule imbalance shall not clear in the Real-Time spot market. Where Load and generation are not balanced in Real-Time, excess generation over Load or excess Load over generation will settle as a spot Energy sale or purchase at the Hourly Real-Time Ex Post LMP. Where cleared Regulating Reserve, cleared Spinning Reserve and cleared Supplement Reserve on GFA Resources is less than the Carved-Out GFA's Regulating Reserve, Spinning Reserve and Supplemental Reserve Obligations, the Carved-Out GFA billing entity will be charged for a spot purchase of the shortfall in accordance with Schedules 3, 5 and 6. Generation schedules related to Carved-Out GFAs are subject to the settlement provisions set forth in Section 40.3.4 of this Tariff.

Except as otherwise set forth in this Section 38.8, Carved-Out GFAs or agreements administered as Carved-Out GFAs shall not be subject to any charges under this Tariff except Schedules 3, 5, 6, 10, 17, 18, and 51 charges. Parties to Carved-Out GFAs or agreements administered as Carved-Out GFAs shall be subject to Capacity Deficiency Charges in Section 69A.10.

Carved-Out GFAs shall be subject to monitoring by the IMM, and to the provisions of the Tariff incorporating Market Behavior Rule 2.

The treatment of the Grandfathered Agreements and Carved-Out GFAs as set forth in this Section 38.8.5 shall terminate no earlier than February 1, 2008, and thereafter upon acceptance by the Commission of new provisions governing treatment of GFAs. No later than twenty-four (24) months prior to February 1, 2008, the Transmission Provider shall begin its evaluation of the impact on the Energy Market and comparable access to Transmission Service related to the optional treatments available to Grandfathered Agreements. No later than twelve (12) months prior to February 1, 2008, the Transmission Provider shall file a new proposal for treatment of the remaining Grandfathered Agreements.

Access to Confidential Information by Market Participants and Others.

a) Non-Disclosure of Confidential Information. No Market Participant shall have a right hereunder to receive or review any documents, data, or other information of another Market Participant, including documents, data, or other information provided to the Transmission Provider, to the extent such documents, data, or information have been designated as confidential pursuant to the procedures adopted by the Transmission Provider specified in the Business Practices Manuals, or to the extent that they have been designated as confidential by such other Market Participant; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based on such confidential documents, data, or information if the composite does not disclose any individual Market Participant's Confidential Information.

b) Confidential Information Procedures. Except as otherwise provided in Sections 38.9, 54.3 and 54.4 of this Tariff, the Transmission Provider shall not disclose to Market Participants or to third parties, any documents, data, or other information of a Market Participant or a Market Participant Applicant, to the extent such documents, data, or other information has been designated as Confidential Information pursuant to the procedures adopted by the Transmission Provider specified in the Business Practices Manuals, or by such Market Participant, or Market Participant Applicant; provided, however, that third parties requesting disclosure of information designated as "Confidential Information" may challenge the designation pursuant to procedures specified in the Business Practices Manuals; provided, further, that nothing contained herein shall prohibit the Transmission Provider from providing any such Confidential Information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality. The Transmission Provider shall collect and use Confidential Information only in connection with its authority under this Tariff and the retention of such information shall be in accordance with the Transmission Provider's data retention policies.

c) Authorization by Market Participant to Release its Confidential Information.

Nothing contained herein shall prevent the Transmission Provider from releasing a Market Participant's Confidential Information to a third party provided that the Market Participant has delivered to the Transmission Provider specific, written authorization for such release setting forth:

i. the data or information to be released;

ii. to whom such release is authorized; and

iii. the period of time for which such release shall be authorized (including a period specified as ending with withdrawal of authorization).

The Transmission Provider shall limit the release of a Market Participant's Confidential Information to that specific authorization received from the Market Participant. Nothing herein shall prohibit a Market Participant from withdrawing such authorization upon written notice to the Transmission Provider who shall cease such release as soon as practicable after receipt of such withdrawal notice.

Disclosure of Certain Confidential Market Participant Data to Balancing Authorities, Transmission Operators; other Regional Transmission Organizations or Independent System Operators; and Interstate Natural Gas Pipeline Operators, Natural Gas Local Distribution Companies, and/or Intrastate Natural Gas Pipeline Operators.

Nothing contained herein shall prevent the Transmission Provider from providing certain reliability-related Market Participant Confidential Information to the entities described in this Section 38.9.1(A) to the extent that the Transmission Provider determines, in its reasonable discretion, that the provision of such information is required to enhance and/or maintain reliability within the Transmission Provider Region and its neighboring Balancing Authority Areas, consistent with the Balancing Authority Agreement; and any such receiving entity is bound by a written agreement to maintain such confidentiality as set forth below. Such reliability-related Confidential Information shall be limited to the following data that the Transmission Provider utilizes to arrive at its market and reliability solutions:

a) Data That May Be Provided to Local Balancing Authorities. The Local Balancing Authority shall receive data as specified in Section 4.6 of the Balancing Authority Agreement, subject to the confidentiality provisions specified in Section 9 of the Balancing Authority Agreement;

b) Data That May Be Provided to Transmission Operators. To enable them to perform local reliability analysis, Transmission Operators shall be provided with the following hourly information for their respective operational areas and adjacent areas, updated with each execution of RAC; provided that the Transmission Operator enters into a written agreement, substantially in the form of Attachment Z (Non-Disclosure and Confidentiality Agreement) of this Tariff to maintain the confidentiality of such information. The Transmission Provider's staff shall work with the Transmission Operators to determine the format of the data provided (portal reports, XML, or both):

i. MISO Balancing Authority Load Forecast;

ii. Commitment status (each Generator);

iii. Day-Ahead Schedules for all Resources;

iv. Total Generation within applicable area assumed available for the RAC based upon Offers;

v. Forecast commitment status used so that the Transmission Operator can determine what units are anticipated to be offline but available for the remaining part of the day; and

vi. Binding constraints that impact the MISO Balancing Authority Area;

c) Data That May Be Provided to another Regional Transmission Organization or Independent System Operator. Nothing contained herein shall prohibit the Transmission Provider or its designated agents, representatives, or contractors from providing to another Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"), upon their request, the complete electronic tags ("e-Tags") of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) for intra-region transactions and interchange transactions scheduled to flow into, out of or through the Transmission Provider's region, to the extent such RTO or ISO has requested such information as part of its investigation of possible market violations or market design flaws, to the extent that such RTO or ISO is bound by a tariff provision requiring that the e-Tag data be maintained as confidential or, in the absence of a tariff requirement governing confidentiality, a written agreement with the Transmission Provider consistent with FERC Order No. 771 and any clarifying orders and implementing regulations; and

d) Data That May Be Provided to Interstate Natural Gas Pipeline Operators, Natural Gas Local Distribution Companies, and/or Intrastate Natural Gas Pipeline Operators. To the extent permitted pursuant to 18 C.F.R. § 38.2 (as may be amended from time to time), nothing contained herein shall prevent the Transmission Provider from providing non-public, operational information for the purpose of promoting reliable service or operational planning to the following entities, subject to a receiving entity being bound by the appropriate written non-disclosure agreement(s) with the Transmission Provider to maintain the confidentiality of the information:

i. Interstate natural gas pipeline operators.

ii. Natural gas local distribution companies and/or intrastate natural gas pipeline operators, as appropriate, provided that Confidential Information regarding a specific generator will be shared only with the pipeline(s) directly serving that generator.

The written non-disclosure agreement shall prohibit the receiving entity from illegal and non-legitimate use of the non-public, operational information. This prohibition includes the use of anyone as a conduit for disclosure of non-public, operational information received from the Transmission Provider to a third party or to the receiving entity’s marketing function employees, or use of such information in an unduly discriminatory or preferential manner, or to the detriment of any natural gas and/or electric market. Any non-public, operational information the

Transmission Provider receives from the above entities pursuant to this section shall also be subject to the confidentiality protection provisions set forth in Section 38.9 and other relevant provisions of this Tariff.

e) **Form of Data.** The foregoing Confidential Information may also be provided by MISO in any other appropriate electronic or similar form(s) or format(s) that may be developed in the future.

Required Disclosure Other than for Commission Proceedings or Investigations.

a) Notwithstanding anything in Section 38.9.1 to the contrary, and subject to the provisions of Section 38.9.3 and Section 38.9.4, if a Market Participant or the Transmission Provider is required by applicable law, or in the course of administrative or judicial proceedings other than Commission proceedings or investigations, to disclose to third parties other than the Commission or its staff, information that is otherwise required to be maintained in confidence pursuant to this Tariff, that Market Participant or the Transmission Provider may disclose such information. As soon as the Market Participant or the Transmission Provider learns of the disclosure requirement and prior to making disclosure, that Market Participant or the Transmission Provider shall notify the affected Market Participant(s) of the requirement and the terms thereof and the affected Market Participant(s) may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement.

The disclosing Market Participant and the Transmission Provider shall cooperate with such affected Market Participant(s) to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law.

Each Market Participant and the Transmission Provider shall cooperate with the affected Market Participant(s) to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

b) Nothing in this Section 38.9 shall prohibit or otherwise limit the Transmission Provider's use of information covered herein if such information was: (i) previously known to the Transmission Provider without an obligation of confidentiality; (ii) independently developed by or for the Transmission Provider using non-Confidential Information; (iii) acquired by the

Transmission Provider from a third party which is not, to the Transmission Provider's knowledge, under an obligation of confidence with respect to such information; and (iv) which is or becomes publicly available other than through a manner inconsistent with this Section 38.9.

c) The Transmission Provider shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation or administration of this Tariff a contractual duty of confidentiality consistent with the provisions of this Tariff. A Market Participant shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Transmission Provider shall not provide any information designated as confidential pursuant to this Tariff to any such contractor without the express written permission of the Market Participant providing the information.

d) Section 38.9.2.a) does not apply to disclosure of information to an agency/organization or the staff of an agency/organization that is the subject of Section 38.9.3.a).

Disclosure to Specified Agencies/Organizations.

a) Specified Agencies/Organizations and Treatment of Confidential Information.

Notwithstanding any provisions of this Section 38.9 to the contrary:

i. If the Commission, the Commodity Futures Trading Commission (‘CFTC”), or the staff of one of those agencies, during the course of an investigation or otherwise, requests information from the Transmission Provider that is otherwise required to be maintained in confidence pursuant to this Tariff, the Transmission Provider shall provide the requested information to the agency or its staff within the time provided for in the request for information. Should the Transmission Provider require additional time to provide the information requested due to logistical matters such as the volume of information requested or technical complexity involved, the Transmission Provider will promptly communicate that need to the individual requesting the information and they shall establish the time for production of the requested information.

ii. The Transmission Provider may provide information that is otherwise required to be maintained in confidence pursuant to this Tariff to any federal agency that has cyber-security responsibilities under federal law and/or regulations for the protection of entities outside the federal agency itself, such as the National Cyber Communication Information Center (“NCCIC,” part of the Department of Homeland Security), or the federal agency’s staff to the extent that the Transmission Provider determines, in its reasonable discretion, that the provision of such information responds to a Cyber Exigency. The Transmission Provider will provide the information subject to agreement that the federal agency may only share Confidential Information with agencies/organizations in the U.S. Government that have cybersecurity responsibilities. The Transmission Provider shall, after consultation with a federal agency with which information was shared in response to a Cyber Exigency, notify by appropriate means and to the extent deemed advisable for purposes of preserving Transmission System reliability the entities that provided information to the Transmission Provider that was shared with the federal agency.

iii. The Transmission Provider may provide information that is otherwise required to be maintained in confidence pursuant to this Tariff to the ERO, a Regional Entity, or the staff of one of those agencies/organizations to the extent that the Transmission Provider determines, in its reasonable discretion, that the provision of such information will enhance or maintain reliability within the Transmission Provider Region or neighboring Balancing Authority Areas.

Paragraphs a)i through and a)iii above shall apply to the specified agencies/organizations and their successor agencies/organizations.

b) Request for Confidential Treatment.

The Transmission Provider shall request that the information submitted to the agencies/organizations as provided in part a) of this section or their staffs be treated as confidential and non-public, and that the information be withheld from public disclosure, consistent with Applicable Laws and Regulations as well as other applicable policies or procedures of the agency/organizations that receives the information.

c) General Provision for Release of Information to Third Parties.

The Transmission Provider shall promptly notify, by appropriate means, the entities that submitted the requested Confidential Information when it receives from an agency/organization specified in part a) of this section or their staffs a request for disclosure to a third party that is not an agency/organization of the U.S. Government of Confidential Information that was previously provided to the agency/organization by the Transmission Provider.

d) Electronic Delivery of Confidential and Non-Public Data to the Commission

The Transmission Provider shall electronically deliver to the Commission, on a confidential and ongoing basis, in a form and manner consistent with its own collection of data, and which is acceptable to the Commission, certain confidential and non-public data related to the markets the Transmission Provider administers.

Nothing contained herein shall prevent the Transmission Provider from releasing a Market Participant's Confidential Information or information to a third party provided that the Market Participant has delivered to the Transmission Provider specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Transmission Provider shall limit the release of a Market Participant's Confidential Information to that specific authorization provided from the Market Participant. Nothing herein shall prohibit a Market Participant from withdrawing such authorization upon written notice to the Transmission Provider who shall cease such release as soon as practicable upon receipt of the written notice.

Notwithstanding anything in this Section to the contrary, the Transmission Provider and/or IMM shall only disclose Confidential Information, otherwise required to be maintained in confidence pursuant to this Tariff, to an Authorized Requestor solely under the following conditions:

a. The Authorized Requestor has executed a Non-Disclosure Agreement with the Transmission Provider, stating:

i. the position he or she holds within or the relationship he or she has with the Authorized Agency for which he or she will be an Authorized Requestor;

ii. that he or she is authorized to enter into and perform the obligations of the Non-Disclosure Agreement;

iii. that the relevant Authorized Agency has practices or procedures adequate to protect against the unauthorized release of any Confidential Information received pursuant to the Non-Disclosure Agreement;

iv. that he or she is familiar with, and will comply with, any applicable practices or procedures of the Authorized Agency which the Authorized Requestor represents; and

v. that he or she is not in breach of any Non-Disclosure Agreement entered into with the Transmission Provider.

b. The Transmission Provider will verify that the Authorized Agency employing or retaining the Authorized Requestor has provided the Transmission Provider with the following information pursuant to Section 2.2 of Attachment EE (Form of Non-Disclosure Agreement for Authorized Requestors):

i. a list of statutory authority, obligation or duty establishing or specifying the particular Authorized Agency's duty, responsibility or authority in fulfillment of which it will make requests to the Transmission Provider or the IMM under this Section for information, including, but not limited to, that enumerated and described as available to the IMM in Module D of this Tariff; or, in the case of the Organization of MISO States ("OMS"), an order of the Commission prohibiting the release of Confidential Information by the Organization of MISO States, except in accordance with the terms of the Non-Disclosure Agreement; provided, that, Offers of Proof that state commissions or the OMS filed in FERC Docket No. ER04-691-024 and No. EL04-104-023 shall be deemed *prima facie* evidence of such statutory authority, obligation, duty or responsibility;

ii. a statement notifying and identifying to the Transmission Provider that the Authorized Agency has practices or procedures in place adequate to protect against the unauthorized release of Confidential Information; and

iii. confirmation in writing that the Authorized Requestor is authorized by the Authorized Agency to enter into the Non-Disclosure Agreement and to receive Confidential Information under this Tariff.

c. In fulfilling the verification required by Subsection (b) immediately above, the Transmission Provider shall be able to rely conclusively upon either an order of such Authorized Agency or a certification from counsel to such Authorized Agency, confirming that the Authorized Agency: (i) has statutory authority, or in the case of the OMS is in receipt of and bound by the Commission Order referred to in Subsection (b)(i) above, to protect the confidentiality of any Confidential Information received pursuant to the Non-Disclosure Agreement from public release or disclosure and from release or disclosure to any other entity, including other agencies of state government, except to the extent that such disclosure is required or permitted by state law; (ii) except as provided in Subsection (d) below, will defend against any disclosure of Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders; (iii) will provide the Transmission Provider with prompt notice of any such Third Party Request or legal proceedings and will consult and cooperate with the Transmission Provider and/or any

Affected Participant in its efforts to deny the Third Party Request or defend against such legal process; (iv) in the event a protective order or other remedy is denied, will direct Authorized Requestors authorized by it to furnish only that portion of the Confidential Information that their legal counsel advises MISO in writing is legally required to be furnished; (v) will exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information; (vi) has adequate practices or procedures in place to protect against the release of such Confidential Information; and (vii) has authorized the Authorized Requestor to enter into the Non-Disclosure Agreement and to receive Confidential Information pursuant to the Tariff and under the Non-Disclosure Agreement, and can provide a written copy of such authorization.

d. The certification from counsel for the Authorized Agency referred to in Subsection (c)(ii) above must affirmatively disclose any state law that will prohibit or prevent the Authorized Agency from defending against any disclosure of Confidential Information pursuant to any Third Party Request as otherwise required by

Subsection (c)(ii). In an instance where there is such a state law disclosed, such certification shall confirm that the Transmission Provider would have notice of the Third Party Request and standing to pursue legal processes, including the obtaining of a protective order, before the forum in which state law prohibits or prevents the Authorized Agency from taking such actions itself.

The Transmission Provider shall maintain a schedule of all Authorized Requestors and the Authorized Agencies they represent, which shall be made available on its website or by written request. The schedule shall include phone numbers and e-mail addresses. Such schedule shall be compiled by the Transmission Provider, based on information provided by any Authorized Requestor and/or Authorized Agency. The Transmission Provider shall update the schedule promptly upon receipt of information from an Authorized Requestor or Authorized Agency, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Transmission Provider in the compilation and/or maintenance of the schedule.

The Authorized Requestor shall use the Confidential Information solely for the purpose of assisting an Authorized Agency in discharging its duty, responsibility or authority in fulfillment of which it authorizes Authorized Requestors to make requests for Confidential Information and for no other purpose. Any and all Authorized Requestors sponsored by the same Authorized Agency may have access to the Confidential Information that is provided to the sponsoring Authorized Agency pursuant to an Information Request.

a. The Transmission Provider or the IMM may, in the course of discussions with an Authorized Requestor or Authorized Requestors in meetings or teleconferences, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Requestors or their Authorized Agency to determine whether additional Information Requests are appropriate. The Transmission Provider or the IMM will not make any written or electronic disclosures of Confidential Information to the Authorized Requestor pursuant to this section. In any such discussions, the Transmission Provider or the IMM shall ensure that the individual or individuals receiving such Confidential Information are Authorized Requestors, orally designate Confidential Information that is disclosed, and refrain from identifying any specific Affected Participant whose information is disclosed. The Transmission Provider or IMM shall also be authorized to assist Authorized Requestors in interpreting Confidential Information that is disclosed.

The Transmission Provider or the IMM shall provide any

Affected Participant with oral notice of any oral disclosure promptly, but not later than one (1) business day after the oral disclosure. Such oral notice to the Affected Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Information of any other entity and must be received by the Affected Participant before the name of the Affected Participant is released to the Authorized Requestor; provided, however, the identity of the Affected Participant must be made available to the Authorized Requestor within two (2) business days of the initial oral disclosure.

(a) **Form:** Information Requests to the Transmission Provider or the IMM shall be in writing, and shall include electronic communications addressed to the Transmission Provider or to the IMM as appropriate.

(b) **Content:** Each Information Request shall describe, in as much detail as possible, the particular information sought, including the time period for the requested information; provide a description of the purpose for which the information is being sought and state the time period for which it is expected that the information will need to be retained by the Authorized Requestor.

(c) **Notice:**

(i) The Transmission Provider or the IMM shall provide an Affected Participant with notice of and a copy of an Information Request by an Authorized Requestor as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) The Affected Participant shall have three (3) additional Business Days from the date of the notice that an Information Request has been received to provide, to the IMM and the Transmission Provider, written information which the Affected Participant believes will provide context to the information sought by the Information Request. The Transmission Provider or the IMM will include the contextual statement with the information provided to the Authorized Requestor.

(iii) The Transmission Provider shall maintain all Information Requests of a general nature in an electronic form accessible by Market Participants and Authorized Requestors. Such list shall not include those Information Requests that sought information of or about a named Market Participant or that would, in the Transmission Provider's view, otherwise be readily ascertainable as being directed toward Confidential Information from or about an individual Market Participant. On at least an annual basis the Transmission Provider shall delete from the list all Information Requests for which the Confidential Information has been returned or destroyed by the Authorized Requestor.

(d) **Disclosure:** Subject to the provisions of Section 38.9.4.5(c)(ii) and Section 38.9.4.5(f) and (g) below, the Transmission Provider or the IMM shall supply the information sought to the Authorized Requestor in response to any Information Request within five (5) Business Days after the receipt of the Information Request, or within such longer period as may be specified by the Information Request, unless a timely objection has been made to the Information Request, or unless the requested information can only reasonably be made available within an extended time period.

To the extent that the Transmission Provider or the IMM cannot reasonably prepare and deliver the requested information within the five (5) Business Day period or any longer period specified in the Information Request, it shall, within such period, hold discussions with the Authorized Requestor and provide the Authorized Requestor with a mutually agreed upon written schedule for the provision of such remaining information. Upon providing the requested information to the Authorized Requestor, the Transmission Provider or the IMM shall provide a copy of the disclosed information to the Affected Participant(s), or provide a listing of the Confidential Information disclosed; provided, however, that the Transmission Provider or the IMM shall not reveal any Affected Participant's Confidential Information to any other Market Participant.

(e) **Objection:** Notwithstanding Section 38.9.4.5(d) above, should the Transmission Provider, the IMM or an Affected Participant object to an Information Request or any portion thereof, any of them or the Authorized Requestor may, within four (4) Business Days following the Transmission Provider's or the IMM's receipt of the Information Request, request, in writing, a conference with the Authorized Agency, or the Authorized Agency's Authorized Requestor, to resolve differences concerning the scope or time period covered by the Information Request; provided, however, nothing herein shall require the Authorized Agency to participate in any conference.

Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then the Transmission Provider, the Affected Participant or the Authorized Agency may initiate appropriate legal action at FERC within three (3) Business Days following receipt of written notice from any participant refusing or terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding.

If no FERC proceeding regarding the Information Request is commenced within such three-day period, the Transmission Provider or the IMM shall respond to the Information Request within five (5) Business Days or any longer period that may be specified by the Information Request, counted from the expiration of such three-day period.

(f) **Opportunity to Respond to Confidentiality Claims:** If the Affected Participant, the Transmission Provider or the IMM considers the information sought by the Information Request as Confidential Information, the Authorized Requestor shall be provided an opportunity to challenge the designation or classification of the requested information as Confidential Information.

(g) **Limitation On Disclosure Obligation:** The Transmission Provider or the IMM shall not be required to make disclosure in response to an Information Request in circumstances where an electronic data link, dedicated communication circuit or other hardware or third party services would be necessary to effectuate the disclosure. Nor shall the Transmission Provider or the IMM be required to make disclosure in response to an Information Request that is of a scope or extent materially similar to the flow of data from Market Participants to the Transmission Provider or from the Transmission Provider to the IMM.

Authorized Requestors who are parties to Non-Disclosure Agreements but who are sponsored by different Authorized Agencies may discuss Confidential Information with each other, provided that:

(a) They have each requested and received from the Transmission Provider or the IMM such Confidential Information;

(b) At least one of such Authorized Requestors notifies the Transmission Provider in advance of the identity of the other Authorized Requestor(s) with whom such Confidential Information will be discussed; and

(c) The Transmission Provider confirms that the Authorized Requestors who will participate in the discussion received the Confidential Information as provided in Subsection (a) above. The Transmission Provider shall respond to a notification under Subsection (b) above within two (2) business days from receipt of the notification.

The Transmission Provider shall provide an Affected Participant with notice of the planned discussion within two (2) business days from receipt of notification of the planned discussion. Such discussion among Authorized Requestors shall not change the status of the Confidential Information. It shall remain Confidential Information.

In the event of any breach of a Non-Disclosure Agreement:

a. The Authorized Requestors and/or their respective Authorized Agency shall promptly notify the Transmission Provider or the IMM, who shall, in turn, promptly notify any Affected Participant of any unauthorized release of Confidential Information provided pursuant to any Non-Disclosure Agreement. Upon notification, the Transmission Provider will cease disclosure to the Authorized Requestor pursuant to any Information Requests and will make no disclosure pursuant to any Information Request pending from the Authorized Requestor until it can be determined after consultation with the Authorized Requestor, his or her Authorized Agency and the Affected Participant that an appropriate combination of the following factors justifies resumption of the Authorized Requestor's access to Confidential Information: (i) the unauthorized disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Requestor (ii) there was no harm or economic damage suffered by the Affected Participant; (iii) there are now practices or procedures in place adequate to prevent a recurrence of the unauthorized disclosure; and/or (iv) similar good cause shown.

b. If the Transmission Provider or the IMM receives from an Authorized Requestor or Authorized Agency a written notice that a breach has occurred, or FERC has made a ruling that a breach has occurred, the Transmission Provider and/or, the IMM shall terminate the Non-Disclosure Agreement and require either the immediate return of all Confidential Information obtained by the Authorized Requestor pursuant to the Non-Disclosure Agreement or a certification of its destruction. The Transmission Provider shall verify the breach in consultation with the Authorized Agency. If it is subsequently determined that there was no breach, or if otherwise justified by circumstances described in Subsection (b) above, the Transmission Provider shall restore the status of the Authorized Requestor. Any other rights and remedies shall be pursuant to the terms of the Non-Disclosure Agreement.

c. No Authorized Requestor, who is an employee of an Authorized Agency, shall have responsibility or liability whatsoever under the Non-Disclosure Agreement or this Tariff for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of Confidential Information to persons not authorized to receive it. However, nothing in this Section 38.9.4.7.c is intended to limit the liability of any person who is not an employee of or a member of an Authorized Agency, to the degree not granted limitations as to liability under applicable state law of the Authorized Agency's state, when such a person is under contract to perform services for the Authorized Agency, for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

ENERGY AND OPERATING RESERVE MARKET PROCESSES AND SETTLEMENTS

Day-Ahead Energy and Operating Reserve Market Processes and Settlements

The Day-Ahead Energy and Operating Reserve Market is a forward and financially-binding market in which (i) cleared Day-Ahead Schedules for Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve, (ii) Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs for Energy, and (iii) Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Operating Reserves, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve are calculated for each Hour of the next Operating Day based on submitted Bids and Offers using SCUC, SCED, and SCED-Pricing as set forth herein.

The clearing and pricing of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market is based on a simultaneous co-optimization process which minimizes the total costs of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve to meet the Transmission Provider Region requirements.

The SCED simultaneous co-optimization process ensures: (i) that all Day-Ahead Ex Ante LMPs and Day-Ahead Ex Ante MCPs for each Resource supplying Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve through economic clearing are greater than or equal to the corresponding Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve costs respectively when the resource is not scheduled at a limit. Such Energy, Operating Reserve, Up Ramp Capability, Down Ramp

Capability, and Short-Term Reserve costs are equal to the corresponding Energy, Operating Reserve, and/or Off-Line Short-Term Reserve Offers for the Resource plus any Opportunity Costs incurred from any reductions in the sale of an alternative product; (ii) available Regulating Reserve in excess of requirements can be used to meet Contingency Reserve requirements, where only the Regulating Capacity Offer will be taken into account for the portion of Regulating Reserve used to meet Contingency Reserve requirements, and available Spinning Reserve in excess of requirements can be used to meet Supplemental Reserve requirements, provided that Regulating Reserve cleared on Stored Energy Resources cannot be used to meet Contingency Reserve requirements; and (iii) Day-Ahead Ex Ante MCPs for Regulating Reserve are greater than or equal to Day-Ahead Ex Ante MCPs for Spinning Reserve and Day-Ahead Ex Ante MCPs for Spinning Reserve are greater than or equal to Day-Ahead Ex Ante MCPs for Supplemental Reserve, provided that Day-Ahead Ex Ante MCPs for Regulating Reserve may be less than or equal to Day-Ahead Ex Ante MCPs for Spinning Reserve in the event that all Regulating Reserve is cleared by Stored Energy Resources.

SCED-Pricing, as described in Schedule 29A of this Tariff, uses simultaneous co-optimization to calculate Day-Ahead Ex Post LMPs and Day-Ahead Ex Post MCPs. SCED-Pricing allows Fast Start Resources that are committed by the Transmission Provider that are scheduled at limits by SCED to set Day-Ahead Ex Post Prices at their locations. In instances where SCED indicates Energy or Reserve Scarcity or the violation of transmission constraints, SCED-Pricing may set prices by reflecting the cost of committing an off-line Fast Start Resource.

Day-Ahead Energy and Operating Reserve Market Trading Deadline:

No later than the close of the Day-Ahead Energy and Operating Reserve Market, (1) Market Participants, including GFA Scheduling Entities and Market Participants with SSR Units, must submit to the Transmission Provider any Interchange Schedules, Bids for the purchase of Energy; Self-Schedules and/or Offers for the sale of Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, and Short-Term Reserve; and Offer Dispatch Status for Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for consideration in the Day-Ahead Energy and Operating Reserve Market; and (2) Market Participants must indicate for each Hour of the Operating Day if Resources are to be self-committed or economically committed. The Day-Ahead Energy and Operating Reserve Market shall close at 1030 hours EPT, or such later time as may be required from time to time due to unanticipated events, the Day before the Operating Day. The Transmission Provider may extend or reopen the Day-Ahead Energy and Operating Reserve Market based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive or process Bid, Offer, or Interchange Schedule data; (ii) render Bid, Offer, or Interchange Schedule data plainly inaccurate in a manner that is likely to significantly impede the Transmission Provider's ability to deliver a feasible market solution; or (iii) are otherwise likely to have a widespread negative impact on the results of the Day-Ahead Energy and Operating Reserve Market, in a manner that adversely threatens or affects the reliability of market operations or of the Transmission System. The Transmission Provider shall post a notice of any extension or reopening of the Day-Ahead Energy and Operating Reserve Market. The notice shall state each extension or reopening's circumstances, rationale, duration, and whether such action enabled the Transmission Provider to successfully address or minimize the issue that necessitated the extension or reopening.

a. Designated Capacity Resource Obligation – Energy, Contingency Reserve, and Short-Term Reserve.

Consistent with Section 69A.5, Market Participants with designated Capacity Resources must submit, for any portion of a Resource designated as a Capacity Resource, a Self-Schedule or Offer for Energy, Contingency Reserve, and an Offer for Short-Term Reserve. Such Offers shall be consistent with the requirements specified in this Section and in the Business Practices Manuals. This designated Capacity Resource must-Offer obligation, as specified in RAR, applies to the Day-Ahead Energy and Operating Reserve Market, except to the extent that the designated Capacity Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with this Tariff.

b. Transitional Designated Capacity Resource Obligation – Regulating Reserve

Market Participants with designated Capacity Resources must submit, for any portion of a Resource designated as a Capacity Resource, an Offer for Regulating Reserve if a Regulation Qualified Resource, provided that, such must-offer requirement shall terminate one hundred and eighty (180) days after the implementation of the Energy and Operating Reserve Markets. Such Offers shall be consistent with the requirements specified in this Section and in the Business Practices Manuals. This transitional obligation applies to the Day-Ahead Energy and Operating Reserve Market, except to the extent that the designated Capacity Resource is unable to provide Regulating Reserve due to a forced or planned outage or other physical operating restrictions consistent with this Tariff.

c. Non-designated Capacity Resource Obligation

A Market Participant shall not have the obligation to Offer for Energy and Operating Reserve into the Energy and Operating Reserve Markets for any portion of a Resource not designated as a Capacity Resource.

Market Participants may submit Self-Schedules for Energy and/or Operating Reserve from their Resources, in whole or in part, in the Day-Ahead Energy and Operating Reserve Market. Market Participants that submit Self-Schedules for Energy are required to submit a MWh quantity and the applicable Hour for each Self-Scheduled Resource. Market Participants that submit Self-Schedules for Operating Reserve are required to submit a MW quantity and the applicable Hour for each Self-Scheduled Resource. Market Participants that submit Self-Schedules for Energy and/or Operating Reserve are Price Takers for each Self-Schedule. Self-Schedules for Energy must be greater than or equal to the Hourly Economic Minimum Limit and less than or equal to the Hourly Economic Maximum Limit. Self-Schedules for Regulating Reserve must be greater than or equal to one (1) MW for each Self-Scheduled Resource and can only be submitted for Regulation Qualified Resources. Self-Schedules for Spinning Reserve must be greater than or equal to one (1) MW for each Self-Scheduled Resource and can only be submitted for Spin Qualified Resources. Self-Schedules for Supplemental Reserve must be greater than or equal to one (1) MW for each Self-Scheduled Resource and can only be submitted for Supplemental Qualified Resources that are not also Spin Qualified Resources or for Supplemental Qualified Resources that are Quick Start Resources that are uncommitted. The acceptance of Self-Schedules for a specific Self-Scheduled Resource will be contingent on: (i) the commitment of the Self-Scheduled Resource; and (ii) compliance with the corresponding Self-Scheduled Resource limit and ramping constraints as set forth in Schedule 29. If a Self-Schedule is accepted by the Transmission Provider, the Resource Schedules for Energy and Operating Reserve may clear above the Self-Scheduled amounts based on the submitted Offers, as needed, in an economic manner based upon the simultaneously co-optimized solution. The

Transmission Provider may reduce Self-Schedules as necessary to manage transmission constraints, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. In no case will the Transmission Provider violate the Resource limits.

Resources may not self-schedule Up Ramp Capability, Down Ramp Capability, or Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market.

Financial Schedules may be submitted at any time prior to 1200 hours EST six (6) Calendar Days after the Operating Day. The Transmission Provider is not the Energy Market Counterparty to the sale of Energy under a Financial Schedule transaction. The Financial Schedule shall include:

i. Identification of the Market Participants included in the Financial Schedule;

ii. The Energy and Operating Reserve Market in which the Financial Schedule will be settled, using either the Day-Ahead Ex Post LMPs or Hourly Real-Time Ex Post LMPs; and

iii. The scheduled volume in MWh for each Hour of the Financial Schedule.

Rules for Interchange Schedules to be Considered in Day-Ahead Energy and Operating Reserve Market:

Interchange Schedules include Import Schedules, Export Schedules and Through Schedules. Import Schedules need not be accompanied by reservations of Point-To-Point Transmission Service on the Transmission System, if supported by Network Integration Transmission Service or submitted pursuant to a Grandfathered Agreement. Export Schedules, not submitted pursuant to a Grandfathered Agreement or an individual Coordinating Owners coordination agreement regarding reciprocity provisions with regard to transmission service must be accompanied by reservation of Point-To-Point Transmission Service on the Transmission System. Through Schedules must be accompanied by reservations of Point-To-Point Transmission Services, unless the Transmission Service is provided according to the terms of a Grandfathered Agreement, for segments within the Transmission Provider Region. Interchange Schedules must be submitted by 1030 hours EPT of the Day prior to the Operating Day if they are to be considered for clearing, pricing and settlement in the Day-Ahead Energy and Operating Reserve Market.

a. **Validation of Interchange Schedules.** Interchange Schedules must be validated by the Transmission Provider to ensure a Transmission Service reservation exists and the Interchange Schedule can be supported. The Transmission Provider must have confirmed the accepted Interchange Schedules with the appropriate Interchange Authorities and Market Participants prior to 1030 hours EPT or the Interchange Schedule will be rejected.

b. **Types of Interchange Schedules.** There are three (3) types of Interchange Schedules that can be cleared and settled through the Day-Ahead Energy and

Operating Reserve Market: Fixed Interchange Schedules, Dispatchable Interchange Schedules, and Up-to-TUC Interchange Schedules.

i. Fixed Interchange Schedules are used by Market Participants to schedule fixed amounts of Energy in the Day-Ahead Energy and Operating Reserve Market at a specific Interface. Market Participants that submit these Fixed Interchange Schedules are Price Takers for the amount of the schedule.

ii. Dispatchable Interchange Schedules are used by Market Participants to specify a Bid or Offer, expressed in $/MWh, for specific amounts of Energy in the Day-Ahead Energy and Operating Reserve Market at a specific Interface. Bids or Offers for Dispatchable Interchange Schedules may not exceed the Energy Offer Hard Price Cap.

iii. Up-to-TUC Interchange Schedules are used by Market Participants to specify a maximum Transmission Usage Charge, expressed in $/MWh, beyond which the Market Participant agrees to be curtailed. The maximum Transmission Usage Charge the Market Participant can specify is $25/MWh.

By 1330 hours EPT, or such later time as may be required from time to time due to unanticipated events, on the Day prior to the Operating Day, the Transmission Provider shall post, based on the market clearing results of the Day-Ahead Energy and Operating Reserve Market, the: (i) Day-Ahead Schedules for Energy for each Resource, Load Zone, Interchange Schedule and Virtual Transaction, and (ii) Day-Ahead Schedules for Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for each Resource. All Day-Ahead Schedules shall be considered proprietary, with the posting only visible to entities authorized by the Market Participant, subject to the Commission's applicable standards of conduct. The Day-Ahead Schedules for Energy shall consist of twenty-four (24) hourly values for each Resource, Load Zone, Interchange Schedule and Virtual Transaction, and the Day-Ahead Schedules for Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve shall consist of twenty-four (24) Hourly values for each Resource. Also at 1330 hours EPT, or such later time as may be required from time to time due to unanticipated events, of the Day prior to the Operating Day, the Transmission Provider will post the Day-Ahead Ex Ante LMP (including the Marginal Congestion Component and the Marginal Losses Component) for each Commercial Pricing Node; the Day-Ahead Ex Ante Regulating Reserve MCP, Ex Ante Spinning Reserve MCP, Ex Ante Supplemental Reserve MCP, Ex Ante Up Ramp Capability MCP, Ex Ante Down Ramp Capability MCP, and Ex Ante Short-Term Reserve MCP for each Resource, in each Hour of the Day-Ahead Energy and Operating Reserve Market as determined pursuant to the procedures set forth in Section 39.2.9. Between 1330 and 1630 hours EPT, or such later time as may be required from time to time due to unanticipated events, on the Day prior to the Operating Day, the Transmission Provider will post the Day-Ahead Ex Post LMP (including the Marginal Congestion Component and the Marginal Losses Component) for each Commercial Pricing Node, the Day-Ahead Ex Post Regulating Reserve MCP, Ex Post Spinning Reserve MCP, Ex Post Supplemental Reserve MCP, Ex Post Up Ramp Capability MCP, Ex Post Down Ramp Capability MCP, and Ex Post Short-Term Reserve MCP for each Resource, in each Hour of the Day-Ahead Energy and Operating Reserve Market as determined pursuant to the procedures set forth in Section 39.2.9.

The Transmission Provider in its role as the Energy and Operating Reserve Market Operator shall provide the following services for the Day-Ahead Energy and Operating Reserve Market.

a. Establish and post on the internet rules for eligibility to supply and purchase Energy, to supply Operating Reserve, to supply Up Ramp Capability, to supply Down Ramp Capability, and to supply Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market.

b. Establish and post on the internet procedures, including Bid and Offer rules, to supply and purchase Energy, to supply Operating Reserve, to supply Up Ramp Capability, to supply Down Ramp Capability, and to supply Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market

c. Provide the Settlement functions associated with the purchase and sale of Energy, Operating Reserve, Up Ramp Capability, to supply Down Ramp Capability, and to supply Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market.

d. Calculate and post on the internet the Day-Ahead Schedules, Day-Ahead Ex Ante LMPs, Day-Ahead Ex Post LMPs, Day-Ahead Ex Ante MCPs, and Day-Ahead Ex Post MCPs.

e. Calculate and post on the internet the Market-Wide Regulating Reserve Requirements, the Market-Wide Spinning Reserve Requirements, the Market-Wide Supplemental Reserve Requirements, and the Market-Wide Short-Term Reserve Requirements.

f. The Market-Wide Up Ramp Capability Requirements and Market-Wide Down Ramp Requirements are dynamically calculated and will be posted along with the posting of the results of the Day-Ahead Energy and Operating Reserve Market.

a. Market-Wide Regulating Reserve Product Requirements.

All cleared Regulating Reserve in the Day-Ahead Energy and Operating Reserve Market must be deployable in both the regulation-up and regulation-down directions within the Regulation Response Time consistent with the Resource limit and ramping constraints as set forth in Schedule 29.

The Regulation Response Time will be determined and/or adjusted by the Transmission Provider on a periodic basis to comply with Applicable Reliability Standards. The day-ahead Market-Wide Regulating Reserve Requirement will be established each day by the Transmission Provider to comply with Applicable Reliability Standards in an economic manner. The day-ahead Market-Wide Regulating Reserve Requirement may vary on an Hourly basis if permitted by the Applicable Reliability Standards. All Regulating Reserve cleared in the Day-Ahead Energy and Operating Reserve Market must be supplied by Regulation Qualified Resources. The percentage of Regulating Reserve cleared in the Day-Ahead Energy and Operating Reserve Market on any individual Generation Resource, Demand Response Resource – Type II, Stored Energy Resource, Stored Energy Resource – Type II and/or External Asynchronous Resources shall initially be limited to twenty percent of the hourly day-ahead Market-Wide Regulating Reserve Requirement to the extent that such limitation does not create Regulating Reserve scarcity conditions or any other adverse reliability related conditions, and may be further limited on specific Demand Response Resources – Type II based on Applicable Reliability Standards.

b. Market-Wide Contingency Reserve Product Requirements.

All cleared Contingency Reserve in the Day-Ahead Energy and Operating Reserve Market must be deployable within the Contingency Reserve Deployment Period. The day-ahead Market-

Wide Contingency Reserve Requirement will be set by the Transmission Provider to comply with Applicable Reliability Standards in an economic manner. The day-ahead Market-Wide Contingency Reserve Requirement may vary on an Hourly basis if permitted by Applicable Reliability Standards. All Market-Wide Spinning Reserve cleared in the Day-Ahead Energy and Operating Reserve Market must be supplied by Spin Qualified Resources. All Market-Wide Supplemental Reserve cleared in the Day-Ahead Energy and Operating Reserve Market must be supplied by Supplemental Qualified Resources. The day-ahead Market-Wide Spinning Reserve Requirement will be equal to the Market-Wide Contingency Reserve Requirement multiplied by the greater of (i) the minimum frequency responsive Contingency Reserve percentage requirement in accordance with Applicable Reliability Standards, if applicable, or (ii) the minimum Spinning Reserve percentage requirement specified by Applicable Reliability Standards. The day-ahead Market-Wide Supplemental Reserve requirement will be equal to the day-ahead Market-Wide Contingency Reserve Requirement minus the day-ahead Market-Wide Spinning Reserve Requirement. The percentage of Spinning Reserve and/or Supplemental Reserve cleared in the Day-Ahead Energy and Operating Reserve Market on any individual Resource shall initially be limited to twenty percent of the hourly day-ahead Market-Wide Contingency Reserve Requirement to the extent that such limitation does not create scarcity conditions or any other adverse reliability related conditions, and may be further limited on Demand Response Resource–Type I and/or Demand Response Resources–Type II based on Applicable Reliability Standards.

c. Co-optimized Zonal Operating Reserve Product Requirements. In the Day-Ahead Energy and Operating Reserve Market, one or more Reserve Zones will be established to ensure

Regulating Reserve, Contingency Reserve, and Short-Term Reserve are dispersed in a manner that prevents adverse operating conditions that affect the reliability of the Transmission System in accordance with Good Utility Practice. Reserve Zone Configuration Studies will be performed, as described under Section 39.2.1A.d, on a quarterly basis, in conjunction with the update of the Network Model, except as provided for under Section 39.2.1A.f. Reserve Zone Configuration Studies will establish the number of Reserve Zones and the assignment of Resource, Load and/or Interface Elemental Pricing Nodes to specific Reserve Zones concurrent with the update of the Network Model until the next scheduled update of the Network Model and results will be available electronically to Market Participants through downloadable files no less than two (2) days prior to the effective date. Post Reserve Deployment Constraints within the co-optimized formulation as described in Schedule 29 and Schedule 29A will determine (i) the Co-optimized Zonal Regulating Reserve Requirements for each Reserve Zone, (ii) the Co-optimized Zonal Contingency Reserve Requirements for each Reserve Zone, (iii) the Co-optimized Zonal Spinning Reserve Requirements for each Reserve Zone, and (iv) the Co-optimized Zonal Short-Term Reserve Requirements for each Reserve Zone. In order to enforce the Market-Wide Regulating Reserve Requirement in the Day-Ahead Energy and Operating Reserve Market, the cleared Regulating Reserve in one or more Reserve Zones may exceed the corresponding Co-optimized Regulating Reserve Requirement for that Reserve Zone when necessary. In order to enforce the Co-optimized Zonal Operating Reserve Requirements in the Day-Ahead Energy and Operating Reserve Market, the cleared Market-Wide Operating Reserve may exceed the Market-Wide Operating Reserve Requirement when necessary. In order to enforce the Market-Wide Operating Reserve Requirement in the Day-Ahead Energy and Operating Reserve Market, the cleared Operating Reserve in one or more Reserve Zones may exceed the corresponding Co-optimized Operating Reserve Requirement for that Reserve Zone when necessary. In order to enforce the Market-Wide Short-Term Reserve Requirement in the Day-Ahead Energy and Operating Reserve Market, the cleared Short-Term Reserve in one or more Reserve Zones may exceed the corresponding Co-optimized Short-Term Reserve Requirement for that Reserve Zone when necessary.

d. Reserve Zone Configuration Studies.

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

i Utilizing a Network Model representation within the Reserve Zone study software for the target study period, identify all transmission constraints that could occur through Resource re-dispatch. Transmission constraint identification will consider projected system demands and planned generation and transmission outages for the period.

ii The list of transmission constraints identified under (i) above is then screened to limit the applicable transmission constraints to only those that will have a significant impact on the Reserve Zone determination based on projected system demands and planned generation and transmission outages for the period.

iii Once a final set of transmission constraints is identified under ii above, Resource, Load, and/or Interface Elemental Pricing Nodes are grouped based on similar impact on all of the remaining transmission constraints. The groups of Resource, Load and Interface Elemental Pricing Nodes represent the Reserve Zones. All remaining Resource, Load and Interface Elemental Pricing Nodes not assigned specifically through the Reserve Zone Configuration Study shall be assigned to a separate Reserve Zone and the minimum Contingency Reserve requirement of such Reserve Zone shall be equal to zero (0) MW.

e. Reserve Zone Reconfiguration.

The Transmission Provider may adjust the number of Reserve Zones and/or the assignment of Resource, Load and/or Interface Elemental Pricing Nodes to specific Reserve Zones as required if: 1) a condition or event occurs, including, but not limited to, an unplanned transmission facility outage, a Generator Forced Outage, or an event of Force Majeure, as defined in Section 10.1 of this Tariff; 2) such condition or event results in an adverse reliability condition that cannot be resolved through normal operating procedures; 3) such condition or event has a projected duration of two or more Operating Days and; 4) the Transmission Provider determines such adjustment is necessary to ensure the reliability of the Transmission System. The duration of any such adjustment will coincide with the duration of the condition or event, or until the next quarterly Reserve Zone Configuration Study update, whichever is less. The Transmission Provider will publish notice identifying the reasons for any such Reserve Zone adjustment, and the expected duration thereof. The Transmission Provider shall provide prior notice before the Day-Ahead Energy and Operating Reserve Market trading deadline for the Operating Day for any such Reserve Zone adjustment.

f. Reserve Zone Supply Limitation on Stored Energy Resources.

Regulating Reserve cleared on Stored Energy Resources will be ineligible to satisfy Reserve Zone Operating Reserve requirements.

g. Product Requirements for Up Ramp Capability and Down Ramp Capability.

The Market-Wide Up Ramp Capability Requirements and Market-Wide Down Ramp Capability Requirements represent the need for Resources with ability to adjust their power outputs consistent with the Resource limit and ramping constraints as set forth in Schedule 29 to respond to anticipated requirements which are projected from observed Real-Time Market-Wide Up Ramp Capability Requirements and Real-Time Market-Wide Down Ramp Capability Requirements. Up Ramp Capability and Down Ramp Capability MCPs and analysis of reliable delivery within transmission constraints incorporate the same Reserve Zones defined for Operating Reserve.

i. Market-Wide Up Ramp Capability Product Requirements.

The day-ahead Market-Wide Up Ramp Capability Requirement will be established each day by the Transmission Provider to estimate the hourly average Up Ramp Capability that will be required in the Real-Time Energy and Operating Reserve Market for the operating Hour. The day-ahead Market-Wide Up Ramp Capability Requirement may vary on an Hourly basis. All Up Ramp Capability cleared in the Day-Ahead Energy and Operating Reserve Market must be supplied by Up and Down Ramp Capability Qualified Resources. The percentage of Up Ramp Capability cleared in the Day-Ahead Energy and Operating Reserve Market on any individual Generation Resource, Demand Response Resource – Type II, Stored Energy Resource – Type II, or External Asynchronous Resources shall initially be limited to twenty percent of the hourly day-ahead Market-Wide Up Ramp Capability Requirement to the extent that such limitation does not create Up Ramp Capability shortages or any other adverse reliability related conditions. This individual Resource percentage limit may be adjusted by the Transmission Provider to improve reliability, system operations, and/or market efficiency.

ii. Market-Wide Down Ramp Capability Product Requirements.

The day-ahead Market-Wide Down Ramp Capability Requirement will be established each day by the Transmission Provider to estimate the hourly average Down Ramp Capability that will be required in the Real-Time Energy and Operating Reserve Market for the operating Hour. The day-ahead Market-Wide Down Ramp Capability Requirement may vary on an Hourly basis. All Down Ramp Capability cleared in the Day-Ahead Energy and Operating Reserve Market must be supplied by Up and Down Ramp Capability Qualified Resources. The percentage of Down Ramp Capability cleared in the Day-Ahead Energy and Operating Reserve Market on any individual Generation Resource, Demand Response Resource – Type II, Stored Energy Resource – Type II, or External Asynchronous Resources shall initially be limited to twenty percent of the hourly day-ahead Market-Wide Down Ramp Capability Requirement to the extent that such limitation does not create Down Ramp Capability shortages or any other adverse reliability related conditions. This individual Resource percentage limit may be adjusted by the Transmission Provider to improve reliability, system operations, and/or market efficiency.

h. Product Requirements for Short-Term Reserve.

All cleared Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market must be capable of real-time deployment within the Short-Term Reserve Deployment Period. All Short-Term Reserve cleared in the Day-Ahead Energy and Operating Reserve Market must be supplied by Short-Term Reserve Qualified Resources.

i. Market-Wide Short-Term Reserve Requirements.

The Day-Ahead Market-Wide Short-Term Reserve Requirements will be established each day by the Transmission Provider. The Day-Ahead Market-Wide Short-Term Reserve Requirements may vary on an Hourly basis.

ii. Sub-Regional Short-Term Reserve Requirements.

The Day-Ahead Sub-Regional Short-Term Reserve Requirements will be established as necessary for a sub-region for the operating Hour to establish the required Short-Term Reserve needed to be dispatched as Energy to restore flows within limits following contingencies or abnormal events. Sub-Regional Short-Term Reserve Requirements will be derived from rampable Capacity needs, Energy schedules, and contractual constraints, such as the Sub-Regional Power Balance Constraints, to ensure deliverability. Short-Term Reserve cleared to meet Sub-Regional Short-Term Reserve Requirements will also count towards the Market-Wide Short-Term Reserve Requirements.

iii. Local Short-Term Reserve Requirements.

The Day-Ahead Local Short-Term Reserve Requirements will be established as necessary for a Reserve Zone for the operating Hour to establish the required

Short-Term Reserve needed to be dispatched as Energy to restore flows within limits following contingencies or abnormal events. Local Short-Term Reserve Requirements will be derived from rampable Capacity needs, Energy schedules, and transmission constraints to ensure deliverability. Short-Term Reserve cleared to meet Local Short-Term Reserve Requirements will also count towards applicable Sub-Regional Short-Term Reserve Requirements and the Market-Wide Short-Term Reserve Requirements.

The qualification requirements set forth below allow Regulating Reserve to serve as Spinning Reserve or Supplemental Reserve, and Spinning Reserve to serve as Supplemental Reserve. Accordingly, when it is more economic to do so, the Transmission Provider may make any of the following substitutions: Regulating Reserve for Spinning Reserve, Regulating Reserve for Supplemental Reserve, or Spinning Reserve for Supplemental Reserve.

A. Regulation Qualified Resources.

All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market shall meet all of the requirements for Regulation Qualified Resources specified in this Section. Only Regulation Qualified Resources will be permitted to supply Regulating Reserve in the Day-Ahead Energy and Operating Reserve Market. All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Regulation Qualified Resources. All Resources, except Stored Energy Resources, registered as Regulation Qualified Resources must also be registered in the Energy and Operating Reserve Markets as Spin Qualified Resources and as Supplemental Qualified Resources, to allow cleared on-line Regulation Qualified Resources to supply Spinning Reserve or Supplemental Reserve through substitution of such Resources for Spin Qualified Resources or Supplemental Qualified Resources. All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area, or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of automatically responding to and alleviating frequency deviations through a speed governor or similar device in accordance with the Applicable Reliability Standards. All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of supplying Regulating Reserve for a minimum continuous duration of sixty (60) minutes. The Regulating Reserve Deployment on a Stored Energy Resource or Stored Energy Resource – Type II shall not exceed the energy storage capabilities of such Resource. All Regulation Qualified Resources supplying Regulation in the Day-Ahead Energy and Operating Reserve Market must be capable of receiving and responding to automatic control signals and must provide telemetered output data in accordance with the Business Practices Manuals. Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) committed Generation Resources that are not Dispatchable Intermittent Resources, (ii) available External Asynchronous Resources, (iii) committed Demand Response Resources - Type II, (iv) available Stored Energy Resources, and (v) available Stored Energy Resources – Type II. A Market Participant may disqualify a Regulation Qualified Resource from supplying Regulating Reserve on an Hourly basis if physical operating restrictions make the Resource unable to deploy Regulating Reserve in accordance with the product requirements for Regulating Reserve established in Section 39.2.1A.a and the Business Practices Manuals.

B. Spin Qualified Resources.

All Spin Qualified Resources in the Day-Ahead Energy and Operating Reserve Market shall meet all of the requirements for Spin Qualified Resources specified in this Section. Only Spin Qualified Resources will be permitted to supply Spinning Reserve in the Day-Ahead Energy and Operating Reserve Market. All Spin Qualified Resources in the Day-Ahead Energy and

Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Spin Qualified Resources and as Supplemental Qualified Resources, to allow cleared Spin Qualified Resources to supply Supplemental Reserve.

All Spin Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Spin Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must comply with the requirements imposed by the Applicable Reliability Standards for Resources supplying Spinning Reserve and if applicable, frequency responsive Contingency Reserve. All Spin Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of deploying their cleared Spinning Reserve within the Contingency Reserve Deployment Period consistent with the Resource limit and ramping constraints as set forth in Schedule 29. All Spin Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of deploying their cleared Spinning Reserve, consistent with the Resource limit and ramping constraints as set forth in Schedule 29, for a minimum continuous duration of sixty (60) minutes. All Spin Qualified Resources supplying Spinning Reserve in the Day-Ahead Energy and Operating Reserve Market must provide telemetered output data or, in the case of a Demand Response Resource–Type I that is deployed for Contingency Reserve within the Hour, must provide a minimum of five-minute interval demand data within five (5) days for the Resource through the appropriate data communications equipment, as set forth in the Business Practices Manuals. Spin Qualified Resources in the Day-

Ahead Energy and Operating Reserve Market will be limited to: (i) committed Generation Resources that are not Dispatchable Intermittent Resources; (ii) uncommitted Demand Response Resources - Type I that have a Minimum Interruption Duration of sixty (60) minutes or less; (iii) committed Demand Response Resources – Type II; and (iv) available External Asynchronous Resources. A Market Participant can disqualify a Spin Qualified Resource from supplying Spinning Reserve on an Hourly basis should physical operating restrictions make the Resource unable to deploy Spinning Reserve in accordance with the product requirements for Spinning Reserve established in Section 39.2.1A.b and the Business Practices Manuals. If a Resource is disqualified from providing Spinning Reserve, it is disqualified from providing Regulating Reserve.

C. Supplemental Qualified Resources.

All Supplemental Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must meet all of the requirements for Supplemental Qualified Resources specified in this Section. Only Supplemental Qualified Resources will be permitted to supply Supplemental Reserve in the Day-Ahead Energy and Operating Reserve Market. All Supplemental Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Supplemental Qualified Resources. All Supplemental Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area, or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Supplemental Qualified Resources in the Day-Ahead

Energy and Operating Reserve Market must be capable of deploying one-hundred percent (100%) of their cleared Contingency Reserve within the Contingency Reserve Deployment Period. All Supplemental Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of deploying one-hundred percent (100%) of their cleared Contingency Reserve for a minimum continuous duration of sixty (60) minutes. All Supplemental Qualified Resources supplying Supplemental Reserve in the Day-Ahead Energy and Operating Reserve Market must provide telemetered output data or, in the case of a Demand Response Resource–Type I that is deployed for Contingency Reserve within the Hour, must provide a minimum of five-minute interval demand data within five (5) days for the Resource through the appropriate data communications equipment, as set forth in the Business Practices Manuals. Supplemental Qualified Resources in the Day-Ahead Energy and Operating Reserve Market will be limited to: (i) committed Generation Resources that are not Dispatchable Intermittent Resources; (ii) uncommitted Quick-Start Resources; (iii) uncommitted Demand Response Resources - Type I; (iv) committed Demand Response Resources - Type II; and (v) available External Asynchronous Resources. Uncommitted Quick-Start Resources and uncommitted Demand Response Resources-Type I, must have a Minimum Run Time (or Minimum Interruption Duration, if a Demand Response Resource - Type I) of one-hundred-eighty (180) minutes or less in order to be classified as Supplemental Qualified Resources. A Market Participant can disqualify a Supplemental Qualified Resource from supplying Supplemental Reserve on an Hourly basis should physical operating restrictions make the Resource unable to deploy Supplemental Reserve in accordance with the product requirements for Supplemental Reserve established in Section 39.2.1A.b and the Business Practices Manuals. If a Resource is disqualified from providing

Supplemental Reserve, it is disqualified from providing Regulating Reserve and Spinning Reserve.

The Transmission Provider shall have the right to test Resources with Supplemental Qualified Resource status, or Resources seeking Supplemental Qualified Resource status, to determine whether the Supplemental Qualified Resource is capable of the deployment of Contingency Reserves in response to a Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period.

In the event that the testing of a Resource is subsequent to a Supplemental Qualified Resource’s failure to respond to a Contingency Reserve Deployment Instruction, such Resource shall receive the applicable LMP in the Real-Time Energy and Operating Reserve Markets for the Actual Energy Injection of the Resource during the test or for the duration of the Resource's Minimum Run Time, whichever is longer. Additionally, the amount of Supplemental Reserve the Resource may clear in the Day-Ahead Energy and Operating Reserve Market shall be capped at the actual amount of Contingency Reserve deployed at the end of the Contingency Reserve Deployment Period achieved during the test until the Resource achieves a higher level of output in a subsequent test or actual deployment.

In the event that the Transmission Provider initiates a test of a Supplemental Qualified Resource that is not associated with the Supplemental Qualified Resource’s failure to respond to a Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period, the Resource shall be committed by the Transmission Provider, shall receive the applicable LMP in the Real-Time Energy and Operating Reserve Markets for the Actual Energy Injection of the Resource, and is eligible for Real-Time Revenue Sufficiency Guarantee Credit pursuant to Section 40.3.3.3.c. To the extent that the Resource fails to respond to the Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period during the test deployment, the amount of Supplemental Reserve the Resource may clear in the Day-Ahead Energy and Operating Reserve Market shall be capped at the actual amount of Contingency Reserve deployed at the end of the Contingency Reserve Deployment Period achieved during the test until the Resource achieves a higher level of output in a subsequent test or actual deployment.

D. Resource Requirements for Up Ramp Capability and Down Ramp Capability

All Resources eligible to provide Up Ramp Capability and/or Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area, or the entire Generation Resource must be Pseudo-tied into the MISO Balancing Authority Area and must remain Pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Resources eligible to provide Up Ramp Capability and/or Down Ramp Capability must be dispatchable for Energy in the Day-Ahead Energy and Operating Reserve Market and capable of changing resource Energy output consistent with the Resource limit and ramping constraints set forth in Schedule 29 within the Ramp Capability Response Time. Up Ramp Capability and Down Ramp Capability eligibility in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) committed Generation Resources, (ii) available External Asynchronous Resources, (iii) committed Demand Response Resources - Type II; and (iv) committed Stored Energy Resources – Type II. Market Participants may disqualify a Resource from supplying Up and Down Ramp Capability on an Hourly basis using the Resource Offer Up and Down Ramp Capability Dispatch Status.

E. Resource Requirements for Short-Term Reserve

All Resources eligible to provide Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area, or the entire Generation Resource must be Pseudo-tied into the MISO Balancing Authority Area and must remain Pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource.

Resource requirements for on-line Resources providing Short-Term Reserve

All on-line Resources eligible to provide Short-Term Reserve must be dispatchable for Energy in the Day-Ahead Energy and Operating Reserve Market and capable of changing Resource Energy output consistent with the Resource limit and ramping constraints set forth in Schedule 29 within the Short-Term Reserve Deployment Period. Short-Term Reserve eligibility for on-line Resources in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) committed Generation Resources that are not Dispatchable Intermittent Resources or Intermittent Resources, (ii) available External Asynchronous Resources; and (iii) committed Demand Response Resources - Type II and committed Stored Energy Resources - Type II. Market Participants may disqualify an on-line Resource from supplying Short-Term Reserve on an Hourly basis using the Resource Offer on-line Short-Term Reserve Dispatch Status.

Resource requirements for off-line Resources providing Short-Term Reserve

All Off-Line Short-Term Reserve Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must meet all of the requirements for Off-Line Short-Term Reserve Qualified Resources specified in this Section. Only Off-Line Short-Term Reserve Qualified Resources will be permitted to supply Short-Term Reserve while off-line in the Day-Ahead Energy and Operating Reserve Market. All Off-Line Short-Term Reserve Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Off-Line Short-Term Reserve Qualified Resources. Short-Term Reserve eligibility for off-line Resources in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) uncommitted Generation Resources that are not Dispatchable Intermittent Resources or Intermittent Resources, (ii) uncommitted Demand Response Resources - Type II and uncommitted Stored Energy Resources - Type II; and (iii) uncommitted Demand Response Resources - Type I. Uncommitted Generation Resources, Demand Response Resources - Type II, Stored Energy Resources - Type II and Demand Response Resources-Type I, must be capable of achieving Economic Minimum Dispatch within the Short-Term Reserve Deployment Period and must have a Minimum Run Time (or Minimum Interruption Duration, if a Demand Response Resource - Type I) of two-hundred-forty (240) minutes or less in order to be classified as Off-Line Short-Term Reserve Qualified Resources. All Off-Line Short-Term Reserve Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of deploying one-hundred percent (100%) of their cleared Short-Term Reserve within the Short-Term Reserve Deployment Period in the Real-Time Energy and Operating Reserve Market. All Off-Line Short-Term Reserve Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of deploying one-hundred percent (100%) of their cleared Short-Term Reserve for a minimum continuous duration of sixty (60) minutes in the Real-Time Energy and Operating Reserve Market. All Off-Line Short-Term Reserve Qualified Resources supplying Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market must provide telemetered output data for the Resource through the appropriate data communications equipment, as set forth in the Business Practices Manuals. A Market Participant can disqualify an Off-Line Short-Term Reserve Qualified Resource from supplying Short-Term Reserve on an Hourly basis using the Resource Offer off-line Short-Term Reserve Dispatch Status should physical operating restrictions make the Resource unable to deploy Short-Term Reserve in accordance with the product requirements for Short-Term Reserve established in Section 39.2.1A.h and the Business Practices Manuals.

The Transmission Provider shall have the right to test Resources with Off-Line Short-Term Reserve Qualified Resource status, or Resources seeking Off-Line Short-Term Reserve Qualified Resource status, to determine whether the Resource is capable of the deployment of Short-Term Reserves within the Short-Term Reserve Deployment Period.

In the event that the Transmission Provider initiates a test of an Off-Line Short-Term Reserve Qualified Resource, the Resource shall be committed by the Transmission Provider, shall receive the applicable LMP in the Real-Time Energy and Operating Reserve Markets for the Actual Energy Injection of the Resource, and is eligible for Real-Time Revenue Sufficiency Guarantee Credit pursuant to Section 40.3.3.3.c.

Before January 1, 2022, existing Resources shall self-certify as an Off-Line Short-Term Reserve Qualified Resources. After January 1, 2022, certification as an Off-Line Short-Term Reserve Qualified Resource for all new Resources shall require passing a Transmission Provider initiated test. A new Resource that tests and qualifies as a Supplemental Qualified Resource will not need to undergo additional testing to qualify as an Off-Line Short-Term Reserve Qualified Resource.

Demand Bid Rules in the Day-Ahead Energy and Operating Reserve Market:

a. General Demand Bid Rules. Market Participants that intend to purchase Energy in the Day-Ahead Energy and Operating Reserve Market shall submit Fixed Demand Bids and/or Price Sensitive Demand Bids and shall provide the Bid information specified in this Section. Only Market Participants that have demonstrated to the Transmission Provider's satisfaction that they are Load Serving Entities or are purchasing on behalf of Load Serving Entities may submit Demand Bids. The Transmission Provider shall maintain a list of Commercial Pricing Nodes that may be specified in Demand Bids by Market Participants.

b. Fixed Demand Bid Components. Fixed Demand Bids shall include:

i. The Commercial Pricing Node registered by the Market Participant for which it intends to purchase the designated MWh of Energy.

ii. Hourly MWh quantities, with a default of zero (0) MWh.

c. Price Sensitive Demand Bid Data. Price Sensitive Demand Bids shall include:

i. Commercial Pricing Node registered by the Market Participant for which it intends to purchase the designated MWh of Energy.

ii. A maximum of nine (9) bid blocks for each Hour, where each Bid block specifies a maximum price ($/MWh), and MWh quantity. Price Sensitive Demand Bids may not exceed the Energy Offer Hard Price Cap.

All Market Participants may purchase Energy in the Day-Ahead Energy and Operating Reserve Market through Export Schedules as described in Section 39.1.4 and will be settled at the Commercial Pricing Node defined as the Interface or at the External Asynchronous Resources Commercial Pricing Node for each Export Schedule. Load external to the MISO Balancing Authority Area may be included as part of the Transmission Provider Region if that Load registers through an existing Local Balancing Authority (LBA) and Pseudo-ties into the MISO Balancing Authority Area through that existing LBA.

a. **General Virtual Bid Rules.** Market Participants that intend to purchase Virtual Energy in the Day-Ahead Energy and Operating Reserve Market shall provide the Bid information specified in this Section. Market Participants may purchase Virtual Energy at any Commercial Pricing Node. Virtual Bids may not be used to purchase Operating Reserve.

b. **Virtual Bid Components.** Virtual Bids shall include:

i. The Commercial Pricing Node where the Market Participant desires to purchase the designated MWh of Energy.

ii. A maximum of nine (9) bid blocks for each Hour, where each Bid block specifies a maximum price ($/MWh) and MWh quantity. Virtual Bids may not exceed the Energy Offer Hard Price Cap.

Generation Offer, Demand Response Resource Type - II Offer and Stored Energy Resource – Type II Offer Rules in the Day-Ahead Energy and Operating Reserve Market

Market Participants that intend to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market shall provide the information specified in this Section. Generation Offers, Demand Response Resource – Type II Offers and Stored Energy Resource – Type II Offers shall be submitted in the Day-Ahead Energy and Operating Reserve Market only for registered Generation Resources, registered Demand Response Resources–Type II and registered Stored Energy Resources – Type II. Generation Offers, Demand Response Resource–Type II Offers and Stored Energy Resource – Type II Offers will remain in effect for the Day-Ahead Energy and Operating Reserve Market until specifically superseded by subsequent Generation Offers or Demand Response Resource–Type II Offers or Stored Energy Resource – Type II Offers. Each Market Participant may only submit a single Generation Offer, Demand Response Resource – Type II Offer or Stored Energy Resource – Type II Offer for each individual Resource.

a. Eligibility to Supply. Generation Resources, Demand Response Resources-Type II or Stored Energy Resources – Type II may supply Energy in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to five (5) minute Dispatch Targets for Energy and has the appropriate telemetry installed as set forth in the Business Practices Manuals. A Generation Resource, Demand Response Resource–Type II or Stored Energy Resource – Type II may not (i) offer Energy, (ii) offer and/or supply Operating Reserve, (iii) offer and/or supply Up Ramp Capability or Down

Ramp Capability, or (iv) offer and/or supply Short-Term Reserve unless such Resource has been included in the Network Model. A Market Participant's Generation Resources, Demand Response Resources–Type II or Stored Energy Resources – Type II can supply Regulating Reserve, Spinning Reserve, Supplemental Reserve Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Regulation Qualified Resource, Spin Qualified Resource, Supplemental Qualified Resource, Up and Down Ramp Capability Qualified Resource, and/or Short-Term Reserve Qualified Resource, respectively. Market Participants that offer to supply Day-Ahead Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve shall provide the Offer information specified below.

b. Required Generation Offer, Demand Response Resource–Type II Offer and Stored Energy Resource – Type II Offer Components. Market Participants that submit Generation Offers, Demand Response Resource–Type II Offers and/or Stored Energy Resource – Type II Offers shall include an Energy Offer curve, a Regulating Capacity Offer and a Regulating Mileage Offer (if a Regulation Qualified Resource), a Spinning Reserve Offer (if a Spin Qualified Resource), an On-Line Supplemental Reserve Offer (if a Supplemental Qualified Resource but not a Spin Qualified Resource), an Off-Line Supplemental Reserve Offer (if a Quick-Start Resource), an Off-Line Short-Term Reserve Offer (if an Off-Line

Short-Term Reserve Qualified Resource), a Start-Up Offer, a No-Load Offer, an Up and Down Ramp Capability Dispatch Status Offer, and an on-line and off-line Short-Term Reserve Dispatch Status Offer. Market Participants can provide Generation Offers, Demand Response Resource – Type II Offers and/or Stored Energy Resource – Type II Offers for the full MW range of their Operable Capacity, from the Hourly Emergency Minimum Limit to the Hourly Emergency Maximum Limit and may indicate, as part of the Offer, that the Generation Resource, Demand Response Resource–Type II or Stored Energy Resource – Type II Offer is only available to be committed during an Emergency. Market Participants may submit Generation Offers, Demand Response Resource–Type II Offers and/or Stored Energy Resource – Type II Offers to the Day-Ahead Energy and Operating Reserve Market up to seven (7) Days prior to the Operating Day, and may modify these Generation Offers, Demand Response Resource–Type II Offers and/or Stored Energy Resource – Type II Offers up until the time the Day-Ahead Energy and Operating Reserve Market closes, as specified in Section 39.1.1. Market Participants may submit a Generation Offer, Demand Response Resource–Type II Offer and/or Stored Energy Resource – Type II Offer that contains zero dollar ($0) amounts for No-Load and Start-Up Offers, in which case only the Energy Offer curve, Regulating Capacity Offer and Regulating Mileage Offer (if applicable), Spinning Reserve Offer (if applicable), On-Line Supplemental Reserve Offer (if applicable), Off-Line Supplemental Reserve Offer (if applicable), Off-Line Short-Term Reserve Offer (if applicable), Up and Down

Ramp Capability Dispatch Status Offer, and/or online or off-line Short-Term Reserve Dispatch Status Offer will be considered in the market clearing process pursuant to Section 39.2.9. Any limits on the Offer over the full quantity (MW) range of the Operable Capacity must be consistent with Module D. A single Generation Offer, Demand Response Resource–Type II Offer or Stored Energy Resource – Type II Offer may be submitted in the Day-Ahead Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Energy and Operating Reserve from a given Resource. The Transmission Provider shall maintain a Day-Ahead Energy and Operating Reserve Market Generation Offer, Demand Response Resource–Type II Offer and/or Stored Energy Resource – Type II Offer for each Resource. These Offers are standing Offers and are maintained for the Day-Ahead Energy and Operating Reserve Market independent of the Real-Time Energy and Operating Reserve Market. These Offers may be updated prior to the close of the Day-Ahead Energy and Operating Reserve Market. Generation Resource, Demand Response Resource–Type II Offer and/or Stored Energy Resource – Type II components are as follows:

i. Energy Offer Curve. The Energy Offer curve shall be expressed for each Hour in $/MWh and shall consist of either a stepped or a piecewise linear Offer curve of up to ten (10) segments, shall be monotonically increasing, and shall cover the full operating range, including the Hourly Emergency Minimum Limit and Hourly Emergency Maximum Limit.

ii. Regulating Capacity Offer and Regulating Mileage Offer. For DRR – Type II Resources or Stored Energy Resource – Type II, the Regulating Capacity Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Regulation Qualified Resources. For Generation Resources, the Regulating Capacity Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW.

iii. Spinning Reserve Offer. For DRR-Type II Resources or Stored Energy Resources – Type II, the Spinning Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments and shall be monotonically increasing and is only applicable to Spin Qualified Resources. For Generation Resources, the Spinning Reserve Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Spin Qualified Resources.

iv. On-Line Supplemental Reserve Offer. For DRR - Type II Resources or Stored Energy Resources – Type II, the On-Line Supplemental Reserve

Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Supplemental Qualified Resources. For Generation Resources, the On-Line Supplemental Reserve Offer shall be a single value expressed for each Hour in $/MW and is only applicable to synchronized Supplemental Qualified Resources that are not Spin Qualified Resources.

v. Off-Line Supplemental Reserve Offer. For DRR - Type II Resources or Stored Energy Resources – Type II, the Off-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Resources that are uncommitted Quick-Start Resources. For Generation Resources, the Off-Line Supplemental Reserve Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Resources that are uncommitted Quick-Start Resources.

vi. Start-Up Offer. The Start-Up Offer shall be expressed for each Day in $/start. A separate Start-Up Offer shall be submitted for hot, intermediate, and cold Start-Up conditions.

vii. No-Load Offer. The No-Load Offer shall be expressed for each Hour in $/Hour.

viii. Commercial Pricing Node. A Commercial Pricing Node shall be specified for the Generation Resource, Demand Response Resource–Type II or Stored Energy Resource – Type II at the time the asset is registered. The Commercial Pricing Node type shall not be a Load Zone, Interface, or Hub. A Demand Response Resource–Type II or Stored Energy Resource – Type II cannot be modeled using an Aggregate Pricing Node.

ix. Hourly Ramp Rate. An Offer shall include an Hourly Ramp Rate, expressed for each Hour in MW/minute. If no Hourly Ramp Rate is submitted, the default ramp rate specified during the asset registration process will be used and can be updated by Market Participant from the Market Portal.

x. Hourly Economic Minimum Limit. An Offer shall include an Hourly Economic Minimum Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xi. Hourly Economic Maximum Limit. An Offer shall include an Hourly Economic Maximum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Economic Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xii. Hourly Emergency Minimum Limit. An Offer shall include an Hourly Emergency Minimum Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xiii. Hourly Emergency Maximum Limit. An Offer shall include an Hourly Emergency Maximum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Emergency Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xiv. Hourly Regulation Minimum Limit. An Offer shall include, if the Resource is a Regulation Qualified Resource and subject to the transitional must offer requirements specified under Section 39.1.1A.b, an Hourly

Regulation Minimum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Regulating Reserve capability of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR during the transitional must offer requirement period specified under Section 39.1.1A.b unless the Resource is unavailable due to a forced or planned outage or the Resource is not qualified to supply Regulating Reserve due to physical operating restrictions. If no Hourly Regulation Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xv. Hourly Regulation Maximum Limit. An Offer shall include, if the Resource is a Regulation Qualified Resource and subject to the transitional must offer requirements specified under Section 39.1.1A.b, an Hourly Regulation Maximum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR during the transitional must offer requirement period specified under Section 39.1.1A.b unless the Resource is unavailable due to a forced or planned outage or the Resource is not qualified to supply Regulating Reserve due to physical operating restrictions. If no Hourly Regulation Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xvi. Minimum Run Time. An Offer shall include a Minimum Run Time, expressed for each Day in Hours.

xvii. Maximum Run Time. An Offer shall include a Maximum Run Time, expressed for each Day in Hours.

xviii. Minimum Down Time. An Offer shall include a Minimum Down Time, expressed for each Day in Hours.

xix. Start-Up Times. An Offer shall include a hot, intermediate, and cold Start-Up Time, each of which is expressed for each Hour in Hours and/or Minutes.

xx. Start-Up Notification Times. An Offer shall include a hot, intermediate, and cold Start-Up Notification Time, each of which is expressed for each Hour in Hours and/or Minutes.

xxi. Maximum Off-Line Response Limit. An Offer shall include a Maximum Off-Line Response Limit, expressed for each Hour in MW. This requirement applies to Quick-Start Resources only. If no hourly Maximum Off-Line Response Limit is submitted, the default Maximum Off-Line Response Limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xxii. Maximum Start-Up Limit. An Offer shall include a Maximum Start-Up Limit, expressed for each Day in Starts per Day.

xxiii. Maximum Daily Energy. An Offer shall include specification of a Maximum Daily Energy amount, if applicable, expressed for each Day in MWh.

xxiv. Hot-to-Intermediate Time. An Offer shall include a Hot-to-Intermediate Time, expressed for each Day in Hours and/or minutes.

xxv. Hot-to-Cold Time. An Offer shall include a Hot-to-Cold Time, expressed for each Day in Hours and/or minute.

xxvi. Commitment Status. An Offer shall include specification of a Commitment Status for each Hour. Valid Commitment Status specifications include: Economic, Must-Run, Emergency, Outage and Not Participating. An Economic Commitment Status indicates the Transmission Provider is authorized to commit the Resource on an economic basis for the Hour. A Must-Run Commitment Status indicates that the Market Participant is self-committing the Resource for the Hour. An Emergency Commitment Status indicates the Transmission Provider is authorized to commit the Resource only under an Emergency condition for the Hour. An Outage Commitment Status indicates the Resource is not available for commitment during the Hour due to a planned or forced outage. A Not Participating Commitment Status indicates the Market Participant will not operate a Resource that is otherwise available. The

Not Participating Commitment Status will not be available to any Resource that has all or a portion of its capacity designated as a Capacity Resource.

xxvii. Energy Dispatch Status. An Offer shall include specification of an Energy Dispatch Status for Energy for each Hour. Valid Energy Dispatch Status specifications include: Economic and Self-Schedule.

An Economic Energy Dispatch Status indicates that the Transmission Provider is authorized to economically clear Energy on the Resource for the Hour. A Self-Schedule Energy Dispatch Status indicates that the Market Participant is Self-Scheduling Energy on the Resource for the Hour. The Energy Dispatch Status only applies to Resources that are committed for the Hour.

xxviii. Regulating Reserve Dispatch Status. An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve for each Hour. Valid Regulating Reserve Dispatch Status specifications include: Economic, Self-Schedule, Not Qualified and Not Participating. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour.

A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Regulating Reserve on the Resource for the Hour. A Not Qualified Regulating Reserve Dispatch Status indicates that the Resource is not qualified to provide Regulating Reserve for an Hour. A Not Participating Regulating Reserve Dispatch Status indicates the Market Participant will not provide Regulating Reserve on a Resource that is otherwise qualified to provide Regulating Reserve. The Not Participating Regulating Reserve Dispatch Status will not be available to any Resource that has all or a portion of its capacity designated as a Capacity Resource for the first 180 days of the Energy and Operating Reserve Market. The Regulating Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) registered as Regulation Qualified Resources.

xxix. Spinning Reserve Dispatch Status. An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve for each Hour. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Spinning Reserve on the Resource for the Hour. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. The Spinning Reserve Dispatch Status cannot be set to Not Qualified for a specific Resource in a specific Hour unless the Regulating

Reserve Dispatch Status is also set to Not Qualified for that Resource in that Hour.

For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to Section 39.2.5.b.xxiii of the Tariff in order to not participate in providing Spinning Reserve. The Spinning Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) are registered as Spin Qualified Resources.

xxx. On-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an On-Line Supplemental Reserve Dispatch Status for Supplemental Reserve for each Hour. Valid On-Line Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic On-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Self-Schedule On-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Not Qualified On-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour as a committed Resource. For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to Section 39.2.5.b.xxiii of the Tariff in order to not participate in providing On-Line Supplemental Reserve. The On-Line Supplemental Reserve Dispatch Status only applies to Resources that are i) committed for the Hour, ii) registered as Supplemental Qualified Resources and, iii) not registered as Spin Qualified. Resources or have been disqualified by the Market Participant as Spin Qualified Resources for the Hour.

xxxi. Off-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an Off-Line Supplemental Reserve Dispatch Status for Supplemental Reserve for each Hour. Valid Off-Line Supplemental Reserve Dispatch Status specifications include: Economic, Emergency, Self-Schedule, Not Qualified and Not Participating. An Economic Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour if the Resource is uncommitted.

An Emergency Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour if the Resource is uncommitted and all available Resources with an Economic Commit Status have been committed. A Self-Schedule Off-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is Self-

Scheduling Off-Line Supplemental Reserve on the Resource for the Hour if the Resource is uncommitted. A Not Qualified Off-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Off-Line Supplemental Reserve for an Hour as an uncommitted Quick-Start Resource.

A Not Participating Off-Line Supplemental Reserve Dispatch Status indicates the Market Participant will not provide Off-Line Supplemental Reserve on an uncommitted Resource that is otherwise qualified to provide Off-Line Supplemental Reserve. The Not Participating Off-Line Supplemental Reserve Dispatch Status will not be available to any Resource that has all or a portion of its capacity designated as a Capacity Resource. The Off-Line Supplemental Reserve Dispatch Status only applies to Resources that are uncommitted for the Hour and registered as Quick-Start Resources.

xxxii. Up and Down Ramp Capability Dispatch Status. An Offer shall include specification of an Up and Down Ramp Capability Dispatch Status which applies to both Up Ramp Capability and Down Ramp Capability for each Hour. Valid Up and Down Ramp Capability Dispatch Status specifications include: Economic and Not Participating. An Economic Up and Down Ramp Capability Dispatch Status indicates that the Transmission Provider is authorized to economically clear Up Ramp Capability and/or Down Ramp Capability on the Resource for the Hour. A Not Participating Up and Down Ramp Capability Dispatch Status indicates that the Resource shall not be cleared to supply Up Ramp Capability or Down Ramp Capability for an Hour.

The Up and Down Ramp Capability Dispatch Status only applies to Resources that are i) committed for the Hour and ii) have offered an Energy Dispatch Status of Economic for the Hour.

xxxiii. On-Line Short-Term Reserve Dispatch Status. An Offer shall include specification of an on-line Short-Term Reserve Dispatch Status for each Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for the Hour.

xxxiv. Off-Line Short-Term Reserve Dispatch Status. An Offer shall include specification of an off-line Short-Term Reserve Dispatch Status for each Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for the Hour.

xxxv. Off-Line Short-Term Reserve Offer. For DRR - Type II Resources or Stored Energy Resources – Type II, the Off-Line Short-Term Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Off-Line Short-Term Reserve Qualified Resources. For Generation Resources, the Off-Line Short-Term Reserve Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Off-Line Short-Term Reserve Qualified Resources.

xxxvi. Maximum Off-Line Short-Term Reserve Response Limit. An Offer shall include a Maximum Off-Line Short-Term Reserve Response Limit, expressed for each Hour in MW. This requirement applies to Off-Line Short-Term Reserve Qualified Resources only. If no hourly Maximum Off-Line Short-Term Reserve Response Limit is submitted, the default Maximum Off-Line Short-Term Reserve Response Limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal. The Maximum Off-Line Short-Term Reserve Response limit must be greater than or equal to the Resource's Economic Minimum Dispatch.

c. Values in Offers. The values in Offers representing the non-price information identified in Section 39.2.5.b. shall reflect the actual known physical capabilities and characteristics of the Generation Resource, Demand Response Resource–

Type II and/or Stored Energy Resource – Type II on which the Offer is based, except that the Hourly Emergency Maximum Limit and Hourly Economic Maximum Limit of a Generation Resource may, at the discretion of the Market Participant, be reduced by an amount equal to any Capacity associated with the Resource that is not designated as a Capacity Resource and that is not (i) providing Energy Operating Reserve, Up Ramp Capability, or Short-Term Reserve to the Day-Ahead Energy and Operating Reserve Market and (ii) providing Energy Operating Reserve, Up Ramp Capability, or Short-Term Reserve to any other party or entity.

d. Combined Cycle Units. A Generation Offer for a Generation Resource with combined cycle capability shall be submitted as either an independent Offer for each combustion turbine (CT) and steam turbine (ST) with an alternate steam or thermal source or an aggregate Offer for the combined cycle combustion turbine (CCCT) unit, not both. This selection is made on a daily basis.

e. Jointly Owned Generation Resource. Each Market Participant may submit a Generation Offer, including Start-up and No-Load Offers, for their respective ownership of a Jointly Owned Generation Resource as long as each share of the Jointly Owned Generation Resource is modeled as an independent Resource in the Network Model and Commercial Models. Each share of a Jointly Owned Generation Resource will be considered an independent Generation Resource. Therefore, a Market Participant may Pseudo-tie its entire share of a Jointly Owned Generation Resource into the MISO Balancing Authority Area for the purpose of providing Operating Reserve to the Energy and Operating Reserve Markets.

f. Day-Ahead Energy and Operating Reserve Market Offer Price Caps and Floor. The following Offer price caps and floors will apply to Generation Resources, Demand Response Resource – Type II and Stored Energy Resource – Type II Offers in the Day-Ahead Energy and Operating Reserve Market:

i. Energy Offer Soft Price Cap: $1,000/MWh, applied to non-Verified Energy Offers, and non-Verified Fast Start Resource All-In Energy Offers. Energy Offers, and the components of Fast Start Resource All-In Energy Offers, above the Energy Offer Soft Price Cap, submitted before the Day-Ahead Energy and Operating Reserves Market close, but not verified by the Independent Market Monitor until after market clearing, will be used in the determination of Day-Ahead Revenue Sufficiency Guarantee Credits in accordance with section 39.3.2B of this Tariff.

ii. Energy Offer Hard Price Cap: $2,000/MWh, applied to Verified Energy Offers and Verified Fast Start Resource All-In Energy Offers. Verified Energy Offers, and the components of Verified Fast Start Resource All-In Energy Offers, above the Energy Offer Hard Price Cap will be used in the determination of Day-Ahead Revenue Sufficiency Guarantee Credits in accordance with section 39.3.2B of this Tariff.

iii. Energy Offer Price Floor: Negative $500/MWh

iv. Regulating Total Cost Price Cap: $500/MW/Hour

v. Regulating Total Cost Price Floor: $0/MW/Hour

vi. Contingency Reserve Offer Price Cap: $100/MW/ Hour

vii. Contingency Reserve Offer Price Floor: $0/MW/Hour

viii. Regulating Mileage Offer Price Floor: $0/MW

ix. Off-Line Short-Term Reserve Offer Price Cap: $100/MW/Hour

x. Off-Line Short-Term Reserve Offer Price Floor: $0/MW/Hour

Demand Response Resource - Type I Offer Rules in the Day-Ahead Energy and Operating Reserve Market

Market Participants that intend to supply Energy and Contingency Reserve from a Demand Response Resource-Type I in the Day-Ahead Energy and Operating Reserve Market shall provide the information specified in this Section. Demand Response Resource-Type I Offers shall be submitted in the Day-Ahead Energy and Operating Reserve Market only for registered Demand Response Resources-Type I. Demand Response Resource-Type I Offers will remain in effect for the Day-Ahead Energy and Operating Reserve Market until specifically superseded by subsequent Demand Response Resource-Type I Offers. Each Market Participant may only submit a single Demand Response Resource-Type I Offer for each individual Demand Response Resource-Type I.

a. **Eligibility to Supply.** Demand Response Resources – Type I may supply Energy in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to hourly demand reduction instructions and has data communication equipment installed that can provide metering data in accordance with Attachment TT. A Market Participant's Demand Response Resource - Type I may supply Spinning Reserve in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Spin Qualified Resource, Supplemental Reserve in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Supplemental Qualified Resource, or Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Short-Term Reserve Qualified Resource. Demand Response Resources – Type I may not supply Up Ramp Capability or Down Ramp Capability because they are not required to respond to five (5) minute Dispatch Targets for Energy. Market Participants that offer to supply Day-Ahead Energy, Spinning Reserve, Supplemental Reserve, and/or Short-Term Reserve shall provide the Offer information specified below.

b. Required Demand Response Resource-Type I Offer Components. For Demand Response Resources-Type I that are Spin Qualified Resources, a Market Participant may submit an Energy Offer curve, a Spinning Reserve Offer, a Supplemental Reserve Offer, a Shut-Down Offer, an Hourly Curtailment Offer, an Off-Line Short-Term Reserve Offer, a Demand Response Resource – Type I Contingency Reserve status and an off-line Short-Term Reserve Dispatch Status. For Demand Response Resources-Type I that are not Spin Qualified Resources but which qualify as a Supplemental Qualified Resource, a Market Participant may submit a Supplemental Reserve Offer, an Energy Offer curve, a Shut-Down Offer, an Hourly Curtailment Offer, an Off-Line Short-Term Reserve Offer, and an off-line Short-Term Reserve Dispatch Status. For Demand Response Resources - Type I that are neither Spin Qualified Resources nor Supplemental Qualified Resources, but which qualify as an Off-Line Short-Term Reserve Qualified Resource, a Market Participant may submit an Energy Offer curve, a Shut-Down Offer, an Hourly Curtailment Offer, an Off-Line Short-Term Reserve Offer, and an off-line Short-Term Reserve Dispatch Status. For Demand

Response Resources - Type I that are not Spin Qualified Resources, Supplemental Qualified Resources, or Off-Line Short-Term Reserve Qualified Resources, a Market Participant may submit an Energy Offer curve, a Shut-Down Offer, and an Hourly Curtailment Offer for the purposes of offering Energy only. A Market Participant may indicate, as part of the Offer, that the Demand Response Resource - Type I is only available to be committed for Energy during an Emergency or that it is only available to be cleared for Contingency Reserve during an Emergency. Market Participants may submit Demand Response Resource – Type I Offers to the Day-Ahead Energy and Operating Reserve Market up to seven (7) Days prior to the Operating Day and may modify these Demand Response Resource - Type I Offers up until the time the Day-Ahead Energy and Operating Reserve Market closes, as specified in Section 39.1.1.

i. **Energy Offer Curve:** The Energy Offer curve shall be expressed for each Hour in $/MWh and shall consist of a stepped, single segment representation at the Targeted Demand Reduction Level.

ii. **Spinning Reserve Offer.** The Spinning Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, and shall be monotonically increasing. A Spinning Reserve Offer only applies if the Demand Response Resource - Type I is a Spin Qualified Resource.

iii. **Supplemental Reserve Offer**. The Supplemental Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, and shall be monotonically increasing. A Supplemental Reserve Offer only applies if the Demand Response Resource -Type I is a Supplemental Qualified Resource.

iv. **Shut-Down Offer.** A Shut-Down Offer is expressed for each Day in $/shut-down.

v. **Hourly Curtailment Offer**. An Hourly Curtailment Offer is expressed for each Hour in $/Hour.

vi. **Demand Response Resource – Type I Contingency Reserve Status.** An Offer shall include a Demand Response Resource – Type I Contingency Reserve status, expressed for each Day. The Demand Response Resource – Type I Contingency Reserve status shall specify whether the Demand Response Resource – Type I will be cleared and deployed in the same manner as Resources clearing and deploying on-line Spinning or Supplemental Reserve, or whether the Demand Response Resource – Type I will be cleared and deployed in the same manner as off-line Resources clearing and deploying Supplemental Reserves. If a Demand Response Resource – Type I elects to clear and deploy in the same manner as Resources clearing and deploying on-line Spinning or Supplemental Reserve, any Resource commitments made for Contingency Reserve Deployment events will not be SCUC Instructed Hours of Operation.

If a Demand Response Resource – Type I elects to clear and deploy in the same manner as off-line Resources clearing and deploying Supplemental Reserves, any Resource commitments made for Contingency Reserve Deployment events will be SCUC Instructed Hours of Operation.

vii. **Commercial Pricing Node.** A Commercial Pricing Node shall be specified for the Demand Response Resource–Type I. The Commercial Pricing Node cannot be an Interface, Load Zone, or Hub, but may be an Aggregate Price Node. The Commercial Pricing Node can include an aggregation of Elemental Pricing Zones or portions of Elemental Pricing Nodes all within a single Local Balancing Authority Area and based on the EPNodes for Demand Response Resources Type - I registered by the Market Participant.

viii. **Reserved.**

ix. **Targeted Demand Reduction Level.** An Offer for a Demand Response Resource - Type I shall include a Targeted Demand Reduction Level, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity was used to calculate the Unforced Capacity of a designated Capacity Resource pursuant to Section 69, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Targeted Demand Reduction Level is submitted, the default Targeted Demand Reduction

Level specified during the asset registration process will be used.

x. **Minimum Interruption Duration.** An Offer shall include a Minimum Interruption Duration, expressed for each Day in Hours.

xi. **Maximum Interruption Duration.** An Offer shall include a Maximum Interruption Duration, expressed for each Day in Hours.

xii. **Minimum Non-Interruption Interval.** An Offer shall include a Minimum Non-Interruption Interval, expressed for each Day in Hours.

xiii. **Maximum Interruption Limit**. An Offer shall include a Maximum Interruption Limit, expressed for each Day in number of interruptions per Day.

xiv. **Maximum Daily Energy**. An Offer shall include specification of a Maximum Daily Energy amount, if applicable, expressed for each Day in MWh.

xv. **Shut-Down Time.** An Offer shall include a Shut-Down Time, expressed for each Hour in Hours and/or Minutes.

xvi. **Shut-Down Notification Time.** An Offer shall include a Shut-Down Notification Time, expressed for each Hour in Hours and/or Minutes.

xvii. **Energy Commitment Status.** An Offer shall include specification of an Energy Commitment Status for each Hour. Valid Energy Commitment Status specifications include: Economic, Emergency and Not Participating. An Economic Commitment Status indicates the

Transmission Provider is authorized to commit the Resource to provide Energy for the Hour on an economic basis.

An Emergency Commitment Status indicates the Transmission Provider is authorized to commit the Resource to provide Energy for the Hour under Emergency conditions only. A Not Participating Commitment Status indicates the Market Participant will not provide Energy for the Hour from the Resource, but the Resource could be available for Contingency Reserve depending on the Spinning Reserve Dispatch Status and/or Supplemental Reserve Dispatch Status, as described below.

For a Demand Response Resource-Type I that is a designated Capacity Resource, the Not Participating Commitment Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

xviii. **Spinning Reserve Dispatch Status.** An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule, Emergency, Not Qualified and Not Participating.

An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is self-scheduling Spinning Reserve on the Resource for the Hour. An Emergency Spinning

Reserve Dispatch Status indicates the Transmission Provide is authorized to clear Spinning Reserve on the Resource only under Emergency Conditions. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. A Not Participating Spinning Reserve Dispatch Status indicates the Market Participant will not provide Spinning Reserve on a Resource that is otherwise qualified to provide Spinning Reserve. For a Demand Response Resource–Type I that is a designated Capacity Resource, the Not Participating Spinning Reserve Dispatch Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions. The Spinning Reserve Dispatch Status only applies to Demand Response Resources - Type I that are i) uncommitted for the Hour and ii) registered as Spin Qualified Resources.

xix. **Supplemental Reserve Dispatch Status.** An Offer shall include specification of a Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule, Emergency, Not Qualified and Not Participating.

An Economic Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour. A Self-Schedule Supplemental

Reserve Dispatch Status indicates that the Market Participant is self-scheduling Supplemental Reserve on the Resource for the Hour.

An Emergency Supplemental Reserve Dispatch Status indicates the Transmission Provider is authorized to clear Supplemental Reserve on the Resource only under Emergency Conditions. A Not Qualified Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour. A Not Participating Supplemental Reserve Dispatch Status indicates the Market Participant will not provide Supplemental Reserve on a Resource that is otherwise qualified to provide Supplemental Reserve. For a Demand Response Resource–Type I that is a designated Capacity Resource, the Not Participating Supplemental Reserve Dispatch Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

The Supplemental Reserve Dispatch Status only applies to Demand Response Resources-Type I that i) are uncommitted for the Hour and ii) are registered as Supplemental Qualified Resources.

xxi. **Off-Line Short-Term Reserve Dispatch Status.** An Offer shall include specification of an off-line Short-Term Reserve Dispatch Status. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economicallyclear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for an Hour. The Short-Term Reserve Dispatch Status only applies to Demand Response Resources-Type I that i) are uncommitted for the Hour and ii) are registered as Off-Line Short-Term Reserve Qualified Resources.

xxii. **Off-Line Short-Term Reserve Offer.** The Off-Line Short-Term Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, and shall be monotonically increasing. An Off-Line Short-Term Reserve Offer only applies if the Demand Response Resource -Type I is an Off-Line Short-Term Reserve Qualified Resource.

c. Day-Ahead Energy and Operating Reserve Market Offer Price Cap and Floors. The following Offer price caps and floors will apply to Demand Response Resources – Type I Offers in the Day-Ahead Energy and Operating Reserve Market:

i. Energy Offer Soft Price Cap: $1,000/MWh, applied to non-Verified Energy Offers, and non-Verified Fast Start Resource All-In Energy Offers. Energy Offers, and the components of Fast Start Resource All-In Energy Offers, above the Energy Offer Soft Price Cap, submitted before the Day-Ahead Energy and Operating Reserves Market close, but not verified by the Independent Market Monitor until after market clearing, will be used in the determination of Day-Ahead Revenue Sufficiency Guarantee Credits in accordance with section 39.3.2B of this Tariff, provided that the cost verification process for DRR – Type I Offers above that threshold shall be different and suitable for such types of Resources, as determined and implemented by the Independent Market Monitor.

ii. Energy Offer Hard Price Cap: $2,000/MWh, applied to Verified Energy Offers, and Verified Fast Start Resource All-In Energy Offers. Verified Energy Offers, and the components of Verified Fast Start Resource All-In Energy Offers, above the Energy Offer Hard Price Cap will be used in the determination of Day-Ahead Revenue Sufficiency Guarantee Credits in accordance with section 39.3.2B of this Tariff, provided that the cost verification process for DRR – Type I Offers above that threshold shall be different and suitable for such types of Resources, as determined and implemented by the Independent Market Monitor.

iii. Energy Offer Price Floor: Negative $500/MWh

iv. Contingency Reserve Offer Price Cap: $100/MW/Hour

v. Contingency Reserve Offer Price Floor: $0/MW/Hour

vi. Off-Line Short-Term Reserve Offer Price Cap: $100/MW/Hour

vii. Off-Line Short-Term Reserve Offer Price Floor: $0/MW/Hour

External Asynchronous Resource Offer Rules in the Day-Ahead Energy and Operating Reserve Market:

Market Participants that intend to supply Energy Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve from an External Asynchronous Resource in the Day-Ahead Energy and Operating Reserve Market shall provide the information specified in this Section.

External Asynchronous Resource Offers shall be submitted in the Day-Ahead Energy and Operating Reserve Market only for qualified External Asynchronous Resources. External Asynchronous Resource Offers shall remain in effect for the Day-Ahead Energy and Operating Reserve Market until specifically superseded by subsequent External Asynchronous Resource Offers. Each Market Participant shall only submit a single External Asynchronous Resource Offer for each individual External Asynchronous Resource.

a. **Eligibility to Supply.** A Market Participant's External Asynchronous Resources may supply Energy in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to five (5) minute Dispatch Targets for Energy and has the appropriate telemetry installed as set forth in the Business Practices Manuals.

A Market Participant's External Asynchronous Resources can supply Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Regulation Qualified Resource, a Spin Qualified Resource, a

Supplemental Qualified Resource, Up and Down Ramp Capability Qualified Resource, and/or Short-Term Reserve Qualified Resource, respectively. Market Participants that offer to supply Day-Ahead Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve shall provide the Offer information specified below for each individual External Asynchronous Resource.

b. **Required External Asynchronous Resource Offer Components.** All External Asynchronous Resources can submit an Offer for Energy, an Up and Down Ramp Capability Dispatch Status Offer, and an on-line Short-Term Reserve Dispatch Status Offer. For External Asynchronous Resources that are Regulation Qualified Resources, a Market Participant may submit a Regulating Capacity Offer and a Regulating Mileage Offer. For External Asynchronous Resources that are Spin Qualified Resources, a Market Participant may submit a Spinning Reserve Offer. For External Asynchronous Resources that are not Spin Qualified Resources but which qualify as a Supplemental Qualified Resource, a Market Participant may submit a Supplemental Reserve Offer. Market Participants can provide External Asynchronous Resource Offers for the full MW range of their Operable Capacity. Market Participants may submit External Asynchronous Resource Offers to the Day-Ahead Energy and Operating Reserve Market up to seven (7) Days prior to the Operating Day and may modify these External Asynchronous Resource Offers up until the time the Day-Ahead Energy and Operating Reserve Market closes, as specified in Section 39.1.1.

A single External Asynchronous Resource Offer may be submitted in the Day-Ahead Energy and Operating Reserve Market for each Hour of the Operating Day for a given External Asynchronous Resource. The Transmission Provider shall maintain a Day-Ahead Energy and Operating Reserve Market Offer for each External Asynchronous Resource. These Offers are standing Offers and are maintained for the Day-Ahead Energy and Operating Reserve Market independent of the Real-Time Energy and Operating Reserve Market. These Offers may be updated prior to the closing of the Day-Ahead Energy and Operating Reserve Market. External Asynchronous Resource Offer components are as follows:

i. **Energy Offer Curve.** The Energy Offer curve shall be expressed for each Hour in $/MWh and shall consist of either a stepped or a piecewise linear Offer curve of up to ten (10) segments, shall be monotonically increasing, and shall cover the full operating range. The Energy Offer Curve may include negative MW and/or negative price segments.

ii. **Regulating Capacity Offer and Regulating Mileage Offer.** The Regulating Capacity Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to External Asynchronous Resources that are Regulation Qualified Resources. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW.

iii. **Spinning Reserve Offer.** The Spinning Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to External Asynchronous Resources that are Spin Qualified Resources.

iv. **Supplemental Reserve Offer**. The Supplemental Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to External Asynchronous Resources that are Supplemental Qualified Resources but not Spin Qualified Resources.

v. **Commercial Pricing Node.** A Commercial Pricing Node shall be specified for the External Asynchronous Resource. The Commercial Pricing Node shall not be an Interface, Load Zone, or Hub.

vi. **Hourly Ramp Rate.** An Offer shall include an Hourly Ramp Rate, expressed for each Hour in MW/minute. If no Hourly Ramp Rate is submitted, the default ramp rate specified during the asset registration process will be used and can be updated by Market Participant from the Market Portal.

vii. **Hourly Economic Maximum Limit**. An Offer shall include an Hourly Economic Maximum Limit, expressed for each Hour in MW. If no Hourly Economic Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

viii. **Hourly Regulation Minimum Limit.** An Offer shall include, if the

Resource is a Regulation Qualified Resource, an Hourly Regulation Minimum Limit, expressed for each Hour in MW. If no Hourly Regulation Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

ix. **Hourly Regulation Maximum Limit**. An Offer shall include, if the Resource is a Regulation Qualified Resource, an Hourly Regulation Maximum Limit, expressed for each Hour in MW. If no Hourly Regulation Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

x. **Hourly Emergency Maximum Limit.** An Offer shall include an Hourly Emergency Maximum Limit, expressed for each Hour in MW. If no Hourly Emergency Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xi. **Hourly Economic Minimum Limit.** An Offer shall include an Hourly Economic Minimum Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xii. **Hourly Emergency Minimum Limit.** An Offer shall include an Hourly Emergency Minimum Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xiii. **Availability Status.** An Offer shall include an Availability Status to indicate if the External Asynchronous Resource is available for participation in the Day-Ahead Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Unavailable, then the External Asynchronous Resource will be unavailable to provide Energy and Operating Reserve in the Day-Ahead Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Available, then the External Asynchronous Resource will be available to provide Energy and Operating Reserve in the Day-Ahead Energy and Operating Reserve Market during the Hour.

xiv. **Energy Dispatch Status.** An Offer shall include specification of an Energy Dispatch Status for Energy. Valid Energy Dispatch Status specifications include: Economic and Self-Schedule. An Economic Energy Dispatch Status indicates that the Transmission Provider is authorized to economically clear Energy on the Resource for the Hour. A Self-Schedule Energy Dispatch Status indicates that the Market Participant is Self-Scheduling Energy on the Resource for the Hour.

xv. **Regulating Reserve Dispatch Status.** An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve. Valid Regulating Reserve Dispatch Status specifications include: Economic, Self-Schedule, Not Qualified and Not Participating. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour. A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Regulating Reserve on the Resource for the Hour. A Not Qualified Regulating Reserve Dispatch Status indicates that the Resource is not qualified to provide Regulating Reserve for an Hour. A Not Participating Regulating Reserve Dispatch Status indicates the Market Participant will not provide Regulating Reserve on a Resource that is otherwise qualified to provide Regulating Reserve. The Regulating Reserve Dispatch Status only applies to Resources that are registered as Regulation Qualified Resources.

xvi. **Spinning Reserve Dispatch Status.** An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A

Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is self-scheduling Spinning Reserve on the Resource for the Hour. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. The Spinning Reserve Dispatch Status cannot be set to Not Qualified for a specific Resource in a specific Hour unless the Regulating Reserve Dispatch Status is also set to Not Qualified for that Resource in that Hour. The Spinning Reserve Dispatch Status only applies to Resources that are registered as Spin Qualified Resources.

xvii. **Supplemental Reserve Dispatch Status.** An Offer shall include specification of a Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour. A Self-Schedule Supplemental Reserve Dispatch Status indicates that the Market Participant is self-scheduling Supplemental Reserve on the Resource for the Hour. A Not Qualified Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour. The Supplemental Reserve Dispatch Status only applies to Resources that are i) registered as Supplemental Qualified Resources and, ii) not Spin

Qualified Resources or have been disqualified by the Market Participant as Spin Qualified Resources for the Hour.

xviii. **Up and Down Ramp Capability Dispatch Status.** An Offer shall include specification of an Up and Down Ramp Capability Dispatch Status which applies to both Up Ramp Capability and Down Ramp Capability for each Hour. Valid Up and Down Ramp Capability Dispatch Status specifications include: Economic and Not Participating. An Economic Up and Down Ramp Capability Dispatch Status indicates that the Transmission Provider is authorized to economically clear Up Ramp Capability and/or Down Ramp Capability on the Resource for the Hour. A Not Participating Up and Down Ramp Capability Dispatch Status indicates that the Resource shall not be cleared to supply Up Ramp Capability or Down Ramp Capability for an Hour. The Up and Down Ramp Capability Dispatch Status only applies to Resources that have offered an Energy Dispatch Status of Economic for the Hour.

xix. **On-Line Short-Term Reserve Dispatch Status.** An Offer shall include specification of an on-line Short-Term Reserve Dispatch Status for each Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A

Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for an Hour.

c. **Values in Offers.** The values in Offers representing the non-price information identified in Section 39.2.5B.b shall reflect the actual known physical capabilities and characteristics of the External Asynchronous Resource on which the Offer is based.

d. **Day-Ahead Energy and Operating Reserve Market Offer Price Cap and Floors**. The following Offer price caps and floors will apply to External Asynchronous Resource Offers in the Day-Ahead Energy and Operating Reserve Market:

i. Energy Offer Soft Price Cap: $1,000/MWh, applied to non-Verified Energy Offers. Energy Offers above the Energy Offer Soft Price Cap, submitted before the close of the Day-Ahead Energy and Operating Reserves Market, but not verified by the Independent Market Monitor until after market clearing, will be used in the determination of Day-Ahead Revenue Sufficiency Guarantee Credits in accordance with section 39.3.2B of this Tariff.

ii. Energy Offer Hard Price Cap: $2,000/MWh, applied to Verified Energy Offers. Verified Energy Offers above the Energy Offer Hard Price Cap will be used in the determination of Day-Ahead Revenue Sufficiency Guarantee Credits in accordance with section 39.3.2B of this Tariff.

iii. Energy Offer Price Floor: Negative $500/MWh

iv. Regulating Total Cost Price Cap: $500/MW/Hour;

v. Regulating Reserve Total Cost Price Floor: $0/MW/Hour;

vi. Contingency Reserve Offer Price Cap: $100/MW/Hour.

vii. Contingency Reserve Offer Price Floor: $0/MW/Hour.

viii. Regulating Mileage Offer Price Floor: $0/MW.

Stored Energy Resource Offer Rules in the Day-Ahead Energy and Operating Reserve Market:

Market Participants that intend to supply Regulating Reserve in the Day-Ahead Energy and Operating Reserve Market shall provide the information specified in this Section. Stored Energy Resource Offers shall be submitted in the Day-Ahead Energy and Operating Reserve Market only for registered Stored Energy Resource. Stored Energy Resource Offers will remain in effect for the Day-Ahead Energy and Operating Reserve Market until specifically superseded by subsequent Stored Energy Resource Offers. Each Market Participant may only submit a single Stored Energy Resource Offer for each individual Resource.

a. **Eligibility to Supply.** Market Participants may offer or Self-Schedule Regulating Reserve into the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified that (i) the Stored Energy Resource is capable of responding to five (5) minute Dispatch Targets for Energy, (ii) the appropriate telemetry has been installed as set forth in the Business Practices Manuals, (iii) such Stored Energy Resource has been included in the Network Model, and (iv) such Stored Energy Resource is a Regulation Qualified Resource. Stored Energy Resources may not supply Up Ramp Capability, Down Ramp Capability, or Short-Term Reserve because they are only qualified for Regulation and not longer duration sustained energy products. Market Participants that offer to supply Day-Ahead Regulating Reserve shall provide the Offer information specified below.

b. **Required Stored Energy Resource Offer Components.** Market Participants that submit Stored Energy Resource Offers shall include a Regulating Capacity

Offer and a Regulating Mileage Offer. Market Participants can provide Stored Energy Resource Offers for the full energy storage capabilities of their resource pursuant to the requirements outlined in Section 39.2.1B.

Market Participants may submit Stored Energy Resource Offers to the Day-Ahead Energy and Operating Reserve Market up to seven (7) Days prior to the Operating Day, and may modify these Stored Energy Resource Offers up until the time the Day-Ahead Energy and Operating Reserve Market closes, as specified in Section 39.1.1. Any limits on the Offer over the full energy storage capability of the Resource must be consistent with Module D. A single Stored Energy Resource Offer may be submitted in the Day-Ahead Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Regulating Reserve from a given Resource.

The Transmission Provider shall maintain a Day-Ahead Energy and Operating Reserve Market Stored Energy Resource Offer for each Resource. These Offers are standing Offers and are maintained for the Day-Ahead Energy and Operating Reserve Market independent of the Real-Time Energy and Operating Reserve Market. These Offers may be updated prior to the close of the Day-Ahead Energy and Operating Reserve Market. Stored Energy Resource Offer components are as follows:

i. **Regulating Capacity Offer and Regulating Mileage Offer.** The Regulating Capacity Offer shall be a single value expressed for each Hour in $/MW/Hour. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW.

ii. **Commercial Pricing Node.** A Commercial Pricing Node shall be specified for the Stored Energy Resource at the time the asset is registered. The Commercial Pricing Node type shall not be a Load Zone, Interface, or Hub.

iii. **Hourly Ramp Rate.** An Offer shall include an Hourly Ramp Rate, expressed for each Hour in MW/minute. If no Hourly Ramp Rate is submitted, the default ramp rate will be used. The default ramp rate is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

iv. **Hourly Regulation Minimum Limit.** An Offer shall include an Hourly Regulation Minimum Limit, expressed for each Hour in MW. If no Hourly Regulation Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal. The Hourly Regulation Minimum Limit may be negative.

v. **Hourly Regulation Maximum Limit.** An Offer shall include an Hourly Regulation Maximum Limit, expressed for each Hour in MW. If no Hourly Regulation Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

vi. **Hourly Maximum Energy Storage Level.** An Offer shall include an Hourly Maximum Energy Storage Level, expressed for each Hour in MWh. The hourly maximum energy storage level represents the maximum amount of energy the Stored Energy Resource can store and maintain. If no Hourly Maximum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

vii. **Hourly Maximum Energy Charge Rate.** An Offer shall include an Hourly Maximum Energy Charge Rate, expressed for each Hour in MWh / Minute. If no Hourly Maximum Energy Charge Rate is submitted, the default value specified during the asset registration process will be used.

viii. **Hourly Maximum Energy Discharge Rate.** An Offer shall include an Hourly Maximum Energy Discharge Rate, expressed for each Hour in MWh / Minute. If no Hourly Maximum Energy Discharge Rate is submitted, the default value specified during the asset registration process will be used.

ix**.** **Availability Status.** An Offer shall include an Availability Status to indicate if the Stored Energy Resource is available for participation in the Day-Ahead Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Unavailable, then the Stored Energy Resource will be unavailable to provide Regulating Reserve in the Day-Ahead Energy and Operating Reserve Market during the Hour. If the Availability

Status is set to Available, then the Stored Energy Resource will be available to provide Regulating Reserve in the Day-Ahead Energy and Operating Reserve Market during the Hour.

x. **Regulating Reserve Dispatch Status.** An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve for each Hour. Valid Regulating Reserve Dispatch Status specifications include: Economic and Self-Schedule. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour. A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Regulating Reserve on the Resource for the Hour.

xi. **Hourly Energy Storage Loss Rate.** An Offer shall include specification of an Hourly Energy Storage Loss Rate for each Hour, expressed in MWh/Minute, which is the amount of Energy consumed by the Stored Energy Resource over a one-minute time period to maintain an energy storage level equal to the Hourly Maximum Energy Storage Level assuming no Regulating Reserve deployment. If no Hourly Storage Loss Rate is submitted, the default value specified during the asset registration process will be used.

xii. **Hourly Full Charge Energy Withdrawal Rate.** An Offer shall include specification of an Hourly Full Charge Energy Withdrawal Rate for each

Hour, expressed in MWh/Minute, which is the amount of additional Energy that can be consumed by the Stored Energy Resource during a one-minute time period while at its Maximum Energy Storage Level to provide Regulation down capability. If no Hourly Full Charge Energy Withdrawal Rate is submitted, the default value specified during the asset registration process will be used.

c. **Values in Offers.** The values in Offers representing the non-price information identified in Section 39.2.5C.b. shall reflect the actual known physical capabilities and characteristics of the Stored Energy Resource on which the Offer is based.

d. **Day-Ahead Energy and Operating Reserve Market Offer Price Caps and Floors.** The following Offer Price Caps will apply to Stored Energy Resources in the Day-Ahead Energy and Operating Reserve Market:

i. Regulating Total Cost Price Cap: $500/MW/Hour

ii. Regulating Total Cost Price Floor $0/MW/Hour

iii. Regulating Mileage Offer Price Floor: $0/MW

Electric Storage Resource Offer Rules in the Day-Ahead Energy and Operating Reserve Market.

Market Participants that intend to supply Energy, Operating Reserves, Up Ramp Capability, and/or Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market from Electric Storage Resources shall provide the information specified in this Section. Electric Storage Resource Offers shall be submitted in the Day-Ahead Energy and Operating Reserve Market only for registered Electric Storage Resources. Electric Storage Resource Offers will remain in effect for the Day-Ahead Energy and Operating Reserve Market until specifically superseded by subsequent Electric Storage Resource Offers. Each Market Participant may only submit a single Electric Storage Resource Offer for each individual Resource.

a. Eligibility to Discharge and/or Charge.

Electric Storage Resources may Discharge (sell) or Charge (purchase) Energy in the Day-Ahead Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to five (5) minute Dispatch Targets for Energy and has the appropriate telemetry installed as set forth in the Business Practices Manuals. An Electric Storage Resource may not (i) offer to Charge and/or Discharge Energy, (ii) offer and/or supply Operating Reserve, or (iii) offer and/or supply Up Ramp Capability or Down Ramp Capability unless such Resource has been included in the Network Model. An Electric Storage Resource can supply Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, and/or Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market if the Transmission

Provider has certified that the Resource is a Regulation Qualified Resource, Spin Qualified Resource, Supplemental Qualified Resource, and/or Up and Down Ramp Capability Qualified Resource, respectively. Market Participants that offer to transact Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, and/or Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market shall provide the Offer information specified below.

b. Required Electric Storage Resource Offer Components.

Market Participants that submit Electric Storage Resource Offers shall include a Charge Energy Offer Curve, a Regulating Capacity Offer and a Regulating Mileage Offer (if a Regulation Qualified Resource), a Spinning Reserve Offer (if a Spin Qualified Resource), an On-Line Supplemental Reserve Offer (if a Supplemental Qualified Resource but not a Spin Qualified Resource), an Off-Line Supplemental Reserve Offer (if a Quick-Start Resource), a Start-Up Offer, a No-Load Offer, and an Up and Down Ramp Capability Dispatch Status Offer. Market Participants can provide Electric Storage Resource Offers for the full energy storage capabilities of their Resource pursuant to the requirements outlined in Section 39.2.1B. Market Participants may submit Electric Storage Resource Offers to the Day-Ahead Energy and Operating Reserve Market up to seven (7) Days prior to the Operating Day, and may modify these Electric Storage Resource Offers up until the time the Day-Ahead Energy and Operating Reserve Market closes, as specified in Section 39.1.1. Any limits on the Electric Storage Resource

Offer covering the full energy storage capability of the Resource must be consistent with Module D. A single Electric Storage Resource Offer may be submitted in the Day-Ahead Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Operating Reserve and/or purchase Energy to Charge and/or Discharge to sell Energy from a given Resource. The Transmission Provider shall maintain a Day-Ahead Energy and Operating Reserve Market Electric Storage Resource Offer for each Resource. These Offers are standing Offers and are maintained for the Day-Ahead Energy and Operating Reserve Market independent of the Real-Time Energy and Operating Reserve Market. These Offers may be updated prior to the close of the Day-Ahead Energy and Operating Reserve Market. Electric Storage Resource Offer components are as follows:

i. Energy Offer Curve. The Energy Offer curve to either Charge and/or Discharge shall be expressed for each Hour in $/MWh and shall consist of either a stepped or a piecewise linear Offer curve of up to ten (10) segments, shall be monotonically increasing, and shall cover the full operating including Emergency range as applicable to the Commitment Status of the Electric Storage Resource.

ii. Regulating Capacity Offer and Regulating Mileage Offer. The Regulating Capacity Offer shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Regulation Qualified Resources expressed for each

Hour in $/MW/Hour. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW.

iii. Spinning Reserve Offer. The Spinning Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments and shall be monotonically increasing and is only applicable to Spin Qualified Resources.

iv. On-Line Supplemental Reserve Offer. The On-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Supplemental Qualified Resources that are not Spin Qualified Resources.

v. Off-Line Supplemental Reserve Offer. The Off-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing to Discharge and is only applicable to Resources that are Quick-Start Resources and have Commitment Status as Available.

vi. Start-up Offer. The Start-Up Offer shall be expressed for each Day in $/start. A separate Start-Up Offer shall be submitted for hot, intermediate, and cold Start-Up conditions.

vii. No-Load Offer. The No-Load Offer shall be expressed for each Hour in $/Hour.

viii. Commercial Pricing Node. A Commercial Pricing Node shall be specified for the Electric Storage Resource at the time the asset is registered. The Commercial Pricing Node type shall not be a Load Zone, Interface, or Hub.

ix. Hourly Charge Ramp Rate. An Offer shall include an Hourly Charge Ramp Rate, expressed for each Hour in MW/minute. If no Hourly Charge Ramp Rate is submitted, the default Charge Ramp Rate will be used. The default Charge Ramp Rate is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. A single Hourly Charge Ramp Rate value will be used for an Electric Storage Resource to ramp up or down for Energy and for regulating up or down between the corresponding Hourly Economic Maximum Charge Limit and zero (0).

x. Hourly Discharge Ramp Rate. An Offer shall include an Hourly Discharge Ramp Rate, expressed for each Hour in MW/minute. If no Hourly Discharge Ramp Rate is submitted, the default Hourly Discharge Ramp Rate will be used. The default Hourly Discharge Ramp Rate is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. A single Hourly Discharge Ramp Rate value will be used for an Electric Storage Resource to ramp up or down for Energy and for regulating up or down between the corresponding Hourly Economic Maximum Discharge Limit and zero (0). When the Commitment Status is Continuous, the Ramp Rate value would be determined based on which side of zero (0) the Resource is getting dispatched. If the Electric Storage Resource is being dispatched between zero (0) and the corresponding Hourly Economic Maximum Discharge Limit then the Hourly Discharge Ramp Rate is used. Conversely, if the Electric Storage Resource is being dispatched between zero (0) and the corresponding Hourly Economic Maximum Charge Limit then the Charge Ramp Rate is used for an Electric Storage Resource to ramp up or down for Energy and for regulating up or down.

xi. Hourly Regulation Minimum Charge Limit. An Offer shall include an Hourly Regulation Minimum Charge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Minimum Charge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Minimum Charge Limit shall be greater than or equal to Hourly Economic Minimum Charge Limit, and shall be less than or equal to the Hourly Regulation Maximum Charge Limit. When the Commitment Status is Continuous, the Hourly Regulation Minimum Charge Limit will not be used.

xii. Hourly Regulation Maximum Charge Limit. An Offer shall include an Hourly Regulation Maximum Charge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Maximum Charge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Maximum Charge Limit shall be less than or equal to the Hourly Economic Maximum Charge Limit, shall be greater than or equal to the Hourly Economic Minimum Charge Limit, and shall be greater than or equal to the Hourly Regulation Minimum Charge Limit. This limit will be used as the minimum MW dispatch limit when Commitment Status is Charge or Continuous under normal operating conditions for ESRs qualified and committed for Regulation.

xiii. Hourly Regulation Minimum Discharge Limit. An Offer shall include an Hourly Regulation Minimum Discharge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Minimum Discharge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the

Market Portal. The Hourly Regulation Minimum Discharge Limit shall be greater than or equal to the Hourly Economic Minimum Discharge Limit, and shall be less than or equal to the Hourly Regulation Maximum Discharge Limit. When the Commitment Status is Continuous, the Hourly Regulation Minimum Discharge Limit will not be used.

xiv. Hourly Regulation Maximum Discharge Limit. An Offer shall include an Hourly Regulation Maximum Discharge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Maximum Discharge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Maximum Discharge Limit shall be less than or equal to the Hourly Economic Maximum Discharge Limit, shall be greater than or equal to the Hourly Economic Minimum Discharge Limit, and shall be greater than or equal to the Hourly Regulation Minimum Discharge Limit. This limit will be used as the maximum MW dispatch limit when the Commitment Status is Discharge or Continuous under normal operating conditions for ESRs qualified and committed for Regulation.

xv. Hourly Maximum Energy Storage Level. An Offer shall include an Hourly Maximum Energy Storage Level, expressed for each Hour in MWh. If no

Hourly Maximum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xvi. Hourly Minimum Energy Storage Level. An Offer shall include an Hourly Minimum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Minimum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xvii. Hourly Emergency Maximum Energy Storage Level. An Offer shall include an Hourly Emergency Maximum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Emergency Maximum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xviii. Hourly Emergency Minimum Energy Storage Level. An Offer shall include an Hourly Emergency Minimum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Emergency Minimum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xix. Hourly Economic Maximum Charge Limit. An Offer shall include an Hourly Economic Maximum Charge Limit, expressed for each Hour in MW. If no Hourly Economic Maximum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Minimum Charge Limit. This limit will be used as the minimum MW dispatch limit when Commitment Status is Charge or Continuous under normal operating conditions.

xx. Hourly Economic Maximum Discharge Limit. An Offer shall include an Hourly Economic Maximum Discharge Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Economic Maximum Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Minimum Discharge Limit. This limit will be used as the maximum MW dispatch limit when the Commitment Status is Charge, Available or Continuous under normal operating conditions.

xxi. Hourly Economic Minimum Charge Limit. An Offer shall include an Hourly Economic Minimum Charge Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Charge as maximum MW dispatch limit under normal operating conditions. When the Commitment Status is Continuous, this limit will not be used.

xxii. Hourly Economic Minimum Discharge Limit. An Offer shall include an Hourly Economic Minimum Discharge Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Energy Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Discharge or Available as minimum MW dispatch limit under normal operating conditions. When the Commitment Status is Continuous, this limit will not be used.

xxiii. Hourly Emergency Maximum Charge Limit. An Offer shall include an Hourly Emergency Maximum Charge Limit, expressed for each Hour in MW. If no Hourly Emergency Maximum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Maximum Charge Limit. This limit will be used as the minimum MW dispatch limit when the Commitment Status is Emergency Charge, Charge or Continuous under Emergency operating conditions.

xxiv. Hourly Emergency Maximum Discharge Limit. An Offer shall include an Hourly Emergency Maximum Discharge Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Day-Ahead Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Emergency Maximum Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Maximum Discharge Limit. This limit will be used as the maximum MW dispatch limit when the Commitment Status is Emergency Discharge, Discharge, Available or Continuous under Emergency operating conditions.

xxv. Hourly Emergency Minimum Charge Limit. An Offer shall include an Hourly Emergency Minimum Charge Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Emergency Charge or Charge as maximum MW dispatch limit under Emergency operating conditions. When the Commitment Status is Continuous, this limit will not be used.

xxvi. Hourly Emergency Minimum Discharge Limit. An Offer shall include an Hourly Emergency Minimum Discharge Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Energy Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Emergency Discharge, Discharge, or Available as minimum MW dispatch limit under normal operating conditions. When the Commitment Status is Continuous, this limit will not be used.

xxvii. Minimum Discharge Time. An Offer shall include a Minimum Discharge Time, expressed for each Day in Hours.

xxviii. Maximum Discharge Time. An Offer shall include a Maximum Discharge Time, expressed for each Day in Hours.

xxix. Minimum Down Time. An Offer shall include a Minimum Down Time, expressed for each Day in Hours.

xxx. Minimum Charge Time. An Offer shall include a Minimum Charge Time, expressed for each Day in Hours.

xxxi. Maximum Charge Time. An Offer shall include a Maximum Charge Time, expressed for each Day in Hours.

xxxii. Commitment Status. An Offer shall include specification of a Commitment Status for each Hour. Valid Commitment Status specifications include: Charge, Discharge, Continuous, Emergency Charge, Emergency Discharge, Available, Outage and Not Participating. An Available Commitment Status indicates the Transmission Provider is authorized to commit the Resource on an economic basis for the Hour using Offer parameters associated with the Commitment Status of Discharge. A Charge, Discharge, or Continuous Commitment Status indicates that the Market Participant is self-committing the Resource for the Hour. An Emergency Charge or Emergency Discharge Commitment

Status indicates the Transmission Provider is authorized to commit the Resource only under an Emergency condition for the Hour. An Outage Commitment Status indicates the Resource is not available for commitment during the Hour due to a planned or forced outage. A Not Participating Commitment Status indicates the Market Participant will not operate a Resource that is otherwise available. The Not Participating Commitment Status will be available to an Electric Storage Resource that has all or a portion of its capacity designated as a Capacity Resource, but must be used consistent with Module E-1 obligations.

xxxiii. Energy Dispatch Status. An Offer shall include specification of an Energy Dispatch Status for Energy for each Hour. Valid Energy Dispatch Status specifications include: Economic, Self-Schedule, and Not Participating. An Economic Energy Dispatch Status indicates that the Transmission Provider is authorized to economically clear Energy on the Resource for the Hour. A Self-Schedule Energy Dispatch Status indicates that the Market Participant is Self-Scheduling Energy on the Resource for the Hour and will follow the Self-Scheduling Rules defined in section 39.1.2. The Not Participating Energy Dispatch Status will be available to an Electric Storage Resource in Continuous Commitment Status and that has all or a portion of its capacity designated as a Capacity Resource, but must be used consistent with Module E-1 obligations. The Energy Dispatch Status only applies to Resources that are committed for the Hour.

xxxiv. Regulating Reserve Dispatch Status. An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve for each Hour. Valid Regulating Reserve Dispatch Status specifications include: Economic, Self-Schedule, Not Qualified and Not Participating. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour. A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Regulating Reserve on the Resource for the Hour. A Not Qualified Regulating Reserve Dispatch Status indicates that the Resource is not qualified to provide Regulating Reserve for an Hour. A Not Participating Regulating Reserve Dispatch Status indicates the Market Participant will not provide Regulating Reserve on a Resource that is otherwise qualified to provide Regulating Reserve. The Regulating Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) registered as Regulation Qualified Resources. The Resource cleared or Self-Scheduled for Regulation will not impact the Energy Storage Level. However, there should be sufficient Energy Storage Level to clear Regulating Reserves or honor Self-Scheduled Regulation for the Hour.

xxxv. Spinning Reserve Dispatch Status. An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve for each Hour.

Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Spinning Reserve on the Resource for the Hour. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. The Spinning Reserve Dispatch Status cannot be set to Not Qualified for a specific Resource in a specific Hour unless the Regulating Reserve Dispatch Status is also set to Not Qualified for that Resource in that Hour. The Resource cleared or Self-Scheduled for Spinning Reserve will not impact the Energy Storage Level. However, there should be sufficient Energy Storage Level to clear Spinning Reserves or honor Self-Scheduled Spinning Reserves for the Hour.

For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to section 39.2.5D.b.xxxii of the Tariff in order to not participate in providing Spinning Reserve. The Spinning Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) registered as Spin Qualified Resources.

xxxvi. On-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an On-Line Supplemental Reserve Dispatch Status for Supplemental Reserve for each Hour. Valid On-Line Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic On-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Self-Schedule On-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Not Qualified On-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour as a committed Resource. The Resource cleared or Self-Scheduled for Supplemental Reserve will not impact the Energy Storage Level. However, there should be sufficient Energy Storage Level to clear Supplemental Reserves or honor Self-Scheduled Supplemental Reserves for the Hour.

For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to section 39.2.5D.b.xxxii of the Tariff in order to not participate in providing On-Line Supplemental Reserve. The On-Line Supplemental Reserve Dispatch Status only applies to Resources that are i) committed for the Hour, ii) registered as Supplemental Qualified Resources and, iii) not registered as Spin Qualified Resources or have been disqualified by the Market Participant as Spin Qualified Resources for the Hour.

xxxvii. Off-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an Off-Line Supplemental Reserve Dispatch Status for Supplemental Reserve for each Hour. Valid Off-Line Supplemental Reserve Dispatch Status specifications include: Economic, Emergency, Self-Schedule, Not Qualified and Not Participating. An Economic Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour when the Resource's Commitment Status is Available.

An Emergency Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour when the Resource's Commitment Status is Available and all available Resources with Economic or Available Commitment Status have been committed. A Self-Schedule Off-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Off-Line Supplemental Reserve on the Resource for the Hour. A Not Qualified Off-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Off-Line Supplemental Reserve for an Hour.

A Not Participating Off-Line Supplemental Reserve Dispatch Status indicates the Market Participant will not provide Off-Line Supplemental Reserve on a Resource that has a Commitment Status of Available and that is otherwise qualified to provide Off-Line Supplemental Reserve. The Not Participating Off-Line Supplemental Reserve Dispatch Status will be available to an Electric Storage Resource that has all or a portion of its capacity designated as a Capacity Resource, but must be used consistent with Module E-1 obligations. The Off-Line Supplemental Reserve Dispatch Status only applies to Resources when their Commitment Status is Available for the Hour and they are registered as Quick-Start Resources.

xxxviii. Up and Down Ramp Capability Dispatch Status. An Offer shall include specification of an Up and Down Ramp Capability Dispatch Status which applies to both Up Ramp Capability and Down Ramp Capability for each Hour. Valid Up and Down Ramp Capability Dispatch Status specifications include: Economic and Not Participating. An Economic Up and Down Ramp Capability Dispatch Status indicates that the Transmission Provider is authorized to economically clear Up Ramp Capability and/or Down Ramp Capability on the Resource for the Hour. A Not Participating Up and Down Ramp Capability Dispatch Status indicates that the Resource shall not be cleared to supply Up Ramp Capability or Down Ramp Capability for an Hour.

The Up and Down Ramp Capability Dispatch Status only applies to Resources that are i) committed for the Hour and ii) have offered an Energy Dispatch Status of Economic for the Hour.

xxxiv. Hourly Electric Storage Resource Efficiency Factor. An Offer shall include specification of an Hourly Electric Storage Resource Efficiency Factor for each Hour, expressed as a percentage. If no Hourly Electric Storage Resource Efficiency Factor is submitted, the default value specified during the asset registration process will be used.

xxxv. Initial Energy Storage Level. An Offer shall include specification of an Initial Energy Storage Level expressed in MWh for each Day.

c. Values in Offers.

The values in Offers representing the non-price information identified in Section 39.2.5D.b shall reflect the actual known physical capabilities and characteristics of the Electric Storage Resource on which the Offer is based.

d. Day-Ahead Energy and Operating Reserve Market Offer Price Caps and Floors.

The following Offer Price Caps will apply to Electric Storage Resources in the Day-Ahead Energy and Operating Reserve Market:

i. Energy Offer Price Cap: $1,000/MWh

ii. Energy Offer Price Floor: Negative $500/MWh

iii. Regulating Total Cost Price Cap: $500/MW/Hour

iv. Regulating Total Cost Price Floor $0/MW/Hour

v. Contingency Reserve Offer Price Cap: $100/MW/Hour

vi. Contingency Reserve Offer Price Floor: $0/MW/Hour

vii. Regulating Mileage Offer Price Floor: $0/MW

a. **General Virtual Offers Rules.** Market Participants that intend to sell Virtual Energy in the Day-Ahead Energy and Operating Reserve Market shall provide the Offer information specified in this Section 39.2.7. Market Participants may sell Virtual Energy at any Commercial Pricing Node. Virtual Supply Offers shall not be used to supply Operating Reserve.

b. **Virtual Offer Components.** Virtual Offers shall include:

i. The Commercial Pricing Node where the Market Participant desires to sell the designated MWh of Energy;

ii. Hourly MWh quantities; and

iii. Offer price expressed in $/MWh which shall not be greater than $2,000/MWh or less than negative $500/MWh.

a. **Energy.** All Market Participants may Offer to sell Energy in the Day-Ahead Energy and Operating Reserve Market through Import Schedules and will be settled at the Commercial Pricing Node defined as the Interface or at the External Asynchronous Resources Commercial Pricing Node for each Import Schedule.

b. **Operating Reserve and Short-Term Reserve.** All Generation Resources Pseudo-tied to the MISO Balancing Authority Area and all External Asynchronous Resources supplying Energy, Operating Reserve, and/or Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market must maintain firm transmission capacity to the MISO Balancing Authority Area in an amount not less than the Emergency Maximum Limit of such Resources.

A. General.

Demand Curves will be utilized in the Day-Ahead Energy and Operating Reserve Market to clear Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Market-Wide Short-Term Reserve. The methodology for constructing Demand Curves is described in Schedule 28.

B. Market-Wide Demand Curves.

A Market-Wide Operating Reserve Demand Curve will be used to price Operating Reserve when sufficient Operating Reserves are not cleared to meet the corresponding Market-Wide Operating Reserve Requirement. A Market Wide Regulating and Spinning Reserve Demand Curve will be used to price Regulating and Spinning Reserve when sufficient Regulating and Spinning Reserves are not cleared to meet the corresponding Market-Wide Regulating and Spinning Reserve Requirement. A Market-Wide Regulating Reserve Demand Curve will be used to price Regulating Reserve when sufficient Regulating Reserves are not cleared to meet the corresponding Market-Wide Regulating Reserve Requirement. A Market-Wide Up Ramp Capability Demand Curve will be used to price Up Ramp Capability when sufficient Up Ramp Capability is not cleared to meet the corresponding Market-Wide Up Ramp Capability Requirement. A Market-Wide Down Ramp Capability Demand Curve will be used to price Down Ramp Capability when sufficient Down Ramp Capability is not cleared to meet the corresponding Market-Wide Down Ramp Capability Requirement. A Market-Wide Short-Term Reserve Demand Curve will be used to price Short-Term Reserve when sufficient Short-Term Reserve is not cleared to meet the corresponding Market-Wide Short-Term Reserve Requirement.

C. Transmission Constraint Demand Curves (TCDCs)

TCDCs shall be used to price a transmission constraint during any dispatch interval in which the transmission constraint cannot be managed within its binding limit using the Security Constrained Economic Dispatch (SCED) engine.

D. Sub-Regional Power Balance Constraint Demand Curves

Sub-Regional Power Balance Constraint Demand Curves shall be used to price Sub-Regional Power Balance Constraints during any Dispatch Interval in which such constraint(s) cannot be managed within its binding limit using the Security Constrained Economic Dispatch (SCED) engine.

E. Post Reserve Deployment Constraints Demand Curves

Post Reserve Deployment Constraints Demand Curves shall be used to price Post Reserve Deployment Constraints during any Dispatch Interval in which such constraint(s) cannot be managed within its binding limit using the Security Constrained Economic Dispatch (SCED) engine.

The Transmission Provider shall use SCUC, SCED, and SCED-Pricing algorithms to: (i) commit Resources; (ii) clear Offers, Bids, Self-Schedules, Interchange Schedules, and Virtual Transactions; (iii) establish Day-Ahead Schedules, Day-Ahead Ex Ante LMPs, and Day-Ahead Ex Ante MCPs; and (iv) establish Day-Ahead Ex Post LMPs and Day-Ahead Ex Post MCPs, for each Hour of the Operating Day.

a. **Determination of Day-Ahead Schedules.**

In the Day-Ahead Energy and Operating Reserve Market, the Transmission Provider shall determine: (i) Energy Schedules for Resources, Load Zones, Interchange Schedules, and Virtual Transactions; (ii) Operating Reserve Schedules for Resources; (iii) Up Ramp Capability and Down Ramp Capability Schedules for Resources; and (iv) Short-Term Reserve schedules for Resources.

b. **Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Elemental Pricing Nodes.**

The Transmission Provider shall calculate Day-Ahead Ex Ante LMPs for each Hour and Elemental Pricing Node in the Day-Ahead Energy and Operating Reserve Market using the SCED algorithm. The Day-Ahead Ex Ante LMP at an Elemental Pricing Node in a specific Hour is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity cost, and/or Short-Term Reserve scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Hour using the SCED algorithm. The Day-Ahead Ex Post LMPs will be based upon the SCED-Pricing algorithm described in Schedule 29A. The Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs are based on: (i) Generation Offers; (ii) Demand Response Resource–Type II Offers; (iii) External Asynchronous Resource Offers; (iv) Virtual Supply Offers; (v) Price Sensitive Demand Bids; (vi) Dispatchable Interchange Schedules; (vii) Up-to-TUC Interchange Schedules; (viii) Virtual Bids; (ix) Demand Curves; (x) Stored Energy Resource – Type II Offers and (xi) Proxy Offers when appropriate as specified in Schedule 29A.

i. Calculation of Marginal Congestion Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Day-Ahead Ex Ante LMP reflects the marginal cost of managing transmission congestion and enforcing Sub-Regional Power Balance Constraints, that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED algorithm. The Marginal Congestion Component of a Day-Ahead Ex Post LMP reflects the marginal cost of managing transmission congestion and enforcing Sub-Regional Power Balance Constraints, that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED-Pricing algorithm.

ii. Calculation of Marginal Losses Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of any Day-Ahead Ex Ante LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy injection at the Reference Bus in the SCED algorithm. The Marginal Losses Component of any Day-Ahead Ex Post LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy injection at the Reference Bus in the SCED-Pricing algorithm.

c. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate LMPs for each Hour and Aggregate Price Node in the Day-Ahead Energy and Operating Reserve Market. The calculation of LMPs for Aggregate Price Nodes will be based on the established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Node LMP is equal to the sum of the products of the LMP at each Elemental Pricing Node and the associated normalized weighting factors for the Elemental Pricing Node.

d. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Commercial Pricing Nodes.

The Transmission Provider shall establish relevant LMPs for each Hour and Commercial Pricing Node in the Day-Ahead Energy and Operating Reserve Market. The respective LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the respective LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

e. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the relevant LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the relevant LMP for the Resource Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node representing the Bus connected to the single injection point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the relevant LMP for the Resource Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource. The Aggregate Price Node weighing factors are specified by the Market Participant when the asset is registered.

f. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the relevant LMP for the Load Zone Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the relevant LMP for the Load Zone Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Load Zone. The Aggregate Price Node representing the Load Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the Load Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total demand of the Load Zone as determined by the results of the State Estimator from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

g. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Hub Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

h. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at an Interface Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the relevant LMP for the Interface Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the relevant LMP for the Interface Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Interface. The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for the Interface.

i. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante and Ex Post Regulating Reserve MCP for

Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost of managing the transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

j. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Regulating Reserve Market Clearing Price for Stored Energy Resources and Stored Energy Resources – Type II

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Regulating Reserve for Stored Energy Resources and Stored Energy Resources – Type II for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCP for Regulating Reserve and Day-Ahead Ex Post MCP for Regulating Reserve for Stored Energy Resources and Stored Energy Resources – Type II is the sum of the (i) Market-Wide Operating Reserve

Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Maximum Stored Energy Resource Regulation Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

k. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Spinning Reserve Market Clearing Price for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I

Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

l. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Spinning Reserve Market Clearing Price for Demand Response Resources – Type I.

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm respectively, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

m. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Supplemental Reserve Market Clearing Price for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

n. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Supplemental Reserve Market Clearing Price for Demand Response Resources - Type I

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

o. **Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Up Ramp Capability Market Clearing Price**

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Up Ramp Capability for qualified Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for a Resource for Up Ramp Capability is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up

Ramp Capability Requirement Constraint is as set forth in Schedule 29 and Schedule 29A, respectively.

p. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Down Ramp Capability Market Clearing Price

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Down Ramp Capability for qualified Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Down Ramp Capability is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint is as set forth in Schedule 29 and Schedule 29A, respectively.

q. Day-Ahead Ex Ante LMP, Day-Ahead Ex Post LMP, Day-Ahead Ex Ante MCP, and Day-Ahead Ex Post MCP Price Cap.

All Day-Ahead Ex Ante LMPs, Day-Ahead Ex Post LMPs, Day-Ahead Ex Ante MCPs, and Day-Ahead Ex Post MCPs will be capped at the VOLL.

r. Day-Ahead Offer Revenue Sufficiency Guarantee.

The Transmission Provider shall ensure the recovery of a Market Participant's Production Cost and Operating Reserve Cost for Resources committed by the Transmission Provider and scheduled in the Day-Ahead Energy and Operating Reserve Market, pursuant to Section 39.3.2B.

s. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Short-Term Reserve Market Clearing Price.

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Short-Term Reserve for qualified reserves for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCP and Day-Ahead Ex Post MCP for Short-Term Reserve are the applicable Cooptimized Zonal Short-Term Reserve Requirement constraint Shadow Prices.

If the sum of the fixed Demand Bids, Fixed Export Schedules, System Losses and Operating Reserve Requirements in the Day-Ahead Energy and Operating Reserve Market cannot be satisfied by the maximum non-Emergency supply level of all available non-Emergency Resources, Import Schedules and Virtual Supply Offers, the Transmission Provider shall clear the Day-Ahead Energy and Operating Reserve Market pursuant to the following procedures.

a. Step One. The Transmission Provider shall incorporate for use in the Day-Ahead Energy and Operating Reserve Market (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource – Type II, Stored Energy Resource – Type II and External Asynchronous Resource up to the Hourly Emergency Maximum Limit except for Resources selected to provide Regulating Reserve, and (ii) the commitment of Generation Resources, Demand Response Resources - Type I, Demand Response Resources - Type II, and Stored Energy Resources – Type II that are designated as available for Emergency conditions only, in amounts required to relieve the shortage condition in an economic manner. Day-Ahead Schedules, Ex Ante LMPs, and Ex Ante MCPs are then determined using the SCED algorithm. Ex Post LMPs and Ex Post MCPs are then determined using the SCED-Pricing algorithm, where Proxy Offers will be used as specified in Schedule 29A. Both SCED and SCED-Pricing algorithms will include Scarcity Pricing based on the Operating Reserve Demand Curves, Regulating and Spinning Reserve Demand Curves, and Regulating Reserve Demand Curves if Operating Reserve is insufficient to meet the Market-Wide Operating Reserve Requirement following the release of Emergency

Capacity described under (i) and (ii) above. Both SCED and SCED-Pricing algorithms will include Scarcity Prices based on the Market-Wide Short-Term Reserve Demand Curve if Short-Term Reserve is insufficient to meet the Market-Wide Short-Term Reserve Requirement following the release of Emergency Capacity described under (i) and (ii) above.

b. Step Two. If Operating Reserve is depleted and the Energy balance cannot be achieved after the process described in Step One above has been implemented, the Transmission Provider will curtail Fixed Demand Bids and Fixed Export Schedules in proportion to the scheduled amounts. Under this situation, all Energy and Operating Reserve will be priced at the VOLL.

Surplus Conditions in the Day-Ahead Energy and Operating Reserve Market:

If the non-Emergency minimum supply from Offers and Fixed Import Schedules exceed cleared Demand Bids plus cleared Export Schedules plus cleared Virtual Bids less the Market-Wide Regulating Reserve Requirement, the Transmission Provider shall use the following procedures to clear the Day-Ahead Energy and Operating Reserve Market.

a. Step One. The Transmission Provider shall incorporate for use in the Day-Ahead Energy and Operating Reserve Market the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource – Type II and Stored Energy Resource –Type II down to the Emergency Minimum Limit except for Resources selected to provide Regulating Reserve in amounts required to relieve the surplus condition in an economic manner.

b. Step Two. If the Energy balance is not achieved after Step One, the Transmission Provider will reduce supply, including Fixed Import Schedules, proportionately until Energy balance is achieved and the Day-Ahead Energy and Operating Reserve Market is cleared. If Regulating Reserve Scarcity occurs, then Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs shall contain negative Regulating Reserve Scarcity Prices and Day-Ahead Ex Ante MCPs for Regulating Reserve and Day-Ahead Ex Post MCPs for Regulating Reserve shall include positive Regulating Reserve Scarcity Prices, based upon the Market-Wide Regulating Reserve Demand Curves.

c. The Transmission Provider shall not partially commit Fast Start Resources, in SCED-Pricing, under both Step One and Step Two Surplus Conditions in the Day-Ahead EORM.

The Transmission Provider shall develop Hourly Load Forecasts for the MISO Balancing Authority Area and shall post these Load Forecasts as set forth in the Business Practices Manuals.

All Day-Ahead Schedules in the Day-Ahead Energy and Operating Reserve Market shall be financially binding, except for GFA Schedules associated with Carved-Out GFAs as described under Section 38.8.4 of this Tariff. The fees and charges set forth in this Section shall be assessed to Market Participants with Day-Ahead Schedules and FTRs.

a. Market Participants that purchase Energy in the Day-Ahead Energy and Operating Reserve Market shall be charged the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node for all Bids cleared, net of Day-Ahead Financial Schedules, for each Hour in the Day-Ahead Energy and Operating Reserve Market.

b. If a Market Participant elects to calculate and settle Energy purchases at the Day-Ahead Ex Post LMP for a Commercial Pricing Node for a Load Zone, the Market Participant shall be charged for its entire Load scheduled to be served from the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post LMP for a Commercial Pricing Node for a Load Zone.

c. Market Participants that purchase Energy using an External Asynchronous Resources Export Schedule shall be charged for exported Energy in Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post LMP at the External Asynchronous Resources Commercial Pricing Node.

d. Market Participants that purchase Energy for Electric Storage Resource Transactions shall be charged for Energy in the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post LMP at the Electrical Storage Resource’s Commercial Pricing Node.

Market Participants scheduled to purchase Energy in the Day-Ahead Energy and Operating Reserve Market, Virtual Bids, and Export Schedules, shall be charged a Day-Ahead Revenue Sufficiency Guarantee Charge, excluding Energy purchases associated with schedules to charge for Electric Storage Resource Transactions. The Market Participant's Day-Ahead Revenue Sufficiency Guarantee Charge in a specific Hour shall equal the product of: (i) the Market Participant's total cleared Demand Bid, Virtual Bids, and Export Schedules (in MWh) scheduled in that Hour of the Day-Ahead Energy and Operating Reserve Market, and (ii) the per unit Day-Ahead Revenue Sufficiency Guarantee Charge rate in that Hour.

The per unit Day-Ahead Revenue Sufficiency Guarantee Charge rate for a specific Hour shall equal: (i) the aggregate Day-Ahead Revenue Sufficiency Guarantee Credit payable to Generation Resources, Electric Storage Resources, Demand Response Resources–Type I and Demand Response Resources–Type II in the Day-Ahead Energy and Operating Reserve Market for that Hour, excluding Day-Ahead Revenue Sufficiency Guarantee Credits attributable to Voltage and Local Reliability Commitments, divided by (ii) the sum of the total cleared Demand Bids, Virtual Bids, and Exports Schedules in (MWh) of all Market Participants scheduled in that Hour of the Day-Ahead Energy and Operating Reserve Market.

Day-Ahead Revenue Sufficiency Guarantee Credits attributable to Voltage and Local Reliability Commitments for a Resource shall be equal to the product of (a) Day-Ahead Revenue Sufficiency Guarantee Credits in an Hour for Day-Ahead Voltage and Local Reliability Commitments and (b) the Voltage and Local Reliability Commitment Allocation Ratio. Day-Ahead Revenue Sufficiency Guarantee Credits attributable to Voltage and Local Reliability Commitments shall be allocated pursuant to Section 40.3.3.2.b.

a. **Regulating Reserve Procurement Charges.** Charges for the procurement of Regulating Reserve in the Day-Ahead Energy and Operating Reserve Market shall be assessed to Load Serving Entities, as set forth in Schedule 3.

b. **Spinning Reserve Procurement Charges.** Charges for the procurement of Spinning Reserves in the Day-Ahead Energy and Operating Reserve Market shall be assessed to Load Serving Entities, and Exporting Entities as set forth in Schedule 5.

c. **Supplemental Reserve Procurement Charges.** Charges for the procurement of Supplemental Reserves in the Day-Ahead Energy and Operating Reserve Market shall be assessed to Load Serving Entities, and Exporting Entities as set forth in Schedule 6.

d. **Up Ramp Capability Procurement Charges.** Charges for the procurement of Up Ramp Capability in the Day-Ahead Energy and Operating Reserve Market shall be assessed to Load Serving Entities and Exporting Entities as set forth in Section 40.3.3.1.b.

e. **Down Ramp Capability Procurement Charges.** Charges for the procurement of Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market shall be assessed to Load Serving Entities and Exporting Entities as set forth in Section 40.3.3.1.b.

f. **Short-Term Reserve Procurement Charges.** Charges for the procurement of Short-Term Reserves in the Day-Ahead Energy and Operating Reserve Market shall be assessed to Load Serving Entities, and Exporting Entities as set forth in Schedule 51.

Payments for Day-Ahead Energy and Operating Reserve Market Sales:

Market Participants that sell Energy, other than Energy from Demand Response Resources – Type I or Demand Response Resources - Type II, in the Day-Ahead Energy and Operating Reserve Market shall be credited each Hour at the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node, net of Day-Ahead Financial Schedules for all Offers cleared, other than cleared Offers for Demand Response Resources – Type I or Demand Response Resources - Type II, in the Day-Ahead Energy and Operating Reserve Market.

a. Market Participants scheduled to supply Regulating Reserve from Generation Resources, Demand Response Resources – Type II, Stored Energy Resources, Stored Energy Resources – Type II, and/or External Asynchronous Resources in the Day-Ahead Energy and Operating Reserve Market shall be credited for all Regulating Reserve Schedules cleared in the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post MCP for Regulating Reserve.

b. Market Participants scheduled to supply Spinning Reserve in the Day-Ahead Energy and Operating Reserve Market from Resources, excluding Stored Energy Resources, shall be credited for all Spinning Reserve Schedules cleared in the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post MCP for Spinning Reserve.

c. Market Participants scheduled to supply Supplemental Reserve in the Day-Ahead Energy and Operating Reserve Market from Resources, excluding Stored Energy Resources, shall be credited for all Supplemental Reserve Schedules cleared in the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post MCP for Supplemental Reserve.

d. Day-Ahead Ramp Capability Procurement Credits

   i. Market Participants scheduled to supply Up Ramp Capability in the Day-Ahead Energy and Operating Reserves Market from Resources, excluding Demand Response Resource - Type I and Stored Energy Resources, shall be credited for all Up Ramp Capability Schedules cleared in the Day-Ahead Energy and

Operating Reserve Market at the applicable Day-Ahead Ex Post MCP for Up Ramp Capability.

ii. Market Participants schedule to supply Down Ramp Capability in the Day-Ahead Energy and Operating Reserves Market from Resources, excluding Demand Response Resource - Type I and Stored Energy Resources, shall be credited for all Down Ramp Capability Schedules cleared in the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post MCP for Down Ramp Capability.

e. Market Participants scheduled to supply Short-Term Reserve in the Day-Ahead Energy and Operating Reserve Market from Resources, excluding Stored Energy Resources, shall be credited for all Short-Term Reserve schedules cleared in the Day-Ahead Energy and Operating Reserve Market at the applicable Day-Ahead Ex Post MCP for Short-Term Reserve.

The Transmission Provider shall determine whether any Generation Resources or Demand Response Resources committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market have not recovered their Production Cost and Operating Reserve Cost through the revenue received from the Day-Ahead Energy and Operating Reserve Market for the Hours during the SCUC Instructed Hours of Operation.

If the Production Cost and Operating Reserve Cost of a Generation Resource or Demand Response Resource exceeds the revenue received in the Day-Ahead Energy and Operating Reserve Market over all the SCUC Instructed Hours of Operation in the Day for that Resource, then the Market Participant's revenue from the Day-Ahead Energy and Operating Reserve Market shall be augmented by an additional payment, called the Day-Ahead Revenue Sufficiency Guarantee Credit, in the amount of the shortfall for that Resource.

The Transmission Provider shall evaluate the day-ahead Offers for a Resource from the current Operating Day and the prior Operating Day if the Resource has: (1) a non-zero Day-Ahead Schedule for Energy in the last Hour of the prior Operating Day; and (2) a non-zero Day-Ahead Schedule for Energy in the first Hour of the SCUC Instructed Hours of Operation in the current Operating Day; and (3) a positive initial on Hours value (*i.e.*, the number of hours elapsed since the Resource was online in the prior Operating Day up to the start of the current Operating Day, calculated in the Day-Ahead Energy and Operating Reserve Market process) that is less than the Resource's Minimum Run Time for the current Operating Day. The Transmission Provider shall use the lesser of the hourly Production Cost and Operating Reserve Cost calculated using (1) the Resource's day-ahead Offer from the prior Operating Day; or (2) the Resource's day-ahead Offer from the current Operating Day, for the SCUC Instructed Hours of Operation on the current

Operating Day that are impacted by the Minimum Run Time. For Demand Response Resource-Type I, the Minimum Interruption Duration will be evaluated in lieu of Minimum Run Time.

The Transmission Provider shall determine hourly whether any Resource with a Must-Run Commitment has not recovered the Resource's Incremental Energy Cost for Energy scheduled above the achievable minimum and Operating Reserve costs for Operating Reserves scheduled above Self Schedule MWs. When calculating cost recovery, revenues considered are the revenues received for Energy scheduled above the achievable minimum for Operating Reserves scheduled above Self Schedule MWs, for Short-Term Reserve, for Up Ramp Capability and for Down Ramp Capability. The achievable minimum shall equal the maximum of: (i) the maximum of the Hourly Economic Minimum Limit (or Hourly Regulation Minimum Limit if scheduled to provide Regulation Reserve), or Self Schedule MW amount for Energy; and (ii) the Day-Ahead schedule for Energy in the prior hour minus the product of the Hourly Ramp Rate and sixty (60) minutes. If there is a shortfall, then the Transmission Provider shall augment the Market Participant's revenue with a Day-Ahead Revenue Sufficiency Guarantee Credit.

The Transmission Provider shall determine on an hourly basis whether Price Sensitive Demand Bid, Virtual Bid, and External Asynchronous Resources Export Schedule, or dispatchable Export Schedule charges are greater than the Energy value, calculated as the area under the demand curve for Energy as specified in the Market Participant's Demand Bid, External Asynchronous Resources Export Schedule, or dispatchable Export Schedule. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue with a Day-Ahead Revenue Sufficiency Guarantee Credit.

The Transmission Provider shall determine on an hourly basis whether Virtual Supply Offer and dispatchable Import Schedule revenues are less than the Offer Costs for Energy as specified in the Market Participant's Virtual Supply Offer or dispatchable Import Schedule. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue with a Day-Ahead Revenue Sufficiency Guarantee Credit.

The Transmission Provider shall determine on an hourly basis whether Up-to-TUC Interchange Schedule transmission usage costs are greater than the Transmission Usage Charge Bid or Offer. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue with a Day-Ahead Revenue Sufficiency Guarantee Credit.

The Transmission Provider shall determine on an hourly basis whether a Market Participant's revenues are less than the associated Verified Energy Offer costs. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue with a Day-Ahead Revenue Sufficiency Guarantee Credit.

All Market Participant Day-Ahead Revenue Sufficiency Guarantee Credits shall be funded in accordance with Section 39.3.1A and the Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge as set forth in Section 40.3.3.2.b.

Charges and Payments for Purchases and Sales for Demand Response Resources

When the Day-Ahead LMP is greater than or equal to the Net Benefit Price Threshold, Market Participants that sell Energy in the Day-Ahead Energy and Operating Reserve Market from Demand Response Resources shall be credited each Hour at the Day-Ahead LMP at the applicable Commercial Pricing Node. When the Day-Ahead LMP is less than the Net Benefit Price Threshold, Market Participants that sell Energy in the Day-Ahead Energy and Operating Reserve Market from Demand Response Resources shall be credited each Hour at the Day-Ahead LMP at the applicable Commercial Pricing Node. Market Participants with Day-Ahead Financial Schedules will be charged or credited the applicable Day-Ahead LMP for Day-Ahead Financial Schedule(s).

a. Financial Schedules and Through Schedules are settled only for the Transmission Usage Charge derived pursuant to Section 39.3.3.c.

b. Import Schedules, net of Day-Ahead Financial Schedules, shall be credited, and Export Schedules, net of Day-Ahead Financial Schedules, shall be charged for all scheduled MWh at the Day-Ahead Ex Post LMP at the appropriate Interface Commercial Pricing Node.

c. The Transmission Provider shall collect a Transmission Usage Charge for all Through Schedules in the Day-Ahead Energy and Operating Reserve Market. The Transmission Usage Charges for Through Schedules from a given Point of Receipt to a given Point of Delivery shall be the product of: (i) the amount of Energy scheduled to be withdrawn by the Market Participant in each Hour at the Point of Delivery, in MWh; and (ii) the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node for the Point of Delivery minus the Day-Ahead Ex Post LMP at the Commercial Pricing Node for the Point of Receipt, in $/MWh. The Transmission Usage Charge includes the Cost of Congestion and the Cost of Losses as defined below; provided, however, that Energy delivered to a non-jurisdictional Generation Resource with existing Firm Point-To-Point Transmission Service at the Transmission Provider Interface is not subject to the Cost of Congestion or Cost of Losses as long as it does not schedule Energy into the Transmission Provider Region and does not Offer Energy into the Energy and Operating Reserve Markets.

i. **Cost of Congestion.** The Cost of Congestion shall be calculated as the Marginal Congestion Component of the Day-Ahead Ex Post LMP at the Point of

Delivery minus the Marginal Congestion Component of the Day-Ahead Ex Post LMP at the Point of Receipt, as described in this Section.

ii. **Cost of Losses.** The Cost of Losses shall be calculated as the Marginal Losses Component of the Day-Ahead Ex Post LMP at the Point of Delivery minus the Marginal Losses Component of the Day-Ahead Ex Post LMP at the Point of Receipt, as described in this Section.

d. The Transmission Provider shall collect and disburse a Transmission Usage Charge for all Financial Schedules submitted to be considered for Settlement in the Day-Ahead Energy and Operating Reserve Market. The Transmission Usage Charges for the seller shall be the product of (i) the amount of Energy scheduled, in MWh, and (ii) the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node for the Delivery Point minus the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node for the Source Point. The Transmission Usage Charges for the buyer shall be the product of: (i) the amount of Energy scheduled, in MWh, and (ii) the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node for the Sink Point minus the Day-Ahead Ex Post LMP at the applicable Commercial Pricing Node for the Delivery Point.

e. The Transmission Provider is not the Energy Market Counterparty to the sale of Energy under a Financial Schedule transaction and collects and disburses the Transmission Usage Charge for a Financial Schedule as agent for the buyer and seller.

All FTRs will be settled pursuant to the provisions set forth below, irrespective of whether they are obtained through the initial allocation, FTR Auctions, contributions made to Network Upgrades, or through a secondary FTR transaction.

a. **Calculation of the Transmission Congestion Credit Target Allocation.** For each Hour in the Day-Ahead Energy and Operating Reserve Market, the Transmission Provider shall determine the Cost of Congestion associated with Transmission Service from a designated FTR Receipt Point to a designated FTR Delivery Point specified in each FTR Obligation or FTR Option. In each instance when the applicable Cost of Congestion from the FTR Receipt Point to the FTR Delivery Point is positive, the Transmission Provider shall credit to the FTR Holder (of either a FTR Obligation or FTR Option) an amount equal to the applicable hourly Cost of Congestion from the FTR Receipt Point to the FTR Delivery Point multiplied by the specified FTR Quantity (Transmission Congestion Credit). In each instance when the applicable Cost of Congestion from the FTR Receipt Point to the FTR Delivery Point is negative, the Transmission Provider shall charge to each FTR Holder of a FTR Obligation (but not the FTR Holder of a FTR Option) an amount equal to the absolute value of the applicable Cost of Congestion from the FTR Receipt Point to the FTR Delivery Point multiplied by the specified FTR Quantity.

The Transmission Provider shall calculate for each FTR Holder for each Hour, the FTR Holder's Target Allocation for the Transmission Congestion Credit, which shall be the sum of the FTR Holder's Transmission Congestion Credits for that Hour.

b. **Settlement of FTRs.** The Transmission Provider shall compare, for each Hour, the total of all Target Allocations for the Transmission Congestion Credit to the Hourly Transmission Congestion Charges collection.

i. If the total of all Target Allocations for the

Transmission Congestion Credit for a given Hour is less than the Hourly Transmission Congestion Charges collection for that same Hour, the Transmission Provider shall pay to each FTR Holder an amount equal to its Target Allocation for the Transmission Congestion Credit for that Hour (Transmission Congestion Charge). The difference between the total of all Transmission Congestion Charges for a given Hour and the Hourly Transmission Congestion Charges collection for that same Hour shall accrue in the Excess Congestion Charge Fund. After the end of a given Month, the Excess Congestion Charge Fund shall be distributed to fund any deficiency in the share of Transmission Congestion Credits received by each FTR Holder as described in Section 39.3.4.c.

ii. If the total of all Transmission Congestion Credit Target Allocations for a given Hour is equal to the total of the Hourly Transmission Congestion Charges collection for that same Hour, the

Transmission Provider shall credit to each FTR Holder an amount equal to its Target Allocation for the Transmission Congestion Credit for that Hour.

iii If the total of all Target Allocations for the Transmission Congestion Credit for a given Hour is greater than the total of the Hourly Transmission Congestion Charges collection for that same Hour, the Transmission Provider shall credit to each FTR Holder an amount equal to its share of the Hourly

Transmission Congestion Charges collection for that same Hour in proportion to its Target Allocation for the Transmission Congestion Credit, concurrent with an FTR full funding guarantee credit which when summed with the discounted Transmission Congestion Credit will equal the Transmission Congestion Credit Target Allocation. The cost of full funding guarantee within each Hour is allocated to FTR Holders on a *pro rata* basis based upon the portion of the Transmission Congestion Credit Target Allocation associated only with FTRs representing credit to FTR Holder. The Transmission Provider shall suspend fully funding revenue deficient FTRs under extraordinary circumstances. For the purposes of this Section 39.3.4.b.iii, "extraordinary circumstances" shall mean an event of Force Majeure, as defined in Section 10.1 of this Tariff, affecting existing or planned transmission facilities that Transmission Provider determines is likely to result in a substantial revenue deficiency relating to the full funding of FTRs.

The shortfalls in Hourly Transmission Congestion Charges shall be offset by credits from the Excess Congestion Charge Fund after the end of each Month.

c. Determination and Disposition of Excess Congestion Charge Fund.

i. The Transmission Provider will distribute the amounts accumulated in the Excess Congestion Charge Fund collected for Operating Days during the Month in question after the end of each Month to each FTR Holder in proportion to the difference between Transmission Congestion Credits received by the FTR Holder during that Month and its total Transmission Congestion Credit Target Allocations for the Month. Amounts distributed to FTR Holders will be accompanied by an equal and opposite reduction of the FTR full funding guarantee credit accumulated over the Month in hourly funding processes as set forth in the Business Practices Manuals.

The cost of the FTR full funding guarantee credit allocated to FTR Holders will be reduced such that the remaining total of funds for all FTR Holders is distributed *pro rata* on the basis of the sum total of the portion of the Transmission Congestion Credit Target Allocation associated only with FTRs representing a credit to the FTR Holder over the entire Month. If insufficient funds exist in the Excess Congestion Charge Fund to satisfy all deficiencies, then deficiencies will carry forward to the end of the Year.

ii.After the end of each calendar year, the Excess Congestion Fund will be distributed, on a *pro rata* basis, to FTR Holders who did not receive their total Transmission Congestion Credit Target Allocations for the same calendar year. Amounts distributed to FTR Holders will be accompanied by an equal and opposite reduction of the FTR full funding guarantee credit accumulated over the Year in hourly and monthly funding processes. The cost of the FTR full funding guarantee credit allocated to FTR Holders is distributed *pro rata* on the basis of the sum total of the portion of the Transmission Congestion Credit Target Allocation associated with FTRs representing a credit to the FTR Holder over the Year. If insufficient funds exist in the Excess Congestion Charge Fund to satisfy all deficiencies at the end of the year, the deficiencies shall not be carried forward to the following calendar year.

To the extent FTRs are fully funded and there is a surplus of funds in the Excess Congestion Fund, the aggregate remaining excess revenues attributable to the year-end Excess Congestion Charge Fund will be distributed to all Transmission Customers taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service based on a *pro rata* share of their billing determinants used in calculating the Schedule 10 charges and Schedule 23 charges associated with such Transmission Service taken during the same calendar year, regardless of whether these Transmission Customers hold FTRs for their Transmission Service. This year-end distribution of the Excess Congestion Charge Fund to FTR Holders and/or to Network Integration Transmission Service and Firm Point-to-Point Transmission Service customers constitutes final settlement and such distribution is not subject to subsequent resettlements that may occur. Any residual positive or negative Excess Congestion Charge Fund that may result from such resettlements shall be reflected in the then-current calendar year annual distribution.

The Transmission Provider shall calculate the Day-Ahead Marginal Losses Surplus, as specified below. The Day-Ahead Marginal Losses Surplus is summed with the Real-Time Marginal Losses Surplus, calculated pursuant to Section 40.5, to determine the Marginal Losses Surplus, allocated to Market Participants as described in Section 40.6.

a. The Transmission Provider shall calculate for each Hour of the Day-Ahead Energy and Operating Reserve Market the Day-Ahead Marginal Losses Surplus as the Total Day-Ahead Charges for Energy purchases, minus Total Day-Ahead Credits for Energy sales, minus Total Day-Ahead Congestion Charges:

i. The total Day-Ahead Energy and Operating Reserve Market Charges for Energy purchases (including cleared Virtual Bids and Export Schedules) for each Hour of the Day-Ahead Energy and Operating Reserve Market will be the sum across all Commercial Pricing Nodes of Day-Ahead Ex Post LMP multiplied by the Scheduled Withdrawals excluding any purchases covered by Grandfathered Agreement schedules or Day 1 Inadvertent Credit Schedules.

ii. The total Day-Ahead Energy and Operating Reserve Market Credits for Energy sales (including cleared Virtual Supply and Import Schedules) for each Hour of the Day-Ahead Energy and Operating Reserve Market will be the sum across all Commercial Pricing Nodes of Day-Ahead Ex Post LMP multiplied by the Scheduled Injections excluding any sales covered by Grandfathered Agreements or Day 1 Inadvertent Credit Schedules.

iii. The total Day-Ahead Energy and Operating Reserve Market Congestion credits for each Hour of the Day-Ahead Energy and Operating Reserve Market will be the sum across all Commercial Pricing Nodes of: (a) the Marginal Congestion Component of the Day-Ahead Ex Post LMP multiplied by the Scheduled Withdrawals (including cleared Virtual Bids and Export Schedules but excluding withdrawals covered by Grandfathered Agreements or Day 1 Inadvertent Credit Schedules); minus (b) the Marginal Congestion Component of the Day-Ahead Ex Post LMP multiplied by the Scheduled Injections (including cleared Virtual Supply Offers and Export Schedules but excluding any injections covered by Grandfathered Agreements or Day 1 Inadvertent Credit Schedules).

Real-Time Energy and Operating Reserve Market and Operating Day Processes and Settlement:

This Section contains the RAC procedures the Transmission Provider will follow using SCUC to commit Resources to meet forecast Energy, Operating Reserve Requirements, Up Ramp Capability Requirement, Down Ramp Capability Requirement, and Short-Term Reserve Requirements in each Hour of the SCUC Instructed Hours of Operation based on Market Participants' Offers submitted in the Real-Time Energy and Operating Reserve Market. The RAC processes are as follows: (i) any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, (ii) the RAC process conducted after the posting of the Day-Ahead Energy and Operating Reserve Market results on the Day prior to the Operating Day, and (iii) any intra-Day Operating Day RAC process.

The Transmission Provider in its role as the Energy and Operating Reserve Market Operator shall provide the following services for the Real-Time Energy and Operating Reserve Market.

i. Establish and post on the internet, rules and procedures, including Offer rules, for eligibility to participate in the RAC process in the Real-Time Energy and Operating Reserve Market.

ii. Establish and post Offer rules for RAC, as such rules are set forth in Section 40.

iii. Commit Resources to provide Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market based on, but not limited to, system reliability needs, system operational considerations, and the use of a SCUC algorithm to determine the least costly means of supplying the Capacity required to serve the forecast demand and satisfy the Operating Reserve Requirements, Up Ramp Capability Requirements, Down Ramp Capability Requirements, and Short-Term Reserve Requirements. The selection will be communicated either electronically or through other means to the Market Participants. Virtual Transactions and Resources on either planned or forced outages are not permitted to participate in any RAC process in the Real-Time Energy and Operating Reserve Market.

a. **Designated Capacity Resource Obligation – Energy, Contingency Reserve, and Short-Term Reserve.** Consistent with Section 69A.5, Market Participants with designated Capacity Resources must submit, for any portion of a Resource designated as a Capacity Resource, a Self-Schedule or Offer for Energy, Contingency Reserve, and Short-Term Reserve. A designated Capacity Resource is eligible to clear Up Ramp Capability and/or Down Ramp Capability if the Resource is dispatchable and indicates participation through its Up and Down Ramp Capability Dispatch Status. Such Offers shall be consistent with the requirements specified in Section 40 and in the Business Practices Manuals. This designated Capacity Resource must Offer obligation applies to all RAC processes executed prior to the Operating Day as specified in RAR, except to the extent that the designated Capacity Resource is unavailable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restriction consistent with this Tariff.

b. **Transitional Designated Capacity Resource Obligation – Regulating Reserve.** Market Participants with designated Capacity Resources must submit, for any portion of a Resource designated as a Capacity Resource, an Offer for Regulating Reserve if a Regulation Qualified Resource, provided that, such must-offer requirement shall terminate one hundred eighty (180) days after the implementation of the Energy and Operating Reserve Markets. Such Offers shall be consistent with the requirements specified in this Section and in the Business Practices Manuals. This transitional obligation applies to all RAC processes executed prior to the Operating Day, except to the extent that the designated Capacity Resource is unable to provide Regulating Reserve due to a forced or planned outage or other physical operating restrictions consistent with this Tariff.

c. **Releasing Designated Capacity Resource Obligation.** The Market Participants are released from the must Offer obligation if not committed in the Day-Ahead Energy and Operating Reserve Market or any RAC process prior to the Operating Day. The Transmission Provider may curtail Market Participants' Export Schedules sourced from designated Capacity Resources during the Operating Day for Emergencies or to maintain MISO Balancing Authority Area reliability. Procedures for such Curtailments shall be specified in the Business Practices Manuals.

d. **Non-designated Capacity Resource Obligation.** A Market Participant shall not have the obligation to Offer Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve into the Energy and Operating Reserve Markets for any portion of a Resource not designated as a Capacity Resource.

The Transmission Provider shall use the data inputs set forth in this Section in executing the RAC process.

a. Load Forecast

The Transmission Provider shall conduct Hourly Load Forecasts for the Transmission Provider Region pursuant to procedures set forth in the Business Practices Manuals.

b. Net Scheduled Interchange

The Transmission Provider shall consider cleared Day-Ahead Interchange Schedules and Real-Time Interchange Schedules when executing the RAC process.

c. Resource Information

Market Participants may, but are not obligated to, submit Offers for any Capacity not selected for a Day-Ahead Schedule. Market Participants must indicate for each Hour of the Operating Day if Resources are to be self-committed. Market Participants whose Resources were not selected for a Day-Ahead Schedule, but are designated as Capacity Resources pursuant to RAR, are obligated to submit Offers or Self-Schedules into the RAC process conducted the Day prior to the Operating Day after the Day-Ahead Energy and Operating Reserve Market results are posted. A Market Participant must submit or update their real-time Offers and/or Self-Schedules prior to the execution of the RAC process, which normally occurs at 1430 EPT or one hour following the posting of the Day-Ahead Energy and Operating Reserve results, whichever is later.

d. Offer Requirements and Specifications for the RAC Process

A Market Participant intending to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve into the RAC process shall submit the information requested in the Real-Time Offer specifications described in Sections 40.2.5 through 40.2.7.

e. Intermittent and Dispatchable Intermittent Resource Forecast

The Transmission Provider shall conduct Hourly Intermittent Resource and Dispatchable Intermittent Resource Forecasts for the Transmission Provider Region pursuant to procedures set forth in the Business Practices Manuals.

a. Timing

The Transmission Provider will conduct RAC processes as necessary beginning seven (7) Days prior to the Operating Day. The Transmission Provider will conduct a Day-Ahead RAC process sequentially after the closing and publishing of the Day-Ahead Energy and Operating Reserve Market results at 1330 hours EPT, or such later time as may be required from time to time due to unanticipated events. The Day-Ahead RAC rebid process starts at 1330 hours EPT or following the posting of the Day-Ahead Energy and Operating Reserve Market results, whichever is greater, and closes one Hour after the posting of the Day-Ahead Energy and Operating Reserve Market results, at which time the Day-Ahead RAC analysis begins. The Transmission Provider will conduct RAC processes as necessary during the Operating Day.

b. RAC Objective Function

The Transmission Provider shall use the RAC process to commit Resources in a manner that minimizes the total Capacity costs to satisfy the Load Forecast, Operating Reserve Requirements, Up Ramp Capability Requirement, Down Ramp Capability Requirement, and Short-Term Reserve Requirements using a SCUC algorithm that minimizes the total commitment costs of procuring the Capacity needed to meet one-hundred percent (100%) of the Transmission Provider Load Forecast, Regulating Reserve Requirement, Spinning Reserve Requirement, Supplemental Reserve Requirement, Up Ramp Capability Requirement, Down Ramp Capability Requirement, and Short-Term Reserve Requirement while enforcing physical and reliability constraints.

The commitment costs to procure Capacity include all costs based on Start-Up Offers, No-Load Offers, Energy Offer curves up to the Hourly Economic Minimum Limit for Generation

Resources, Demand Response Resources-Type II and Stored Energy Resources – Type II, all costs based on Energy Offers, Shut-Down Offers, and Hourly Curtailment Offers for Demand Response Resources-Type I.

c. Notification

The Transmission Provider will notify the Market Participants of those Resources that have been committed in any RAC process sufficiently in advance to enable the Market Participant to comply with RAC obligations, consistent with the design and operating characteristics of such Resources, and will instruct such Market Participants when to start their Resources and operate at the Hourly Economic Minimum Limit. The Transmission Provider will notify the Market Participant by phone or electronic communication prior to the start of the Operating Day of those Resources that have been committed for a Voltage and Local Reliability Commitment in the Day-Ahead Energy and Operating Reserve Market or any RAC Process conducted prior to the Operating Day. The Transmission Provider will notify the Market Participant by phone or electronic communication during the Operating Day for those Resources that have been committed for a Voltage and Local Reliability Commitment in any RAC process that is necessary during the Operating Day.

d. Resource Obligations

Resources committed by the Transmission Provider in any RAC process must adhere to instructions on when to start and operate in their normal dispatch range, to the extent feasible, and must submit an Energy Offer, applicable Operating Reserve Offers, a Resource Offer Up and Down Ramp Capability Dispatch Status, and an on-line Short-Term Reserve Dispatch Status for the Resource’s full Capacity in the Real-Time Energy and Operating Reserve Market regardless of whether all or a portion of the Resource's Capacity is or is not designated as a Capacity Resource.

This Section contains the procedures the Transmission Provider follows using a security constrained unit commitment algorithm to recommend Resource commitments and decommitments to meet forecast Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve requirements in each interval of the LAC process based on Market Participants' Offers submitted in the Real-Time Energy and Operating Reserve Market.

The Transmission Provider, in its role as the Energy and Operating Reserve Market operator, shall provide the following services for the Real-Time Energy and Operating Reserve Market.

i. Establish and post on the internet, rules and procedures, including Offer rules, for eligibility to participate in the LAC process in the Real-Time Energy and Operating Reserve Market, consistent with this Section 40.

ii. Commit and decommit Resources to provide Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market based on, but not limited to, system reliability needs, system operational considerations, and the use of a security constrained unit commitment algorithm to determine the least costly means to serve the Load Forecast, Operating Reserve Requirements, Up Ramp Capability requirement, Down Ramp Capability requirement, Short-Term Reserve Requirements, and other demand requirements. The selection will be communicated either electronically or through other means to the Market Participants. Virtual Transactions and Resources on either planned or Forced Outages are not permitted to participate in the LAC process in the Real-Time Energy and Operating Reserve Market.

The Transmission Provider shall use the data inputs set forth in this Section in executing the LAC process.

a. Load Forecast

The Transmission Provider shall conduct Load Forecasts for the LAC process intervals for the Transmission Provider Region pursuant to procedures set forth in the Business Practices Manuals.

b. Net Scheduled Interchange

The Transmission Provider shall consider Interchange Schedules cleared in the Day-Ahead Energy and Operating Reserve Market and Interchange Schedules in the Real-Time Energy and Operating Reserve Market when executing the LAC process.

c. Intermittent Resource and Dispatchable Intermittent Resource Forecasts

The Transmission Provider shall conduct Intermittent Resource and Dispatchable Intermittent Resource forecasts for the LAC process intervals for the Transmission Provider Region pursuant to procedures set forth in the Business Practices Manuals.

d. Resource Information

Market Participants may, but are not obligated to, submit Offers for any Capacity not selected for a Day-Ahead Schedule. Market Participants must indicate for each Hour of the Operating Day if Resources are to be self-committed.

e. Offer Requirements and Specifications for the LAC Process

A Market Participant intending to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve into the LAC process shall submit the information requested in the Real-Time Offer specifications described in Sections 40.2.5 through 40.2.7.

a. Timing

The Transmission Provider will conduct the LAC process every fifteen (15) minutes or more frequently as may be deemed necessary during the Operating Day. The LAC study period shall be three (3) hours or such other period as may be determined by the Transmission Provider based on operational conditions. The LAC process will use the following rules for the granularity of the LAC intervals: (i) each interval shall be 15 minutes for the first two hours of the study; (ii) each interval shall be 30 minutes for the third hour of the study; and (iii) each interval shall be 60 minutes for any other hours of the study. Each LAC study involves simultaneous analysis of up to three (3) scenarios with varying assumptions for the forecasted system conditions of the LAC study period. The LAC study period will generally overlap with the Intra-Day RAC study period, which includes all remaining hours of the Operating Day. When considering Resource commitments and decommitments during the LAC study period, the Transmission Provider will primarily rely on the LAC study results. The Transmission Provider will primarily rely on the Intra-Day RAC study results for Resource commitment decisions beyond the LAC study period.

b. LAC Objective Function

The Transmission Provider shall use the LAC process, using a security constrained unit commitment algorithm to recommend Resource commitments and decommitments for each interval of the LAC process with the objective of minimizing the Production Costs and Operating Reserve Costs while meeting the Transmission Provider Load Forecast, Regulating Reserve requirement, Spinning Reserve requirement, Supplemental Reserve requirement, Up Ramp Capability Requirement, Down Ramp Capability Requirement, Short-Term Reserve

Requirement and other demand requirements, and while enforcing physical and reliability constraints.

Resource commitments that have been made previously by the Transmission Provider shall be considered in the following manner in the LAC process:

i. A Resource is deemed committed, and not considered eligible to be decommitted through the LAC process, during the portion of the LAC study period for which the Resource has been committed by the Day-Ahead Energy and Operating Reserve Market.

ii. A Resource is deemed committed, and is eligible to be decommitted through the LAC process, during the portion of the LAC study period for which the Resource has been committed through any prior RAC process or any prior LAC process.

iii. A Resource is deemed uncommitted, and is eligible for commitment and subsequent decommitment through the LAC process, during the portion of the LAC study period for which the Resource has not been committed by any prior process.

c. Notification

The Transmission Provider will notify the Market Participants of Resources that have been committed or decommitted in the LAC process sufficiently in advance to enable the Market Participants to comply with LAC obligations, consistent with the design and operating characteristics of such Resources, and will instruct such Market Participants when to start their Resources and operate at the Hourly Economic Minimum Limit, or when to stop their Resources. The Transmission Provider will notify the Market Participant by phone or electronic communication during the Operating Day for those Resources that have been committed for a Voltage and Local Reliability Commitment in any LAC process.

d. Resource Obligations

Resources committed by the Transmission Provider in the LAC process must adhere to instructions on when to start and operate in their normal dispatch range, to the extent feasible, and must submit an Energy Offer, applicable Operating Reserve Offers, a Resource Offer Up and Down Ramp Capability dispatch status, and an on-line Short-Term Reserve Dispatch Status for the Resource's full Capacity in the Real-Time Energy and Operating Reserve Market regardless of whether all or a portion of the Resource's Capacity is or is not designated as a Capacity Resource.

The Real-Time Energy and Operating Reserve Market is a physically binding market in which (i) cleared values and Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve, (ii) Real-Time Ex Ante LMPs and Real-Time Ex Post LMPs for Energy, and (iii) Real-Time Ex Ante and Real-Time Ex Post Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, Down Ramp Capability MCP, and Short-Term Reserve MCP are calculated for each five (5) minute Dispatch Interval based on submitted Offers and using SCED and SCED-Pricing algorithms as set forth in this Section 40.2. The clearing and pricing of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market is based on a simultaneous co-optimization processes in which the total costs of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve are minimized. The SCED simultaneous co-optimization process ensures: (i) that all Real-Time Ex Ante LMPs, Operating Reserve MCPs, Up Ramp Capability MCPs, Down Ramp Capability MCPs, and Short-Term Reserve MCPs for each Resource supplying Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve through economic clearing are greater than or equal to the corresponding Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve costs respectively when the Resource is not scheduled at a limit. Such Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve costs are equal to the corresponding Energy, Operating Reserve, and/or off-line Short-Term Reserve Offers for the Resource plus any Opportunity Costs incurred from any reductions in the sale of an alternative product; (ii) available Regulating Reserve in excess of requirements can be utilized to meet Contingency Reserve requirements, where only Regulating Capacity Offer will be taken into account for the portion of Regulating Reserve used to meet Contingency Reserve requirements, and available Spinning Reserve in excess of requirements can be used to meet Supplemental Reserve requirements, provided that Regulating Reserve cleared on Stored Energy Resources cannot be used to meet Contingency Reserve requirements; and (iii) Regulating Reserve Real-Time Ex Ante MCPs are greater than or equal to Spinning Reserve Real-Time Ex Ante MCPs, and Spinning Reserve Real-Time Ex Ante MCPs are greater than or equal to Supplemental Reserve Real-Time Ex Ante MCPs, provided that Regulating Reserve Real-Time Ex Ante MCPs may be less than or equal to Spinning Reserve Real-Time Ex Ante MCPs in the event that all Regulating Reserve is cleared by Stored Energy Resources.

SCED-Pricing, as described in Schedule 29A of this Tariff, uses simultaneous co-optimization to calculate Real-Time Ex Post LMP and Real-Time Ex Post MCPs. SCED-Pricing allows Fast Start Resources and Emergency Operations Resources that are committed in any RAC process and scheduled at limits by SCED to set Real-Time Ex Post Prices. In instances when SCED indicates Energy or Reserve scarcity or the violation of transmission constraints, SCED-Pricing can set prices by reflecting the cost of committing a Fast Start Resource if this is an action that the Transmission Provider could take to alleviate the scarcity or violation at lower cost than the scarcity price or transmission violation penalty price.

The Real-Time Energy and Operating Reserve Market operates continuously throughout the Operating Day on a five (5) minute basis. The Real-Time Energy and Operating Reserve Market is cleared each Dispatch Interval based on Real-Time Energy, Operating Reserve and Short-Term Reserve Offers and the Up and Down Ramp Capability Dispatch Status to determine Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for each Resource for the end of the next Dispatch Interval.

The Transmission Provider, in its role as the Energy and Operating Reserve Market Operator, shall provide the following services for the Real-Time Energy and Operating Reserve Market.

a. Establish and post on the internet rules and procedures, including Offer rules, for eligibility to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market.

b. Establish and post on the internet rules for determination of any additional charges necessary to support efficient operations of the Real-Time Energy and Operating Reserve Market.

c. Determine the power system conditions within the Transmission Provider Region every five (5) minutes by using the most recent power flow solution produced by the State Estimator.

d. Dispatch Resources to provide Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market based on, but not limited to, system reliability needs, system operational considerations, and the use of a SCED algorithm to determine the least costly means of serving the forecast demand and satisfying the Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve Requirements.

e. Communicate Dispatch Targets to Resources every five (5) minutes based on the results of the SCED algorithm

f. Calculate and transmit Setpoint Instructions to Resources as set forth in the

Business Practices Manuals.

g. Provide the Settlement functions associated with the purchase and sale of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market.

h. Determine and post the Real-Time Ex Ante LMPs and Real-Time Ex Post LMPs for Energy, Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Operating Reserves, Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Up Ramp Capability, Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Down Ramp Capability, and Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Short-Term Reserve for each five (5) minute Dispatch Interval.

a. Market-Wide Regulating Reserve Requirements

All cleared Regulating Reserve in the Real-Time Energy and Operating Reserve Market must be deployable in both the regulation-up and regulation-down directions within the Regulation Response Time consistent with the Resource limit and ramping constraints as set forth in Schedule 29. The Regulation Response Time will be determined and/or adjusted by the Transmission Provider on a periodic basis to comply with Applicable Reliability Standards. The hourly Real-Time Market-Wide Regulating Reserve Requirements will be initially set equal to the corresponding hourly day-ahead Market-Wide Regulating Reserve Requirements as established by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market, but may be adjusted if necessary to ensure reliable operations. The Real-Time Market-Wide Regulating Reserve Requirement may vary on an hourly basis if permitted by Applicable Reliability Standards. All Regulating Reserve cleared in the Real-Time Energy and Operating Reserve Market must be supplied by Regulation Qualified Resources. The percentage of Regulating Reserve cleared in the Real-Time Energy and Operating Reserve Market on any individual Generation Resource, Demand Response Resource–Type II, Stored Energy Resource, Stored Energy Resource – Type II and/or External Asynchronous Resource shall initially be limited to twenty percent of the hourly Real-Time Market-Wide Regulating Reserve Requirement to the extent that such limitation does not create Regulating Reserve scarcity conditions or any other adverse reliability related conditions, and may be further limited on Demand Response Resources – Type II or Stored Energy Resources – Type II based on Applicable Reliability Standards.

b. Market-Wide Contingency Reserve Product Requirements

All cleared Contingency Reserve in the Real-Time Energy and Operating Reserve Market must be deployable within the Contingency Reserve Deployment Period. The Real-Time Market-Wide Contingency Reserve Requirement shall be equal to the corresponding hourly Market-Wide Contingency Reserve Requirements as established by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market, but may be adjusted by the Transmission Provider if necessary to comply with Applicable Reliability Standards. The Real-Time Market-Wide Contingency Reserve Requirement may vary on an hourly basis if permitted by Applicable Reliability Standards. Following a Contingency Reserve Deployment Instruction, the Market-Wide Contingency Reserve Requirement may be temporarily reduced by the amount of the deployment, and then restored to the pre-contingency Market-Wide Contingency Reserve Requirement ninety (90) minutes after the end of the Disturbance Recovery Period or such other replenishment time as may be specified by Applicable Reliability Standards. All Market-Wide Spinning Reserve cleared in the Real-Time Energy and Operating Reserve Market must be supplied by Spin Qualified Resources. All Market-Wide Supplemental Reserve cleared in the Real-Time Energy and Operating Reserve Market must be supplied by Supplemental Qualified Resources. The Real-Time Market-Wide Spinning Reserve requirement will be equal to the Market-Wide Contingency Reserve Requirement multiplied by the greater of (i) the minimum frequency responsive Contingency Reserve percentage requirement specified by Applicable Reliability Standards, if applicable, and (ii) the minimum Spinning Reserve percentage requirement specified by Applicable

Reliability Standards. The Real-Time Market-Wide Supplemental Reserve requirement will be equal to the Market–Wide Contingency Reserve Requirement minus the Real-Time Market-Wide Spinning Reserve Requirement. The percentage of Spinning Reserve and/or Supplemental Reserve cleared in the Real-Time Energy and Operating Reserve Market on any individual Resource shall be limited to twenty percent of the hourly Real-Time Market-Wide Contingency Reserve Requirement to the extent that such limitation does not create scarcity conditions or any other adverse reliability related conditions, and may be further limited on Demand Response Resource – Type I, Demand Response Resources – Type II and/or Stored Energy Resources – Type II specific Resources based on Applicable Reliability Standards.

c. Co-optimized Zonal Operating Reserve Product Requirements

In the Real-Time Energy and Operating Reserve Market, one or more Reserve Zones will be established to ensure Regulating Reserve, Contingency Reserve, and Short-Term Reserve are dispersed in a manner that prevents adverse operating conditions that affect the reliability of the Transmission System in accordance with Good Utility Practice. The definition and attributes of the Reserve Zones utilized in the Real-Time Energy and Operating Reserve Market for a specific Operating Day will be the same as the definition and attributes of the Reserve Zones utilized in the Day-Ahead Energy and Operating Reserve Market, including the number of Reserve Zones required, and the assignment of Resource, Load and/or Interface Elemental Pricing Nodes to Reserve Zones.

d. Reserve Zone Supply Limitation on Stored Energy Resources.

Regulating Reserve cleared on Stored Energy Resources will be ineligible to satisfy Co-optimized Zonal Operating Reserve requirements.

e. Product Requirements for Up Ramp Capability and Down Ramp Capability

The Market-Wide Up Ramp Capability Requirements and Market-Wide Down Ramp Capability Requirements represent the need for Resources with ability to adjust their power outputs consistent with the Resource limit and ramping constraints as set forth in Schedule 29 to respond to future expected changes in dispatchable generation to account for forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatachable generation and a selected degree of confidence in short-term uncertainty associated with the Load Forecast, non-dispatchable generation forecast, and units not responding to their real-time Setpoints within the Ramp Capability Response Time. Up Ramp Capability and Down Ramp Capability MCPs and analysis of reliable delivery within transmission constraints incorporate the same Reserve Zones defined for Operating Reserve.

i. Market-Wide Up Ramp Capability Product Requirements.

The Real-Time Market-Wide Up Ramp Capability Requirement will be established each Dispatch Interval by the Transmission Provider to estimate the required Up Ramp Capability which represents the future need to ramp from the Resource Dispatch Targets for Energy calculated for the end of the Dispatch Interval to the expected increase in required Energy (negative for a decrease in required Energy) plus the unexpected upward variation in the market-wide Energy needs at the Ramp Capability Response Time beyond the end of the Dispatch Interval for a selected degree of confidence. The Market-

Wide Up Ramp Capability Requirement must be non-negative; if the expected upward change in the required Energy plus the variability is less than zero, then the Market-Wide Up Ramp Capability Requirement will be set to zero. The Market-Wide Up Ramp Capability Requirement will be updated each Dispatch Interval based on the most recently available forecast and uncertainty data. The Market-Wide Up Ramp Capability Requirement may be manually adjusted to ensure reliable operations. All Up Ramp Capability cleared in the Real-Time Energy and Operating Reserve Market must be supplied by Up and Down Ramp Capability Qualified Resources. The percentage of Up Ramp Capability cleared in the Real-Time Energy and Operating Reserve Market on any individual Generation Resource, Demand Response Resource – Type II, Stored Energy Resource – Type II or External Asynchronous Resources shall initially be limited to twenty percent of the Real-Time Market-Wide Up Ramp Capability Requirement to the extent that such limitation does not create Up Ramp Capability shortages or any other adverse reliability related conditions. This individual Resource percentage limit may be adjusted by the Transmission Provider to improve reliability, system operations, or market efficiency.

ii. Market-Wide Down Ramp Capability Product Requirements.

The Real-Time Market-Wide Down Ramp Capability Requirement will be established each Dispatch Interval by the Transmission Provider to estimate the required Down Ramp Capability which represents the future need to ramp from the Resource Dispatch Targets for Energy calculated for the end of the Dispatch Interval to the expected decrease in required Energy (negative for an increase in required Energy) plus the unexpected downward variation in the market-wide Energy needs at the Ramp Capability Response Time beyond the end of the Dispatch Interval for a selected degree of confidence. The Market-Wide Down Ramp Capability Requirement must be non-negative; if the expected downward change in the required Energy plus the downward variability is less than zero, then the Market-Wide Down Ramp Capability Requirement will be set to zero. The Market-Wide Down Ramp Capability Requirement will be updated each Dispatch Interval based on the most recently available forecast and uncertainty data. The Market-Wide Down Ramp Capability Requirement may be manually adjusted to ensure reliable operations. All Down Ramp Capability cleared in the Real-Time Energy and Operating Reserve Market must be supplied by Up and Down Ramp Capability Qualified Resources. The percentage of Down Ramp Capability cleared in the Real-Time Energy and Operating Reserve Market on any individual Generation Resource, Demand Response Resource – Type II, Stored Energy Resource – Type II, or External Asynchronous Resources shall initially be limited to twenty percent of the Real-Time Market-Wide Down Ramp Capability Requirement to the extent that such limitation does not create Down Ramp Capability shortages or any other adverse reliability related conditions. This individual Resource percentage limit may be adjusted by the Transmission Provider to improve reliability, system operations, or market efficiency.

f. Short-Term Reserve Product Requirements

All cleared Short-Term Reserve in the Real-Time Energy and Operating Reserve Market must be deployable within the Short-Term Reserve Deployment Period. All Short-Term

Reserve cleared in the Real-Time Energy and Operating Reserve Market must be supplied by Short-Term Reserve Qualified Resources. Market-Wide Short-Term Reserve Requirements, Sub-Regional Short-Term Reserve Requirements, and Local Short-Term Reserve Requirements are explained below.

i. Market-Wide Short-Term Reserve Requirements.

The real-time Market-Wide Short-Term Reserve Requirement shall be equal to the corresponding hourly Market-Wide Short-Term Reserve Requirements as established by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market, but may be adjusted by the Transmission Provider if necessary to address market-wide reliability needs.

ii. Sub-Regional Short-Term Reserve Requirements.

The real-time Sub-Regional Short-Term Reserve Requirements will be established as necessary for a sub-region for each Dispatch Interval to establish the required Short-Term Reserve needed to be dispatched as Energy to restore flows within limits following contingencies or abnormal events. Sub-Regional Short-Term Reserve Requirements will be derived from rampable Capacity needs, Energy schedules, and contractual constraints, such as the Sub-Regional Power Balance Constraints, to ensure deliverability. Short-Term Reserve cleared to meet Sub-Regional Short-Term Reserve Requirements will also count towards the Market-Wide Short-Term Reserve Requirement.

iii. Local Short-Term Reserve Requirements.

The real-time Local Short-Term Reserve Requirements will be established as necessary for a Reserve Zone for each Dispatch Interval to establish the required Short-Term Reserve needed to be dispatched as Energy to restore flows within limits following contingencies or abnormal events. Local Short-Term Reserve Requirements will be derived from rampable Capacity needs, Energy schedules, and local transmission constraints to ensure deliverability. Short-Term Reserve cleared to meet Local Short-Term Reserve Requirements will also count towards applicable Sub-Regional Short-Term Reserve Requirements and the Market-Wide Short-Term Reserve Requirement.

The qualification requirements set forth below allow Regulating Reserve to serve as Spinning Reserve or Supplemental Reserve, and Spinning Reserve to serve as Supplemental Reserve. Accordingly, when it is more economic to do so, the Transmission Provider may make any of the following substitutions: Regulating Reserve for Spinning Reserve, Regulating Reserve for Supplemental Reserve, or Spinning Reserve for Supplemental Reserve.

a. Regulation Qualified Resources

All Regulation Qualified Resources in the Real-Time Energy and Operating Reserve Market must meet all of the requirements for Regulation Qualified Resources specified in this Section. Only Regulation Qualified Resources will be permitted to supply Regulating Reserve in the Real-Time Energy and Operating Reserve Market. All Regulation Qualified Resources in the Real-Time Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Regulation Qualified Resources. All Resources, except Stored Energy Resources, registered as Regulation Qualified Resources must also be registered in the Energy and Operating Reserve Markets as Spin Qualified Resources and as Supplemental Qualified Resources, to allow cleared on-line Regulation Qualified Resources to supply Spinning Reserve or Supplemental Reserve through substitution of such Resources for Spin Qualified Resources or Supplemental Qualified Resources. All Regulation Qualified Resources in the Real-Time Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Regulation Qualified Resources in the Real-Time Energy and Operating Reserve

Market must be capable of automatically responding to and alleviating frequency deviations through a speed governor or similar device in accordance with Applicable Reliability Standards. All Regulation Qualified Resources in the Real-Time Energy and Operating Reserve Market must be capable of supplying Regulating Reserve for a minimum continuous duration of sixty (60) minutes. The Regulating Reserve Deployment on a Stored Energy Resource shall not exceed the energy storage capabilities of such Resource. All Regulation Qualified Resources supplying Regulation in the Real-Time Energy and Operating Reserve Market must be capable of receiving and responding to automatic control signals and must provide telemetered output data. Regulation Qualified Resources in the Real-Time Energy and Operating Reserve Market will be limited to (i) on-line and synchronized Generation Resources that are not Dispatchable Intermittent Resources, (ii) External Asynchronous Resources, (iii) on-line and synchronized Demand Response Resources - Type II, (iv) available Stored Energy Resources, and available Stored Energy Resources – Type II. A Market Participant can disqualify a Regulation Qualified Resource from supplying Regulating Reserve on an Hourly basis should physical operating restrictions make the Resource unable to deploy Regulating Reserve in accordance with the product requirements for Regulating Reserve established in Section 40.2.3 (a) and the Business Practices Manuals.

b. Spin Qualified Resources

All Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market must meet all of the requirements for Spin Qualified Resources specified in this Section. Only Spin Qualified Resources will be permitted to supply Spinning Reserve in the Real-Time Energy and Operating Reserve Market and as Supplemental Qualified Resources, to allow cleared Spin

Qualified Resources to supply Supplemental Reserve. All Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Spin Qualified Resources. All Resources, except Stored Energy Resources, registered as Regulation Qualified Resources will be registered as Spin Qualified Resources by default. All Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resources. All Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market must comply with the requirements imposed by Applicable Reliability Standards for Resources supplying Spinning Reserve and, if applicable, frequency responsive Contingency Reserve. All Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market must be capable of deploying their cleared Spinning Reserve within the Contingency Reserve Deployment Period consistent with the Resource limit and ramping constraints as set forth in Schedule 29. All Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market must be capable of deploying their cleared Spinning Reserve, consistent with the Resource limit and ramping constraints as set forth in Schedule 29, for a minimum continuous duration of sixty (60) minutes. All Spin Qualified Resources supplying Spinning Reserve in the Real-Time Energy and Operating Reserve Market must provide telemetered output data or, in the case of a Demand Response Resource must provide Metered data consistent with Attachment TT. Spin Qualified Resources in the Real-Time Energy and Operating Reserve Market will be limited to (i) on-line and synchronized Generation Resources that are not Dispatchable Intermittent Resources, (ii) uncommitted Demand Response Resources - Type I that have a Minimum Interruption Duration of sixty (60) minutes or less in order to be classified as Spin Qualified Resources, (iii) on-line and synchronized Demand Response Resources - Type II, (iv) available Stored Energy Resources – Type II, and (v) available External Asynchronous Resources. A Market Participant can disqualify a Spin Qualified Resource from supplying Spinning Reserve on an Hourly basis should physical operating restrictions make the Resource unable to deploy Spinning Reserve in accordance with the product requirements for Spinning Reserve established in Section 40.2.3.b and the Business Practices Manuals. If a Resource is disqualified from providing Spinning Reserve, it is disqualified from providing Regulating Reserve

c. Supplemental Qualified Resources

All Supplemental Qualified Resources in the Real-Time Energy and Operating Reserve Market must meet all of the requirements for Supplemental Qualified Resources specified in this Section. Only Supplemental Qualified Resources will be permitted to supply Supplemental Reserve in the Real-Time Energy and Operating Reserve Market. All Supplemental Qualified Resources in the Real-Time Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Supplemental Qualified Resources. All Supplemental Qualified Resources in the Real-Time Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Supplemental Qualified Resources in the Real-Time

Energy and Operating Reserve Market must be capable of deploying one hundred percent (100%) of their cleared Contingency Reserve within the Contingency Reserve Deployment Period. All Supplemental Qualified Resources in the Real-Time Energy and Operating Reserve Market must be capable of deploying one hundred percent (100%) of their cleared Contingency Reserve for a minimum continuous duration of sixty (60) minutes. All Supplemental Qualified Resources supplying Supplemental Reserve in the Real-Time Energy and Operating Reserve Market must provide telemetered output data or, in the case of a Demand Response Resource, must provide Metered data consistent with Attachment TT. Supplemental Qualified Resources in the Real-Time Energy and Operating Reserve Market will be limited to (i) on-line and synchronized Generation Resources that are not Dispatchable Intermittent Resources, (ii) off-line and available Quick-Start Resources, (iii) uncommitted Demand Response Resources - Type I, (iv) on-line and synchronized Demand Response Resources - Type II, (v) on-line and synchronized Stored Energy Resources – Type II, and (vi) available External Asynchronous Resources.

Off-Line Quick-Start Resources and Demand Response Resources - Type I must have a Minimum Run Time (or Minimum Interruption Duration, if a Demand Response Resource–Type I) of one hundred eighty (180) minutes or less in order to be classified as Supplemental Qualified Resources. A Market Participant can disqualify a Supplemental Qualified Resource from supplying Supplemental Reserve on an Hourly basis should physical operating restrictions make the Resource unable to deploy Supplemental Reserve in accordance with the product requirements for Supplemental Reserve established in Section 40.2.3.b and the Business

Practices Manuals. If a Resource is disqualified from providing Supplemental Reserve, it is disqualified from providing Regulating Reserve and Spinning Reserve.

The Transmission Provider shall have the right to test Resources with Supplemental Qualified Resource status, or Resources seeking Supplemental Qualified Resource status, to determine whether the Supplemental Qualified Resource is capable of the deployment of Contingency Reserves in response to a Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period.

In the event that the testing of a Resource is subsequent to a Supplemental Qualified Resource's failure to respond to a Contingency Reserve Deployment Instruction, such Resource shall receive the applicable LMP in the Real-Time Energy and Operating Reserve Markets for the Actual Energy Injection of the Resource during the test or for the duration of the Resource's Minimum Run Time, whichever is longer. Additionally, the amount of Supplemental Reserve the Resource may clear in the Real-Time Energy and Operating Reserve Market shall be capped at the actual amount of Contingency Reserve deployed at the end of the Contingency Reserve Deployment Period achieved during the test until the Resource achieves a higher level of output in a subsequent test or actual deployment.

In the event that the Transmission Provider initiates a test of a Supplemental Qualified Resource that is not associated with the Supplemental Qualified Resource's failure to respond to a Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period, the Resource shall be committed by the Transmission Provider, shall receive the applicable LMP in the Real-Time Energy and Operating Reserve Markets for the Actual Energy Injection of the Resource, and is eligible for Real-Time Revenue Sufficiency Guarantee Credit pursuant to Section 40.3.3.3.c. To the extent that the Resource fails to respond to the Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period during the test deployment, the amount of Supplemental Reserve the Resource may clear in the Real-Time Energy and Operating Reserve Market shall be capped at the actual amount of Contingency Reserve deployed at the end of the Contingency Reserve Deployment Period achieved during the test until the Resource achieves a higher level of output in a subsequent test or actual deployment.

d. Resource Requirements for Up Ramp Capability and Down Ramp Capability

All Resources eligible to provide Up Ramp Capability and/or Down Ramp Capability in the Real-Time Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area, or the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. All Resources eligible to provide Up Ramp Capability and/or Down Ramp Capability must be dispatchable for Energy in the Real-Time Energy and Operating Reserve Market and capable of changing resource Energy output consistent with the Resource limit and ramping constraints set forth in Schedule 29 within the Ramp Capability Response Time. Up Ramp Capability and Down Ramp Capability eligibility in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) on-line and synchronized Generation Resources, (ii) available External Asynchronous Resources, (iii) on-line and synchronized Demand Response Resources - Type II, and (iv) on-line and synchronized Stored Energy Resources – Type II. Market Participants may disqualify a Resource from supplying Up and Down Ramp

Capability on an Hourly basis using the Resource Offer Up and Down Ramp Capability Dispatch Status.

e. Resource Requirements for Short-Term Reserve

All Resources eligible to provide Short-Term Reserve in the Real-Time Energy and Operating Reserve Market must be physically located within the MISO Balancing Authority Area, or the entire Generation Resource must be Pseudo-tied into the MISO Balancing Authority Area and must remain Pseudo-tied into the MISO Balancing Authority Area until the next Network Model update, or the Resource must be an External Asynchronous Resource. Market Participants may restrict a Resource from supplying Short-Term Reserve on an Hourly basis using the Resource Offer on-line or off-line Short-Term Reserve Dispatch Status, consistent with Module E-1 obligations.

i. Resource Requirements for on-line Resources providing Short-Term Reserve

All on-line Resources eligible to provide Short-Term Reserve must be dispatchable for Energy in the Real-Time Energy and Operating Reserve Market and capable of changing Resource Energy output consistent with the Resource limit and ramping constraints set forth in Schedule 29 within the Short-Term Reserve Deployment Period. Short-Term Reserve eligibility for on-line Resources in the Real-Time Energy and Operating Reserve Market will be limited to (i) on-line and synchronized Generation Resources that are not Dispatchable Intermittent Resources or Intermittent Resources, (ii) available External Asynchronous Resources; (iii) on-line and synchronized Demand Response Resources - Type II; and on-line and synchronized Stored Energy Resources-Type II.

ii. Resource Requirements for off-line Resources providing Short-Term Reserve

All Off-Line Short-Term Reserve Qualified Resources in the Real-Time Energy and Operating Reserve Market must meet all of the requirements for Off-Line Short-Term Reserve Qualified Resources specified in this Section. Only Off-Line Short-Term Reserve Qualified Resources will be permitted to supply Short-Term Reserve while off-line in the Real-Time Energy and Operating Reserve Market. All Off-Line Short-Term Reserve Qualified Resources in the Real-Time Energy and Operating Reserve Market must be registered in the Energy and Operating Reserve Markets as Off-Line Short-Term Reserve Qualified Resources. Short-Term Reserve eligibility for off-line Resources in the Real-Time Energy and Operating Reserve Market will be limited to (i) uncommitted Generation Resources that are not Dispatchable Intermittent Resources and Intermittent Resources, (ii) uncommitted Demand Response Resources - Type II, uncommitted Stored Energy Resources – Type II; and (iii) Demand Response Resources - Type I. Uncommitted Generation Resources and Demand Response Resources - Type II, uncommitted Stored Energy Resources – Type II and Demand Response Resources-Type I, must be capable of achieving Economic Minimum Dispatch within the Short-Term Reserve Deployment Period and must have a Minimum Run Time (or Minimum Interruption Duration, if a Demand Response Resource - Type I) of two-hundred-forty (240) minutes or less in order to be classified as Offline Short-Term Reserve Qualified Resources. All Off-Line Short-Term Reserve Qualified Resources in the Real-Time Energy and Operating Reserve Market must be capable of deploying one-hundred percent

(100%) of their cleared Short-Term Reserve within the Short-Term Reserve Deployment Period. All Off-Line Short-Term Reserve Qualified Resources in the Real-Time Energy and Operating Reserve Market must be capable of deploying one-hundred percent (100%) of their cleared Short-Term Reserve for a minimum continuous duration of sixty (60) minutes. All Off-Line Short-Term Reserve Qualified Resources supplying Short-Term Reserve in the Real-Time Energy and Operating Reserve Market must provide telemetered output data for the Resource through the appropriate data communications equipment, as set forth in the Business Practices Manuals. A Market Participant can disqualify an Off-Line Short-Term Reserve Qualified Resource from supplying Short-Term Reserve on an Hourly basis should physical operating restrictions make the Resource unable to deploy Short-Term Reserve in accordance with the product requirements for Short-Term Reserve established in Section 40.2.3.f.

The Transmission Provider shall have the right to test Resources with Off-Line Short-Term Reserve Qualified Resource status, or Resources seeking Off-Line Short-Term Reserve Qualified Resource status, to determine whether each Resource is capable of the deployment of Short-Term Reserves in response to a Short-Term Reserve Deployment Instruction within the Short-Term Reserve Deployment Period.

In the event that the Transmission Provider initiates a test of an Off-Line Short-Term Reserve Qualified Resource, the Resource shall be committed by the Transmission Provider, shall receive the applicable LMP in the Real-Time Energy and Operating Reserve Markets for the Actual Energy Injection of the Resource, and is eligible for Real-Time Revenue Sufficiency Guarantee Credit pursuant to Section 40.3.3.3.c.

Before January 1, 2022, existing Resources shall self-certify as Off-Line Short-Term Reserve Qualified Resources. On or after January 1, 2022, certification as an Off-Line Short-Term Reserve Qualified Resource for all new Resources shall require passing a Transmission Provider initiated test. A new Resources that tests and qualifies as a Supplemental Qualified Resource will not need to undergo additional testing to qualify as an Off-Line Short-Term Reserve Qualified Resource.

Generation Offer, Demand Response Resource-Type II Offer and Stored Energy Resource – Type II Offer Rules in the Real-Time Energy and Operating Reserve Market:

Market Participants that intend to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve in the Real-Time Energy and Operating Reserve Market shall provide the information specified in this Section. Generation Offers, Demand Response Resource-Type II Offers and Stored Energy Resource – Type II Offer shall be submitted in the Real-Time Energy and Operating Reserve Market only for registered Generation Resources, registered Demand Response Resources-Type II and Stored Energy Resources – Type II Offers. Generation Offers, Demand Response Resource-Type II Offers and Stored Energy Resource – Type II Offers will remain in effect for the Real-Time Energy and Operating Reserve Market until specifically superseded by subsequent Generation Offers, Demand Response Resource-Type II Offers or Stored Energy Resource – Type II Offers. Each Market Participant may only submit a single Generation Offer, Demand Response Resource-Type II Offer or Stored Energy Resource – Type II Offers, for each individual Resource. Market Participants may submit new or revised Generation Resource Offers, Demand Response Resource–Type II Offers or Stored Energy Resource – Type II Offers, including Self-Schedules (except for Up Ramp Capability and Down Ramp Capability), to the Real-Time Energy and Operating Reserve Market up to thirty (30) minutes prior to the operating Hour.

a. **Eligibility to Supply**

Generation Resources, Demand Response Resources - Type II or Stored Energy Resources – Type II may supply Energy in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to five (5) minute Dispatch Targets for Energy and has the appropriate telemetry installed. A Generation Resource, Demand Response Resource–Type II or Stored Energy Resource – Type II may not (i) offer Energy, (ii) offer and/or supply Operating Reserve, (iii) offer and/or supply Up Ramp Capability or Down Ramp Capability, or (iv) offer and/or supply Short-Term Reserve unless such Resource has been included in the Network Model. A Market Participant's Generation Resources, Demand Response Resources-Type II or Stored Energy Resources – Type II can supply Regulating Reserve, Spinning Reserve, Supplemental Reserve, and/or Short-Term Reserve in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Regulation Qualified Resource, Spin Qualified Resource, Supplemental Qualified Resource and/or Short-Term Reserve Qualified Resource, respectively. Market Participants that offer to supply Real-Time Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve shall provide the Offer information specified below.

b. Required Generation Offer, Demand Response Resource - Type II and Stored Energy Resources – Type II Offer Components

Market Participants that submit Generation Offers, Demand Response Resource-Type II Offers and/or Stored Energy Resource – Type II Offers shall include an Energy Offer curve, a Regulating Capacity Offer and a Regulating Mileage Offer (if a Regulation Qualified Resource), a Spinning Reserve Offer (if a Spin Qualified Resource), an On-Line Supplemental Reserve Offer (if a Supplemental Qualified Resource but not a Spin Qualified Resource), an Off-Line Supplemental Reserve Offer (if a Quick-Start

Resource), an Off-Line Short-Term Reserve Offer (if an Off-Line Short-Term Reserve Qualified Resource), a Start-Up Offer, a No-Load Offer, an Up and Down Ramp Capability Dispatch Status Offer, and an on-line and off-line Short-Term Reserve Dispatch Status Offer. Market Participants can provide Generation Offers, Demand Response Resource - Type II Offers and/or Stored Energy Resource – Type II Offers for the full MW range of their Operable Capacity, from the Hourly Emergency Minimum Limit to the Hourly Emergency Maximum Limit, or the DIR Feasibility Limit for Dispatchable Intermittent Resources, and may indicate, as part of the Offer, that the Generation Resource, Demand Response Resource – Type II or Stored Energy Resource – Type II is only available to be committed during an Emergency. Market Participants may submit a Generation Offer and/or Demand Response Resource-Type II Offer that contains zero dollar ($0) amounts for No-Load and Start-Up Offers, in which case only the Energy Offer curve, Regulating Capacity Offer and Regulating Mileage Offer (if applicable), Spinning Reserve Offer (if applicable), On-Line Supplemental Reserve Offer (if applicable), Off-Line Supplemental Reserve Offer (if applicable), an Off-Line Short-Term Reserve Offer (if applicable), Up and Down Ramp Capability Dispatch Status Offer, and/or Short-Term Reserve Dispatch Status Offer will be considered by the market clearing process pursuant to Section 40.2.8. Any limits on the Offer over the full quantity (MW) range of the Operable Capacity must be consistent with Module D. A single Generation Offer or Demand Response Resource - Type II Offer may be submitted in the Real-Time Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Energy and Operating Reserve from a given Resource, except that the Forecast Maximum Limit submitted for a Dispatchable Intermittent Resource will be considered by the market clearing process pursuant to Section 40.2.5.b.xxxiii. The Transmission Provider shall maintain a Real-Time Energy and Operating Reserve Market Generation Offer, Demand Response Resource - Type II Offer and/or Stored Energy Resource – Type II Offer for each Resource. These Offers are standing Offers and are maintained for the Real-Time Energy and Operating Reserve Market independent of the Day-Ahead Energy and Operating Reserve Market. These Offers may be updated for a specific Hour up to thirty (30) minutes prior to the beginning of the Hour Generation Resource, Demand Response Resource - Type II Offer and/or Stored Energy Resource – Type II Offer components are as follows:

i. **Energy Offer Curve.** The Energy Offer curve shall be expressed for each Hour in $/MWh and shall consist of either a stepped or a piecewise linear Offer curve of up to ten (10) segments, shall be monotonically increasing, and shall cover the full operating range, including the Hourly Emergency Minimum Limit and Hourly Emergency Maximum Limit, or the DIR Feasibility Limit for Dispatchable Intermittent Resources.

ii. **Regulating Capacity Offer and Regulating Mileage Offer.** For DRR - Type II Resources or Stored Energy Resources – Type II, the Regulation Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Regulation Qualified Resources. For Generation Resources, the Regulating Capacity Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to Regulation Qualified Resources. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must $0/MW. In a given Hour, any Resource with Regulating Reserve cleared in Day-Ahead Energy and Operating Reserve Market must have the same Real-Time Regulating Mileage Offer as its Day-Ahead Regulating Mileage Offer.

iii. **Spinning Reserve Offer.** For DRR - Type II or Stored Energy Resource – Type II, the Spinning Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Spin Qualified Resources. For Generation Resources, the Spinning Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to Spin Qualified Resources.

iv. **On-Line Supplemental Reserve Offer.** For DRR - Type II or Stored Energy Resource – Type II, the On-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to synchronized Supplemental Qualified Resources that are not Spin Qualified Resources. For Generation Resources, the On-Line Supplemental Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to synchronized Supplemental Qualified Resources that are not Spin Qualified Resources.

v. **Off-Line Supplemental Reserve Offer.** For DRR - Type II or Stored Energy Resource – Type II, the Off-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Resources that are uncommitted Quick-Start Resources. For Generation Resources, the Off-Line Supplemental Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to Resources that are uncommitted Quick-Start Resources.

vi. **Start-Up Offer.** The Start-Up Offer shall be expressed for each Day in $/start. A separate Start-Up Offer shall be submitted for hot, intermediate, and cold Start-Up conditions.

vii. **No-Load Offer.** The No-Load Offer shall be expressed for each Hour in $/Hour.

viii. **Commercial Pricing Node.** A Commercial Pricing Node shall be specified for the Generation Resource, Demand Response Resource - Type II or Stored Energy Resource – Type II at the time the asset is registered. The Commercial Pricing Node shall be the same one used for the Resource in the Day-Ahead Energy and Operating Reserve Market.

ix. **Hourly Ramp Rates.** An Offer shall include (i) an Hourly Ramp Rate expressed for each Hour in MW/minute to be used by RAC processes, (ii) an Hourly Single-Directional-Up Ramp Rate expressed for each hour in MW/Minute to be used by the Real-Time Energy and Operating Reserve Market and the LAC process, (iii) an Hourly Single-Directional-Down Ramp Rate expressed for each Hour in MW/Minute to be used by the Real-Time Energy and Operating Reserve Market and the LAC process, and iv) an Hourly Bi-Directional Ramp Rate expressed for each Hour in MW/minute to be used by the Real-Time Energy and Operating Reserve Market and the LAC process. If one or more of these ramp rates is not submitted, the default ramp rates will be used. The default ramp rates are specified during the asset registration process and can be updated by Market Participant from the Market Portal.

x. **Hourly Economic Minimum Limit.** An Offer shall include an Hourly Economic Minimum Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xi. **Hourly Economic Maximum Limit.** An Offer shall include an Hourly Economic Maximum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Real-Time Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR and committed by the Transmission Provider prior to the Operating Day, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions; provided, however, that Offers from Dispatchable Intermittent Resources shall not include an Hourly

Economic Maximum Limit. If no Hourly Economic Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xii. **Hourly Emergency Minimum Limit.** An Offer shall include an Hourly Emergency Minimum Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xiii. **Hourly Emergency Maximum Limit.** An Offer shall include an Hourly Emergency Maximum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Real-Time Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR and committed by the Transmission Provider prior to the Operating Day, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions; provided, however, that Offers from Dispatchable Intermittent Resources shall not include an Hourly Emergency Maximum Limit. If no Hourly Emergency Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xiv. **Hourly Regulation Minimum Limit.** An Offer shall include, if the Resource is a Regulation Qualified Resource and subject to the transitional must offer requirements specified under Sections 40.1.2.b, an Hourly Regulation Minimum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Regulating Capability of a Resource from the Real-Time Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR during the transitional must offer requirement period specified under Section 40.1.2.b unless the Resource is unavailable due to a forced or planned outage or the Resource is not qualified to supply Regulating Reserve due to physical operating restrictions. If no Hourly Regulation Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xv. **Hourly Regulation Maximum Limit.** An Offer shall include, if the Resource is a Regulation Qualified Resource and subject to the transitional must offer requirements specified under Sections 40.1.2.b, an Hourly Regulation Maximum Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Real-Time Energy and Operating Reserve Market if such Capacity was used to calculate the Unforced Capacity of a designated Capacity Resource pursuant to RAR during the transitional must offer requirement period specified under Section 40.1.2.b unless the Resource is unavailable due to a forced or planned outage or the Resource is not qualified to supply Regulating Reserve due to physical operating restrictions. If no Hourly Regulation Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xvi. **Minimum Run Time.** An Offer shall include a Minimum Run Time, expressed for each Day in Hours.

xvii. **Maximum Run Time.** An Offer shall include a Maximum Run Time, expressed for each Day in Hours.

xviii. **Minimum Down Time.** An Offer shall include a Minimum Down Time, expressed for each Day in Hours.

xix. **Start-Up Times.** An Offer shall include a hot, intermediate, and cold Start-Up Time, each of which is expressed for each Hour in Hours and minutes.

xx. **Start-Up Notification Times.** An Offer shall include a hot, intermediate, and cold Start-Up Notification Time, each of which is expressed for each Hour in Hours and/or Minutes.

xxi. **Maximum Off-Line Response Limit.** An Offer shall include a Maximum Off-Line Response Limit, expressed for each Hour in MW. This requirement applies to Quick-Start Resources only. If no Hourly Maximum Off-Line Response Limit is submitted, the default Maximum Off-Line Response Limit will be used. The default Maximum Off-Line Response Limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xxii. Maximum Start-Up Limit. An Offer shall include a Maximum Start-Up Limit, expressed for each Day in Starts per Day.

xxiii. Maximum Daily Energy. An Offer shall include specification a Maximum Daily Energy amount, if applicable, expressed for each Day in MWh.

xxiv. Hot-to-Intermediate Time. An Offer shall include a Hot-to-Intermediate Time, expressed for each Day in Hours and/or minutes.

xxv. Hot-to-Cold Time. An Offer shall include a Hot-to-Cold Time, expressed for each Day in Hours and/or minutes.

xxvi. Commitment Status. An Offer shall include specification of a Commitment Status for each Hour. Valid Commitment Status specifications include: Economic, Must-Run, Emergency, Outage and Not Participating. An Economic Commitment Status indicates the Transmission Provider is authorized to commit the Resource on an economic basis for the Hour. A Must-Run Commitment Status indicates that the Market Participant is self-committing the Resource for the Hour. An Emergency Commitment Status indicates the Transmission Provider is authorized to commit the Resource only under an Emergency condition for the Hour. An Outage Commitment Status indicates the Resource is not available for commitment during the Hour due to a planned or forced outage. A Not Participating Commitment Status indicates the Market Participant will not operate a Resource that is otherwise available. The Not Participating Commitment Status will not be available prior to the Operating Day to any Resource that has all or a portion of its Capacity designated as a Capacity

Resource nor will the Not Participating Commitment Status be available once the Resource has been committed in the Day-Ahead Energy and Operating Reserve Market, any RAC process, or the LAC process.

xxvii. **Energy Dispatch Status.** An Offer shall include specification of an Energy Dispatch Status for Energy. Valid Energy Dispatch Status specifications include: Economic and Self-Schedule. An Economic Energy Dispatch Status indicates that the Transmission Provider is authorized to economically clear Energy on the Resource for the Hour. A Self-Schedule Energy Dispatch Status indicates that the Market Participant is self-scheduling Energy on the Resource for the Hour. The Energy Dispatch Status only applies to Resources that are committed for the Hour.

xxviii. **Regulating Reserve Dispatch Status.** An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve. Valid Regulating Reserve Dispatch Status specifications include: Economic, Self-Schedule, Not Qualified and Not Participating. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour. A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is self-scheduling Regulating Reserve on the Resource for the Hour. A Not Qualified Regulating Reserve Dispatch Status indicates that the Resource is not qualified to provide Regulating Reserve for an Hour. A Not Participating Regulating Reserve

Dispatch Status indicates the Market Participant will not provide Regulating Reserve on a Resource that is otherwise qualified to provide Regulating Reserve. The Not Participating Regulating Reserve Dispatch Status will not be available prior to the Operating Day to any Resource that has all or a portion of its Capacity designated as a Capacity Resource for the first 180 days of the Energy and Operating Reserve Market. The Regulating Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) registered as Regulation Qualified Resources.

xxix. **Spinning Reserve Dispatch Status.** An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is self-scheduling Spinning Reserve on the Resource for the Hour. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. The Spinning Reserve Dispatch Status cannot be set to Not Qualified for a specific Resource in a specific Hour unless the Regulating Reserve Dispatch Status is also set to Not Qualified for that Resource in that Hour. For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to Section 40.2.5.b.xxiii of the Tariff in order to not participate in providing Spinning Reserve. The Spinning Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) are registered as Spin Qualified Resources.

xxx. **On-Line Supplemental Reserve Dispatch Status.** An Offer shall include specification of an On-Line Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid On-Line Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic On-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Self-Schedule On-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is self-scheduling Supplemental Reserve on the Resource for the Hour if the Resource is committed and not a Spin Qualified Resource. A Not Qualified On-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour as a committed Resource. For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to Section 40.2.5.b.xxiii of the Tariff in order to not participate in providing On-Line Supplemental Reserve. The On-Line Supplemental Reserve Dispatch Status only applies to Resources that are i) committed for the Hour, ii) registered as Supplemental Qualified Resources and, iii) not Spin Qualified Resources or have been disqualified by the Market Participant as Spin Qualified Resources for the Hour.

xxxi. Off-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an Off-Line Supplemental Reserve Dispatch Status for Off-Line Supplemental Reserve. Valid Off-Line Supplemental Reserve Dispatch Status specifications include: Economic, Emergency, Self-Schedule, Not Qualified and Not Participating. An Economic Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour if the Resource is uncommitted. An Emergency Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour if the Resource is uncommitted and all available Resources with an Economic Commit Status have been committed. A Self-Schedule Off-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is self-scheduling Off-Line Supplemental Reserve on the Resource for the Hour if the Resource is uncommitted. A Not Qualified Off-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Off-Line Supplemental Reserve for an Hour as an uncommitted Quick-Start Resource. A Not Participating Off-Line Supplemental Reserve Dispatch Status indicates the Market Participant will not provide Off-Line Supplemental Reserve on an uncommitted Resource that is otherwise qualified to provide Off-Line Supplemental Reserve. The Not Participating Off-Line Supplemental Reserve Dispatch Status will not be available to any Resource in an Hour where the

Resource cleared Off-Line Supplemental Reserve as an uncommitted Resource in the Day-Ahead Energy and Operating Reserve Market. The Not Participating Off-Line Supplemental Reserve Dispatch Status will not be available to any Resource that has all or a portion of its capacity designated as a Capacity Resource. The Off-Line Supplemental Reserve Dispatch Status only applies to Resources that are uncommitted for the Hour and registered as Quick-Start Resources.

xxxii. Up and Down Ramp Capability Dispatch Status. An Offer shall include specification of an Up and Down Ramp Capability Dispatch Status which applies to both Up Ramp Capability and Down Ramp Capability for each Hour. Valid Up and Down Ramp Capability Dispatch Status specifications include: Economic and Not Participating. An Economic Up and Down Ramp Capability Dispatch Status indicates that the Transmission Provider is authorized to economically clear Up Ramp Capability and/or Down Ramp Capability on the Resource for the Hour. A Not Participating Up and Down Ramp Capability Dispatch Status indicates that the Resource shall not be cleared to supply Up Ramp Capability or Down Ramp Capability for an Hour.

The Up and Down Ramp Capability Dispatch Status only applies to Resources that are i) committed for the Hour and ii) have offered an Energy Dispatch Status of Economic for the Hour.

xxxiii. Forecast Maximum Limit. A Market Participant may submit a Forecast Maximum Limit for each Dispatchable Intermittent Resource, expressed for each

Dispatch Interval in MW, to be used in the real-time SCED algorithm to establish the Economic Maximum Dispatch of the Resource for each Dispatch Interval. The Market Participant-submitted Forecast Maximum Limit will be used for the applicable Dispatch Interval if it meets the following criteria: (A) the Forecast Maximum Limit must be submitted less than 30 minutes prior to the end of the Dispatch Interval; (B) the submitted Forecast Maximum Limit must be less than or equal to the DIR Feasibility Limit, plus a technical margin, as set forth in the Business Practices Manuals; (C) the Forecast Maximum Limit must be submitted prior to the execution of the SCED algorithm for the Dispatch Interval. In the event that the Market Participant-submitted Forecast Maximum Limit does not meet the aforementioned criteria, the Transmission Provider will use either a Transmission Provider-calculated Forecast Maximum Limit, or the State Estimator output for the Resource, in the SCED algorithm, whichever is deemed appropriate by the Transmission Provider using standards set forth in the Business Practices Manuals. To the extent that the Transmission Provider-calculated Forecast Maximum Limit is used in the case, it must meet the following criteria: (A) the Forecast Maximum Limit must be calculated less than 30 minutes prior to the end of the Dispatch Interval; (B) the calculated Forecast Maximum Limit must be less than or equal to the DIR Feasibility Limit, plus a technical margin, as set forth in the Business Practices Manuals; (C) the Forecast Maximum Limit must be calculated prior to the execution of the SCED algorithm for the Dispatch Interval.

xxxiv. **DIR Feasibility Limit.** A DIR Feasibility Limit must be associated with each Dispatchable Intermittent Resource and specified during the Transmission Provider's asset registration process.

xxxv. **Maximum Daily Regulation Up Deployment.** A Maximum Daily Regulation Up Deployment is associated with each DRR-Type II Resource and Stored Energy Resource – Type II, if applicable, and is expressed for each Day in MWh. If no daily Maximum Daily Regulation Up Deployment is submitted, the default Maximum Daily Regulation Up Deployment specified during the asset registration process will be used.

xxxvi. **Maximum Daily Regulation Down Deployment.** A Maximum Daily Regulation Down Deployment is associated with each DRR-Type II Resource and Stored Energy Resource – Type II, if applicable, and is expressed for each Day in MWh. If no daily Maximum Daily Regulation Down Deployment is submitted, the default Maximum Daily Regulation Down Deployment specified during the asset registration process will be used.

xxxvii. **Maximum Daily Contingency Reserve Deployment.** A Maximum Daily Contingency Reserve Deployment is associated with each DRR-Type II Resource and Stored Energy Resource – Type II, if applicable, and is expressed for each Day in MWh. If no daily Maximum Daily Contingency Reserve Deployment is submitted, the default Maximum Daily Contingency Reserve Deployment specified during the asset registration process will be used.

xxxviii. Fast Ramping Resource Offer. An Offer shall include specification of whether the Resource is eligible or ineligible to be treated as a Fast Ramping Resource for each Hour. A valid Fast Ramping Resource Offer shall state a specification of either "Yes" or "No." "Yes" indicates that the Resource could receive fast AGC signals while deploying Regulating Reserves, and "No" indicates that the Resource will not accept fast AGC signals while deploying Regulating Reserves.

(a) Eligibility at Start of Each Hour. At the beginning of each Hour, a Regulation Qualified Resource that is offered as a Fast Ramping Resource shall be deemed eligible to receive fast AGC signals regardless of its performance in the last Dispatch Interval of the preceding Hour.

(b) Eligibility During Each Dispatch Interval. A Regulation Qualified Resource that is offered as a Fast Ramping Resource for a particular Hour shall be eligible to receive fast AGC signals in the first Dispatch Interval of that Hour, and in any ensuing Dispatch Interval of that Hour which is immediately preceded by a Dispatch Interval when the Resource met or exceeded the Fast Ramping Resource Performance Threshold in the Fast Ramping Resource Performance Test during that preceding Dispatch Interval.

(c) Treatment When Ineligible to Receive Fast AGC Signals. If a Regulation Qualified Resource that is offered as a Fast Ramping Resource for a particular Hour fails to meet the Fast Ramping Resource Performance Threshold in the Fast Ramping Resource Performance Test during a particular Dispatch

Interval, other than the last Dispatch Interval of that Hour, the Resource shall receive only regular AGC signals in the next Dispatch Internal. Even when receiving regular AGC signals in a Dispatch Interval, the Resource shall continue undergoing the Fast Ramping Resource Performance Test in that Dispatch Interval, and if it meets the Fast Ramping Resource Performance Threshold, shall be eligible to receive fast AGC signals in the following Dispatch Interval.

xxxix. **Hourly Neutral Zone Upper Limit.** An Offer shall include an Hourly Neutral Zone Upper Limit, expressed in percentage of Hourly Maximum Energy Storage Level. A single Hourly Neutral Zone Upper Limit value of less than or equal to 100 should be used. Resources that are not Use Limited Resources should use a value of 100. This limit value will be used to compute the Fast Ramping Resource AGC signal while sending the Regulating Resource signal.

xl. **Hourly Neutral Zone Lower Limit.** An Offer shall include an Hourly Neutral Zone Lower Limit, expressed in percentage of Hourly Maximum Energy Storage Level. A single Hourly Neutral Zone Lower Limit value of greater than or equal to 0, and less than Hourly Neutral Zone Upper Limit should be used. Resources that are not Use Limited Resources should use a value of 0. This limit value will be used to compute the Fast Ramping Resource AGC signal while sending the Regulating Resource signal.

xli. **Off-Line Short-Term Reserve Offer.** For DRR - Type II Resources or Stored Energy Resources – Type II, the Off-Line Short-Term Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Off-Line Short-Term Reserve Qualified Resources. For Generation Resources, the Off-Line Short-Term Reserve Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Off-Line Short-Term Reserve Qualified Resources.

xlii. **On-line Short-Term Reserve Dispatch Status.** An Offer shall include specification of an on-line Short-Term Reserve Dispatch Status which applies to on-line Resources for each Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for an Hour.

xliii. **Off-line Short-Term Reserve Dispatch Status.** An Offer shall include specification of an off-line Short-Term Reserve Dispatch Status which applies to off-line Resources for each Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for an Hour.

xliv. Maximum Off-Line Short-Term Reserve Response Limit. An Offer shall include a Maximum Off-Line Short-Term Reserve Response Limit, expressed for each Hour in MW. This requirement applies to Off-Line Short-Term Reserve Qualified Resources only. If no hourly Maximum Off-Line Short-Term Reserve Response Limit is submitted, the default Maximum Off-Line Short-Term Reserve Response Limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal. The Maximum Off-Line Short-Term Reserve Response limit must be greater than or equal to the Resource's Economic Minimum Dispatch.

c. Ramp Rate Curves

A Market Participant may specify a Single-Directional-Up Ramp Rate curve, a Single-Directional-Down Ramp Rate curve and a Bi-Directional Ramp Rate curve for use in the Real-Time Energy and Operating Reserve Market and each curve may include up to ten (10) linear segments. Such ramp rate curves may be updated for a specific Hour no less than thirty (30) minutes prior to the beginning of the Hour. The participant may activate the use of such ramp rate curves for a specific Hour no less than thirty (30) minutes prior to the beginning of the Hour. If activated, such ramp rate curves will be used in lieu of the Hourly Single-Directional-Up Ramp Rate, the Hourly Single-Directional Down Ramp Rate and the Hourly Bi-Directional Ramp Rate for a specific Resource during a specific Hour in the Real-Time Energy and Operating Reserve Market. If such ramp rate curves are activated, the LAC process will use the information from the ramp rate curves for a specific Resource during a specific Hour as specified in the Business Practices Manuals.

d. Limit and Ramp Rate Priority

Default operating limits for Resources provided to the Transmission Provider during asset registration and can be overridden by hourly Resource limits (limits applicable to an Operating Hour). Furthermore, hourly limits can be overridden as necessary within an Hour by the Transmission Provider at the request of the Market Participant to reflect real-time changes in the operational capabilities associated with Generation Resources, Demand Response Resources – Type II and/or Stored Energy Resources – Type II. Weather curves for Combustion Turbines apply to all applicable limits. Default ramp rates for Resources provided to the Transmission Provider during asset registration can be overridden by hourly ramp rates and hourly ramp rates can be overridden by ramp rate curves. Furthermore, all ramp rates can be overridden as necessary by the Transmission Provider at the request of the Market Participant within an Hour to reflect changes in the operational capabilities associated with Generation Resources, Demand Response Resources – Type II and/or Stored Energy Resources – Type II. All specified Resource limits, ramp rates and other physical operating parameters are subject to investigation by the Independent Market Monitor pursuant to provisions set forth in Module D.

e. Values in Offers

The values in Offers representing the non-price information in Section 40.2.5.b shall reflect the actual known physical capabilities and characteristics of the Generation Resources, Demand Response Resources - Type II and/or Stored Energy Resources – Type II on which the Offer is based except that the Emergency Maximum Limit, Economic Maximum Limit and Forecast Maximum Limit may, at the discretion of the

Market Participant, be reduced by an amount equal to any Capacity associated with the Resource that is i) not designated as a Capacity Resource, ii) not being used to provide Energy, Operating Reserve, Up Ramp Capability, or Short-Term Reserve to the Day-Ahead Energy and Operating Reserve Market, iii) not being used to provide Capacity in any RAC process or the LAC process, iv) not being used to provide Energy, Operating Reserve, Up Ramp Capability, or Short-Term Reserve to the Real-Time Energy and Operating Reserve Market and iii) not being used to provide Energy, Operating Reserve, Up Ramp Capability, or Short-Term Reserve to any other party or entity.

f. Combined Cycle Units

A Generation Offer for a Generation Resource with combined cycle capability shall be submitted as either an independent Offer for each combustion turbine (CT) and steam turbine (ST) with an alternate steam or thermal source or an aggregate Offer for the combined cycle combustion turbine (CCCT) unit, not both. Once the combined cycle Generation Resource is committed, either as part of the Day-Ahead Energy and Operating Reserve Market, any RAC processes or the LAC process, subsequent Generation Offers submitted must be submitted using the same option, either independent Offer or Aggregate Offer that was used in the commitment of the combined cycle Generation Resource.

g. Weather Curves

Only CTs and CCCTs may submit weather curves. Weather curves specify MW limits for CTs and CCCTs as a function of temperature. Forecast points shall consist of a daytime temperature and a nighttime temperature. The Market Participant shall submit separate weather curves for the Economic Maximum Limit and the Emergency Maximum Limit. Each CT is assigned to a Weather Point, which is entered by the Market Participant and may be changed by the Market Participant. The Market Participant may submit the forecast for the Weather Point. If no forecast is submitted the default values will be used. Submittal timing requirements for Weather Points and forecasts shall be as specified in the Business Practices Manuals.

h. Jointly Owned Generation Resource

Each Market Participant may submit a Generation Offer, including Start-up and No-Load Offers for their respective ownership of a Jointly Owned Generation Resource as long as each share of the Jointly Owned Generation Resource is modeled as an independent Resource in the network and commercial models. Each share of a Jointly Owned Generation Resource will be considered an independent Generation Resource and therefore, a Market-Participant may Pseudo-Tie an entire share of a Jointly Owned Generation Resource into the MISO Balancing Authority Area for the purpose of providing Operating Reserve to the Energy and Operating Reserve Markets. The Transmission Provider will send one Dispatch Instruction signal, to the Market Participant designated as operator by the owners of the Jointly Owned Generation Resource for operations purposes only.

i. Real-Time Energy and Operating Reserve Market Offer Price Caps and Floors.

The following Offer price caps and floors will apply to Generation Resources, Demand Response Resource – Type II Offers and Stored Energy Resource – Type II Offers in the Real-Time Energy and Operating Reserve Market:

i. Energy Offer Soft Price Cap: $1,000/MWh; applied to non-Verified Energy Offers, non-Verified Fast Start Resource All-In Energy Offers, and non-Verified Emergency Operations Resource All-In Energy Offers. Energy Offers, the components of Fast Start Resource All-In Energy Offers, and the components of Emergency Operations Resource All-In Energy Offers, above the Energy Offer Soft Price Cap, submitted before the close of the Real-Time Energy and Operating Reserves Market, but not verified by the Independent Market Monitor until after market clearing, will be used in the determination of Real-Time Revenue Sufficiency Guarantee Credits in accordance with section 40.2.19 of this Tariff.

ii. Energy Offer Hard Price Cap: $2,000/MWh, applied to Verified Energy Offers, Verified Fast Start Resource All-In Energy Offers, and Verified Emergency Operations Resource All-In Energy Offers. Verified Energy Offers, the components of Verified Fast Start Resource All-In Energy Offers, and the components of Verified Emergency Operations Resource All-In Energy Offers, above the Energy Offer Hard Price Cap will be used in the determination of Real-Time Revenue Sufficiency Guarantee Credits in accordance with section 40.2.19 of this Tariff.

iii. Energy Offer Price Floor: Negative $500/MWh

iv. Regulating Total Cost Price Cap: $500/MW/Hour

v. Regulating Total Cost Price Floor: $0/MW/Hour

vi. Contingency Reserve Offer Price Cap: $100/MW/Hour

vii. Contingency Reserve Offer Price Floor: $0/MW/Hour

viii. Regulating Mileage Offer Price Floor: $0/MW

ix. Off-Line Short-Term Reserve Offer Price Cap: $100/MW/Hour

x. Off-Line Short-Term Reserve Offer Price Floor: $0/MW/Hour

Demand Response Resource-Type I Offer Rules in the Real-Time Energy and Operating Reserve Market

Market Participants that intend to supply Energy and Contingency Reserve through a Demand Response Resource - Type I in the Real-Time Energy and Operating Reserve Market shall provide the information specified in this Section. Demand Response Resource - Type I Offers shall be submitted in the Real-Time Energy and Operating Reserve Market only for registered Demand Response Resources - Type I. Demand Response Resource - Type I Offers will remain in effect for the Real-Time Energy and Operating Reserve Market until specifically superseded by subsequent Demand Response Resource - Type I Offers. Each Market Participant may only submit a single Demand Response Resource - Type I Offer for each individual Demand Response Resource - Type I. Market Participants may submit new or revised Demand Response Resource – Type I Offers, including Self-Schedules, to the Real-Time Energy and Operating Reserve Market up to thirty (30) minutes prior to the operating Hour.

a. Eligibility to Supply

Demand Response Resources - Type I may supply Energy in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to real-time demand reduction instructions and has data communication equipment installed that can provide a minimum of hourly demand data for the Resource for Hours in which the Demand Response Resource – Type I that has been committed for Energy, as set forth in the Business Practices Manuals. A Market Participant's Demand Response Resources - Type I can supply Spinning Reserve in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Spin Qualified Resource, Supplemental Reserve in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Supplemental Qualified Resource, or Short-Term Reserve in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Short-Term Reserve Qualified Resource. Demand Response Resources – Type I may not supply Up Ramp Capability or Down Ramp Capability because they are not required to respond to five (5) minute Dispatch Targets for Energy. Market Participants that offer to supply Real-Time Energy, Spinning Reserve, Supplemental Reserve, and/or Short-Term Reserve shall provide the Offer information specified below.

b. Required Demand Response Resource - Type I Offer Components

For Demand Response Resources - Type I that are Spin Qualified Resources, a Market Participant may submit an Energy Offer curve, a Spinning Reserve Offer, a Supplemental Reserve Offer, a Shut-Down Offer, an Hourly Curtailment Offer, an Off-Line Short-Term Reserve Offer, a Demand Response Resource – Type I Contingency Reserve status and an off-line Short-Term Reserve Dispatch Status. For Demand Response Resources - Type I that are not Spin Qualified Resources but which qualify as a Supplemental Qualified Resource, a Market Participant may submit an Energy Offer curve, a Supplemental Reserve Offer, a Shut-Down Offer, an Hourly Curtailment Offer, an Off-Line Short-Term Reserve Offer, and an off-line Short-Term Reserve Dispatch Status. For Demand Response Resources – Type I that are neither Spin Qualified Resources nor Supplemental Qualified Resources, but which qualify as Short-Term Reserve Qualified

Resources, a Market Participant may submit an Energy Offer curve, a Shut-Down Offer, an Hourly Curtailment Offer, an Off-Line Short-Term Reserve Offer, and an off-line Short-Term Reserve Dispatch Status. For Demand Response Resources - Type I that are not Spin Qualified Resources, Supplemental Qualified Resources, or Short-Term Reserve Qualified Resources, a Market Participant may submit an Energy Offer curve, a Shut-Down Offer and an Hourly Curtailment Offer for supply of Energy only. A Market Participant may indicate, as part of the Offer, that the Demand Response Resource – Type I is only available to be committed for Energy during an Emergency or that it is only available to be cleared for Contingency Reserve during an Emergency. A single Demand Response Resource - Type I Offer may be submitted in the Real-Time Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Energy, Contingency Reserve, and/or Short-Term Reserve for a given Resource. The Transmission Provider shall maintain a Real-Time Energy and Operating Reserve Market Offer for each Demand Response Resource - Type I. These Offers are standing Offers and are maintained for the Real-Time Energy and Operating Reserve Market independent of the Day-Ahead Energy and Operating Reserve Market. These Offers may be updated for a specific Hour up to thirty (30) minutes prior to the beginning of the Hour. Demand Response Resource - Type I Offer components are as follows:

i. **Energy Offer Curve.** The Energy Offer curve shall be expressed for each Hour in $/MWh and shall consist of a stepped, single segment representation at the Targeted Demand Reduction Level.

ii. **Spinning Reserve Offer.** The Spinning Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or piecewise linear Offer curve of up to three (3) segments and shall be monotonically increasing. The Spinning Reserve Offer only applies if the Demand Response Resource - Type I is a Spin Qualified Resource.

iii. **Supplemental Reserve Offer.** The Supplemental Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or piecewise linear Offer curve of up to three (3) segments and shall be monotonically increasing. The Supplemental Reserve Offer only applies if the Demand Response Resource - Type I is a Supplemental Qualified.

iv. **Shut-Down Offer.** The Shut-Down Offer is expressed for the Day in $/shut-down.

v. **Hourly Curtailment Offer.** The Hourly Curtailment Offer is expressed for each Hour in $/Hour.

vi. **Demand Response Resource – Type I Contingency Reserve Status.** An Offer shall include a Demand Response Resource – Type I Contingency Reserve status, expressed for each Day. The Demand Response Resource – Type I Contingency Reserve status shall specify whether the Demand Response Resource – Type I will be cleared and deployed in the same manner as Resources clearing and deploying on-line Spinning or Supplemental Reserve, or whether the Demand Response Resource – Type I will be cleared and deployed in the same manner as off-line Resources clearing and deploying Supplemental Reserves. If a Demand

Response Resource – Type I elects to clear and deploy in the same manner as Resources clearing and deploying on-line Spinning or Supplemental Reserve, any Resource commitments made for Contingency Reserve Deployment events will not be SCUC Instructed Hours of Operation. If a Demand Response Resource – Type I elects to clear and deploy in the same manner as off-line Resources clearing and deploying Supplemental Reserves, any Resource commitments made for Contingency Reserve Deployment events will be SCUC Instructed Hours of Operation. If no daily Demand Response Resource – Type I Contingency Reserve status is submitted, the Demand Response Resource – Type I Contingency Reserve status specified during the asset registration process will be used.

vii. **Commercial Pricing Node.** A Commercial Pricing Node shall be specified for the Demand Response Resource - Type I. The Commercial Pricing Node cannot be an Interface, Load Zone, or Hub, but may be an Aggregate Price Node. The Commercial Pricing Node can include an aggregation of Elemental Pricing Nodes or portions of Elemental Pricing Nodes all within a single Local Balancing Authority Area and based on the injection EPNodes for demand response registered by the Market Participant.

viii. **Targeted Demand Reduction Level.** An Offer for a Demand Response Resource - Type I shall include a Targeted Demand Reduction Level, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity Resource from the Real-Time Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR and committed by the Transmission Provider prior to the Operating Day, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Targeted Demand Reduction Level is submitted, the default Targeted Demand Reduction Level specified during the asset registration process will be used.

ix. **Minimum Interruption Duration.** An Offer shall include a Minimum Interruption Duration, expressed for each Day in Hours.

x. **Maximum Interruption Duration.** An Offer shall include a Maximum Interruption Duration, expressed for each Day in Hours.

xi. **Minimum Non-Interruption Interval.** An Offer shall include a Minimum Non-Interruption Interval, expressed for each Day in Hours.

xii. **Maximum Interruption Limit.** An Offer shall include a Maximum Interruption Limit, expressed for each Day in number of interruptions per Day.

xiii. **Maximum Daily Energy.** An Offer shall include specification of a Maximum Daily Energy amount, if applicable, expressed for each Day in MWh.

xiv. **Shut-Down Time.** An Offer shall include a Shut-Down Time, expressed for each Hour in Hours and/or Minutes.

xv. **Shut-Down Notification Time.** An Offer shall include a Shut-Down Notification Time, expressed in Hours and/or Minutes.

xvi. **Energy Commitment Status.** An Offer shall include specification of an Energy Commitment Status for each Hour. Valid Energy Commitment Status specifications include: Economic, Emergency and Not Participating. An Economic Commitment Status indicates the Transmission Provider is authorized to commit the Resource to provide Energy for the Hour on an economic basis. An Emergency Commitment Status indicates the Transmission Provider is authorized to commit the Resource to provide Energy for the Hour under Emergency conditions only. A Not Participating Commitment Status indicates the Market Participant will not provide Energy for the Hour from the Resource, but the Resource could be available for Contingency Reserve depending on the Spinning Reserve Dispatch Status and/or Supplemental Reserve Dispatch Status, as described below. For a Demand Response Resource – Type I that is a designated Capacity Resource, the Not Participating Commitment Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

xvii. Spinning Reserve Dispatch Status. An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule, Emergency, Not Qualified and Not Participating. An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is self-scheduling Spinning Reserve on the Resource for the Hour. An Emergency Spinning

Reserve Dispatch Status indicates the Transmission Provider is authorized to clear Spinning Reserve on the Resource only under Emergency Conditions.

A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. A Not Participating Spinning Reserve Dispatch Status indicates the Market Participant will not provide Spinning Reserve on a Resource that is otherwise qualified to provide Spinning Reserve. For a Demand Response Resource – Type I that is a designated Capacity Resource, the Not Participating Spinning Reserve Dispatch Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

The Spinning Reserve Dispatch Status only applies to Demand Response Resources – Type I that are i) uncommitted for the Hour and ii) registered as Spin Qualified Resources.

xviii. **Supplemental Reserve Dispatch Status.** An Offer shall include specification of a Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule, Emergency, Not Qualified and Not Participating. An Economic Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour. A Self-Schedule Supplemental Reserve Dispatch Status indicates that the Market Participant is self-scheduling Supplemental Reserve on the Resource for the Hour. An Emergency Supplemental Reserve Dispatch Status indicates the

Transmission Provider is authorized to clear Supplemental Reserve on the Resource only under Emergency Conditions.

A Not Qualified Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour. A Not Participating Supplemental Reserve Dispatch Status indicates the Market Participant will not provide Supplemental Reserve on a Resource that is otherwise qualified to provide Supplemental Reserve. For a Demand Response Resource – Type I that is a designated Capacity Resource, the Not Participating Supplemental Reserve Dispatch Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions. The Supplemental Reserve Dispatch Status only applies to Demand Response Resources – Type I that are i) uncommitted for the Hour and ii) registered as Supplemental Qualified.

xix. **Maximum Daily Contingency Reserve Deployment.** A Maximum Daily Contingency Reserve Deployment is associated with each DRR-Type I Resource, if applicable, and is expressed for each day in MW. If no daily Maximum Daily Contingency Reserve Deployment is submitted, the default Maximum Daily Contingency Reserve Deployment specified during the asset registration process will be used.

xx. **Off-Line Short-Term Reserve Offer.** The Off-Line Short-Term Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, and shall be monotonically increasing. An Off-Line Short-Term Reserve Offer only applies if the Demand Response Resource -Type I is an Off-Line Short-Term Reserve Qualified Resource.

xxi. Off-line Short-Term Reserve Dispatch Status. An Offer shall include specification of an off-line Short-Term Reserve Dispatch Status. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for an Hour. The Short-Term Reserve Dispatch Status only applies to Demand Response Resources-Type I that i) are uncommitted for the Hour and ii) are registered as Short-Term Reserve Qualified Resources.

c. Reserved.

d. Real-Time Energy and Operating Reserve Market Offer Price Caps and Floors

The following Offer price caps will apply to Demand Response Resource – Type I Offers in the Real-Time Energy and Operating Reserve Market:

i. Energy Offer Soft Price Cap: $1,000/MW, applied to non-Verified Energy Offers, non-Verified Fast Start Resource All-In Energy Offers, and non-Verified Emergency Operations Resource All-In Energy Offers. Energy Offers, the components of Fast Start Resource All-In Energy Offers, and the components of Emergency Operations Resource All-In Energy Offers, above the Energy Offer

Soft Price Cap, submitted before the close of the Real-Time Energy and Operating Reserve Market, but not verified by the Independent Market Monitor until after market clearing, will be used in the determination of Real-Time Revenue Sufficiency Guarantee Credits in accordance with section 40.2.19 of this Tariff, provided that the cost verification process for DRR – Type I Offers above that threshold shall be different and suitable for such types of Resources, as determined and implemented by the Independent Market Monitor.

ii. Energy Offer Hard Price Cap: $2,000/MWh, applied to Verified Energy Offers, Verified Fast Start Resource All-In Energy Offers, and Verified Emergency Operations Resource All-In Energy Offers. Verified Energy Offers, the components of Verified Fast Start Resource All-In Energy Offers, and the components of Verified Emergency Operations Resource All-In Energy Offers, above the Energy Offer Hard Price Cap will be used in the determination of Real-Time Revenue Sufficiency Guarantee Credits in accordance with section 40.2.19 of this Tariff, provided that the cost verification process for DRR – Type I Offers above that threshold shall be different and suitable for such types of Resources, as determined and implemented by the Independent Market Monitor.

iii. Energy Offer Price Floor: Negative $500/MWh

iv. Contingency Reserve Offer Price Cap: $100/MW/Hour

v. Contingency Reserve Offer Price Floor: $0/MW/Hour

vi. Off-Line Short-Term Reserve Offer Price Cap: $100/MW/Hour

vii. Off-Line Short-Term Reserve Offer Price Floor: $0/MW/Hour

External Asynchronous Resource Offer Rules in the Real-Time Energy and Operating Reserve Market:

Market Participants that intend to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve from an External Asynchronous Resource in the Real-Time Energy and Operating Reserve Market shall provide the information specified in this Section. External Asynchronous Resource Offers shall be submitted in the Real-Time Energy and Operating Reserve Market only for qualified External Asynchronous Resources. External Asynchronous Resource Offers shall remain in effect for the Real-Time Energy and Operating Reserve Market until specifically superseded by subsequent External Asynchronous Resource Offers. Each Market Participant shall only submit a single External Asynchronous Resource Offer for each individual External Asynchronous Resource. Market Participants may submit new or revised External Asynchronous Resource Offers, including Self-Schedules, to the Real-Time Energy and Operating Reserve Market up to thirty (30) minutes prior to the operating Hour.

a. Eligibility to Supply

A Market Participant's External Asynchronous Resources may supply Energy in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to five (5) minute Dispatch Targets for Energy and has the appropriate telemetry installed as set forth in the Business Practices Manuals. A Market Participant's External Asynchronous Resources may supply Regulating Reserve, Spinning Reserve, Supplemental Reserve, and/or Short-Term Reserve in the Real-Time Energy and Operating Reserve Market if the Transmission

Provider has certified that the Resource is a Regulation Qualified Resource, Spin Qualified Resource, Supplemental Qualified Resource, or Short-Term Reserve Qualified Resource, respectively. Market Participants that offer to supply Real-Time Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve shall provide the Offer information specified below for each individual External Asynchronous Resource.

b. Required External Asynchronous Resource Offer Components

All External Asynchronous Resources can submit an Offer for Energy, an Up and Down Ramp Capability Dispatch Status Offer, and an on-line Short-Term Reserve Dispatch Status Offer. For External Asynchronous Resources that are Regulation Qualified Resources, a Market Participant may submit a Regulating Capacity Offer and a Regulating Mileage Offer. For External Asynchronous Resources that are Spin Qualified Resources, a Market Participant may submit a Spinning Reserve Offer. For External Asynchronous Resources that are not Spin Qualified Resources but which qualify as a Supplemental Qualified Resource, a Market Participant may submit a Supplemental Reserve Offer. Market Participants can provide External Asynchronous Resource Offers for the full MW range of their Operable Capacity. A single External Asynchronous Resource Offer may be submitted in the Real-Time Energy and Operating Reserve Market for each Hour of the Operating Day for a given External Asynchronous Resource. The Transmission Provider shall maintain a Real-Time Energy and Operating Reserve Market Offer for each External Asynchronous Resource. These Offers are standing Offers and are maintained for the Real-Time Energy and Operating Reserve Market independent of the Day-Ahead Energy and Operating Reserve Market. These Offers may be updated for a specific Hour up to thirty (30) minutes prior to the beginning of the Hour. Offer components are as follows:

i. **Energy Offer Curve.** The Energy Offer curve shall be expressed for each Hour in $/MWh and shall consist of either a stepped or a piecewise linear Offer curve of up to ten (10) segments, shall be monotonically increasing, and shall cover the full operating range. The Energy Offer curve may include negative MW and/or price segments.

ii. **Regulating Capacity Offer and Regulating Mileage Offer.** The Regulating Capacity Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to External Asynchronous Resources that are Regulation Qualified Resources. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW. In a given Hour, any Resource with Regulating Reserve cleared in Day-Ahead Energy and Operating Reserve Market must have the same Real-Time Regulating Mileage Offer as its Day-Ahead Regulating Mileage Offer.

iii. **Spinning Reserve Offer.** The Spinning Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to External Asynchronous Resources that are Spin Qualified Resources.

iv. Supplemental Reserve Offer. The Supplemental Reserve Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to External Asynchronous Resources that are Supplemental Qualified Resources but not Spin Qualified Resources.

v. Commercial Pricing Node. A Commercial Pricing Node shall be specified for the External Asynchronous Resource. The Commercial Pricing Node shall not be an Interface, Load Zone, or Hub. The Commercial Pricing Node shall be the same one used for the Resource in the Day-Ahead Energy and Operating Reserve Market.

vi. Hourly Ramp Rate. An Offer shall include (i) an Hourly Ramp Rate, expressed for each Hour in MW/minute to be used by RAC processes, (ii) an Hourly Single-Directional-Up Ramp Rate, expressed for each hour in MW/Minute to be used by the Real-Time Energy and Operating Reserve Market and the LAC process, (iii) an Hourly Single-Directional-Down Ramp Rate expressed for each Hour in MW/Minute to be used by the Real-Time Energy Operating Reserve Market and the LAC process, and iv) an Hourly Bi-Directional Ramp Rate expressed for each Hour in MW/minute to be used by the Real-Time energy and Operating Reserve Market and the LAC process. If one or more of such ramp rates is not submitted, the default ramp rates specified during the asset registration process will be used and can be updated by Market Participant from the Market Portal.

vii. Hourly Economic Maximum Limit. An Offer shall include an Hourly Economic Maximum Limit, expressed for each Hour in MW. If no Hourly Economic Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

viii. Hourly Regulation Maximum Limit. An Offer shall include, if the Resource is a Regulation Qualified Resource, an Hourly Regulation Maximum Limit, expressed for each Hour in MW. If no Hourly Regulation Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

ix. Hourly Regulation Minimum Limit. An Offer shall include, if the Resource is a Regulation Qualified Resource, an Hourly Regulation Minimum Limit, expressed for each Hour in MW. If no Hourly Regulation Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

x. Hourly Emergency Maximum Limit. An Offer shall include an Hourly Emergency Maximum Limit, expressed for each Hour in MW. If no Hourly Emergency Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xi. **Hourly Economic Minimum Limit.** An Offer shall include an Hourly Economic Minimum Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xii. **Hourly Emergency Minimum Limit.** An Offer shall include an Hourly Emergency Minimum Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

xiii. **Availability Status.** An Offer shall include an Availability Status to indicate if the External Asynchronous Resource is available for participation in the Real-Time Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Unavailable, the External Asynchronous Resource will be unavailable to provide Energy and Operating Reserve in the Real-Time Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Available, then the External Asynchronous Resource will be available to provide Energy and Operating Reserve in the Real-Time Energy and Operating Reserve Market during the Hour.

xiv. **Energy Dispatch Status.** An Offer shall include specification of an Energy Dispatch Status for Energy. Valid Energy Dispatch Status specifications include: Economic and Self-Schedule. An Economic Energy Dispatch Status indicates that the Transmission Provider is authorized to economically clear Energy on the Resource for the Hour. A Self-Schedule Energy Dispatch Status indicates that the Market-Participant is self-scheduling Energy on the Resource for the Hour.

xv. **Regulating Reserve Dispatch Status.** An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve. Valid Regulating Reserve Dispatch Status specifications include: Economic, Self-Schedule, Not Qualified and Not Participating. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour. A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is self-scheduling Regulating Reserve on the Resource for the Hour. A Not Qualified Regulating Reserve Dispatch Status indicates that the Resource is not qualified to provide Regulating Reserve for an Hour. A Not Participating Regulating Reserve Dispatch Status indicates the Market Participant will not provide Regulating Reserve on a Resource that is otherwise qualified to provide Regulating Reserve. The Regulating Reserve Dispatch Status only applies to Resources that are registered as Regulation Qualified Resources.

xvi. **Spinning Reserve Dispatch Status.** An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Spinning Reserve Dispatch Status indicates that the

Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is self-scheduling Spinning Reserve on the Resource for the Hour. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. The Spinning Reserve Dispatch Status cannot be set to Not Qualified for a specific Resource in a specific Hour unless the Regulating Reserve Dispatch Status is also set to Not Qualified for that Resource in that Hour. The Spinning Reserve Dispatch Status only applies to Resources that are registered as Spin Qualified Resources.

xvii. Supplemental Reserve Dispatch Status. An Offer shall include specification of a Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour. A Self-Schedule Supplemental Reserve Dispatch Status indicates that the Market Participant is self-scheduling Supplemental Reserve on the Resource for the Hour. A Not Qualified Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour. The Supplemental Reserve Dispatch Status only applies to Resources that i) are registered as Supplemental Qualified Resources and, iii) are not Spin Qualified

Resources or have been disqualified by the Market Participant as Spin Qualified Resources for the Hour.

xviii. Up and Down Ramp Capability Dispatch Status. An Offer shall include specification of an Up and Down Ramp Capability Dispatch Status which applies to both Up Ramp Capability and Down Ramp Capability for each Hour. Valid Up and Down Ramp Capability Dispatch Status specifications include: Economic and Not Participating. An Economic Up and Down Ramp Capability Dispatch Status indicates that the Transmission Provider is authorized to economically clear Up Ramp Capability and/or Down Ramp Capability on the Resource for the Hour. A Not Participating Up and Down Ramp Capability Dispatch Status indicates that the Resource shall not be cleared to supply Up Ramp Capability or Down Ramp Capability for an Hour. The Up and Down Ramp Capability Dispatch Status only applies to Resources that have offered an Energy Dispatch Status of Economic for the Hour.

xix. Fast Ramping Resource Offer. An Offer shall include specification of whether the Resource is eligible or ineligible to be treated as a Fast Ramping Resource for each Hour. A valid Fast Ramping Resource Offer shall state a specification of either “Yes” or “No.” “Yes” indicates that the Resource could receive fast AGC signals while deploying Regulating Reserves, and “No” indicates that the Resource will not accept fast AGC signals while deploying Regulating Reserves.

(a) Eligibility at Start of Each Hour. At the beginning of each Hour, a Regulation Qualified Resource that is offered as a Fast Ramping Resource shall be deemed eligible to receive fast AGC signals regardless of its performance in the last Dispatch Interval of the preceding Hour.

(b) Eligibility During Each Dispatch Interval. A Regulation Qualified Resource that is offered as a Fast Ramping Resource for a particular Hour shall be eligible to receive fast AGC signals in the first Dispatch Interval of that Hour, and in any ensuing Dispatch Interval of that Hour which is immediately preceded by a Dispatch Interval when the Resource met or exceeded the Fast Ramping Resource Performance Threshold in the Fast Ramping Resource Performance Test during that preceding Dispatch Interval.

(c) Treatment When Ineligible to Receive Fast AGC Signals. If a Regulation Qualified Resource that is offered as a Fast Ramping Resource for a particular Hour fails to meet the Fast Ramping Resource Performance Threshold in the Fast Ramping Resource Performance Test during a particular Dispatch Interval, other than the last Dispatch Interval of that Hour, the Resource shall receive only regular AGC signals in the next Dispatch Internal. Even when receiving regular AGC signals in a Dispatch Interval, the Resource shall continue undergoing the Fast Ramping Resource Performance Test in that Dispatch Interval, and if it meets the Fast Ramping Resource Performance Threshold, shall be eligible to receive fast AGC signals in the following Dispatch Interval.

xx. Hourly Neutral Zone Upper Limit. An Offer shall include an Hourly Neutral Zone Upper Limit, expressed in percentage of Hourly Maximum Energy Storage Level. A single Hourly Neutral Zone Upper Limit value of less than or equal to 100 should be used. Resources that are not Use Limited Resources should use a value of 100. This limit value will be used to compute the Fast Ramping Resource AGC signal while sending the Regulating Resource signal.

xxi. Hourly Neutral Zone Lower Limit. An Offer shall include an Hourly Neutral Zone Lower Limit, expressed in percentage of Hourly Maximum Energy Storage Level. A single Hourly Neutral Zone Lower Limit value of greater than or equal to 0, and less than Hourly Neutral Zone Upper Limit should be used. Resources that are not Use Limited Resources should use a value of 0. This limit value will be used to compute the Fast Ramping Resource AGC signal while sending the Regulating Resource signal.

xxii. On-Line Short-Term Reserve Dispatch Status. An Offer shall include specification of an on-line Short-Term Reserve Dispatch Status for each Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating. An Economic Short-Term Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. A Not Participating Short-Term Reserve Dispatch Status indicates that the Resource shall not be cleared to supply Short-Term Reserve for an Hour.

c. Values in Offers. The values in Offers representing the non-price information identified in Section 40.2.7B.b shall reflect the actual known physical capabilities and characteristics of the External Asynchronous Resource on which the Offer is based.

d. Real-Time Energy and Operating Reserve Market Offer Price Caps and Floors

The following Offer price cap will apply to External Asynchronous Resource Offers in the Real-Time Energy and Operating Reserve Market:

i. Energy Offer Soft Price Cap: $1,000/MWh, applied to non-Verified Energy Offers. Energy Offers above the Energy Offer Soft Price Cap, submitted before the close of the Real-Time Energy and Operating Reserves Market, but not verified by the Independent Market Monitor until after market clearing, will be used in the determination of Real-Time Revenue Sufficiency Guarantee Credits in accordance with section 40.2.19 of this Tariff.

ii. Energy Offer Hard Price Cap: $2,000/MWh, applied to Verified Energy Offers. Verified Energy Offers above the Energy Offer Hard Price Cap will be used in the determination of Real-Time Revenue Sufficiency Guarantee Credits in accordance with section 40.2.19 of this Tariff.

iii. Energy Offer Price Floor: Negative $500/MWh

iv. Regulating Total Cost Price Cap: $500/MW/Hour

v. Regulating Total Cost Price Floor: $0/MW/Hour

vi. Contingency Reserve Offer Price Cap: $100/MW/Hour

vii. Contingency Reserve Offer Price Floor: $0/MW/Hour

viii. Regulating Mileage Offer Price Floor: $0/MW

Stored Energy Resource Offer Rules in the Real-Time Energy and Operating Reserve Market:

Market Participants that intend to supply Operating Reserve from Stored Energy Resources in the Real-Time Energy and Operating Reserve Market shall provide the information specified in this Section. Stored Energy Resource Offers shall be submitted in the Real-Time Energy and Operating Reserve Market only for registered Stored Energy Resources. Stored Energy Resources Offers will remain in effect for the Real-Time Energy and Operating Reserve Market until specifically superseded by subsequent Stored Energy Resource Offers. Each Market Participant may only submit a single Stored Energy Resource Offer for each individual Stored Energy Resource. Market Participants may submit new or revised Stored Energy Resource Offers to the Real-Time Energy and Operating Reserve Market up to thirty (30) minutes prior to the Operating Hour.

a. **Eligibility to Supply.** Market Participants may not offer Energy from Stored Energy Resources into the Real-Time Energy and Operating Reserve Market; however, the Real-Time SCED algorithm will determine a Dispatch Target for Energy which maximizes the Stored Energy Resource's capability to provide Regulating Reserves. The Regulating Reserve deployment on a Stored Energy Resource shall not exceed the energy storage capabilities of such Resource. A Stored Energy Resource's Dispatch Target for Energy will be determined in this manner with the exception that the Regulating Reserve availability may be reduced in order to manage transmission constraints, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. Market Participants may offer Regulating Reserve from Stored Energy Resources into the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified that (i) the Stored Energy Resource is capable of responding to five (5) minute Dispatch Targets for Energy, (ii) the appropriate telemetry installed as set forth in the Business Practices Manuals, (iii) such Stored Energy Resource has been included in the Network Model, and (iv) such Stored Energy Resource is a Regulation Qualified Resource. Stored Energy Resources may not supply Up Ramp Capability, Down Ramp Capability, or Short-Term Reserve because they are only qualified for Regulation and not longer duration sustained energy products. Market Participants that offer to supply Real-Time Regulating Reserve shall provide the Offer information specified below.

b. Required Stored Energy Resource Offer Components. Market Participants that submit Stored Energy Resource Offers shall include a Regulating Capacity Offer and a Regulating Mileage Offer. Market Participants can provide Stored Energy Resource Offers for the full energy storage capabilities of their Stored Energy Resource pursuant to the requirements outlined in Section 40.2.4; however, the Regulating Reserve availability to the Transmission Provider on a Stored Energy Resource may be reduced in order to manage transmission constraints, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. A single Stored Energy Resource Offer may be submitted in the Real-Time Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Regulating Reserve for a given Stored Energy Resource. The Transmission Provider shall maintain a Real-Time Energy and Operating Reserve Market Offer for each Stored Energy Resource. These Offers are standing Offers and are maintained for the Real-Time Energy and Operating Reserve Market independent of the Day-Ahead Energy and Operating Reserve Market. These Offers may be updated for a specific Hour up to thirty (30) minutes prior to the beginning of the Hour. Offer components are as follows:

i. **Regulating Capacity Offer and Regulating Mileage Offer.** The Regulating Capacity Offer shall be a single value expressed for each Hour in $/MW/Hour and is only applicable to Regulation Qualified Resources. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW. In a given Hour, any Resource with Regulating Reserve cleared in Day-Ahead Energy and Operating Reserve Market must have the same Real-Time Regulating Mileage Offer as its Day-Ahead Regulating Mileage Offer.

ii. **Commercial Pricing Node.** A Commercial Pricing Node shall be specified for the Stored Energy Resource at the time the asset is registered. The Commercial Pricing Node type shall not be a Load Zone, Interface, or Hub. The Commercial Pricing Node shall be the same one used for the Resource in the Day-Ahead Energy and Operating Reserve Market.

iii. **Hourly Bi-Directional Ramp Rate.** An Offer shall include an Hourly Bi-Directional Ramp Rate, expressed for each Hour in MW/minute. If no Hourly Bi-Directional Ramp Rate is submitted, the default bi-directional ramp rate will be used. The default bi-directional ramp rate is specified during the asset registration process and can be updated by Market Participant from the Market Portal.

iv. **Hourly Regulation Minimum Limit.** An Offer shall include an Hourly Regulation Minimum Limit, expressed for each Hour in MW. If no Hourly Regulation Minimum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by the Market Participant from the Market Portal. The Hourly Regulation Minimum Limit may be negative.

v. **Hourly Regulation Maximum Limit.** An Offer shall include an Hourly Regulation Maximum Limit, expressed for each Hour in MW. If no Hourly Regulation Maximum Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by the Market Participant from the Market Portal.

vi. **Hourly Maximum Energy Storage Level.** An Offer shall include an Hourly Maximum Energy Storage Level, expressed for each Hour in MWh. The hourly maximum energy storage level represents the maximum amount of energy the Stored Energy Resource can store and maintain. If no Hourly Maximum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

vii. **Hourly Maximum Energy Charge Rate.** An Offer shall include an Hourly Maximum Energy Charge Rate, expressed for each Hour in MWh / Minute. If no Hourly Maximum Energy Charge Rate is submitted, the default value specified during the asset registration process will be used.

viii. **Hourly Maximum Energy Discharge Rate.** An Offer shall include an Hourly Maximum Energy Discharge Rate, expressed for each Hour in MWh / Minute. If no Hourly Maximum Energy Discharge Rate is submitted, the default value specified during the asset registration process will be used.

ix. **Availability Status.** An Offer shall include an Availability Status to indicate if the Stored Energy Resource is available for participation in the Real-Time Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Unavailable, then the Stored Energy Resource will be unavailable to provide Regulating Reserve in the Real-Time Energy and Operating Reserve Market during the Hour. If the Availability Status is set to Available, then the Stored Energy Resource will be available to provide Regulating Reserve in the Real-Time Energy and Operating Reserve Market during the Hour.

x. **Hourly Energy Storage Loss Rate.** An Offer shall include specification of an Hourly Energy Storage Loss Rate for each Hour, expressed in

MWh/Minute, which is the amount of Energy consumed by the Stored Energy Resource over a one-minute time period to maintain an Energy storage level equal to the Hourly Maximum Energy Storage Level assuming no Regulating Reserve deployment. If no Hourly Storage Loss Rate is submitted, the default value specified during the asset registration process will be used.

xi. **Hourly Full Charge Energy Withdrawal Rate.** An Offer shall include specification of an Hourly Full Charge Energy Withdrawal Rate for each Hour, expressed in MWh/Minute, which is the amount of additional Energy that can be consumed by the Stored Energy Resource over a one-minute time period while at its Maximum Energy Storage Level to provide Regulation down capability. If no Hourly Full Charge Energy Withdrawal Rate is submitted, the default value specified during the asset registration process will be used.

xii. **Fast Ramping Resource Offer.** An Offer shall include specification of whether the Resource is eligible or ineligible to be treated as a Fast Ramping Resource for each Hour. A valid Fast Ramping Resource Offer shall state a specification of either “Yes” or “No.” “Yes” indicates that the Resource could receive fast AGC signals while deploying Regulating Reserves, and “No” indicates that the Resource will not accept fast AGC signals while deploying Regulating Reserves.

(a) Eligibility at Start of Each Hour. At the beginning of each Hour, a Regulation Qualified Resource that is offered as a Fast Ramping Resource shall be deemed eligible to receive fast AGC signals regardless of its performance in the last Dispatch Interval of the preceding Hour.

(b) Eligibility During Each Dispatch Interval. A Regulation Qualified Resource that is offered as a Fast Ramping Resource for a particular Hour shall be eligible to receive fast AGC signals in the first Dispatch Interval of that Hour, and in any ensuing Dispatch Interval of that Hour which is immediately preceded by a Dispatch Interval when the Resource met or exceeded the Fast Ramping Resource Performance Threshold in the Fast Ramping Resource Performance Test during that preceding Dispatch Interval.

(c) Treatment When Ineligible to Receive Fast AGC Signals. If a Regulation Qualified Resource that is offered as a Fast Ramping Resource for a particular Hour fails to meet the Fast Ramping Resource Performance Threshold in the Fast Ramping Resource Performance Test during a particular Dispatch Interval, other than the last Dispatch Interval of that Hour, the Resource shall receive only regular AGC signals in the next Dispatch Internal. Even when receiving regular AGC signals in a Dispatch Interval, the Resource shall continue undergoing the Fast Ramping Resource Performance

Test in that Dispatch Interval, and if it meets the Fast Ramping Resource Performance Threshold, shall be eligible to receive fast AGC signals in the following Dispatch Interval.

xiii. **Hourly Neutral Zone Upper Limit.** An Offer shall include an Hourly Neutral Zone Upper Limit, expressed in percentage of Hourly Maximum Energy Storage Level. A single Hourly Neutral Zone Upper Limit value of less than or equal to 100 should be used. Resources that are not Use Limited Resources should use a value of 100. This limit value will be used to compute the Fast Ramping Resource AGC signal while sending the Regulating Reserve signal.

xiv. **Hourly Neutral Zone Lower Limit.** An Offer shall include an Hourly Neutral Zone Lower Limit, expressed in percentage of Hourly Maximum Energy Storage Level. A single Hourly Neutral Zone Lower Limit value of greater than or equal to 0, and less than Hourly Neutral Zone Upper Limit should be used. Resources that are not Use Limited Resources should use a value of 0. This limit value will be used to compute the Fast Ramping Resource AGC signal while sending the Regulating Resource signal.

c. **Values in Offers.** The values in Offers representing the non-price information identified in Section 40.2.7A.b. shall reflect the actual known physical capabilities and characteristics of the Stored Energy Resource on which the Offer is based.

d. Real-Time Energy and Operating Reserve Market Offer Price Caps and Floors. The following Offer Price Caps will apply to Stored Energy Resources in the Real-Time Energy and Operating Reserve Market:

i. Regulating Total Cost Price Cap: $500/MW/Hour

ii. Regulating Total Cost Price Floor: $0/MW/Hour

iii. Regulating Mileage Offer Price Floor: $0/MW

Electric Storage Resource Offer Rules in the Real-Time Energy and Operating Reserve Market

Market Participants that intend to supply Energy, Operating Reserves, Up Ramp Capability, and/or Down Ramp Capability in the Real-Time Energy and Operating Reserve Market on Electric Storage Resources shall provide the information specified in this Section. Electric Storage Resource Offers shall be submitted in the Real-Time Energy and Operating Reserve Market only for registered Electric Storage Resources. Electric Storage Resource Offers will remain in effect for the Real-Time Energy and Operating Reserve Market until specifically superseded by subsequent Electric Storage Resource Offers. Each Market Participant may only submit a single Electric Storage Resource Offer for each individual Resource. Market Participants may submit new or revised Electric Storage Resource Offers, including Self-Schedules (except for Up Ramp Capability and Down Ramp Capability), to the Real-Time Energy and Operating Reserve Market up to thirty (30) minutes prior to the operating Hour.

a. Eligibility to Discharge and/or Charge

Electric Storage Resources may Discharge (sell) or Charge (purchase) Energy in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified the Resource is capable of responding to five (5) minute Dispatch Targets for Energy and has the appropriate telemetry installed including telemetry for Energy Storage Level. An Electric Storage Resource may not (i) offer to Charge and/or Discharge Energy, (ii) offer and/or supply Operating Reserve, or (iii) offer and/or supply Up Ramp Capability or Down Ramp Capability unless such Resource has been included in the Network Model. A

Market Participant's Electric Storage Resource can supply Regulating Reserve, Spinning Reserve, and/or Supplemental Reserve in the Real-Time Energy and Operating Reserve Market if the Transmission Provider has certified that the Resource is a Regulation Qualified Resource, Spin Qualified Resource, and/or Supplemental Qualified Resource, respectively. Market Participants that offer to transact Real-Time Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, and/or Down Ramp Capability shall provide the Offer information specified below.

b. Required Electric Storage Resource Offer Components

Market Participants that submit Electric Storage Resource Offers shall include a Energy Offer Curve, a Regulating Capacity Offer and a Regulating Mileage Offer (if a Regulation Qualified Resource), a Spinning Reserve Offer (if a Spin Qualified Resource), an On-Line Supplemental Reserve Offer (if a Supplemental Qualified Resource but not a Spin Qualified Resource), an Off-Line Supplemental Reserve Offer (if a Quick-Start Resource), a Start-Up Offer, a No-Load Offer, and an Up and Down Ramp Capability Dispatch Status Offer. Market Participants can provide Electric Storage Resource Offers for the full MW range of their Operable Capacity, from: (i) the Hourly Emergency Minimum Charge Limit to the Hourly Emergency Maximum Charge Limit in Charge Commitment Status; (ii) the Hourly Emergency Minimum Discharge Limit to the Hourly Emergency Maximum Discharge Limit in Discharge and Available Commitment Status; (iii) the Hourly Emergency Maximum Charge Limit to the Hourly Emergency

Maximum Discharge Limit in Continuous Commitment Status; and may indicate, as part of the Offer, that the Electric Storage Resource, can be committed during an Emergency in either Emergency Charge or Emergency Discharge. Market Participants may submit an Electric Storage Resource Offer that contains zero dollar ($0) amounts for No-Load and Start-Up Offers, in which case only the Charge Offer curve and/or Discharge Offer curve, Regulating Capacity Offer and Regulating Mileage Offer (if applicable), Spinning Reserve Offer (if applicable), On-Line Supplemental Reserve Offer (if applicable), Off-Line Supplemental Reserve Offer (if applicable), and/or Up and Down Ramp Capability Dispatch Status Offer will be considered by the market clearing process pursuant to Section 40.2.8. Any limits on the Electric Storage Resource Offer covering the full energy storage capability of the Resource must be consistent with Module D. A single Electric Storage Resource Offer may be submitted in the Real-Time Energy and Operating Reserve Market for each Hour of the Operating Day for which the Market Participant is willing to sell Operating Reserve and/or purchase Energy to Charge and/or Discharge to sell Energy from a given Resource. The Transmission Provider shall maintain a Real-Time Energy and Operating Reserve Market Electric Storage Resource Offer for each Electric Storage Resource. These Offers are standing Offers and are maintained for the Real-Time Energy and Operating Reserve Market independent of the Day-Ahead Energy and Operating Reserve Market. These Offers may be updated for a specific Hour up to thirty (30) minutes prior to the beginning of the Hour. Electric Storage Resource Offer components are as follows:

i. Energy Offer Curve. The Energy Offer curve to either Charge and/or Discharge shall be expressed for each Hour in $/MWh and shall consist of either a stepped or a piecewise linear Offer curve of up to ten (10) segments, shall be monotonically increasing, and shall cover the full operating range, including Emergency range, as applicable to the Commitment Status of the Electric Storage Resource.

ii. Regulating Capacity Offer and Regulating Mileage Offer. The Regulating Capacity Offer shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Regulation Qualified Resources expressed for each Hour in $/MW/Hour. The Regulating Mileage Offer shall be a single value expressed for each Hour in $/MW and is only applicable to Regulation Qualified Resources. If the Regulating Capacity Offer is negative, then the Regulating Mileage Offer must be $0/MW. In a given Hour, any Resource with Regulating Reserve cleared in the Day-Ahead Energy and Operating Reserve Market must have the same Real-Time Regulating Mileage Offer as its Day-Ahead Regulating Mileage Offer.

iii. Spinning Reserve Offer. The Spinning Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Spin Qualified Resources.

iv. On-Line Supplemental Reserve Offer. The On-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW/Hour and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing and is only applicable to Supplemental Qualified Resources that are not Spin Qualified Resources.

v. Off-Line Supplemental Reserve Offer. The Off-Line Supplemental Reserve Offer shall be expressed for each Hour in $/MW and shall consist of either a stepped or a piecewise linear Offer curve of up to three (3) segments, shall be monotonically increasing to Discharge and is only applicable to Resources that are Quick-Start Resources and have Commitment Status as Available.

vi. Start-Up Offer. The Start-Up Offer shall be expressed for each Day in $/start. A separate Start-Up Offer shall be submitted for hot, intermediate, and cold Start-Up conditions.

vii. No-Load Offer. The No-Load Offer shall be expressed for each Hour in $/Hour.

viii. Commercial Pricing Node. A Commercial Pricing Node shall be specified for the Electric Storage Resource at the time the asset is registered. The Commercial Pricing Node shall be the same one used for the Resource in the Day-Ahead Energy and Operating Reserve Market.

ix. Hourly Charge Ramp Rate. An Offer shall include (i) an Hourly Charge Ramp Rate expressed for each Hour in MW/minute. This Charge Ramp Rate value will be used in the Real-Time Energy and Operating Reserve Market, RAC and LAC process while ramping up or down for Energy and for regulating up or down between corresponding Hourly Economic Maximum Charge Limit and zero (0). If no Hourly Charge Ramp Rate is submitted, the default Charge Ramp Rate will be used. The default Charge Ramp Rate is specified during the asset registration process and can be updated by a Market Participant from the Market Portal.

x. Hourly Discharge Ramp Rate. An Offer shall include (i) an Hourly Discharge Ramp Rate expressed for each Hour in MW/minute. This Discharge Ramp Rate value will be used in the Real-Time Energy and Operating Reserve Market, RAC and LAC process while ramping up or down for Energy and for regulating up or down between corresponding Hourly Economic Maximum Discharge Limit and zero (0). If no Hourly Discharge Ramp Rate is submitted, the default Discharge Ramp Rate will be used. The default Hourly Discharge Ramp Rate is specified during the asset registration process and can be updated by a Market Participant from the Market Portal.

When the Commitment Status is Continuous, the Ramp Rate value would be determined based on which side of zero (0) the resource is getting dispatched. If the Electric Storage Resource is being dispatched between zero (0) and the corresponding Hourly Economic Maximum Discharge Limit then the Hourly Discharge Ramp Rate is used, conversely, if the Electric Storage Resource is being dispatched between zero (0) and the corresponding Hourly Economic Maximum Charge Limit then the Hourly Charge Ramp Rate is used for Electric Storage Resource to ramp up or down for Energy and for regulating up or down.

xi. Hourly Regulation Minimum Charge Limit. An Offer shall include an Hourly Regulation Minimum Charge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Minimum Charge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Minimum Charge Limit shall be greater than or equal to the Hourly Economic Minimum Charge Limit, and shall be less than or equal to the Hourly Regulation Maximum Charge Limit. When the Commitment Status is Continuous, the Hourly Regulation Minimum Charge Limit will not be used.

xii. Hourly Regulation Maximum Charge Limit. An Offer shall include an Hourly Regulation Maximum Charge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Maximum Charge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Maximum Charge Limit shall be less than or equal to the Hourly Economic Maximum Charge Limit, shall be greater than or equal to the Hourly Economic Minimum Charge Limit, and shall be greater than or equal to the Hourly Regulation Minimum Charge Limit. This limit will be used as the minimum MW dispatch limit when the Commitment Status is Charge or Continuous under normal operating conditions for ESRs qualified and committed for Regulation.

xiii. Hourly Regulation Minimum Discharge Limit. An Offer shall include an Hourly Regulation Minimum Discharge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no Hourly Regulation Minimum Discharge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Minimum Discharge Limit shall be greater than or equal to the Hourly Economic Minimum Discharge Limit, and shall be less than or equal to the Hourly Regulation Maximum Discharge Limit. When the Commitment Status is Continuous, the Hourly Regulation Minimum Discharge Limit will not be used.

xiv. Hourly Regulation Maximum Discharge Limit. An Offer shall include an Hourly Regulation Maximum Discharge Limit if the Resource is a Regulation Qualified Resource, expressed for each Hour in MW. If no

Hourly Regulation Maximum Discharge Limit is submitted, the default limit will be used. The default limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal. The Hourly Regulation Maximum Discharge Limit shall be less than or equal to the Hourly Economic Maximum Discharge Limit, shall be greater than or equal to the Hourly Economic Minimum Discharge Limit, and shall be greater than or equal to the Hourly Regulation Minimum Discharge Limit. This limit will be used as the maximum MW dispatch limit when the Commitment Status is Discharge or Continuous under normal operating conditions for ESRs qualified and committed for Regulation.

xv. Hourly Maximum Energy Storage Level. An Offer shall include an Hourly Maximum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Maximum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xvi. Hourly Minimum Energy Storage Level. An Offer shall include an Hourly Minimum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Minimum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xvii. Hourly Emergency Maximum Energy Storage Level. An Offer shall include an Hourly Emergency Maximum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Emergency Maximum Energy

Storage Level is submitted, the default value specified during the asset registration process will be used.

xviii. Hourly Emergency Minimum Energy Storage Level. An Offer shall include an Hourly Emergency Minimum Energy Storage Level, expressed for each Hour in MWh. If no Hourly Emergency Minimum Energy Storage Level is submitted, the default value specified during the asset registration process will be used.

xiv. Hourly Economic Maximum Charge Limit. An Offer shall include an Hourly Economic Maximum Charge Limit, expressed for each Hour in MW. If no Hourly Economic Maximum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Minimum Charge Limit. This limit will be used as the minimum MW dispatch limit when the Commitment Status is Charge or Continuous under normal operating conditions.

xx. Hourly Economic Maximum Discharge Limit. An Offer shall include an Hourly Economic Maximum Discharge Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Real-Time Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Economic Maximum

Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Minimum Discharge Limit. This limit will be used as the maximum MW dispatch limit when the Commitment Status is Discharge, Available or Continuous under normal operating conditions.

xxi. Hourly Economic Minimum Charge Limit. An Offer shall include an Hourly Economic Minimum Charge Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Charge as maximum MW dispatch limit under normal operating conditions. When the Commitment Status is Continuous, this limit will not be used.

xxii. Hourly Economic Minimum Discharge Limit. An Offer shall include an Hourly Economic Minimum Discharge Limit, expressed for each Hour in MW. If no Hourly Economic Minimum Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Discharge or Available as minimum MW dispatch limit under normal operating conditions. When the Commitment Status is Continuous, this limit will not be used.

xxiii. Hourly Emergency Maximum Charge Limit. An Offer shall include an Hourly Emergency Maximum Charge Limit, expressed for each Hour in MW. If no Hourly Emergency Maximum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to Hourly Economic Maximum Charge Limit. This limit will be used as the minimum MW dispatch limit when the Commitment Status is Emergency Charge, Charge or Continuous under Emergency operating conditions.

xxiv. Hourly Emergency Maximum Discharge Limit. An Offer shall include an Hourly Emergency Maximum Discharge Limit, expressed for each Hour in MW, which shall not be used to withhold a portion of the Capacity of a Resource from the Real-Time Energy and Operating Reserve Market if such Capacity is designated as a Capacity Resource pursuant to RAR, unless such portion is unavailable due to a forced or planned outage or other physical operating restrictions. If no Hourly Emergency Maximum Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to the Hourly Economic Maximum Discharge Limit. This limit will be used as the maximum MW dispatch limit when the Commitment Status is Emergency Discharge, Discharge, Available or Continuous under Emergency operating conditions.

xxv. Hourly Emergency Minimum Charge Limit. An Offer shall include an Hourly Emergency Minimum Charge Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Charge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Emergency Charge, Charge as maximum MW dispatch limit under Emergency operating conditions. When Commitment Status is Continuous, this limit will not be used.

xxvi. Hourly Emergency Minimum Discharge Limit. An Offer shall include an Hourly Emergency Minimum Discharge Limit, expressed for each Hour in MW. If no Hourly Emergency Minimum Energy Discharge Limit is submitted, the default value specified during the asset registration process will be used. This value shall be greater than or equal to zero (0). This Limit will be used when the Commitment Status is Emergency Discharge, Discharge, and/or Available as minimum MW dispatch limit under normal operating conditions. When Commitment Status is Continuous, this limit will not be used.

xxvii. Hourly Electric Storage Resource Efficiency Factor. An Offer shall include specification of an Hourly Electric Storage Resource Efficiency Factor for each Hour, expressed as a percentage. If no Hourly Electric Storage Resource Efficiency Factor is submitted, the default value specified during the asset registration process will be used.

xxviii. Minimum Discharge Time. An Offer shall include a Minimum Discharge Time, expressed for each Day in Hours.

xxix. Maximum Discharge Time. An Offer shall include a Maximum Discharge Time, expressed for each Day in Hours.

xxx. Minimum Down Time. An Offer shall include a Minimum Down Time, expressed for each Day in Hours.

xxxi. Minimum Charge Time. An Offer shall include a Minimum Charge Time, expressed for each Day in Hours.

xxxii. Maximum Charge Time. An Offer shall include a Maximum Charge Time, expressed for each Day in Hours.

xxxiii. Maximum Off-Line Response Limit. An Offer shall include a Maximum Off-Line Response Limit, expressed for each Hour in MW. This requirement applies to Quick-Start Resources only. If no Hourly Maximum Off-Line Response Limit is submitted, the default Maximum Off-Line Response Limit will be used. The default Maximum Off-Line Response Limit is specified during the asset registration process and can be updated by a Market Participant from the Market Portal.

xxxiv. Commitment Status. An Offer shall include specification of a Commitment Status. Valid Commitment Status specifications include: Charge, Discharge, Continuous, Emergency Charge, Emergency Discharge, Available, Outage and Not Participating. An Available Commitment Status indicates the Transmission Provider is authorized to commit the Resource on an economic basis for the Hour using Offer parameters associated with the Commitment Status of Discharge. A Charge, Discharge, or Continuous Commitment Status indicates that the Market Participant is self-committing the Resource for the Hour. An Emergency Charge or Emergency Discharge Commitment Status indicates the Transmission Provider is authorized to commit the Resource only under an Emergency condition for the Hour. An Outage Commitment Status indicates the Resource is not available for commitment during the Hour due to a planned or forced outage. A Not Participating Commitment Status indicates the Market Participant will not operate a Resource that is otherwise available. The Not Participating Commitment Status will be available to an Electric Storage Resource that has all or a portion of its capacity designated as a Capacity Resource, but must be used consistent with Module E-1 obligations.

xxxv. Energy Dispatch Status. An Offer shall include specification of an Energy Dispatch Status for Energy. Valid Energy Dispatch Status specifications include: Economic, Self-Schedule, and Not Participating. An Economic Energy Dispatch Status indicates that the Transmission Provider is authorized to economically clear Energy on the Resource for the Hour. A Self-Schedule Energy Dispatch Status indicates that the Market Participant is Self-Scheduling Energy on the Resource for the Hour and will follow the Self-Scheduling Rules defined in section 39.1.2. The Not Participating

Energy Dispatch Status will be available to an Electric Storage Resource in Continuous Commitment Status and that has all or a portion of its capacity designated as a Capacity Resource, but must be used consistent with Module E-1 obligations. The Energy Dispatch Status only applies to Resources that are committed for the Hour.

xxxvi. Regulating Reserve Dispatch Status. An Offer shall include specification of a Regulating Reserve Dispatch Status for Regulating Reserve. Valid Regulating Reserve Dispatch Status specifications include: Economic, Self-Schedule, Not Qualified and Not Participating. An Economic Regulating Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Regulating Reserve on the Resource for the Hour. A Self-Schedule Regulating Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Regulating Reserve on the Resource for the Hour. A Not Qualified Regulating Reserve Dispatch Status indicates that the Resource is not qualified to provide Regulating Reserve for an Hour. A Not Participating Regulating Reserve Dispatch Status indicates the Market Participant will not provide Regulating Reserve on a Resource that is otherwise qualified to provide Regulating Reserve. The Regulating Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) registered as Regulation Qualified Resources. The Resource should have sufficient

Energy Storage Level to clear Regulating Reserves or honor Self-Scheduled Regulation volume for the Hour.

xxxvii. Spinning Reserve Dispatch Status. An Offer shall include specification of a Spinning Reserve Dispatch Status for Spinning Reserve. Valid Spinning Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic Spinning Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Spinning Reserve on the Resource for the Hour. A Self-Schedule Spinning Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Spinning Reserve on the Resource for the Hour. A Not Qualified Spinning Reserve Dispatch Status indicates that the Resource is not qualified to provide Spinning Reserve for an Hour. The Spinning Reserve Dispatch Status cannot be set to Not Qualified for a specific Resource in a specific Hour unless the Regulating Reserve Dispatch Status is also set to Not Qualified for that Resource in that Hour. The Resource should have sufficient Energy Storage Level to clear Spinning Reserves or honor Self-Scheduled Spinning Reserves volume for the Hour.

For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to Section 40.2.7B.b.xxxiv of the Tariff in order to not participate in providing Spinning Reserve. The Spinning Reserve Dispatch Status only applies to Resources that are i) committed for the Hour and ii) are registered as Spin Qualified Resources.

xxxviii. On-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an On-Line Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid On-Line Supplemental Reserve Dispatch Status specifications include: Economic, Self-Schedule and Not Qualified. An Economic On-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Self-Schedule On-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Supplemental Reserve on the Resource for the Hour if the Resource is committed. A Not Qualified On-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Supplemental Reserve for an Hour as a committed Resource. The Resource should have sufficient Energy Storage Level to clear Supplemental Reserves or honor Self-Scheduled Supplemental Reserves for the Hour.

For a Resource not designated as a Capacity Resource, a Market Participant must select a Not Participating Commitment Status pursuant to Section 40.2.7B.b.xxxiv of the Tariff in order to not participate in providing On-Line Supplemental Reserve. The On-Line Supplemental Reserve Dispatch Status only applies to Resources that are i) committed for the Hour, ii) registered as Supplemental Qualified Resources and, iii) not registered as Spin Qualified Resources or have been disqualified by the Market Participant as Spin Qualified Resources for the Hour.

xxxix. Off-Line Supplemental Reserve Dispatch Status. An Offer shall include specification of an Off-Line Supplemental Reserve Dispatch Status for Supplemental Reserve. Valid Off-Line Supplemental Reserve Dispatch Status specifications include: Economic, Emergency, Self-Schedule, Not Qualified and Not Participating. An Economic Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour when the Resource's Commitment Status is Available.

An Emergency Off-Line Supplemental Reserve Dispatch Status indicates that the Transmission Provider is authorized to economically clear Off-Line Supplemental Reserve on the Resource for the Hour when the Resource's Commitment Status is Available and all available Resources with Economic or Available Commitment Status have been committed. A Self-Schedule Off-Line Supplemental Reserve Dispatch Status indicates that the Market Participant is Self-Scheduling Off-Line Supplemental Reserve on the Resource for the Hour. A Not Qualified Off-Line Supplemental Reserve Dispatch Status indicates that the Resource is not qualified to provide Off-Line Supplemental Reserve for an Hour.

A Not Participating Off-Line Supplemental Reserve Dispatch Status indicates the Market Participant will not provide Off-Line Supplemental Reserve on a Resource that has a Commitment Status of Available and that is otherwise qualified to provide Off-Line Supplemental Reserve. The Not Participating Off-Line Supplemental Reserve Dispatch Status will be available to an Electric Storage Resource that has all or a portion of its capacity designated as a Capacity Resource, but must be used consistent with Module E-1 obligations. The Off-Line Supplemental Reserve Dispatch Status only applies to Resources when their Commitment Status is Available for the Hour and they are registered as Quick-Start Resources.

xxxx. Up and Down Ramp Capability Dispatch Status. An Offer shall include specification of an Up and Down Ramp Capability Dispatch Status which applies to both Up Ramp Capability and Down Ramp Capability. Valid Up and Down Ramp Capability Dispatch Status specifications include: Economic and Not Participating. An Economic Up and Down Ramp Capability Dispatch Status indicates that the Transmission Provider is authorized to economically clear Up Ramp Capability and/or Down Ramp Capability on the Resource for the Hour. A Not Participating Up and Down Ramp Capability Dispatch Status indicates that the Resource shall not be cleared to supply Up Ramp Capability or Down Ramp Capability for an Hour.

c. Ramp Rate Curves

A Market Participant may specify a Charge Ramp Rate curve and Discharge Ramp Rate curve for use in the Real-Time Energy and Operating Reserve Market and each curve may include up to ten (10) linear segments. Such ramp rate curves may be updated for a specific Hour no less than thirty (30) minutes prior to the beginning of the Hour. The Market Participant may activate the use of such ramp rate curves for a specific Hour no less than thirty (30) minutes prior to the beginning of the Hour. If activated, such ramp rate curves will be used in lieu of the Hourly Charge Ramp Rate and/or the Hourly Discharge Ramp Rate for a specific Resource during a specific Hour in the Real-Time Energy and Operating Reserve Market. When the Commitment Status is Continuous, the Ramp Rate curve would be determined based on which side of zero (0) the Resource is getting dispatched. If the Electric Storage Resource is being dispatched between zero (0) and the corresponding Hourly Discharge Maximum Limit, then the Hourly Discharge Ramp Rate curve is used, conversely, if the Electric Storage Resource is being dispatched between zero (0) and the corresponding Hourly Economic Maximum Charge Limit, then the Charge Ramp Rate curve will be used for Electric Storage Resource to ramp up or down for Energy and for regulating up or down.

d. Limit and Ramp Rate Priority

Default operating limits for Resources shall be provided to the Transmission Provider during asset registration and can be overridden by hourly Resource limits (limits applicable to an Operating Hour). Furthermore, hourly limits can be overridden as necessary within an Hour by the Transmission Provider at the request of the Market Participant to reflect real-time changes in the operational capabilities associated with Electric Storage Resources. Default Charge and Discharge Ramp Rate for Electric Storage Resources provided to the Transmission Provider during asset registration can be overridden by hourly Charge and Discharge Ramp Rate, and hourly Charge and Discharge Ramp Rate can be overridden by Charge and Discharge Ramp Rate curve. Furthermore, all Charge and Discharge Ramp Rates can be overridden as necessary by the Transmission Provider at the request of the Market Participant within an Hour to reflect changes in the operational capabilities associated with Electric Storage Resources. All specified Resource limits, ramp rates and other physical operating parameters are subject to investigation by the Independent Market Monitor pursuant to provisions set forth in Module D.

e. Values in Offers

The values in Offers representing the non-price information identified in Section 40.2.7B.b shall reflect the actual known physical capabilities and characteristics of the Electric Storage Resource on which the Offer is based.

f. Real-Time Energy and Operating Reserve Market Offer Price Caps and Floors.

The following Offer Price Caps will apply to Electric Storage Resources in the Real-Time Energy and Operating Reserve Market:

i. Energy Offer Price Cap: $1,000/MWh

ii. Energy Offer Price Floor: Negative $500/MWh

iii. Regulating Total Cost Price Cap: $500/MW/Hour

iv. Regulating Total Cost Price Floor: $0/MW/Hour

v. Contingency Reserve Offer Price Cap: $100/MW/Hour

vi. Contingency Reserve Offer Price Floor: $0/MW/Hour

vii. Regulating Mileage Offer Price Floor: $0/MW

Market Participants may submit Self-Schedules for Energy and/or Operating Reserve from their Resources, in whole or in part, in the Real-Time Energy and Operating Reserve Market. Market Participants that submit Self-Schedules for Energy are required to submit a MWh quantity and the applicable time period for each Self-Scheduled Resource.

Market Participants that submit Self-Schedules for Operating Reserve are required to submit a MW quantity and the applicable time period for each Self-Scheduled Resource. Market Participants that submit Self-Schedules for Energy and/or Operating Reserve are Price Takers for each Self-Schedule. Self-Schedules for Energy must be greater than or equal to the Hourly Economic Minimum Limit and less than or equal to the Hourly Economic Maximum Limit, or the Forecast Maximum Limit. In the event that the Forecast Maximum Limit is less than the Self Schedule for Energy, the Self Schedule for Energy shall be set equal to the Forecast Maximum Limit. Self-Schedules for Regulating Reserve must be greater than or equal to one (1) MW for each Self-Scheduled Resource and can only be submitted for Regulation Qualified Resources. Self-Schedules for Spinning Reserve must be greater than or equal to one (1) MW for each Self-Scheduled Resource and can only be submitted for Spin Qualified Resources. Self-Schedules for Supplemental Reserve must be greater than or equal to one (1) MW for each Self-Scheduled Resource and can only be submitted for Supplemental Qualified Resources that are not also Spin Qualified Resources. The acceptance of Self-Schedules for a specific Self-Scheduled Resource will be contingent on i) the on-line status of the Self-Scheduled Resource, and ii) compliance with the corresponding Self-Scheduled Resource limit and ramping constraints as set forth in Schedule 29. If a Self-Schedule is accepted by the Transmission Provider, the Resource Schedules for Energy and Operating Reserve may clear above the Self-Scheduled amounts based on the submitted Offers, as needed, in an economic manner based upon the simultaneously co-optimized solution. The Transmission Provider may reduce Self-Schedules as necessary to manage transmission constraints, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. In no case will the Transmission Provider violate the Resource limits. Stored Energy Resources cannot Self-Schedule Regulating Reserve in the Real-Time Energy and Operating Reserve Market.

Market Participants may not submit Self-Schedules for Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve from their Resources in the Real-Time Energy and Operating Reserve Market.

Financial Schedules may be submitted at any time prior to 1200 hours EST six (6) Calendar Days after the Operating Day. The Transmission Provider is not the Energy Market Counterparty to the sale of Energy under a Financial Schedule transaction. The Financial Schedule shall include:

i. Identification of the Market Participants included in the Financial Schedule;

ii. The Commercial Pricing Nodes identified as the Source Point, the Sink Point and the Delivery Point;

iii. The Energy and Operating Reserve Market in which the Financial Schedule will be settled, using either the Day-Ahead Ex Post LMPs or Hourly Real-Time Ex Post LMPs; and

iv. The scheduled volume in MWh for each Hour of the Financial Schedule.

External Demand in the Real-Time Energy and Operating Reserve Market:

Market Participants may purchase Energy in the Real-Time Energy and Operating Reserve Market through Export Schedules and will be settled at the Commercial Pricing Node defined as the Interface or at the External Asynchronous Resources Commercial Pricing Node for each Export Schedule.

The Transmission Provider shall obtain State Estimator solutions at least every five (5) minutes that provide information on (i) Energy injections and withdrawals, (ii) transmission system losses, (iii) marginal loss sensitivity factors, (iv) transmission voltages, and (v) actual flows on transmission facilities.

External Supply in the Real-Time Energy and Operating Reserve Market:

a. Energy Interchange Transaction

All Market Participants may Offer to sell Energy in the Real-Time Energy and Operating Reserve Market through Import Schedules and will be settled at the Commercial Pricing Node defined as the Interface for each Import Schedule.

b. External Resources

All Generation Resources Pseudo-tied to the MISO Balancing Authority Area and all External Asynchronous Resources supplying Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or Short-Term Reserve in the Real-Time Energy Operating Reserve Market must maintain firm transmission capacity to the MISO Balancing Authority Area in an amount not less than the Hourly Emergency Maximum Limit of such Resources, or the DIR Feasibility Limit for Dispatchable Intermittent Resources.

Rules for Interchange Schedules in the Real-Time Energy and Operating Reserve Market:

Interchange Schedules include Import Schedules, Export Schedules, and Through Schedules. Import Schedules need not be accompanied by reservations of Point-To-Point Transmission Service on the Transmission System, if supported by Network Integration Transmission Service or are submitted pursuant to a Grandfathered Agreement.

Export Schedules, not submitted pursuant to a Grandfathered Agreement or an individual Coordinating Owners coordination agreement regarding reciprocity provisions with regard to Transmission Service, must be accompanied by reservation of Point-To-Point Transmission Service on the Transmission System. Through Schedules must be accompanied by reservations of Point-To-Point Transmission Service, unless the Transmission Service is provided according to the terms of a Grandfathered Agreement, for segments within the Transmission Provider Region.

Interchange Schedules may be submitted or modified in accordance with the terms in Attachment J.

a. Validation of Interchange Schedules

Interchange Schedules are validated by the Transmission Provider to ensure an OASIS reservation exists for Point-to-Point Transmission Service, Network Integration Transmission Service, or a spot-in market transaction and the schedule can be supported.

b. Types of Interchange Schedules

Interchange Schedules in the Real-Time Energy and Operating Reserve Market include: Fixed Interchange Schedules, cleared Day-Ahead Interchange Schedules, Dynamic Interchange Schedules, and cleared Coordinated Transaction Schedules.

i. Fixed Interchange Schedules are used by

Market Participants to schedule fixed amounts of Interchange in the Real-Time Energy and Operating Reserve Market. Market Participants that submit Fixed Interchange Schedules are Price-Takers for the amount of Fixed Interchange scheduled.

ii. Cleared Day-Ahead Interchange Schedules are Interchange Schedules that cleared and settled in the Day-Ahead Energy and Operating Reserve Market and are being implemented as Fixed Interchange Schedules in the Real-Time Energy and Operating Reserve Market.

iii. Dynamic Interchange Schedules are used to dynamically schedule Energy in the Real-Time Energy and Operating Reserve Market. The Market Participant will submit an estimated Dynamic Interchange Schedule for a specific Hour up to twenty (20) minutes prior to the beginning of the schedule, and that schedule will be used in the Real-Time Energy and Operating Reserve Market clearing process. The Market Participant or the Local Balancing Authority will then provide the Transmission Provider with the updated actual dynamic schedule after the fact.

iv. Cleared Coordinated Transaction Schedules are Interchange Schedules that clear in the Coordinated Transaction Scheduling process and are being implemented in the Real-Time Energy and Operating Reserve Market.

a. General

Demand Curves will be utilized in the Real-Time Energy and Operating Reserve Markets to clear Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Market-Wide Short-Term Reserve. The methodology for constructing Demand Curves is described in Schedule 28.

b. Market-Wide Demand Curves

A Market-Wide Operating Reserve Demand Curve will be utilized to price Operating Reserve when sufficient Operating Reserves are not cleared to meet the corresponding Market-Wide Operating Reserve Requirement. A Market Wide Regulating and Spinning Reserve Demand Curve will be used to price Regulating and Spinning Reserve when sufficient Regulating and Spinning Reserves are not cleared to meet the corresponding Market-Wide Regulating and Spinning Reserve Requirement. A Market-Wide Regulating Reserve Demand Curve will be utilized to price Regulating Reserve when sufficient Regulating Reserves are not cleared to meet the corresponding Market-Wide Regulating Reserve Requirement. A Market-Wide Up Ramp Capability Demand Curve will be used to price Up Ramp Capability when sufficient Up Ramp Capability is not cleared to meet the corresponding Market-Wide Up Ramp Capability Requirement. A Market-Wide Down Ramp Capability Demand Curve will be used to price Down Ramp Capability when sufficient Down Ramp Capability is not cleared to meet the corresponding Market-Wide Down Ramp Capability Requirement. A Market-Wide Short-Term Reserve Demand Curve will be used to price Short-Term Reserve when sufficient Short-Term Reserve is not cleared to meet the corresponding Market-Wide Short-Term Reserve Requirement.

c. Transmission Constraint Demand Curves (TCDCs)

TCDCs shall be used to price a transmission constraints during any dispatch interval in which the transmission constraint cannot be managed within its binding limit using the Security Constrained Economic Dispatch (SCED) engine.

d. Sub-Regional Power Balance Constraint Demand Curves

Sub-Regional Power Balance Constraint Demand Curves shall be used to price Sub-Regional Power Balance Constraints during any Dispatch Interval in which such constraint(s) cannot be managed within its binding limit using the Security Constrained Economic Dispatch (SCED) engine.

e. Post Reserve Deployment Constraints Demand Curves

Post Reserve Deployment Constraints Demand Curves shall be used to price Post Reserve Deployment Constraints during any Dispatch Interval in which such constraint(s) cannot be managed within its binding limit using the Security Constrained Economic Dispatch (SCED) engine.

The Transmission Provider shall consider the data inputs set forth in this Section in clearing the Real-Time Energy and Operating Reserve Market.

a. Load Forecast

The Transmission Provider shall conduct Real-Time Load Forecasts pursuant to procedures set forth in the Business Practices Manuals. The Load Forecast shall be allocated to individual Load Buses, using the most recent State Estimator results.

b. Dispatch Model

The Dispatch Model in the Real-Time Energy and Operating Reserve Market is populated with the most recent State Estimator results or most recent SCADA data as deemed appropriate by Transmission Provider and most recent Contingency Analysis results before the start of the Real-Time Energy and Operating Reserve Market clearing process for each five (5) minute Dispatch Interval.

c. Resource Information

The Transmission Provider shall accept and consider Offers from Market Participants for Resources thirty (30) minutes prior to the operating Hour.

The Transmission Provider shall (i) use a SCED algorithm to clear Offers, Self-Schedules, and Interchange Schedules, (ii) determine the MISO Balancing Authority NSI, and (iii) establish prices and physically-binding Dispatch Targets for each Resource and Dispatch Interval.

a. Determination of Dispatch Targets

In the Real-Time Energy and Operating Reserve Market, the Transmission Provider shall determine Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for each Resource for the end of each Dispatch Interval.

b. Determination of the Real-Time Ex Ante LMPs at Elemental Pricing Nodes

The Transmission Provider shall calculate Real-Time Ex Ante LMPs for each Dispatch Interval and Elemental Pricing Node in the Real-Time Energy and Operating Reserve Market using the SCED algorithm. The Real-Time Ex Ante LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity costs, and/or Short-Term Reserve scarcity costs to supply Energy to a Load at the Elemental Pricing Node during the Dispatch Interval using the SCED algorithm. The Real-Time Ex Ante LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource – Type II Offers, and (iii) External Asynchronous Resource Offers.

i. **Calculation of Marginal Congestion Component.** The Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the Real-Time Ex Ante LMP (the Marginal Congestion Component).

The Marginal Congestion Component of a Real-Time Ex Ante LMP reflects the marginal cost of managing the transmission congestion and enforcing Sub-Regional Power Balance Constraints that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED algorithm.

ii. **Calculation of Marginal Losses Component.** The Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the Real-Time Ex Ante LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of a Real-Time Ex Ante LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy Injection at the Reference Bus in the SCED algorithm.

c. **Determination of the Real-Time Ex Ante LMPs at Aggregate Price Nodes.** The Transmission Provider shall calculate Real-Time Ex Ante LMPs for each Dispatch Interval and Aggregate Price Node in the Real-Time Energy and Operating Reserve Market. The calculation of Real-Time Ex Ante LMPs for Aggregate Price Nodes will be based on established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Nodes LMP is equal to the sum the products of the Real-Time Ex Ante LMP at each Elemental Pricing Node and the associated weighting factor for the Elemental Pricing Node.

d. Determination of the Real-Time Ex Ante LMPs at Commercial Pricing Nodes.

The Transmission Provider shall establish Real-Time Ex Ante LMPs for each Dispatch Interval and Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market. The Real-Time Ex Ante LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the Real-Time Ex Ante LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

e. Determination of the Real-Time Ex Ante LMP at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the Real-Time Ex Ante LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the Real-Time Ex Ante LMP for the Resource Commercial Pricing Node is set equal to the calculated Ex Ante LMP for the Elemental Pricing Node representing the Bus connected to the single injection point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the Real-Time Ex Ante LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource. The Aggregate Price Node weighting factors are specified by the Market Participant when the asset is registered.

f. Determination of the Real-Time Ex Ante LMP at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Load Zone.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total Demand of the Load Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operation Day.

g. Determination of the Real-Time Ex Ante LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Ante LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

h. Determination of the Real-Time Ex Ante LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Ante LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the Real-Time Ex Ante LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Interface.

i. Determining the Real-Time Ex Ante Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources is equal to the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint

Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone; all such Constraints noted herein are as set forth in Schedule 29.

j. Determining the Real-Time Ex Ante Regulating Reserve Market Clearing Prices for Stored Energy Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Regulating Reserve for Stored Energy Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Regulating Reserve for Stored Energy Resources is equal to the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Maximum Stored Energy Resource Regulation Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price. All such constraints noted herein are as set forth in Schedule 29.

k. Determining the Real-Time Ex Ante Spinning Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29. Such Spinning Reserved MCPs for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

l. Determining the Ex Ante Spinning Reserve Market Clearing Price for Demand Response Resources – Type I

The Transmission Provider shall calculate the Ex Ante Spinning Reserve MCPs for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Spinning Reserve MCP for Demand Response Resources –Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

m. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources is the sum of the (i)

Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (ii) Market-Wide Generation-based Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

n. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Price for Demand Response Resources - Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

o. Determining the Ex Ante Up Ramp Capability Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante Up Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and

Operating Reserve Market, based on the SCED algorithm. The Real-Time Ex Ante Up Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Constraint is as set forth in Schedule 29. Such Up Ramp Capability MCPs for Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

p. Determining the Ex Ante Down Ramp Capability Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante Down Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm. The Real-Time Ex Ante Down Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Constraint is as set forth in Schedule 29. Such Down Ramp Capability MCPs for Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

q. Real-Time Ex Ante LMP and Real-Time Ex Ante MCP Price Cap.

All Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs will be capped at the VOLL.

r. Determining the Ex Ante Regulating Mileage Market Clearing Price

The Transmission Provider shall calculate the Ex Ante Regulating Mileage MCPs for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market. The Ex Ante Regulating Mileage MCP for a Dispatch Interval is the highest Regulating Mileage Offer among all Resources that meet the following criteria: (1) if the Resource has a Day-Ahead schedule for cleared Regulating Reserve, then the Regulating Reserve Dispatch Status in the Day-Ahead Energy and Operating Reserve Market must be economic, (2) the Regulating Reserve Dispatch Status has to be economic in the Real-Time Energy and Operating Reserve Market, and (3)the Resource has a non-zero Dispatch Target for Regulating Reserve in that Dispatch Interval.

s. Determining the Real-Time Ex Ante Short-Term Reserve Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Short-Term Reserve for qualified reserves for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Short-Term Reserve is the applicable Co-optimized Zonal Short-Term Reserve Requirement constraint Shadow Price.

For each Dispatch Interval, the Transmission Provider shall use the SCED-Pricing algorithm to establish Real-Time Ex Post LMPs and Real-Time Ex Post MCPs. The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be subject to input data validation and adherence to the price calculation requirements. Input data validation corrections will be made pursuant to Section 40.2.18 of this Tariff. The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs are used to settle Real-Time Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve deviations and are determined as described below:

a. Determination of the Real-Time Ex Post LMPs at Elemental Pricing Nodes

The Transmission Provider shall calculate Real-Time Ex Post LMPs for each Dispatch Interval and Elemental Pricing Node in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity costs, and/or Short-Term Reserve scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Dispatch Interval using the SCED-Pricing algorithm, described in Schedule 29A. The Real-Time Ex Post LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource Offers, (iii) External Asynchronous Resource Offers, (iv) Emergency Demand Response resource Offers; and (v) Proxy Offers when appropriate as specified in Schedule 29A.

i. Calculation of Marginal Congestion Component. The Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the Real-Time Ex Post LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Real-Time Ex Post LMP reflects the marginal cost of managing the transmission congestion and enforcing Sub-Regional Power Balance Constraints that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus.

ii. Calculation of Marginal Losses Component. The Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the Real-Time Ex Post LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of any Real-Time Ex Post LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy Injection at the Reference Bus.

b. Determination of Real-Time Ex Post LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate Real-Time Ex Post LMPs for each Dispatch Interval and Aggregate Price Node in the Real-Time Energy and Operating Reserve Market. The calculation of Real-Time Ex Post LMPs for Aggregate Price Nodes will be based on established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Node is equal to the sum of the products of the Real-Time Ex Post LMP at each Elemental Pricing Node and the associated weighting factor for the Elemental Pricing Node.

c. Determination of the Real-Time Ex Post LMPs at Commercial Pricing Nodes

The Transmission Provider shall establish Real-Time Ex Post LMPs for each Dispatch Interval and Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market. The Real-Time Ex Post LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the Real-Time Ex Post LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

d. Determination of the Real-Time Ex Post LMP at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the Real-Time Ex Post LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the Real-Time Ex Post LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node representing the Bus connected to the single injection point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the Real-Time Ex Post LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource.

The Aggregate Price Node weighing factors are specified by the Market Participant when the asset is registered.

e. Determination of the Real-Time Ex Post LMP at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine an Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Load Zone. The Aggregate Price Node representing the Load Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the Load Zone are connected. The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total demand of the Load Zone as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operation Day.

f. Determination of the Real-Time Ex Post LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Post LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

g. Determination of the Real-Time Ex Post LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Post LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single external Elemental Pricing Node, the Real-Time Ex Post LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple external Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Interface. The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for the Interface.

h. Determining the Real-Time Ex Post Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources is equal to the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

i. Determining the Real-Time Ex Post Regulating Reserve Market Clearing Prices for Stored Energy Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post for MCPs for Regulating Reserve for Stored Energy Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Regulating Reserve for Stored Energy Resources is equal to the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Maximum Stored Energy Resource Regulation Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price. All such constraints noted herein are as set forth in Schedule 29A.

j. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

k. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices for Demand Response Resources- Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Real-Time Ex Post MCP for Spinning Reserve for Demand Response Resources –Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market- Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

l. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources

The Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II or External Asynchronous Resources is the sum of the (i) Market-Wide

Operating Reserve Constraint Shadow Price, (ii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, if applicable, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

m. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices for Demand Response Resources - Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

n. Determining the Real-Time Ex Post Up Ramp Capability Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post Up Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED-Pricing algorithm.

The Real-Time Ex Post Up Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Constraint is as set forth in Schedule 29A.

o. Determining the Real-Time Ex Post Down Ramp Capability Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post Down Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED-Pricing algorithm. The Real-Time Ex Post Down Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Constraint is as set forth in Schedule 29A.

p. Real-Time Ex Post LMP and Real-Time Ex Post MCP Price Cap. All Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be capped at the VOLL.

q. Determining the Ex Post Regulating Mileage Market Clearing Price

The Transmission Provider shall calculate the Ex Post Regulating Mileage MCPs for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market. The Ex Post Regulating Mileage MCP is the highest Regulating Mileage Offer among all Resources that meet the following criteria: (1) if the Resource has a Day-Ahead Schedule for cleared Regulating Reserve, then the Regulating Reserve Dispatch Status in the Day-Ahead Energy and Operating Reserve Market must be economic, (2) the Regulating Reserve Dispatch Status has to be economic in the Real-Time Energy and

Operating Reserve Market, and (3) the Resource has a non-zero Dispatch Target for Regulating Reserve in that Dispatch Interval. The Ex Post Regulating Mileage MCP is used to settle Additional Regulating Mileage in that Dispatch Interval.

r. Determining the Real-Time Ex Post Short-Term Reserve Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the real-time Ex Post Short-Term reserve MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED-Pricing algorithm. The real-time Ex Post Short-Term Reserve MCP for a Resource is the applicable Co-optimized Zonal Short-Term Reserve Requirement constraint Shadow Price.

The Transmission Provider shall continually monitor the various processes associated with the calculation of Real-Time Ex Post LMPs and Real-Time Ex Post MCPs. In the event of a data input failure or program failure, corrective actions may be engaged to ensure that the resulting Real-Time Ex Post LMPs and Real-Time Ex Post MCPs are as reasonably accurate as is attainable. Where the input data is unavailable, the Transmission Provider shall take all reasonable measures to recover the original data for use in the Real-Time Ex Post LMP and Real-Time Ex Post MCP calculations respectively. In the event of a program failure, the Transmission Provider shall attempt to correct the reason for the failure and to recalculate Real-Time Ex Post LMP and Real-Time Ex Post MCP values for the affected intervals. If the Transmission Provider is unable to correct the failure and the original data cannot be recovered, the Transmission Provider shall use data from the best available alternate data sources including, but not limited to, backup systems, dispatcher logs, raw telemetry data, Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs, and Market Participant data sources. In the event of a data input or program failure, Real-Time Ex Post LMP and Real-Time Ex Post MCP replacements shall be performed as follows:

a. Where the stale data or program failure exists for eleven (11) or fewer Dispatch Intervals within the same Hour, the affected Dispatch Intervals shall be replaced with data from the last successful interval or the next successful Dispatch interval, as appropriate, within the same Hour;

b. Where the stale data or program failure exists for all Dispatch Intervals within the same Hour, the following shall occur:

i. Where the Hour is unconstrained, Operating Reserve is not scarce, Up

Ramp Capability is not scarce, Down Ramp Capability is not scarce, and Short-Term Reserve is not scarce, the Hourly Real-Time Ex Post LMP and Hourly Real-Time Ex Post MCP values shall be replaced with the loss-adjusted hourly integrated Real-Time Ex Ante LMP and Real-Time Ex Ante MCP; and

ii. Where the system is constrained, Operating Reserve is scarce, Up Ramp Capability is scarce, Down Ramp Capability is scarce, and/or Short-Term Reserve is scarce, the Real-Time Ex Post LMP and Real-Time Ex Post MCP values shall be recalculated using data from the best available sources. The Real-Time Ex Post LMP and Real-Time Ex Post MCP values shall be recalculated for each five-minute Dispatch Interval and then integrated and weighted in accordance with the standard procedure.

c. Real-Time Ex Post MCPs and Real-Time Ex Post LMPs will be finalized and posted as soon as practicable following the Operating Day and in accordance with the timeframes specified in the Business Practices Manuals, except that the finalization and posting of such Real-Time Ex Post MCPs and Real-Time Ex Post LMPs shall not exceed five (5) Business Days from the applicable Operating Day. Any posting of final Real-Time Ex Post MCPs and Real-Time Ex Post LMPs exceeding five (5) Business Days from the applicable Operating Day shall require approval by the Transmission Provider Board.

a. The Transmission Provider shall ensure the recovery of a Market Participant's Production Cost for Non-Excessive Energy and Operating Reserve Cost for Generation Resources and Demand Response Resource – Type II committed by the Transmission Provider, in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, the RAC process conducted the Day prior to the Operating Day, and any intra-day RAC processes as scheduled in the Real-Time Energy and Operating Reserve Market, in accordance with Section 40.3.3.3.c. The Transmission Provider shall determine on the basis of the SCUC Instructed Hours of Operation whether the Resource's costs as specified above are greater than the revenues received for Energy, Operating Reserves, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue by a Real-Time Revenue Sufficiency Guarantee Credit that shall be funded in accordance with Section 40.3.3.2. Notwithstanding the foregoing, the Market Participant shall not receive the portion of a Real-Time Revenue Sufficiency Guarantee Credit for any shortfall with respect to Incremental Energy Costs that exceed the Hourly Real-Time Ex Post LMP revenue for resources providing Spinning Reserves as a result of following a Contingency Reserve Deployment Instruction.

b. The Transmission Provider shall ensure the recovery of a Market Participant's Shut-Down Offer and Hourly Curtailment Offer for Demand Response Resources – Type I committed by the Transmission Provider for Energy or Contingency Reserve in any RAC processes, or in the LAC process, including any RAC processes conducted prior to the

Day-Ahead Energy and Operating Reserve Market, the RAC process conducted the day prior to the Operating Day, and any intra-day RAC processes as scheduled in the Real-Time Energy and Operating Reserve Market, in accordance with Section 40.3.3.3.c. The Transmission Provider shall determine on the basis of the SCUC Instructed Hours of Operation whether the Resource's costs as specified above are greater than the revenues received for Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue by a Real-Time Revenue Sufficiency Guarantee Credit that shall be funded in accordance with Section 40.3.3.2. Notwithstanding the foregoing, the Market Participant shall not receive the portion of a Real-Time Revenue Sufficiency Guarantee Credit for any shortfall with respect to Shut-Down Offers and/or Hourly Curtailment Offers that exceed the Hourly Real-Time Ex Post LMP revenue for resources providing Spinning Reserves as a result of following a Contingency Reserve Deployment Instruction.

Capacity Shortage Conditions in the Real-Time Energy and Operating Reserve Market: The Transmission Provider shall take the measures set forth below during Capacity shortage conditions to maintain reliability within the MISO Balancing Authority Area.

a. RAC

If during any RAC process, the Transmission Provider's forecast of Real-Time demand and Operating Reserve Requirements, either on a MISO Balancing Authority Area basis or Sub-Area basis, cannot be satisfied by committing all available non-Emergency Capacity, up to Hourly Economic Maximum Limits, and the Forecast Maximum Limit for Dispatchable Intermittent Resources, the Transmission Provider shall implement the following procedures:

i. Step One. The Transmission Provider shall: incorporate for use in the RAC commitment process, the order of which is specified in the Transmission Provider's Emergency operating procedures: (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource - Type II, External Asynchronous Resource and Stored Energy Resource – Type II up to the Hourly Emergency Maximum Limit, or the Forecast Maximum Limit for Dispatchable Intermittent Resources, except for Resources selected to provide Regulating Reserve, (ii) the commitment of Generation Resources, Demand Response Resources - Type I, Demand Response Resources - Type II and Stored Energy Resources – Type II that are designated as available for Emergency conditions only, (iii) the curtailment of Export Schedules, in amounts required to relieve the shortage condition in an economic manner; and (iv) the schedules of External Resources that qualified as Planning Resources.

ii. Step Two. If the action under Step One above is not sufficient to relieve the anticipated shortage condition, the Transmission Provider shall declare an EEA Level 1. In the event that a significant shortage of Operating Reserve is anticipated, the Transmission Provider shall declare an EEA Level 2 and shall mitigate, but not necessarily eliminate, the Operating Reserve deficiency through use of the following options, the order of which is specified in the Transmission Provider's Emergency operating procedures: (a) Issuing EDR Dispatch Instructions to EDR Participants based upon EDR Offers submitted (b) initiating Emergency Energy purchases in accordance with the procedures set forth in Section 40.2.22, (c) issuing public appeals to reduce demand as appropriate, (d) directing Local Balancing Authorities to implement voltage reductions, and (e) directing Load Serving Entities to curtail appropriate amounts of Load Modifying Resources.

b. Real-Time Dispatch Interval

During any SCED Dispatch Interval for which the Transmission Provider has previously issued an EEA Level 1 or EEA Level 2, the Transmission Provider shall implement the following procedures to clear the Real-Time Energy and Operating Reserve Market:

i. For those Resources selected to operate above the Hourly Economic Maximum Limits during the RAC process pursuant to Section 40.2.20.a.i., the Transmission Provider shall use the Market Participant's Offers for such Resources up to the

Hourly Emergency Maximum Limit in the SCED to calculate Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs, and shall use the Resource's Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs which will reflect Scarcity Pricing based upon Demand Curves, if sufficient Operating Reserve is not cleared to meet the Market-Wide Operating Reserve Requirement, if sufficient Up Ramp Capability is not cleared to meet the Market-Wide Up Ramp Capability Requirement, and/or if sufficient Short-Term Reserve is not cleared to meet the Market-Wide Short-Term Reserve Requirement. For scheduled External Resources that qualified as Planning Resources, the Transmission Provider shall also use their Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs.

ii. For Load Modifying Resources, Emergency Demand Response resources and Emergency Energy Purchases selected to operate during the RAC process pursuant to Section 40.2.20.a.ii, the Transmission Provider shall use their Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs

iii. If as a result of the Transmission Provider actions pursuant to Section 40.2.20.b.i, Energy balance cannot be achieved, the Transmission Provider shall declare an EEA-Level 3 and may implement Load Shedding pursuant to the Transmission Provider's Emergency operating procedures. Load Shedding will be implemented on a MISO Balancing Authority Area basis, or a on a Sub-Area basis if limited by transmission constraints or Sub-regional Power Balance Constraints, as required to restore Energy balance. The Load Shedding obligation of each Load Serving Entity shall be implemented through instructions to the affected Local Balancing Authorities as set forth in the protocols of the Balancing Authority Agreement. Load Shedding shall be allocated to each affected Local Balancing Authority on a pro rata, Load Ratio Share basis, determined by the ratio of the total amount of Load Shedding required to achieve Energy balance to the amount of the real-time load remaining, or if the Load Shedding is to occur in the next hour, to the projected load for the next-hour, for the Sub-Area or the entire MISO Balancing Authority Area, as applicable. During Emergency conditions where Load Shedding is instructed by the Transmission Provider when the affected area is the MISO Balancing Authority Area or Sub-Area, Real-Time Ex Ante LMPs, Real-Time Ex Ante MCPs, Real-Time Ex Post LMPs and Real-Time Ex Post Operating Reserve MCPs will be set to the VOLL, either on a MISO Balancing Authority Area basis or Sub-Area basis, as applicable, until the Emergency condition is no longer in effect.

c. Notice

The Transmission Provider shall post on its public website notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.20.

Capacity Surplus under Minimum Load Conditions in Real-Time Energy and Operating Reserve Market:

The Transmission Provider shall take the measures set forth below during Capacity surplus conditions under minimum Load conditions to maintain reliability within the MISO Balancing Authority Area.

a. RAC

If during any RAC process, the Transmission Provider's forecast of Real-Time demand less Regulating Reserve within the MISO Balancing Authority Area is less than the sum of the minimum non-Emergency supply, the Transmission Provider shall declare an appropriate Emergency alert and implement the following procedures:

i. Step One. The Transmission Provider shall incorporate for use in the RAC commitment process the Market Participants' Offers submitted for each Generation Resource, Demand Response Resources Type – II and Stored Energy Resources – Type II down to the Emergency Minimum Limit except for Resources selected to provide Regulating Reserve, in amounts required to relieve the surplus condition in an economic manner.

ii. Step Two. The Transmission Provider may economically decommit Resources previously committed by the Transmission Provider based on Market Participants' Offers.

b. Emergency Real-Time Dispatch Interval

During any SCED Dispatch Interval:

i. For those Resources selected to operate below their Hourly Economic Minimum Limits during the RAC process pursuant to Section 40.2.21.a, the Transmission Provider shall use the Market Participant's Offers for such Resources down to the Hourly Emergency Minimum Limit in the SCED to calculate Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs, and in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs which may reflect Scarcity Pricing based on Demand Curves. SCED-Pricing does not allow partial commitment of Fast Start Resources or Emergency Operations Resources when setting prices.

ii. If Real-Time demand less Regulating Reserve within the MISO Balancing Authority Area is less than the minimum supply during any Dispatch Interval, Scarcity Pricing will be invoked. Real-Time Ex Ante LMPs and Real-Time Ex Post LMPs will be set based on the negative of the Regulating Reserve Scarcity Price as set by the Regulating Reserve Demand Curve, and the Real-Time Ex Ante MCPs for Regulating Reserve and Real-Time Ex Post MCPs for Regulating Reserve will be set based on the Regulating Reserve Scarcity Price as set by the Regulating Reserve Demand Curve.

c. Notice

The Transmission Provider shall post on its public website notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.21.

If the Transmission Provider declares an EEA Level 2 pursuant to Section 40.2.20, the Transmission Provider may arrange Emergency Energy purchases for and on behalf of Market Participants through applicable MISO Balancing Authority to Balancing Authority agreements in an attempt to resolve the declared Emergency Energy event and maintain reliability within the MISO Balancing Authority Area. Additionally, the MISO Balancing Authority may arrange Emergency Energy sales for and on behalf of Market Participants to other Balancing Authorities if requested through applicable MISO Balancing Authority to Balancing Authority agreements.

Charges to the MISO Balancing Authority for Emergency Energy purchases for and on behalf of Market Participants will be recovered from Market Participants with Resources or Load that participate in the Real-Time Energy and Operating Reserve Market and that have Resource output below their Day-Ahead Schedules for Energy or Load consumption in excess of their Day-Ahead Schedule for Energy, on a pro rata basis based upon deviations from Day-Ahead Schedules for Energy in such instances. Deviations instructed by the Transmission Provider are exempt from charges for Emergency Energy purchases. Credits to the MISO Balancing Authority for Emergency Energy sales arranged for and on behalf of Market Participants will be distributed to Market Participants in accordance with Section 40.3.3.5.b of the Tariff.

If during the Operating Day, the Transmission Provider experiences a Generator Forced Outage or other abnormal condition that requires the Transmission Provider to deploy Contingency Reserve from cleared Resources in the Real-Time Energy and Operating Reserve Market, the Transmission Provider shall select such Resources for deployment until the Contingency Reserve deployment amount is satisfied utilizing the following criteria:

i. Contingency Reserve will be deployed on all on-line Generation Resources, on-line Demand Response Resources - Type II, online Stored Energy Resources – Type II, Electric Storage Resources, and Demand Response Resources – Type I that have selected "on-line" as their Demand Response Resource – Type I Contingency Reserve status for that Operating Day, and External Asynchronous Resources in a manner that minimizes the deployment response time; and

ii. If the Contingency Reserve deployed under (i) above is not sufficient, Contingency Reserve will be deployed on all off-line Generation Resources, off-line Demand Response Resources - Type II, Stored Energy Resources – Type II, Electric Storage Resources with a Commitment Status of Available, and Demand Response Resources - Type I that have selected "off-line" as their Demand Response Resource – Type I Contingency Reserve status for that Operating Day, on an economic basis as determined by the Generation Resource's, Demand Response Resource - Type II's, Stored Energy Resource – Type II's, or Electric Storage Resource's Start-up Offer, No-Load Offer, Minimum Run Time and Energy Offer curve or the Demand Response Resource - Type I's Shut-Down

Offer, Hourly Curtailment Offer and Minimum Interruption Duration, subject to Reserve Zone import limits.

If during the Operating Day, the Transmission Provider experiences a Generator Forced Outage, violation of Short-Term Reserve constraints, or other abnormal condition that requires the Transmission Provider to deploy Short-Term Reserve from cleared Resources in the Real-Time Energy and Operating Reserve Market, the Transmission Provider shall select such Resources for deployment until the Short-Term Reserve deployment amount is satisfied, utilizing the following criteria:

i. Short-Term Reserve will be deployed on on-line Resources through the Unit Dispatch System. The Unit Dispatch System will determine the needed Short-Term Reserve response from on-line Resources for each market interval subject to sub-regional and Reserve Zone constraint limits; and

ii. If the Short-Term Reserve deployed under (i) above is not sufficient or deliverable, Short-Term Reserve will be deployed by operator commitment of off-line Generation Resources, off-line Demand Response Resources - Type II, Stored Energy Resources – Type II, and Demand Response Resources - Type I for that Operating Day, on an economic basis as determined by the Generation Resource's, Demand Response Resource - Type II's, or Stored Energy Resource – Type II's Start-up Offer, No-Load Offer, Minimum Run Time and Energy Offer curve or the Demand Response Resource - Type I's Shut-Down Offer, Hourly Curtailment Offer and Minimum Interruption Duration, subject to sub-regional and Reserve Zone constraint limits.

The Transmission Provider shall provide timely Settlement of purchases and sales of Energy, Regulating Reserve, Spinning Reserves, Supplemental Reserves, Regulating Mileage, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in the Real-Time Energy and Operating Reserve Market. Settlement of the Real-Time Energy and Operating Reserve Market will be conducted as described below. Settlement of the Real-Time Energy and Operating Reserve Market for purchases and sales of Energy and Operating Reserve is based on: (i) applicable Real-Time Ex Post LMPs for Interchange Schedules, and applicable Hourly Real-Time Ex Post LMPs for non-Interchange transactions, for Metered MWh values; (ii) applicable Hourly Real-Time Ex Post MCPs for Dispatch Targets for Operating Reserve and Additional Regulating Mileage; (iii) applicable Hourly Real-Time Ex Post MCPs for Up Ramp Capability cleared schedules; (iv) applicable Hourly Real-Time Ex Post MCPs for Down Capability cleared schedules; and (v) applicable Real-Time Ex Post MCPs for Short-Term Reserve cleared schedules. Settlement is performed on quantity deviations from Day-Ahead Energy and Operating Reserve Schedules.

Hourly Real-Time Ex Post LMPs are the time weighted average of the five (5) minute interval Real-Time Ex Post LMPs. Because separate Commercial Pricing Nodes are defined for each Resource, Load Zone, Hub, and Interface, Hourly Real-Time Ex Post LMPs for Commercial Pricing Nodes associated with the same Elemental Pricing Node or Aggregate Price Node may differ due to weighting differences. Hourly Real-Time Ex Post MCPs are the time and quantity weighted average of the Dispatch Interval Real-Time Ex Post MCPs.

40.3.3 Real-Time Energy and Operating Reserve Market Settlement Calculations

The Real-Time Energy and Operating Reserve Market shall be settled on quantity deviations from the Day-Ahead Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability schedules, and Short-Term Reserve schedules with consideration for Real-Time Financial Schedules. Settlement for the Real-Time Energy and Operating Reserve Market uses applicable Real-Time Ex Post LMPs for reported MW or MWh values, and uses applicable Real-Time Ex Post MCPs for Dispatch Targets for Operating Reserve, Additional Regulating Mileage, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve. Until Market Participants submit their Metered values to be used for injections and withdrawals at each of their Commercial Pricing Nodes, the Transmission Provider may estimate values based on the best information available at the time of Settlements. A Market Participant's reported values are subject to review and validation by the Transmission Provider for Settlements. For each Hour of the Operating Day, the following charges and credits are determined.

Charges and Credits for Real-Time Energy and Operating Reserve Market Purchases

a. Energy and Operating Reserve Charges and Credits

i. Energy Charges and Credits. Market Participants shall be charged the applicable Hourly Real-Time Ex Post LMP for any Actual Energy Withdrawals, net of Real-Time Financial Schedules that exceed their Day-Ahead Scheduled Withdrawals (and are credited for the Actual Energy Withdrawals, net of Real-Time Financial Schedules, that are below their Day-Ahead Scheduled Withdrawals). The applicable Hourly Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node at which the withdrawal (or injection) takes place.

ii. Regulating Reserve Procurement Charges. Charges for the procurement of Regulating Reserve in the Real-Time Energy and Operating Reserve Market shall be assessed to Load Serving Entities as set forth in Schedule 3.

iii. Spinning Reserve Procurement Charges: Charges for the procurement of Spinning Reserves in the Real-Time Energy and Operating Reserve Market shall be assessed to Load Serving Entities and Exporting Entities as set forth in Schedule 5.

iv. Supplemental Reserve Procurement Charges. Charges for the procurement of Supplemental Reserves in the Real-Time Energy and Operating Reserve Market shall be assessed to Load Serving Entities and Exporting Entities as set forth in Schedule 6.

v. Regulation Deployment Adjustment. Market Participants with Resources, excluding Stored Energy Resources, that are deploying Regulating Reserve in the upward direction over a Dispatch Interval are subject to a charge (or credit if negative) equal to the product of the time-weighted average Regulation Deployment Instruction and the difference between the applicable Real-Time Ex Post LMP and the Resource's Offer Price at the average Dispatch Target for Energy during the Dispatch Interval. Market Participants with Resources, excluding Stored Energy Resources, that are deploying Regulating Reserve in the downward direction over a Dispatch Interval are subject to a credit (or charge if positive) equal to the product of the time-weighted average Regulation Deployment Instruction and the difference between the applicable Resource Offer Price and Real-Time Ex Post LMP at the average Dispatch Target for Energy during the Dispatch Interval. Stored Energy Resources providing Regulating Reserve Deployment are not subject to the Regulation Deployment Adjustment.

vi. Regulating Reserve Deployment Cost Allocation. The Transmission Provider shall distribute the net charges/credits from the Settlement of Regulating Reserve Deployment in the Real-Time Energy and Operating Reserve Market, as defined under Section 40.3.3.1.a.viii, *pro rata* to Market Participants based on the Market Participant's share of total Actual Energy Withdrawals at all Commercial Pricing Nodes excluding Export Schedules.

vii. Regulating Mileage Cost Allocation. A Charge for Additional Regulating Mileage in the Real-Time Energy and Operating Reserve Market that shall be allocated, pro rata, to Market Participants based on their Market Load Ratio Share, excluding Export Schedules.

viii. Revenue Neutrality. The Transmission Provider shall distribute the revenue inadequacy or surplus from the Settlement of Excessive Energy *pro rata*, to Market Participant Loads based on their Market Load Ratio Share.

b. Ramp Capability Credits and Charges

i. Up Ramp Capability Credits and Charges. Market Participants are credited, for all Dispatch Intervals in an Hour, the sum of the product of: (1) the Real-Time Ex Post MCP; (2) any positive difference between the Real-Time cleared amount for Up Ramp Capability within a Dispatch Interval in an Hour and their Day-Ahead Up Ramp Capability cleared schedule in that Hour; (3) the duration of the Dispatch Interval expressed in Hours (and will be charged, for all Dispatch Intervals in an Hour, the sum of the product of: (1) the Real-Time Ex Post MCP; (2) any negative difference between the Real-Time cleared amount for Up Ramp Capability within the Dispatch Interval in that Hour and their Day-Ahead Up Ramp Capability cleared schedule in that Hour; (3) the duration of the Dispatch Interval expressed in Hours). The applicable Real-Time Ex Post MCP for Up Ramp Capability is for the Commercial Pricing Node at which the procurement occurs.

ii. Down Ramp Capability Credits and Charges. Market Participants are credited, for all Dispatch Intervals in an Hour, the sum of the product of: (1) the Real-Time Ex Post MCP; (2) any positive difference between the Real-Time cleared amount for Down Ramp Capability within a Dispatch Interval in an Hour and their Day-Ahead Down Ramp Capability cleared schedule in that Hour; (3) the duration of the Dispatch Interval expressed in Hours (and will be charged, for all Dispatch Intervals in an Hour, the sum of the product of: (1) the Real-Time Ex Post MCP; (2) any negative difference between the Real-Time cleared amount for Down Ramp Capability within the Dispatch Interval in that Hour and their Day-Ahead Down Ramp Capability cleared schedule in that Hour; (3) the duration of the Dispatch Interval expressed in Hours). The applicable Real-Time Ex Post MCP for Down Ramp Capability is for the Commercial Pricing Node at which the procurement occurs.

iii. Ramp Capability Cost Allocation. The Transmission Provider shall distribute the net charges/credits from the Settlement of Ramp Capability in the Day-Ahead Energy and Operating Reserve Market, as defined under Section 39.3.2A.d, and Real-Time Energy and Operating Reserve Market, as defined under Section 40.3.3.1.b, will be allocated, *pro rata*, to Market Participants based on their Market Load Ratio Share.

c. Short-Term Reserve Credits and Charges

i. Short-Term Reserve Credits and Charges. Market Participants are credited, for all Dispatch Intervals in an Hour, the sum of the product of: (1) the Real-Time Ex Post MCP; (2) any positive difference between the real-time cleared amount for Short-Term Reserve within a Dispatch Interval in an Hour and their day-ahead Short-Term Reserve cleared schedule in that Hour; (3) the duration of the Dispatch Interval expressed in Hours (and will be charged, for all Dispatch Intervals in an Hour, the sum of the product of: (1) the Real-Time Ex Post MCP;

(2) any negative difference between the real-time cleared amount for Short-Term Reserve within the Dispatch Interval in that Hour and their Day-Ahead Short-Term Reserve cleared schedule in that Hour; and (3) the duration of the Dispatch Interval expressed in Hours). The applicable Real-Time Ex Post MCP for Short-Term Reserve is for the Commercial Pricing Node at which the procurement occurs.

ii. Short-Term Reserve Procurement Charges. Charges for the procurement of Short-Term Reserves in the Real-Time Energy and Operating Reserve Market shall be assessed to Load Serving Entities and Exporting Entities as set forth in Schedule 51.

d. Other Market Charges

i. Reserve Zone Demand Response Resource Compensation Recovery Charge: For each Reserve Zone and each Dispatch Interval in which the Real-Time Ex Post LMP during a Dispatch Interval in which the DRR is committed for Energy for a given DRR's CPNode is greater than or equal to the Net Benefits Price Threshold, the Transmission Provider shall recover the total DRR compensation from the Reserve Zone(s) where the DRR that reduces demand during such Dispatch Intervals is located and any other Reserve Zone(s) that also benefits from the reduction in demand. The total DRR compensation for all Dispatch Intervals in an Hour is equal to the sum of the product of: (1) the Real-Time Ex Post LMP for such DRR; (2) the Non-Excessive Energy for such DRR; and (3) the duration of the Dispatch Interval expressed in Hours. The Reserve Zones that benefit are determined by whether an actively Binding Transmission Constraint exists, as reflected by the Hourly Ex Post MCP for an Operating Reserve product within the Reserve Zone in which a DRR is located being unequal to the Hourly Ex Post MCP for that same product in another Reserve Zone (a difference for any product reflecting a Binding Transmission Constraint). The recovery by Reserve Zone shall be as follows:

All Binding Constraints:

If the transmission constraints associated with the Reserve Zone in which such DRR is located are actively binding with all other Reserve Zones then the Transmission Provider shall recover the total DRR compensation from the Reserve Zone in which such DRR is located.

No Binding Transmission Constraints or Mixed Transmission Constraint Situation: If the transmission constraints associated with the Reserve Zone in which such DRR is located are not actively binding with all other Reserve Zones, then the Transmission Provider shall recover the total DRR compensation from the Reserve Zone in which the DRR is located along with all other Reserve Zones having the same Hourly Ex Post MCP.

When a DRR is located in more than one Reserve Zone and an actively Binding Transmission Constraint exists between the affected Reserve Zones, the total

DRR compensation will be apportioned to each affected Reserve Zone, *pro rata*, based on the DRR's Actual Energy Injections within each Reserve Zone.

The Transmission Provider shall allocate the costs of such DRR compensation *pro rata* to Market Participants in such Reserve Zone based upon such Market Participant's share of Real-Time Energy Purchases in the Reserve Zone during such hour.

For each Hour for all Reserve Zone(s) included in the cost allocation of DRR compensation, if the Actual Energy Injections, in MWh, of all DRRs exceeds the amount of Real-Time Energy Purchases, in MWh, then the amount of total DRR compensation allocated to Real-Time Energy Purchases will be equal to the product of the (i) total DRR compensation in the Reserve Zone(s) and (ii) the quotient of (a) Real-Time Energy Purchases for all Reserve Zone(s) included in the cost allocation of DRR compensation and (b) DRR Actual Energy Injections for all Reserve Zone(s) included in the cost allocation of DRR compensation.

Any amount of total DRR compensation that is not recovered from Real-Time Energy Purchases within the Reserve Zone(s) included in the cost allocation of DRR compensation, will be allocated, *pro rata*, to all Market Participants based on their market-wide Load Ratio Share.

Real-Time Revenue Sufficiency Guarantee Distribution

a. Real-Time Revenue Sufficiency Guarantee Constraint Management Charge

i. For deviations occurring prior to the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the following deviations:

(1) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules, any difference between: (a) the greater of (i) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (ii) the Self-Schedule quantity for Energy in effect at the Notification Deadline and (b) the difference between: (i) the Day-Ahead Schedule for Energy and (ii) the Day-Ahead Schedule for Regulating Reserve (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process), when the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline is greater than the Day-Ahead Schedule;

(2) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules, any difference between: (a) the sum of: (i) the Day-Ahead Schedule for Energy, (ii) the Day-Ahead Schedule for Regulating Reserve, (iii) the Day-Ahead Schedule for Spinning Reserve, and for Day-Ahead committed Resources, (iv) the Day-Ahead Schedule for Supplemental Reserve, and (b) the Real-Time Hourly Economic Maximum Limit in effect at the Notification Deadline, or for

Dispatchable Intermittent Resources, the Notification Deadline DIR Forecast (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process), when the Day-Ahead Schedule is greater than the Real-Time Hourly Economic Maximum Limit in effect at the Notification Deadline or for Dispatchable Intermittent Resources, the Notification Deadline DIR Forecast;

(3) for Load Zones, any difference between: (a) the Day-Ahead Schedule and (b) the Real-Time Load Zone Demand Forecast in effect at the Notification Deadline;

(4) any cleared Virtual Supply Offer or cleared Virtual Bid;

(5) for Import Schedules, other than Coordinated Transaction Schedules, any difference between: (a) the real-time Import Schedule in effect at the Notification Deadline and (b) the day-ahead Import Schedule;

(6) for Export Schedules, other than Export Schedules for External Asynchronous Resources and Coordinated Transaction Schedules, any difference between: (a) the day-ahead Export Schedule and (b) the real-time Export Schedule in effect at the Notification Deadline;

(7) any Real-Time Financial Schedule For Deviations for the seller at the Source and any Real-Time Financial Schedule For Deviations for the buyer at the Sink, provided, that, such schedules must be submitted prior to the Notification Deadline in order to be eligible for netting. For these deviations, the Internal Delivery Point of the Real-Time Financial Schedule For Deviations is used to

determine the applicable Commercial Pricing Node Constraint Contribution Factor; and

(8) for Demand Response Resources – Type I, any difference between: (a) the Targeted Demand Reduction Level in effect at the Notification Deadline and (b) the Day-Ahead Schedule (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process).

(9) for Intermittent Resources, any difference between: (a) the Real-Time Intermittent Resource Forecast in effect at the Notification Deadline and (b) the Day-Ahead Schedule for Energy.

ii. For deviations occurring after the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the following deviations to the extent they increase the flow on the Active Transmission Constraint:

(1) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules, any difference between: (a) the real-time hourly Economic Minimum Dispatch and (b) the adjusted Day-Ahead Schedule, where the adjusted Day-Ahead Schedule is equal to the lesser of: (a) the greater of: (i) the greater of (1) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (2) the Self-Schedule quantity of Energy in effect at the Notification Deadline and (ii) the difference between: (1) the Day-Ahead Schedule for Energy and (2) the Day-Ahead Schedule for Regulating Reserve and (b) the real-time

Hourly Economic Maximum Limit in effect at the Notification Deadline, or for Dispatchable Intermittent Resources, the Notification Deadline DIR Forecast (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process), when the real-time hourly Economic Minimum Dispatch is greater than the adjusted Day-Ahead Schedule;

(2) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules, any difference between: (a) the adjusted Day-Ahead Schedule and (b) the real-time hourly Economic Maximum Dispatch or for Dispatchable Intermittent Resources, the Hourly Integrated Forecast Maximum Limit. The adjusted Day-Ahead Schedule is equal to the lesser of: (a) the greater of: (i) the greater of (1) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (2) the Self-Schedule quantity for Energy in effect at the Notification Deadline and (ii) the sum of: (1) the Day-Ahead Schedule for Energy, (2) the Day-Ahead Schedule for Regulating Reserve, (3) the Day-Ahead Schedule for Spinning Reserve, and for Day-Ahead committed Resources, (4) the Day-Ahead Schedule for Supplemental Reserve, and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline, or for Dispatchable Intermittent Resources, the Notification Deadline DIR Forecast (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process), when the adjusted Day-Ahead Schedule is greater than the real-time hourly Economic Maximum Dispatch or for

Dispatchable Intermittent Resources, the Hourly Integrated Forecast Maximum Limit;

(3) for Resources in an Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals, the sum of any Excessive Energy or Deficient Energy, pursuant to Section 40.3.4, in that Hour;

(4) for Load Zones, any difference between: (a) the Real-Time Load Zone Demand Forecast in effect at the Notification Deadline and (b) the Actual Energy Withdrawal or to the extent a Load Zone has Actual Energy Injection, Actual Energy Injection, adjusted by Demand Response Resource's Actual Energy Injections associated with a given Load Zone;

(5) for Import Schedules, other than Coordinated Transaction Schedules, any difference between: (a) the real-time Import Schedule and (b) the real-time Import Schedule in effect at the Notification Deadline;

(6) for Export Schedules, other than Export Schedules for External Asynchronous Resources and Coordinated Transaction Schedules, any difference between: (a) the real-time Export Schedule in effect at the Notification Deadline and (b) the real-time Export Schedule;

(7) for Demand Response Resources – Type I, any difference between: (a) the Dispatch Target for Energy and (b) the Targeted Demand Reduction Level in effect at the Notification Deadline; and

(8) for Intermittent Resources, any difference between: (a) the Actual Energy Injection and (b) the Real-Time Intermittent Resource Forecast in effect at the Notification Deadline.

iii. Adjusted Deviation Volume: Each deviation identified pursuant to Sections 40.3.3.2.a.i and 40.3.3.2.a.ii shall be evaluated using the applicable Commercial Pricing Node Constraint Contribution Factor to determine if the deviation increased the flow on the Active Transmission Constraint, decreased the flow on the Active Transmission Constraint, or neither increased nor decreased flow on the Active Transmission Constraint, thereby representing a deviation volume that had no impact on the Active Transmission Constraint. Each deviation is then multiplied by the applicable Commercial Pricing Node Constraint Contribution Factor to determine the adjusted deviation, which represents the amount of the resulting increase or decrease in flow on the Active Transmission Constraint.

(a) Asset Owner Adjusted Deviations Prior to the Notification Deadline: For deviations occurring prior to the Notification Deadline, the sum, by Asset Owner, of adjusted deviations that increased the flow on the Active Transmission Constraint are reduced to an amount no less than zero by the adjusted deviations that decreased the flow on the Active Transmission Constraint. If the sum of an Asset Owner's adjusted deviations that increased the flow on the Active Transmission Constraint exceeds the sum of the Asset Owner's adjusted deviations that decreased the flow on the Active Transmission Constraint, then the difference shall be multiplied by the per unit Real-Time Revenue Sufficiency

Guarantee Constraint Management Charge Rate to determine the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge to be paid by the Market Participant for deviations occurring prior to the Notification Deadline.

(b) Asset Owner Adjusted Deviations After the Notification Deadline: For deviations occurring after the Notification Deadline, the sum, by Asset Owner, of adjusted deviations that increased the flow on the Active Transmission Constraint shall be multiplied by the per unit Real-Time Revenue Sufficiency Guarantee Constraint Management Charge Rate to determine the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge to be paid by the Market Participant for deviations occurring after the Notification Deadline.

iv. Real-Time Revenue Sufficiency Guarantee Constraint Management Charge Rate: The per unit rate of the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge for deviations for any given Hour, for any given Active Transmission Constraint, shall equal the quotient of: (1) the product of: (a) the aggregate Real-Time Revenue Sufficiency Guarantee Credit in that Hour attributed to Resources committed in any RAC processes, or in the LAC process, and (b) the Constraint Management Charge Allocation Factor, pursuant to Schedule 46 and (2) the greater of: (a) the sum of: (i) the aggregate sum, of Asset Owner adjusted deviations determined pursuant to Section 40.3.3.2.a.iii and (ii) any Topology Adjustment or Transmission De-rate adjusted for the applicable Constraint Contribution Factor and (b) the product of: (i) the aggregate of the hourly Economic Maximum Dispatch amounts, adjusted for the applicable

Commercial Pricing Node Constraint Contribution Factor, of all Resources committed in any RAC processes, or in the LAC process, and (ii) the Constraint Management Charge Allocation Factor, pursuant to Schedule 46.

In the event that the product of: (1) the aggregate Real-Time Revenue Sufficiency Guarantee Credit in any Hour attributed to Resources committed in any RAC processes, or in the LAC process, for the given Active Transmission Constraint and (2) the Constraint Management Charge Allocation Factor, pursuant to Schedule 46, exceeds the sum of (1) the aggregate of the Real-Time Revenue Sufficiency Guarantee Constraint Management Charges to Market Participants and (2) the amount attributable to Topology Adjustment and Transmission De-rate for the given Active Transmission Constraint, the difference shall constitute a residual amount not recovered through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge, that shall be allocated, *pro rata*, to Market Participants based on their Market Load Ratio Share.

The amount of Real-Time Revenue Sufficiency Guarantee Credit in an Hour attributed to Resources committed in any RAC processes, or in the LAC process, but not otherwise attributable to the Active Transmission Constraint, shall be funded through the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and Real-Time Revenue Sufficiency Guarantee Headroom Charge.

The amount of aggregate Real-Time Revenue Sufficiency Guarantee Credit in that Hour attributed to Resources in any RAC processes, or in the LAC process, but not otherwise attributable to the Active Transmission Constraint is equal to the product of: (1) the aggregate Real-Time Revenue Sufficiency Guarantee Credit in any Hour attributed to Resources committed in any RAC processes, or in the LAC process, for the given Active Transmission Constraint and (2) the difference between: (a) one and (b) and the Constraint Management Charge Allocation Factor, pursuant to Schedule 46.

The amount attributable to Topology Adjustment and Transmission De-rate for the given Active Transmission Constraint shall equal the product of: (1) any Topology Adjustment or Transmission De-rate adjusted for the applicable Constraint Contribution Factor and (2) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge rate.

b. Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge

i. Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge: The Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge is based on the sum of Day-Ahead Revenue Sufficiency Guarantee Credits in an Hour attributable to Day-Ahead Voltage and Local Reliability Commitments, pursuant to Section 39.3.1A, and Real-Time Revenue Sufficiency Guarantee Credits in an Hour attributable to Real-Time Voltage and Local Reliability Commitments. The amount attributable to Real-Time Voltage and Local Reliability Commitment for a Resource shall be equal to the product of (a) Real-Time Revenue Sufficiency Guarantee Credits in an Hour for Real-Time Voltage and Local Reliability Commitments and (b) the Voltage and Local Reliability Commitment Allocation Ratio.

The Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge shall be assigned to a single Local Balancing Authority Area, or allocated among two or more affected Local Balancing Authority Areas based on their Voltage and Local Reliability Local Balancing Authority Area Shares, as determined in accordance with Section 40.3.3.2.b.iii and Schedule 44. The Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge thus assigned or allocated to each affected Local Balancing Authority Area shall be assessed pro rata to Market Participants therein based on their Actual Energy Withdrawals at Commercial Pricing Nodes within the Local Balancing Authority Area; provided, however, that in the case of Internal Commercially Pseudo-Tied Load:

(a) The share of Actual Energy Withdrawals attributable to Internal Commercially Pseudo-Tied Load modeled into the affected Local Balancing Authority Area will be excluded from the pro rata assessment.

(b) The share of Actual Energy Withdrawals attributable to Internal Commercially Pseudo-Tied Load modeled out of the affected Local Balancing Authority Area will be included in the pro rata assessment.

ii. Voltage and Local Reliability Commitment Allocation Ratio. The Transmission Provider shall determine the proportion of costs associated with Voltage and Local Reliability Commitments via a study of historical market results. The study will be conducted on a periodic basis consistent with procedures set forth in Schedule 44, using a fixed time period. For the relevant historical time period, the study will consider, but is not limited to, the following:

(1) Day-Ahead or Real-Time Revenue Sufficiency Guarantee Credits paid to Voltage and Local Reliability Commitments,

(2) Capacity needed to meet Load and Operating Reserve Requirements, and,

(3) The avoided Day-Ahead and Real-Time Revenue Sufficiency Guarantee Credits that would have been paid to Resources that may have been committed to meet the Capacity needs in the absence of the Voltage and Local Reliability Commitments.

The avoided Day-Ahead and Real-Time Revenue Sufficiency Guarantee Credits calculated will be subtracted from the total Revenue Sufficiency Guarantee Credits in order to determine the total discounted credits. The Voltage and Local Reliability Commitment Allocation Ratio will be calculated as the total discounted credits divided by the total Revenue Sufficiency Guarantee Credits associated with Voltage and Local Reliability Commitments. For historical periods that include dates prior to establishing the Voltage and Local Reliability Commitment provisions under this Tariff, the Transmission Provider will include costs from those Transmission Provider committed Resources that would have been categorized as Voltage and Local Reliability Commitments.

iii. Voltage and Local Reliability Local Balancing Authority Area Share Calculation. For all Voltage and Local Reliability Commitments not associated with

Commercially Significant Voltage and Local Reliability Issues, the entire share will be allocated to the Local Balancing Authority Area where the Resource exists in the Commercial Model.

For Commercially Significant Voltage and Local Reliability Issues, the Transmission Provider will establish procedures in Schedule 44 that govern the administration and settlement calculation of such issues. Upon designating a transmission issue as a Commercially Significant Voltage and Local Reliability Issue, the Transmission provider will determine the percentage allocation to each affected Local Balancing Authority Area used to calculate the Voltage and Local Reliability Local Balancing Authority Area Share to assign any Revenue Sufficiency Guarantee Charges associated with any Voltage and Local Reliability Commitments. In determining these percentages for affected Local Balancing Authority Areas, the Transmission Provider will:

(1) Establish transmission constraints associated with the transmission issue,

(2) Determine Constraint Contribution Factors for transmission constraints associated with the transmission issue,

(3) Associate Commercial Pricing Nodes, including Load Zones, with the transmission issue based on Constraint Contribution Factors, and

(4) Calculate Local Balancing Authority Area Shares based on Load Zone Commercial Pricing Node information associated with the transmission issue.

c. Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and Real-Time Revenue Sufficiency Guarantee Headroom Charge:

Any residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through: (i) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge, including any residual amount not recovered through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge Rate, (ii) Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge, or (iii) otherwise attributable to Topology Adjustment and Transmission De-rate, shall be funded through the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and the Real-Time Revenue Sufficiency Guarantee Headroom Charge.

i. Real-Time Revenue Sufficiency Guarantee Headroom Charge: The Real-Time Revenue Sufficiency Guarantee Headroom Charge in an Hour is equal to the product of: (i) the lesser of: (1) the Headroom and (2) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes, or in the LAC process, and (ii) the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation and Headroom Charge Rate determined in Section 40.3.3.2.c.v. The Real-Time Revenue Sufficiency Guarantee Headroom Charge will be allocated, *pro rata*, to Market Participants based on their Market Load Ratio Share.

ii. Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge. The Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge shall be calculated and allocated under Sections 40.3.3.2.c.iii, 40.3.3.2.c.iv, and 40.3.3.2.c.v.

iii. For deviations occurring prior to the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge shall be based on the following deviations:

(1) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules, any difference between: (a) the sum of: (i) the Day-Ahead Schedule for Energy, (ii) the Day-Ahead Schedule for Regulating Reserve, (iii) the Day-Ahead Schedule for Spinning Reserve, and for Day-Ahead committed Resources, (iv) the Day-Ahead Schedule for Supplemental Reserve and (v) the Day-Ahead Schedule for Short-Term Reserve, and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline, or for Dispatchable Intermittent Resources, the Notification Deadline DIR Forecast (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process);

(2) for Load Zones, any difference between (a) the Real-Time Load Zone Demand Forecast in effect at the Notification Deadline and (b) the Day-Ahead Schedule;

(3) for Import Schedules, other than Coordinated Transaction Schedules, any difference between (a) the day-ahead Import Schedule and (b) the real-time Import Schedule in effect at the Notification Deadline;

(4) for Export Schedules, other than Export Schedules for External Asynchronous Resources and Coordinated Transaction Schedules, any difference

between (a) the real-time Export Schedule in effect at the Notification Deadline and (b) the day-ahead Export Schedule;

(5) any Virtual Transaction resulting from a cleared Virtual Supply Offer or the negative of any Virtual Transaction resulting from a cleared Virtual Bid;

(6) the negative of any Real-Time Financial Schedule For Deviations for the buyer at the Sink and any Real-Time Financial Schedule For Deviations for the seller at the Source; and

(7) for Demand Response Resources – Type I, any difference between: (a) the Day-Ahead Schedule and (b) the Targeted Demand Reduction Level in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day, or in the LAC process);

(8) for Intermittent Resources, any difference between (a) the Day-Ahead Schedule for Energy and (b) the Real-Time Intermittent Resource Forecast in effect at the Notification Deadline.

iv. For deviations occurring after the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge shall be based on the following deviations:

(1) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules committed in any RAC processes conducted for the Operating Day, or in the LAC process, any positive difference between (a) the real-time Hourly Economic Maximum Limit at the time the Generation Resource, Demand

Response Resource – Type II, Stored Energy Resources – Type II, and External Asynchronous Resource is committed by the Transmission Provider and (b) the real-time hourly Economic Maximum Dispatch;

(2) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules committed in any RAC processes conducted for the Operating Day, or in the LAC process, any positive difference between (a) the real-time hourly Economic Minimum Dispatch and (b) the real-time Hourly Economic Minimum Limit at the time the Generation Resource, Demand Response Resource – Type II, Stored Energy Resources – Type II, and External Asynchronous Resource is committed by the Transmission Provider;

(3) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules not committed in any RAC processes, or in the LAC process, conducted for the Operating Day, any positive difference between (a) the Hourly Economic Maximum Limit in effect at the Notification Deadline and (b) the real-time hourly Economic Maximum Dispatch;

(4) for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules not committed in any RAC processes, or in the LAC process, conducted for the Operating Day, any positive difference between (a) the real-

time hourly Economic Minimum Dispatch and (b) the Hourly Economic Minimum Limit in effect at the Notification Deadline;

(5) for Resources in an Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals, the sum of any Excessive Energy or Deficient Energy, pursuant to Section 40.3.4, in that Hour;

(6) for Load Zones, the positive value of any difference between (a) the Actual Energy Withdrawal or to the extent a Load Zone has Actual Energy Injection, Actual Energy Injection, adjusted by any Demand Response Resource's Actual Energy Injections associated with a given Load Zone, and (b) the Real-Time Load Zone Demand Forecast in effect at the Notification Deadline**;**

(7) for Import Schedules, other than Coordinated Transaction Schedules, the positive value of any difference between (a) the real-time Import Schedule in effect at the Notification Deadline and (b) the real-time Import Schedule;

(8) for Export Schedules, other than Export Schedules for External Asynchronous Resources and Coordinated Transaction Schedules, the positive value of any difference between (a) the real-time Export Schedule and (b) the real-time Export Schedule in effect at the Notification Deadline;

(9) for Demand Response Resources – Type I, the positive value of any difference between: (a) the Targeted Demand Reduction Level in effect at the Notification Deadline and (b) the Dispatch Target for Energy; and

(10) for Intermittent Resources, the positive difference between (a) the Real-Time Intermittent Resource Forecast in effect at the Notification Deadline and (b) the Actual Energy Injection.

The sum, by Asset Owner, of: (1) the net positive sum of the Asset Owner's deviations pursuant to Section 40.3.3.2.c.iii and (2) the sum of such Asset Owner's deviations pursuant to Section 40.3.3.2.c.iv shall be multiplied by the per unit Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge Rate to determine the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge to be paid by the Market Participant.

v. Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge Rate and Real-Time Revenue Sufficiency Guarantee Headroom Charge Rate: The per unit rate of the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and the Real-Time Revenue Sufficiency Guarantee Headroom Charge for any given Hour shall depend on:

Market-Wide Net Deviations: Equal to the aggregate sum of all amounts pursuant to Sections 40.3.3.2.c.iii and 40.3.3.2.c.iv.

Headroom Need: Equal to the greater of: (1) Unloaded Capacity Requirement and (2) sixty percent of hourly Load change.

Economically Committed Capacity: Equal to the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes, or in the LAC process; minus the sum of: (a) the product of (1) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes, or in the LAC process, to manage an Active Transmission Constraint; and (2) the Constraint Management Charge Allocation Factor, pursuant to Schedule 46; and (b) the product of (1) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed for Voltage and Local Reliability in the Real-Time Energy and Operating Reserve Market and (2) the Voltage and Local Reliability Commitment Allocation Ratio, pursuant to Schedule 44.

Day-Ahead Schedule Deviation and Headroom Credit: If the sum of (i) the Market-Wide Net Deviations; and (ii) Headroom Need is less than or equal to zero, the Day-Ahead Schedule Deviation and Headroom Credit is equal to zero. If the sum of: (i) the Market-Wide Net Deviations; and (ii) Headroom Need is greater than or equal to the Economic Committed Capacity, the Day-Ahead Schedule Deviation and Headroom Credit is equal to the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through (i) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge, including any residual amount not recovered through the Real-Time Sufficiency Guarantee Constraint Management Charge Rate, (ii) the Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge, or (iii) otherwise attributable to Topology Adjustment or Transmission De-rate. If the sum of (i) the Market-Wide Net Deviations; and (ii) Headroom Need is greater than zero, but less than the Economic Committed Capacity, the Day-Ahead Schedule Deviation and Headroom Credit is equal to the product of (i) the sum of (a) the Market-Wide Net Deviations and (b) Headroom Need; and (ii) the Real-Time Revenue Sufficiency Guarantee Market-Wide Net Rate.

Real-Time Revenue Sufficiency Guarantee Market-Wide Net Rate: Equal to the quotient of: (1) the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through: (i)the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge, including any residual amount not recovered through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge Rate, (ii) Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge, or (iii) otherwise attributable to Topology Adjustment or Transmission De-rate and (2) the Economically Committed Capacity.

Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge Rate and Real-Time Revenue Sufficiency Guarantee Headroom Charge Rate: The per unit rate of the Real-Time Revenue Sufficiency Guarantee Day-ahead Deviation Charge and the Real-Time Revenue Sufficiency Guarantee Headroom Charge for any given Hour shall equal the quotient of : (1) the Day-Ahead Schedule Deviation and Headroom Credit and (2) the greater of: (a) the sum of: (i) aggregate net positive sum, by Asset Owner, for such amounts pursuant to Sections 40.3.3.2.c.iii and 40.3.3.2.c.iv and (ii) Headroom and (b) the Economically Committed Capacity.

d. Residual Real-Time Revenue Sufficiency Guarantee Credit Distribution

In the event that the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through: (i) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge, including any residual amount not recovered through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge Rate, (ii) Day-Ahead and Real-Time Revenue Sufficiency Guarantee Voltage and Local Reliability Charge, or (iii) otherwise attributable to Topology Adjustment and Transmission De-rates in any Hour exceeds the aggregate of the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and Real-Time Revenue Sufficiency Guarantee Headroom Charge to Market Participants, the Transmission Provider shall allocate the excess, along with any amount attributable to Topology Adjustment, Transmission De-rate, Headroom, and commitment cancellations issued by the Transmission Provider, *pro rata*, to Market Participants based on their Market Load Ratio Share.

e. Real-Time Revenue Sufficiency Guarantee Distribution Exemptions

A Market Participant shall not be allocated Real Time Revenue Sufficiency Guarantee Constraint Management Charges, Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charges, or Real-Time Revenue Sufficiency Guarantee Headroom Charges for deviations occurring as the result of the following exceptions: (1) deviations caused or occurring during the Hour(s) when a Resource is deployed for Contingency Reserves; (2) Deviations of Resources, Load Zones and Interchange Schedules supported by firm Transmission Service, caused by or occurring as a result of Transmission Provider directives during an Emergency; (3) Resource deviations caused or occurring during abnormal operating conditions caused directly and exclusively by the failures or malfunctions of the Transmission Provider software or hardware systems; (4) Intermittent Resource deviations caused by or occurring as a result of Transmission Provider manual curtailment instructions; or (5) deviations resulting from compliance with Transmission Provider directives (particularly those relating to Transmission Loading Relief Procedures or “TLR”) in the case of Interchange Schedules supported by firm Transmission Service.

Credits for Real-Time Energy and Operating Reserve Market Sales

a. Real-Time Energy Credits

i. Non-Excessive Energy Credits. Market Participants are credited the applicable Real-Time Ex Post LMP for Non-Excessive Energy for Generation Resources, Stored Energy Resources, Stored Energy Resources – Type II, and External Asynchronous Resources for Import Schedules pursuant to Section 40.3.4, net of Real-Time Financial Schedules, that exceeds their Day-Ahead Scheduled Injections (and will be charged for Non-Excessive Energy, net of Real-Time Financial Schedules, deviations below their Day-Ahead Scheduled Injections). The applicable Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node at which the injection occurs.

A. A Commercial Pricing Node will be established for a SATOA. Non-Excessive Energy Credits for Storage as Transmission Only Asset. Market Participants are credited the applicable Real-Time Ex Post LMP for Non-Excessive Energy for Storage as Transmission Only Assets (and will be charged for Non-Excessive Energy withdrawals). The applicable Real-Time Ex Post LMP is the LMP at its Commercial Pricing Node at which the injection (or withdrawal) occurs. The Market Activity at a SATOA's Commercial Pricing Node will be limited to the charging and discharging necessary for the SATOA to meet or be ready to mitigate the identified Transmission Issue for which the SATOA was included in the MTEP or selected in the MTEP for purposes of cost allocation.

ii. Excessive Energy Credits. Market Participants are credited the Dispatch Interval Excessive Energy Price for Excessive Energy, as calculated pursuant to Section 40.3.4, where there is Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals in a specific Hour. The Dispatch Interval Excessive Energy Price for Generation Resources (except Dispatchable Intermittent Resources), Demand Response Resource – Type I, Demand Response Resource – Type II, External Asynchronous Resource and Stored Energy Resource – Type II is the lesser of (1) the Real-Time Ex Post LMP and (2) the greater of (a) the Energy Offer at the Dispatch Target and (b) zero. The Dispatch Interval Excessive Energy Price for Dispatchable Intermittent Resources is the lesser of: First, the Real-Time Ex Post LMP; or

Second, the product of: (1) the Real-Time Ex Post LMP and (2) maximum of (a) 1 minus the quotient of Excessive Energy divided by the Excessive Energy Tolerance and (b) zero.

Excessive Energy associated with Stored Energy Resources is settled at the Real-Time Ex Post LMP.

b. Real-Time Operating Reserve and Regulating Mileage Credits

i. Real-Time Energy and Operating Reserve Market Regulating Mileage Sales Definitions. For the purposes of calculating credits for Real-Time Energy and Operating Reserve Market Regulating Mileage Sales, the following terms are calculated as follows:

Instructed Total Mileage is calculated as the sum of the absolute values of up and down movement during a Dispatch Interval, in MW, that a resource is asked to provide in response to Setpoint Instructions using the resource's applicable ramp rate.

Instructed Energy Mileage is calculated as the sum of the absolute values of the up and down movement during a Dispatch Interval, in MW, that a resource is asked to provide in response to Energy Dispatch Targets and Contingency Reserve Deployment Instructions using a resource's applicable ramp rate.

Instructed Regulating Mileage is calculated as the difference between Instructed Total Mileage and Instructed Energy Mileage for each Dispatch Interval.

Regulating Mileage Target is calculated as the minimum of the Instructed Regulating Mileage and the Desired Resource Response for a Dispatch Interval.

Additional Regulating Mileage is calculated as the positive difference between the Regulating Mileage Target for a Resource and the Regulating Mileage considered in the Regulating Total Cost for the Resource during a Dispatch Interval.

Undeployed Regulating Mileage is calculated as the positive difference between the Regulating Mileage considered in the Regulating Total Cost for a Resource and the Regulating Mileage Target for the Resource during a Dispatch Interval.

The Regulating Mileage considered in the Regulating Total Cost for a Resource during a Dispatch Interval is equal to the Regulating Reserve Dispatch Target multiplied by the Market-wide Regulating Mileage Deployment Ratio.

The Transmission Provider shall update the Market-wide Regulating Deployment Ratio each month for the upcoming month to reflect changes in actual regulation deployment. The study will use data from the 15th of the previous month to the 15th of the current month to calculate the Market-wide Regulating Mileage Deployment Ratio that is effective starting the first of the upcoming month. The Market-wide Regulating Mileage Deployment Ratio is equal to the average of the ratio between the Regulating Mileage Target in a Dispatch Interval and the Regulating Reserve Dispatch Target in that Dispatch Interval for all Resources for all Dispatch Intervals with non-zero Regulating Reserve Dispatch Targets.

ii. Regulating Reserve Credit. Market Participants are credited the Real-Time Ex Post MCP for any positive difference between the Real-Time cleared amounts for Regulating Reserve within a Dispatch Interval in an Hour and their Day-Ahead Schedule for Regulating Reserve in that Hour (and will be charged the Ex Post MCP for any negative difference between the Real-Time cleared amounts for Regulating Reserve within a Dispatch Interval in an Hour and their Day-Ahead Schedule for Regulating Reserve in that Hour). The applicable Ex Post MCP for Regulating Reserve is for the Commercial Pricing Node at which the procurement occurs. The Regulating Reserve Credit will be reduced by the product of the Ex Post MCP for Regulating Mileage and Undeployed Regulating Mileage for each Dispatch Interval in the Hour. The sum of Regulating Reserve Credits in the Hour will also be augmented by the Undeployed Regulating Mileage Revenue Sufficiency Guarantee Credit as set forth in Schedule 3.

iii. Spinning Reserve Credits. Market Participants are credited the Real-Time Ex Post MCP for any positive difference between the Real-Time cleared amounts for Spinning Reserve within the Dispatch Interval in an Hour and their Day-Ahead Schedule for Spinning Reserve in that Hour (and will be charged the Real-Time Ex Post MCP for any negative difference between the Real-Time cleared amounts for Spinning Reserve within a Dispatch Interval in an Hour and their Day-Ahead Schedule for Spinning Reserve in that Hour). The applicable Ex Post MCP for Spinning Reserve is for the Commercial Pricing Node at which the procurement occurs.

iv. Supplemental Reserve Credits. Market Participants are credited the Real-Time Ex Post MCP for any positive difference between the Real-Time cleared amounts for Supplemental Reserve within a Dispatch Interval in an Hour and their Day-Ahead Schedule for Supplemental Reserve in that Hour (and will be charged for any negative difference between the Real-Time cleared amounts for Supplemental Reserve within a Dispatch Interval in an Hour less their Day-Ahead Schedule for Supplemental Reserve in that Hour). The applicable Real-Time Ex Post MCP for Supplemental Reserve is for the Commercial Pricing Node at which the procurement occurs.

v. Regulating Mileage Credit. Market Participants are credited the Hourly Real-Time Ex Post Regulating Mileage MCP for the sum of Additional Regulating Mileage for each Dispatch Interval in an Hour.

vi. Short-Term Reserve Credits. Market Participants are credited the Real-Time Ex Post MCP for any positive difference between the real-time cleared amounts for Short-Term Reserve within the Dispatch Interval in an Hour and their Day-Ahead Schedule for Short-Term Reserve in that Hour (and will be charged the Real-Time Ex Post MCP for any negative difference between the real-time cleared amounts for Short-Term Reserve within a Dispatch Interval in an Hour and their Day-Ahead Schedule for Short-Term Reserve in that Hour). The applicable Ex Post MCP for Short-Term Reserve is for the Commercial Pricing Node at which the procurement occurs.

c. Real-Time Revenue Sufficiency Guarantee Credit. The Transmission Provider shall determine, on a daily basis, whether any Generation Resource or Demand Response Resource committed by the Transmission Provider in the Real-Time Energy and Operating Reserve Market did not recover the sum of the Resource's eligible Production Cost and Operating Reserve Cost through the revenue received through the Real-Time Energy and Operating Reserve Market during the SCUC-Instructed Hours of Operation. In addition, the Transmission Provider shall determine on an hourly basis whether External Asynchronous Resources Export Schedule charges are greater than the energy value for export, calculated as the area under the Energy Offer curve for export Energy. If there is a shortfall, the Transmission Provider shall augment the Market Participant's revenue with a Real-Time Revenue Sufficiency Guarantee Credit, pursuant to Section 40.3.3.3.c.iii.

i. Real-Time Revenue Sufficiency Guarantee Full Payment Criteria. In order to be eligible for full payment of Real-Time Revenue Sufficiency Guarantee Credit, all Hours in the SCUC Instructed Hours of Operation for a Resource must comply with the following requirements, provided that the specified Offer data shall include any overrides entered by the Transmission Provider at the request of the Market Participant that owns or represents the Resource:

(a) The Resource must not receive an Excessive/Deficient Energy Deployment Charge, pursuant to Section 40.3.4, during an Hour. Any Resource receiving an Excessive/Deficient Energy Deployment Charge in an Hour will be subject to a Real-Time Revenue Sufficiency Guarantee Credit reduction, pursuant to Section 40.3.3.3.c.ii.b, for that Hour and all remaining contiguous Hours in the Real-Time SCUC Instructed Hours of Operation.

(b) For all Resources other than Demand Response Resource Type-I, the real-time Economic Minimum Dispatch must be less than or equal to the maximum of: (i) the as-committed Hourly Economic Minimum Limit; (ii) the as-committed self-schedule MW for instances where the Energy Dispatch Status is self-schedule; or (iii) the as-committed Hourly Regulation Minimum for instances where the Resource is scheduled to potentially provide Regulating Reserve. For Demand Response Resource - Type I, the real-time Dispatch Target for Energy must be less than or equal to the as committed Targeted Demand Reduction Level. This criterion will be checked for each Dispatch Interval within the Hour and for each Hour of the contiguous Real-Time SCUC Instructed Hours of

Operation, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet this criterion, the Resource will be subject to a Real-Time Revenue Sufficiency Guarantee Credit reduction, pursuant to Section 40.3.3.3.c.ii.b, for that Hour and all remaining contiguous Hours in the Real-Time SCUC Instructed Hours of Operation.

(c) In addition, for Resources where all limits used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval have a dispatch range of greater than 1MW, the following criteria must also be satisfied:

(i) The Real-Time ramp rate utilized by the Unit Dispatch System (UDS) must be greater than 0.5 MW/minute.

(ii) The Real-Time ramp rate utilized by the Unit Dispatch System must be greater than one-half of one percent (0.5%) of the real-time Hourly Economic Maximum Limit of the Generation Resource or Demand Response Resource-Type II per minute and non-decreasing except where:

(1) Resource output is greater than or equal to ninety percent (90%) of the real-time Hourly Economic Maximum Limit as determined by the Unit Dispatch System, then real-time ramp rate utilized by the Unit Dispatch System must be greater than one-half (0.5) MW/minute.

(2) Resource output is less than or equal to the real-time Hourly Economic Minimum Limit plus ten percent (10%) of the real-time Hourly Economic Maximum Limit as determined by the Unit Dispatch System, in which case the

real-time ramp rate utilized by the Unit Dispatch System must be greater than one-half (0.5) MW/minute.

(iii) These criteria will be checked for each Dispatch Interval within the Hour and for each contiguous Hour of the SCUC Instructed Hours of Operation, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet these criteria, the Resource will be subject to a Real-Time Revenue Sufficiency Guarantee Credit reduction, pursuant to Section 40.3.3.3.c.ii.b, for that Hour and the subsequent Hours of the Real-Time SCUC Instructed Hours of Operation.

(d) For all Resources other than Demand Response Resource Type-I, the Resource Offer Up and Down Ramp Capability Dispatch Status must be Economic. This criterion will be checked for each Dispatch Interval within the Hour and for each Hour of the contiguous Real-Time SCUC Instructed Hours of Operation, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet this criterion, the Resource will be subject to a Real-Time Revenue Sufficiency Guarantee Credit reduction, pursuant to Section 40.3.3.3.c.ii.b, for that Hour and all remaining contiguous Hours in the Real-Time SCUC Instructed Hours of Operation.

ii. Calculation of Real-Time Revenue Sufficiency Guarantee Credit for Real-Time SCUC Instructed Hours of Operation

(a) Revenue Sufficiency Guarantee Full Payment: Resources that satisfy the Real-Time Revenue Sufficiency Guarantee Full Payment Criteria described in

Section 40.3.3.3.c.i shall receive a Real-Time Revenue Sufficiency Guarantee Credit for the Real-Time SCUC Instructed Hours of Operation in the current Operating Day, as described below.

If the sum of the Generation Resource's or Demand Response Resource's Production Cost (based on Non-Excessive Energy injection) and Operating Reserve Cost is greater than the revenue over each contiguous commitment period for that Resource, then the Market Participant's Real-Time Energy and Operating Reserve Market credits shall be augmented by an additional credit called the Real-Time Revenue Sufficiency Guarantee Credit in the amount of the revenue shortfall, spread over all the Hours in that contiguous commitment period. The determination of such credit shall consider only Operating Reserve Costs associated with real-time Operating Reserves volumes that are greater than the day-ahead Operating Reserve volumes. The revenue shall be calculated as the sum of the following values:

(i) Energy Revenue. For Generation Resources and Demand Response Resources, as determined, for all Dispatch Intervals in an Hour, by the sum of the products of: (1) the Non-Excessive Energy injections; (2) the Real-Time Ex Post LMP; and (3) the duration of the Dispatch Interval expressed in Hours;

(ii) Operating Reserve Revenue**.** The sum of: real-time Regulating Reserve revenue as determined by the sum, for all Dispatch Intervals in an Hour, of the products of: (1) the real-time Regulating Reserve volume; (2) the real-time Regulating Reserve Ex Post MCP; and (3) the duration of the Dispatch Interval expressed in Hours; and the sum, as determined as follows, of the real-time Contingency Reserve revenue for all Dispatch Intervals in the real-time SCUC Instructed Hours of Operation, plus any applicable Minimum Down Time requirements in the current Operating Day: (a) If the day-ahead Contingency Reserve volume is greater than zero and greater than the real-time Contingency Reserve volume, the real-time Contingency Reserve revenue is determined by the product of: (1) the real-time Contingency Reserve volume minus the day-ahead Contingency Reserve volume; (2) the real-time Contingency Reserve Ex Post MCP minus the day-ahead Contingency Reserve offer cost; and (3) the duration of such Dispatch Intervals expressed in Hours; (b) If the day-ahead Contingency Reserve volume is greater than zero and less than or equal to the real-time Contingency Reserve volume, the real-time Contingency Reserve revenue is determined by the product of: (1) the real-time Contingency Reserve volume minus the day-ahead Contingency Reserve volume; (2) the real-time Contingency Reserve Ex Post MCP; and (3) the duration of such Dispatch Intervals expressed in Hours; (c) If the day-ahead Contingency Reserve volume is equal to zero, the real-time Contingency Reserve revenue is determined by the product of: (1) the real-time Contingency Reserve volume; (2) the real-time Contingency Reserve Ex Post MCP; and (3) the duration of such Dispatch Intervals expressed in Hours.

(iii) Regulating Reserve Deployment Revenue. Real-time Regulating Reserve Deployment revenue as determined, for all Dispatch Intervals in an Hour, by the sum of the product of: (1) the Regulating Reserve Deployment charge/credit determined pursuant to Section 40.3.3.1.a.vi; and (2) the duration of the Dispatch Intervals expressed in Hours.

(iv) Ramp Capability Revenue. Ramp Capability Revenue as determined for the Hour by the sum of (a) the Up Ramp Capability Credit pursuant to Section 40.3.3.1.b.i; and (b) the Down Ramp Capability Credit pursuant to Section 40.3.3.1.b.ii.

(v) Short-Term Reserve Revenue. The Short-Term Reserve revenue is the sum, as determined as follows, of the real-time Short-Term Reserve revenue for all Dispatch Intervals in the real-time SCED Instructed Hours of Operation, plus any applicable Minimum Down Time requirements in the current Operating Day: (a) If the day-ahead Short-Term Reserve volume is greater than zero and greater than the real-time Short-Term Reserve volume, the real-time Short-Term Reserve revenue is determined by the product of: (1) the real-time Short-Term Reserve volume minus the day-ahead Short-Term Reserve volume; (2) the real-time Short-Term Reserve Ex Post MCP minus the day-ahead Short-Term Reserve Offer cost; and (3) the duration of such Dispatch Intervals expressed in Hours; (b) If the day-ahead Short-Term Reserve volume is greater than zero and less than or equal to the real-time Short-Term Reserve volume, the real-time Short-Term Reserve revenue is determined by the product of: (1) the real-time Short-Term Reserve volume minus the day-ahead Short-Term Reserve volume; (2) the real-time Short-Term Reserve Ex Post MCP; and (3) the duration of such Dispatch Intervals expressed in Hours; (c) If the day-ahead Short-Term Reserve volume is equal to zero, the real-time Short-Term Reserve revenue is determined by the product of: (1) the real-time Short-Term Reserve volume; (2) the real-time Short-Term Reserve Ex Post MCP; and (3) the duration of such Dispatch Intervals expressed in Hours.

(b) Revenue Sufficiency Guarantee Credit Reduction

(i) Energy Revenue Reduction: For any Resource that fails to meet the Real-Time Revenue Sufficiency Guarantee Full Payment Criteria for an Hour during the Real-Time SCUC Instructed Hours of Operation, the Revenue Sufficiency Guarantee Full Payment calculation shall be modified such that the Production Costs and Energy Revenue will be based on the eligible MW value. For all Resources other than Demand Response Resource Type-I, the eligible MW value for a given Dispatch Interval is equal to the lesser of: (1) the Actual Energy Injection; (2) the Excessive Energy Threshold; (3) the as-committed Hourly Economic Minimum Limit; (4) the as-committed self-schedule MW for instances where the Energy Dispatch Status is self-schedule; or (5) the as-committed Hourly Regulation Minimum Limit for instances where the Resource is scheduled to potentially provide Regulating Reserve. For Demand Response Resource Type-I, the eligible MW value is equal to the lesser of: (1) the Actual Energy Injection; or (2) the as-committed Targeted Demand Reduction Level.

(ii) Ineligible Energy Margin: In order to avoid increasing the total Real-Time Revenue Sufficiency Guarantee Credit for a Resource that fails to meet the Real-Time Revenue Sufficiency Guarantee Full Payment Criteria, the

Transmission Provider shall also include any additional energy margin that results from Revenue Sufficiency Guarantee Credit Reduction. The additional energy margin is calculated as the greater of: (1) the difference between (a) the Energy Revenue associated with Actual Energy Injections between the eligible MW value and the Non-Excessive Energy injections; and (b) the Production Costs for the Energy associated with Actual Energy Injections between the eligible MW value and the Non-Excessive Energy injections; and (2) zero.

iii. External Asynchronous Resources Export Schedule Real-Time Revenue Sufficiency Guarantee Credit. The hourly basis External Asynchronous Resources Export Schedule credit is the product of 1) the net positive difference between (a) the Real-Time Hourly Export Energy value, and (b) the Day-Ahead Hourly Export Energy value, and 2) the Real-Time Hourly LMP at the External Asynchronous Resources Commercial Pricing Node. The hourly basis for the External Asynchronous Resources Export energy value is the area under the Energy Offer curve between the Day-Ahead hourly Export energy and Real-Time hourly Export energy.

iv. Cost Allocation. This credit shall be supported through revenue collected from the Real-Time Revenue Sufficiency Guarantee Charge.

d. Applicability of Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges

The provisions of Section 40.3.4 related to Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges shall apply to Resources irrespective of the provisions of this Section.

Charges and Credits for Real-Time Energy and Operating Reserve Market Energy Purchases and Sales Associated with Demand Response Resources or Stored Energy Resources – Type II

a. **Energy Charges and Credits.** Market Participants shall be charged the applicable Hourly Real-Time Ex Post LMP for any Actual Energy Withdrawals associated with a Demand Response Resource or Stored Energy Resource – Type II, net of Real-Time Financial Schedules, that exceed their Day-Ahead Scheduled Withdrawals associated with Demand Response Resource or Stored Energy Resource – Type II (and are credited for the Actual Energy Withdrawals, net of Real-Time Financial Schedules, that are below their Day-Ahead Scheduled Withdrawals associated with a Demand Response Resource or Stored Energy Resource – Type II). The applicable Hourly Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node at which the withdrawal (or injection) takes place.

b. **Demand Response Resource or Stored Energy Resource – Type II Non-Excessive Energy Charges and Credits.** Market Participants (including Market Participants that are ARCs) will be credited the applicable Real-Time Ex Post LMP for Non-Excessive Energy for Demand Response Resources or Stored Energy Resources – Type II pursuant to Section 40.3.4, net of Real-Time Financial Schedules, that exceeds their Day-Ahead Scheduled Injections (and will be charged for Non-Excessive Energy, net of Real-Time Financial Schedules, deviations below their Day-Ahead Scheduled Injections). The applicable Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node at which the injection occurs.

c. **Demand Response Resource or Stored Energy Resource – Type II Excessive Energy Credits.** Market Participants are credited the Dispatch Interval Excessive Energy Price for Excessive Energy associated with Demand Response Resources or Stored Energy Resources – Type II where such Excessive Energy is calculated pursuant to Section 40.3.4. The applicable Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node.

d. **Below Net Benefit Price Threshold Revenue Neutrality**. The Transmission Provider shall distribute any revenue inadequacy or surplus that results from the differences between the LMP for a DRR CPNode and the LMP for the associated Load Zone(s) CPNode, pro rata, to Market Participant Loads based on their Market Load Ratio Share.

Charges and Credits for Transmission Provider Balancing Authority Compliance with NERC/RRO Standards and Participation in Reserve Sharing Group

a. Administrative Charges/Credits. Revenue received by the Transmission Provider Balancing Authority as compensation for the performance of administrative services associated with compliance with NERC and/or Regional Entity standards, including but not limited to, participation in a Reserve Sharing Group and/or providing Emergency Energy assistance shall be used to reduce administrative costs recovered from Market Participants pursuant to Schedule 17 of the Tariff. Fees to be paid by the Transmission Provider Balancing Authority associated with the provision of such administrative services shall be recovered from Market Participants pursuant to Schedule 17 of the Tariff.

b. Other Charges/Revenue. Charges owed, other than charges owed under Sections 40.3.3.5.a and 40.2.22, by the Transmission Provider Balancing Authority, for Emergency Energy assistance received from, including but not limited to, Reserve Sharing Group members, shall be recovered from Market Participants on a daily pro rata share basis. Revenue, other than revenue covered under Section 40.3.3.5.a, received by the Transmission Provider Balancing Authority for Emergency Energy assistance received by others, including but not limited to Reserve Sharing Group members and/or Balancing Authorities, shall be distributed to Market Participants on a daily pro rata share basis. For both charges and revenues, the Market Participant's daily pro rata share for each day in which charges and/or revenues apply shall be calculated as the sum of the applicable Market Participant's: (i) withdrawals at Commercial Nodes, excluding withdrawals associated with Carved-Out GFAs and (ii) Export Schedules in that Day divided by the sum of all withdrawals at commercial nodes (excluding withdrawals at commercial nodes with Carved-Out GFAs) and all Export Schedules for all applicable Market Participants in that Day.

Settlement of deviations from Setpoint Instructions is subject to a Tolerance Band as specified in this Section. A Resource shall be charged Excessive/Deficient Energy Deployment Charges in any Hour for which that Resource's average telemetered output over the Dispatch Interval is outside the Tolerance Band in four (4) or more consecutive Dispatch Intervals, except where Resources fall under Section 38.6.1, in which case Section 40.3.4.g applies.

Contingency Reserve Deployment Failure Charges are assessed to Resources that fail to deploy Contingency Reserve, consistent with the Resource limit and ramping constraints as set forth in Schedule 29, in an amount greater than or equal to the amount specified in the Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period, except where Resources fall under Section 38.6.1, in which case Section 40.3.4.h applies.

Short-Term Reserve Deployment Failure Charges are assessed to off-line Resources that fail to deploy Short-Term Reserve, consistent with the Resource limit and ramping constraints as set forth in Schedule 29, in an amount greater than or equal to the Economic Minimum Dispatch within the Short-Term Reserve Deployment Period, except where Resources fall under Section 38.6.1, in which case Section 40.3.4.h applies.

Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges are calculated as set forth below.

a. Tolerance Band and Excessive and Deficient Energy Calculations.

i. Generation Resource (except where as provided under Section 40.3.4.a.ii), Demand Response Resource – Type II, Stored Energy Resource – Type II, and External Asynchronous Resource Tolerance Band. The Dispatch Interval Excessive Energy Threshold of a Generation Resource (except where as provided under Section 40.3.4.a.ii), Demand Response Resource – Type II, Stored Energy Resource – Type II, or External Asynchronous Resource shall be equal to the sum of: (1) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval plus the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate; and (2) the lesser of (a) the ramp rate used for Energy and Regulating Reserve times five and (b) the product of (i) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval plus the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate and (ii) twelve percent (12%).

The Deficient Energy Threshold of a Generation Resource (except where as provided under Section 40.3.4.a.ii), Demand Response Resource – Type II, Stored Energy Resource – Type II, or External Asynchronous Resource shall be equal to the difference between: (1) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval plus the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate; and (2) the lesser of (a) the ramp rate used for Energy and Regulating Reserve times five and (b) the product of (i) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval plus the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate and (ii) twelve percent (12%); provided, however, that the Excessive Energy Threshold and Deficient Energy Threshold shall not be less than the minimum or exceed the maximum levels as specified in section 40.3.4.a.v, except that the resulting Excessive and Deficient Energy Thresholds will be adjusted for achievable Setpoint Instructions based on offered ramp rate when deployments for Energy, Regulation, and/or Contingency Reserves utilize ramping capabilities as set forth Schedule 29.

ii. Dispatchable Intermittent Resource Tolerance Band.

Pursuant to Section 40.2.5.b.xxxiii, the Transmission Provider shall develop a Forecast Maximum Limit for a Dispatchable Intermittent Resource for each Dispatch Interval. When the Transmission Provider uses this Forecast Maximum Limit for a given Dispatch Interval, the Tolerance Band will be determined as follows:

1. For a Dispatch Interval in which the Setpoint Instruction equals the Forecast Maximum Limit, the Excessive Energy Threshold and Deficient Energy Threshold will be set equal to the Dispatchable Intermittent Resource's Dispatch Interval Actual Energy Injections.
2. For a Dispatch Interval in which economic curtailment results in the Setpoint Instruction being less than the Forecast Maximum Limit, the Tolerance Band will be determined the same as a Generation Resource as set forth in Section 40.3.4.a.i.

To the extent the Forecast Maximum Limit provided by a Market Participant is used for a given Dispatch Interval, the Tolerance Band will be determined as set forth in Section 40.3.4.a.i.

iii. Demand Response Resource – Type I Tolerance Band.

The Excessive Energy Threshold of a Demand Response Resource – Type I that has been committed for Energy, shall be equal to one hundred and twelve percent (112%) of the Targeted Demand Reduction Level for that Dispatch Interval and, the Deficient Energy Threshold of a Demand Response Resource - Type I that has been committed for Energy, shall be equal to eighty-eight percent (88%) of the Targeted Demand Reduction Level for that Dispatch Interval; provided, however, that the Excessive Energy Threshold and Deficient Energy Threshold shall not be less than the minimum or exceed the maximum levels as specified in section 40.3.4.a.v. For Demand Response Resources – Type I that have not been committed for Energy, the Excessive Energy Threshold and Deficient Energy Threshold shall be equal to zero.

iv. Stored Energy Resource Tolerance Band. The Excessive Energy Threshold of a Stored Energy Resource shall be equal to the sum of (a) the Dispatch Target for Energy for the current Dispatch Interval, (b) the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate and (c) 12% of the absolute value of the sum of (i) the Dispatch Target for Energy and (ii) the average Regulating Reserve Deployment instruction for that Dispatch Interval. The Deficient Energy

Threshold of a Stored Energy Resource shall be equal to the sum of (a) the Dispatch Target for Energy for the current Dispatch Interval and (b) the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource less 12% of the absolute value of (i) the Dispatch Target for Energy and (ii) the average Regulating Reserve Deployment instruction for that Dispatch Interval.

v. Minimum and Maximum Tolerance Band Thresholds. The Excessive Energy Threshold as specified above will be adjusted so that it shall be no less than six (6) MW or no greater than thirty (30) MW plus the sum of (a) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval, and (b) the average Regulating Reserve Deployment instruction, accounting for the Resource’s applicable ramp rate, for that Dispatch Interval. The Deficient Energy Threshold as specified above will be adjusted so that it shall be no greater than the sum of (a) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval, and (b) the average Regulating Reserve Deployment instruction, accounting for the Resource’s applicable ramp rates, for that Dispatch Interval minus six (6) MW or no less than the sum of (a) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval, and (b) the average Regulating Reserve Deployment instruction, accounting for the Resource’s applicable ramp rate, for that Dispatch Interval minus thirty (30) MW, except that, if the Deficient Energy Threshold is less than zero, the Deficient

Energy Threshold shall be set equal to zero.

The Excessive Energy Threshold as defined above for Stored Energy Resource shall never be less than 6 MW greater than or more than 30 MW greater than the sum of (a) the Dispatch Target for Energy for the current Dispatch Interval, (b) the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate. The Deficient Energy Threshold as defined above for Stored Energy Resources shall never be less than 6 MW less or more than 30 MW less than the sum of (a) the Dispatch Target for Energy for the current Dispatch Interval, (b) the average Regulating Reserve Deployment instruction for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate.

vi. Excessive Energy for Generation Resource, Stored Energy Resource, Stored Energy Resource – Type II, and External Asynchronous Resource. Excessive Energy for a Generation Resource in a Dispatch Interval is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Dispatch Interval Actual Energy Injections, and the Excessive Energy Threshold for that Generation Resource, or (b) zero. Excessive Energy for an External Asynchronous Resource in a Dispatch Interval is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and difference between the Dispatch Interval Actual Energy Injections, and the Excessive Energy Threshold for that External Asynchronous Resource, or (b) zero.

Excessive Energy for a Stored Energy Resource in a Dispatch Interval is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and difference between the Dispatch Interval Actual Energy Injections, and the Excessive Energy Threshold for that Stored Energy Resource, or (b) zero.

vii. Excessive Energy for Demand Response Resource-Type I. Excessive Energy for a Demand Response Resource -Type I in a Dispatch Interval is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Calculated DRR -Type I Output of Demand Response Resource -Type I, expressed in MW, and the Excessive Energy Threshold for such one or more Demand Response Resources -Type I, or (b) zero.

If the Demand Response Resource – Type I has not been committed for Energy for that Hour, the DRR-Type I Calculated Output shall be equal to zero (0).

viii. Excessive Energy for Demand Response Resource-Type II. Excessive Energy for a Demand Response Resource -Type II in a Dispatch Interval is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Calculated DRR -Type II Output of such Demand Response Resource -Type II, expressed in MW, and the Excessive Energy Threshold for such Demand Response Resource -Type II, or (b) zero. If the Demand Response Resource-Type II has not been committed for Energy for that Hour, the Calculated DRR-Type II Output shall be equal to zero (0) MW.

ix. Deficient Energy for Generation Resource, Stored Energy Resource, Stored Energy Resource – Type II, or External Asynchronous Resource. Deficient

Energy in a Dispatch Interval for a Generation Resource is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Deficient Energy Threshold for the Generation Resource and the Dispatch Interval Actual Energy Injections, or (b) zero. Deficient Energy in a Dispatch Interval for an External Asynchronous Resource is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Deficient Energy Threshold for the External Asynchronous Resource and the Dispatch Interval Actual Energy Injections, or (b) zero (0) MW.

Deficient Energy in a Dispatch Interval for a Stored Energy Resource is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Deficient Energy Threshold for the Stored Energy Resource and the Dispatch Interval Actual Energy Injections, or (b) zero (0) MW.

x. Deficient Energy for Demand Response Resource-Type I. Deficient Energy in a Dispatch Interval for a Demand Response Resource-Type I is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Deficient Energy Threshold for Demand Response Resource-Type I and the Calculated DRR-Type I Output of such Demand Response Resource -Type I, expressed in MW or (b) zero. If the Demand Response Resource – Type I has not been committed for Energy for that Hour, the Calculated DRR-Type I Output shall be equal to zero (0) MW.

xi. Deficient Energy for Demand Response Resource-Type II. Deficient Energy in a

Dispatch Interval for a Demand Response Resource-Type II is equal to the greater of (a) the product of the duration of the Dispatch Interval in Hours and the difference between the Deficient Energy Threshold for such Demand Response Resource-Type II and the Calculated DRR-Type II Output of such one or more Demand Response Resource -Type II, expressed in MW, or (b) zero (0) MW. If the Demand Response Resource – Type II has not been committed for Energy for that Hour, the Calculated DRR – Type II output shall be equal to zero (0) MW.

xii. Non-Excessive Energy for Generation Resource, Stored Energy Resource, Stored Energy Resource – Type II, or External Asynchronous Resource. In an Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals, Non-Excessive Energy in a Dispatch Interval for a Generation Resource is equal to the product of the Dispatch Interval duration in Hours and the lesser of the Dispatch Interval Actual Energy Injections, of the Generation Resource or the Generation Resource's Excessive Energy Threshold. Non-Excessive Energy in a Dispatch Interval for an External Asynchronous Resource is equal to the product of the Dispatch Interval duration in Hours and the lesser of the Dispatch Interval Actual Energy Injections, of the External Asynchronous Resource or the External Asynchronous Resource's Excessive Energy Threshold. Non-Excessive Energy in a Dispatch Interval for a Stored Energy Resource is equal to the product of the Dispatch Interval duration in Hours and the lesser of the Dispatch Interval Actual Energy Injections, of the Stored Energy Resource or the Stored Energy Resource's Excessive Energy

Threshold.

In an Hour with Excessive Energy, Deficient Energy or any combination thereof in three (3) or less consecutive Dispatch Intervals, Non-Excessive Energy in a Dispatch Interval for a Generation Resource is equal to the product of the Dispatch Interval duration in Hours and the Dispatch Interval Actual Energy Injections, of the Generation Resource. Non-Excessive Energy in a Dispatch Interval for an External Asynchronous Resource is equal to the product of the Dispatch Interval duration in Hours and the Dispatch Interval Actual Energy Injections, of the External Asynchronous Resource. Non-Excessive Energy in a Dispatch Interval for a Stored Energy Resource is equal to the product of the Dispatch Interval duration in Hours and the Dispatch Interval Actual Energy Injections, of the Stored Energy Resource.

xiii. Non-Excessive Energy for Demand Response Resource-Type I. In an Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals, Non-Excessive Energy in a Dispatch Interval for a Demand Response Resource-Type I is equal to the product of the Dispatch Interval duration in Hours and the lesser of the Calculated DRR-Type I Output of such Demand Response Resource-Type I, or such one or more Demand Response Resource-Type I Excessive Energy Threshold.

In an Hour with Excessive Energy, Deficient Energy or any combination thereof in three (3) or less consecutive Dispatch Intervals Non-Excessive Energy in a Dispatch Interval for a Demand Response Resource - Type I is equal to the product of the Dispatch Interval duration in Hours and the Calculated DRR-Type I Output of such one or more Demand Response Resource-Type I.

The Calculated DRR -Type I Output for a Dispatch Interval is calculated in accordance with Attachment TT. If the Demand Response Resource – Type I has not been committed for Energy for that Hour, the Calculated DRR-Type I Output shall be equal to zero (0) MW.

xiv. Non-Excessive Energy for Demand Response Resource-Type II. In an Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals, Non-Excessive Energy in a Dispatch Interval for a Demand Response Resource-Type II is equal to the product of the Dispatch Interval duration in Hours and the lesser of the Calculated DRR-Type II Output of such Demand Response Resource-Type II, or such Demand Response Resource-Type II Excessive Energy Threshold. In an Hour with Excessive Energy, Deficient Energy or any combination thereof in three (3) or less consecutive Dispatch Intervals, Non-Excessive Energy in a Dispatch Interval for a Demand Response Resource-Type II is equal to the product of the Dispatch Interval duration in Hours and the Calculated DRR-Type II Output of such Demand Response Resource-Type II.

If the DRR–Type II has not been committed for Energy for that Hour, the Calculated DRR – Type II output shall be equal to zero (0) MW.

xv. Contingency Reserve Deployment. During Dispatch Intervals in which there is Contingency Reserve Deployment on a specific Resource, the Excessive Energy

Threshold and Deficient Energy Threshold will not apply to that Resource. A Resource is considered to be deploying Contingency Reserve in any Dispatch Interval that overlaps or is within the Disturbance Recovery Period associated with any event that triggered any of the Contingency Reserve Deployment.

b. Excessive/Deficient Energy Deployment Charges and Consequences

If a Market Participant's Resource has Excessive Energy, Deficient Energy or any combination thereof in four or more consecutive Dispatch Intervals in an Hour, that Market Participant shall be subject to an Excessive/Deficient Energy Deployment Charge associated with such Resource calculated as follows:

i. A Resource's Excessive/Deficient Energy Deployment Charge shall be equal to: (1) the product of the absolute value of the Resource's Actual Energy Injection, in MWh, for the Hour and the Excessive/Deficient Charge Rate, in $/MWh; plus (2) the greater of (a) the sum of (i) the Regulating Reserve credits calculated pursuant to Section 39.3.2A.a, (ii) the Regulating Reserve credits/charges calculated pursuant to Section 40.3.3.3.b.ii, (iii) the Short-Term Reserve credits calculated pursuant to Section 39.3.2A.e, and (iv) the Short-Term Reserve credits/charges calculated pursuant to Section 40.3.3.3.b.vi for that Resource for that Hour or (b) zero. The Excessive/Deficient Charge Rate in an Hour is equal to the greater of (1) the quotient of (a) the sum of the (i) the Day-Ahead Regulating Reserve credits calculated pursuant to Section 39.3.2A.a, (ii) the Real-Time Regulating Reserve charges/credits calculated pursuant to Section 40.3.3.3.b.ii, (iii) the day-ahead Short-Term Reserve credits calculated pursuant to Section 39.3.2A.e, and

(iv) the real-time Short-Term Reserve charges/credits calculated pursuant to Section 40.3.3.3.b.vi in that Hour and (b) the sum of all Actual Energy Withdrawals, in MWh, at all Commercial Pricing Nodes, excluding Export Schedules, in that Hour or (2) zero.

ii. The Transmission Provider may report to the Commission and the Independent Market Monitor a Market Participant's failure to deliver Regulating Reserve deployed as determined through evaluation of actual performance data if the Transmission Provider believes that the Market Participant is inaccurately reporting the physical capability of the Resource to provide Regulating Reserve.

c. Common Bus Substitution. For the purposes of settling Excessive Energy, Excessive/Deficient Energy Deployment Charges, and Contingency Reserve Deployment Failure Charges, all Resources owned by a specific Market Participant and either (i) located at the same electrical bus or (ii) associated with the same Load Zone will be aggregated as one Resource. Common buses will be established as part of the Network Model update process. These Resources will not be aggregated for any other purpose, including, but not limited to, offering, commitment, clearing, dispatching, pricing and instructing.

d. Exemption from Excessive Energy Calculations and Excessive/Deficient Energy Deployment Charges.

i. Treatment of Intermittent Resources.

Notwithstanding any provisions of this Tariff to the contrary, Intermittent Resources designated as such by the Transmission Provider shall not be subject to

Excessive/Deficient Energy Deployment Charges or the calculation of Excessive Energy caused solely by the intermittent nature or characteristics of such Resources, provided, that there be no fault or negligence of the Market Participants or Generation Owners that own or operate them.

ii. Criteria for Intermittent Resources. Prior to March 1, 2013, Generation Resources can be considered Intermittent Resources if they are incapable of being dispatched or following Setpoint Instructions, and the Generation Resource has not previously been registered as a Dispatchable Intermittent Resource. On or after March 1, 2013, a Generation Resource can be considered an Intermittent Resource if such Generation Resource is incapable of being dispatched by the Transmission Provider or incapable of following Setpoint Instructions, the Generation Resource has not previously been registered as a Dispatchable Intermittent Resource, and: (A) the Commercial Operation Date as set forth in the Resource’s Generator Interconnection Agreement or equivalent agreement is prior to April 1, 2005; or (B) any of the following apply to the Capacity of the Generation Resource in an amount, either separately or combined, that equals the total Capacity of the Generation Resource: i) the Generation Resource has been interconnected to the Facilities operated by the Transmission provider through Network Resource Interconnection Service; ii) the Generation Resource has been designated as a Network Resource under Module B of the Tariff; or iii) the Energy produced by the Generation Resource is subject to an agreement for Long-Term Firm Point-to-Point Transmission Service; or (C) the Generation Resource is not fueled by wind or solar; or (D) the Generation Resource is fueled by solar energy and is in commercial operation prior to March 15, 2020. Any Generation Resource fueled by solar energy not in commercial operation prior to March 15, 2020 may qualify as an Intermittent Resource but must register as a Dispatchable Intermittent Resource by March 15, 2022.

iii. Procedure for Designation of Intermittent Resources. Any Generation Resource seeking Intermittent Resource status shall submit to the Transmission Provider a written request to be designated as an Intermittent Resource, certifying and demonstrating its compliance with the criteria and requirements for an Intermittent Resource as set forth above. The Transmission Provider shall designate a Generation Resource as an Intermittent Resource upon review and verification of the request for such designation.

iv. Requirement of Day-Ahead Forecast. For reliability purposes, each Intermittent Resource and Dispatchable Intermittent Resource must submit to the Transmission Provider a Day-Ahead forecast of its intended output for the next day consistent with the procedures for such forecast set forth in the Business Practices Manuals. The Day-Ahead forecast shall not be financially binding on the Resource.

v. Other Grounds for Exemption: Generation Resources, External Asynchronous Resources, Demand Response Resources – Type I, Demand Response Resources-Type II, Stored Energy Resources, and Stored Energy Resources – Type II shall not be subject to Excessive Energy Settlement or Excessive/Deficient Energy

Deployment Charges during events or conditions beyond the control, and without the fault or negligence, of the Market Participant, including but not limited to:

(1) Emergencies;

(2) Test mode of the Resource; or

(3) Start-up or shut-down mode of the Generation Resource, Stored Energy Resource, or Stored Energy Resource – Type II; or

(4) The Hour when a Generation Resource, Stored Energy Resource, or Stored Energy Resource – Type II trips and goes off-line; or

(5) During a Contingency Reserve Deployment; or

(6) Extremely high wind or other weather-related conditions materially impacting a Dispatchable Intermittent Resource's ability to provide Energy and resulting in a substantial reduction or cessation of wind or solar generation activities.

e. Contingency Reserve Deployment Failure Charges and Consequences

Market Participants with Resources that have failed to deploy Contingency Reserve, consistent with the Resource limit and ramping constraints as set forth in Schedule 29, in an amount greater than or equal to the amount specified in their Contingency Reserve Deployment Instructions within the Contingency Reserve Deployment Period shall be subject to the following consequences:

(i) a Contingency Reserve Deployment Failure Charge that is equal to the Resource's Shortfall Amount(s) multiplied by the average of the Real-Time Ex Post LMP of the Resource Commercial Pricing Node for the Dispatch Intervals of the

Contingency Reserve Deployment Period in which the failure(s) occurred, where Shortfall Amount equals the Contingency Reserve Deployment Instruction minus the actual amount of Contingency Reserve deployed at the end of the Contingency Reserve Deployment Period;

(ii) the amount of Contingency Reserve available for payment on that Resource shall be restricted to the amount actually deployed in the Hour of failure every Hour thereafter until the Resource achieves a higher level of output in a subsequent test or actual deployment; and

(iii) Supplemental Qualified Resources that fail to provide Supplemental Reserves pursuant to the Contingency Reserve Deployment Instruction shall be restricted to the amount actually deployed in the Hour of failure for every Hour thereafter until the Resource achieves a higher level of output in a subsequent test or actual deployment; and

(iv) the Transmission Provider may report to the Commission and the Independent Market Monitor a Market Participant's failure to deliver Contingency Reserve deployed as determined through evaluation of actual performance data if the Transmission Provider believes that the Market Participant is inaccurately reporting the physical capability of the Resource to provide Contingency Reserve.

f. Off-Line Short-Term Reserve Deployment Failure Charges and Consequences

Market Participants with off-line Resources, except for DRR – Type I, that have failed to deploy Short-Term Reserve, consistent with the Resource limit and ramping constraints as set forth in Schedule 29, in an amount greater than or equal to the Economic Minimum

Dispatch within the Short-Term Reserve Deployment Period, shall be subject to the following consequences:

(i) A Short-Term Reserve Deployment Failure Charge that is equal to the Resource's Shortfall Amount(s) multiplied by the average of the Real-Time Ex Post LMP of the Resource Commercial Pricing Node for the Dispatch Intervals of the Short-Term Reserve Deployment Period in which the failure(s) occurred, where the Shortfall Amount equals the maximum of the difference between a Resource's Economic Minimum Dispatch and the Actual Energy Injection of the Resource at the end of the Short-Term Reserve Deployment Period or zero;

(ii) The amount of Short-Term Reserve available for payment on that Resource shall be restricted to zero (0) in the Hour of failure to deploy and for the remaining Hours in the Operating Day; and

(iii) The Transmission Provider may report to the Commission and the Independent Market Monitor a Market Participant's failure to deliver Short-Term Reserve deployed as determined through evaluation of actual performance data if the Transmission Provider believes that the Market Participant is inaccurately reporting the physical capability of the Resource to provide Short-Term Reserve.

g. Revenue Distribution from Contingency Reserve Deployment Failure Charge and Excessive/Deficient Energy Deployment Charge. Credits resulting from Contingency Reserve Deployment Failure Charges and Short-Term Reserve Deployment Failure Charges shall be allocated to all Market Participants pro rata, based on their Market Load Ratio Share. Credits resulting from the Excessive/Deficient Energy Deployment Charge shall be allocated to all Market Participants pro rata, based on their Market Load Ratio Share, excluding Export schedules.

h. Excessive/Deficient Energy Deployment Charges and Consequences for Demand Response Resources falling under Section 38.6.1. Demand Response Resources will be assessed charges as follows:

i. Excessive/Deficient Energy Deployment Charge. Settlement of deviations from Setpoint Instructions is conducted hourly subject to a Tolerance Band as specified in this Section 40.3.4.g. A Demand Response Resource shall be charged an Excessive/Deficient Energy Deployment Charge in any Hour for which that Resource's Actual Energy Injections over the Hour are outside the Demand Response Resource Tolerance Band specified in Section 40.3.4.g.ii.

ii. Demand Response Resource Tolerance Band. For Resources under this section, the Tolerance Band will be calculated as follows. The upper limit of a Resource's Tolerance Band, or Excessive Energy Threshold, shall be equal to the maximum of: (1) one hundred and twelve percent (112%) of the hourly Setpoint Instruction, and (2) the sum of the hourly Setpoint Instruction plus four (4) MW. The lower limit of a Resource's Tolerance Band, or Deficient Energy Threshold shall equal the minimum of: (1) eighty-eight percent (88%) of the hourly Setpoint Instruction, and (2) the sum of the hourly Setpoint Instruction minus four (4) MW.

iii. Excessive/Deficient Energy Deployment Charges and Consequences. If a Demand Response Resource exceeds Excessive Energy Threshold, or Deficient Energy Threshold for any Hour, that Market Participant shall be subject to an

Excessive/Deficient Energy Deployment Charge every Hour in that Day associated with such Resource calculated as the maximum of: (1) the Resource's Actual Energy Injection, or (2) the Resources hourly Setpoint Instruction; multiplied by the Excessive/Deficient Charge Rate, in $/MWh as defined in Section 40.3.4.b.i.

i. Contingency Reserve Deployment Failure Charges and Consequences for Demand Response Resources falling under Section 38.6.1. Demand Response Resources will be assessed charges as follows:

i. Market Participants with Resources that have been identified as having failed to deploy Contingency Reserve in an amount greater than or equal to the amount specified in their Contingency Reserve Deployment Instructions within the Contingency Reserve Deployment Period shall be subject to the following consequences:

a. A Contingency Reserve Deployment Failure Charge that is equal to the Resource's Shortfall Amount(s) multiplied by the average of the Real-Time Ex Post LMP of the Resource Commercial Pricing Node for the Dispatch Intervals of the Contingency Reserve Deployment Period in which the failure(s) occurred, where the Shortfall Amount equals the Dispatch Interval Setpoint Instruction minus the Actual Energy Injection in any Dispatch Interval.

b. The amount of Contingency Reserve available for payment on that Resource shall be restricted to the amount determined to be deployed in any Hour of any failure to deploy and for the remaining Hours in the Operating Day, and the subsequent Operating Day; and

c. The Transmission Provider may report to the Commission and the Independent Market Monitor a Market Participant's failure to deliver Contingency Reserve deployed as determined through evaluation of actual performance data if the Transmission Provider reasonably believes that the Market Participant is inaccurately reporting the physical capability of the Resource to provide Contingency Reserve.

Resources scheduled to potentially provide Regulating Reserve that have a Dispatch Target for Energy within the Hourly Regulation Minimum Limit and the Hourly Regulation Maximum Limit for a Dispatch Interval, are subject to the Regulation Performance Accuracy Measurement Test. A Resource shall be charged the Regulation Performance Accuracy Measurement Test Failure Charge in those Hours for which that Resource fails the Regulation Performance Accuracy Measurement Test in any of the Dispatch Intervals. The Regulation Performance Accuracy Measurement Test Failure Charge is calculated as set forth below.

a. Regulation Performance Accuracy Measurement Test

The Actual Resource Response during a Dispatch Interval is calculated by summing the actual MW movement for a Resource within a Dispatch Interval. Within each Dispatch Interval, the actual MW movement towards the Setpoint Instruction is positive, and the actual MW movement away from the Setpoint Instruction is negative. The Desired Resource Response during a Dispatch Interval is calculated by summing absolute values of the expected up and down movement, in MW, that a Resource is capable of providing in response to Setpoint Instructions based on its applicable ramp rate, assuming the Resource starts from its actual output at the beginning of the Dispatch Interval.

For each Dispatch Interval, in which a Resource is subject to the Performance Accuracy Measurement Test, the Resource passes the Performance Accuracy Measurement Test if the Actual Resource Response is either above seventy percent (70%) of the Desired Resource Response or the Actual Resource Response is above the Desired Resource Response minus the tolerance amount defined below. Such tolerance amount is the lesser of:(1) the MW amount that the resource can move in 1.5minutes based on its applicable ramp rate; or(2) the greater of:(i) 4MW, or (ii) one percent (1%) of the average Dispatch Target for Energy for the Dispatch Interval.

If a Resource passes the Performance Accuracy Measurement Test in a Dispatch Interval, the Resource's response percentage is set as one hundred percent (100%) for that Dispatch Interval. If a Resource fails the Performance Accuracy Measurement Test by not passing the Test in a Dispatch Interval and the Desired Resource Response is no less than 0.01MW and Actual Resource Response is non-negative, then the Resource's response percentage is calculated as the Actual Resource Response divided by Desired Resource Response, expressed as a percentage. If a Resource fails the Performance Accuracy Measurement Test in a Dispatch Interval, and its Desired Resource Response is less than 0.01MW or its Actual Resource Response is negative, then the Resource's response percentage is zero percent (0%).

b. Regulation Performance Accuracy Measurement Test Failure Charge

If a Market Participant's Resource fails the Performance Accuracy Measurement Test, then that Market Participant shall be subject to the Performance Accuracy Measurement Test Failure Charges calculated as follows:

i. A Resource that fails Performance Accuracy Measurement Test for a Dispatch Interval shall be charged the Regulating Mileage Credit multiplied by the difference between one hundred percent (100%) and the Resource's response percentage for that Dispatch Interval.

ii. If a Resource has not been assessed Excessive/Deficient Energy Deployment Charges, and fails four or more consecutive Dispatch Intervals in an Hour with the first of such intervals having cleared Regulating Reserves in Real-Time Energy and Ancillary Service Market, the Resource will receive a charge equal to: the greater of (a) the sum of (i) the Regulating Reserve credits calculated pursuant to Section 39.3.2A.a and (ii) the Regulating Reserve credits/charges calculated pursuant to Section 40.3.3.3.b.ii for that Resource for that Hour or (b) zero.

c. Revenue Distribution from Performance Accuracy Measurement Test Failure Charges. Credits resulting from Performance Accuracy Measurement Test Failure Charges shall be allocated to all Market Participants pro rata, based on their Market Load Ratio Share, excluding Export Schedules.

The RTORSGP mechanism protects an eligible Resource from the financial impact of being dispatched in circumstances under which the Resource is unable to fully recover its Incremental Energy Cost from the Hourly Real-Time Ex Post LMP revenue, hourly net Operating Reserve revenue, Up Ramp Capability credit, Down Ramp Capability credit, and Short-Term Reserve revenue during the period the Transmission Provider has directed the Resource to operate through the 5-minute dispatch process used in the Real-Time Energy and Operating Reserve Market operations at Non-Excessive Energy levels above the Resource's Day-Ahead Schedule for Energy. The Manual Redispatch of Generation Resources or Demand Response Resources-Type II shall be compensated pursuant to Section 33.8 of this Tariff, provided, that, if a Resource is dispatched as stated above and afterwards is manually redispatched back to its Day-Ahead Schedule, and the Resource is unable to fully recover its costs as described above, then the Resource shall retain its eligibility for RTORSGP during the intervals it needs to reach its Day-Ahead Schedule in accordance with its real-time ramp rate.

Only Generation Resources and Demand Response Resources – Type II with Non-Excessive Energy greater than their Day-Ahead Schedule for Energy or with Non-Excessive Energy greater than their Hourly Economic Minimum Limit if their Day-Ahead Schedule for Energy is equal to zero that are not entitled to Real-Time Revenue Sufficiency Guarantee Credits, and External Asynchronous Resources for Import Schedules are eligible for the RTORSGP. The RTORSGP provides a Market Participant following Setpoint Instructions with a method to recover incremental Energy costs thereby incurred that are not otherwise collected from the Hourly Real-Time Ex Post LMP and net Operating Reserve revenue. The RTORSGP does not apply to the portion of a Market Participant's Incremental Energy Costs that exceed the

Hourly Real-Time Ex Post LMP revenue for resources providing Spinning Reserves as a result of following a Contingency Reserve Deployment Instruction. Recovery of Incremental Energy Costs shall be limited to costs associated with Non-Excessive Energy and Operating Reserve Costs associated with Self-Schedules shall be set equal to zero. The RTORSGP does not include any compensation for Lost Opportunity Costs. The RTORSGP does not include any compensation for Demand Response Resources that are offered-in and cleared at a price below the net benefits threshold level in either the Day-Ahead or Real-Time Energy and Operating Markets.

Market Participants that satisfy the eligibility criteria set forth in this Section 40.3.5 shall receive a RTORSGP calculated pursuant to Section 40.3.5.6 with respect to the following Resources:

(a) Generation Resources and Demand Response Resources – Type II committed in the Day-Ahead Energy and Operating Reserve Market or committed as Must-Run in the Real-Time Energy and Operating Reserve Market; and

(b) External Asynchronous Resources for Import Schedules.

A Generation Resource and a Demand Response Resource – Type II are only eligible for RTORSGP in Hours in which they have been committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market with Non-Excessive Energy levels greater than their Day-Ahead Schedules for Energy, or received a commitment from the Transmission Provider in the Real-Time Energy and Operating Reserve Market as Must-Run and their Non-Excessive Energy levels are greater than their Hourly Economic Minimum Limit.

An External Asynchronous Resources (EAR) is only eligible for RTORSGP in Hours in which its Non-Excessive Energy level is greater than its Day-Ahead Schedule for Energy. The contiguous Hours within the Operating Day having such Day-Ahead commitments (or Day-Ahead Schedule for Energy in the case of an External Asynchronous Resource) and/or having such Real-Time Must-Run commitments (and/or Non-Excessive Energy levels greater than zero in the case of an External Asynchronous Resource for hours in which the Day-Ahead Schedule for Energy is equal to zero) constitute the RTORSGP contiguous SCUC Instructed Hours of Operation. The contiguous SCUC Instructed Hours of Operation is comprised of adjacent, shorter SCUC Instructed Hours of Operations within the Operating Day. For purposes of the RTORSGP, contiguous Day-Ahead committed Hours are referred to as the Day-Ahead SCUC Instructed Hours of Operation. Contiguous Real-Time Must-Run committed Hours are referred to as the Real-Time Must Run SCUC Instructed Hours of Operation.

There are different eligibility criteria for Day-Ahead committed Hours than there are for Real-Time Must-Run committed Hours. Eligibility is assessed on a Dispatch Interval basis and on an hourly basis, utilizing both hourly data inputs and interval-level data inputs.

RTORSGP Eligibility for Day-Ahead Committed Hours for Generation Resources, Demand Response Resources-Type II and External Asynchronous Resources:

To be eligible for the RTORSGP, the Day-Ahead committed Hours must comply with the following requirements, provided that the specified Offer data shall include any overrides entered by the Transmission Provider at the request of the Market Participant that owns or represents the Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource:

(a) The Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource must offer flexibly for the Dispatch Interval pursuant to the following criteria:

i. Ability to be dispatched by the unit dispatch system, as determined by the following: (1) Real-Time unit dispatch system control status is a 1 or 2; (2) Operating limits used by the unit dispatch system must have an operating range of greater than 1 MW; and, (3) Real-Time Ramp Rate is greater than 0 MW/minute, in the Real-Time Energy and Operating Reserve Market for the applicable Dispatch Interval; and

ii. If four or more consecutive Dispatch Intervals fail eligibility in an Hour, the Resource will be ineligible for RTORSGP in that Hour.

(b) The Real-Time as-dispatched Offer data must meet the following criteria:

i. Within a given day-ahead commitment hour, the following Offer data that the day-ahead committed was based on, may be modified and submitted as Real-Time Offer data for input into the Transmission Provider's dispatch software.

1. The Real-Time Energy Offer Curve must be equal to the Day-Ahead Energy Offer curve for each Hour in the Day-Ahead SCUC Instructed Hours of Operation.
2. Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hourly Regulation Minimum Limit must be equal to the Day-Ahead Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hourly Regulation Minimum Limit, respectively.

   The Real-Time Regulating Capacity Offer must be equal to the Day-Ahead Regulating Capacity Offer. The Real-Time Regulating Mileage Offer must be equal to the Day-Ahead Regulating Mileage Offer. The Real-Time Spinning Reserve Offer must be equal to the Day-Ahead Spinning Reserve Offer and the Real-Time Supplemental Reserve Offer must be equal to the Day-Ahead Supplemental Reserve Offer. This test will be performed for each Dispatch Interval within the Hour.

(c) The Day-Ahead Offer must meet the following requirements, if there is a non-zero Day Ahead Schedule for Energy in the prior Hour:

   i. For the Day Ahead Schedule for Energy in the prior Hour, the price on the Day-Ahead Energy Offer in the current Hour must not increase by greater than ten percent (10%) from the price on the Day-Ahead Energy Offer in the prior Hour.

   ii. The Day-Ahead Hourly Economic Maximum Limit in the current Hour must not decrease, by greater than five times the day-ahead Hourly Ramp Rate, from the minimum of: (1) the Day Ahead Schedule for Energy in the prior Hour; or (2) the Day-Ahead Hourly Economic Maximum Limit in the prior Hour.

iii. If the Resource fails any of the above Day-Ahead Offer eligibility criteria, the Resource will be ineligible for RTORSGP for the given Hour.

(d) The Resource Offer Up and Down Ramp Capability Dispatch Status must be Economic in the Day-Ahead and Real-Time Energy and Operating Reserve Markets. This criterion will be checked for each Hour of the contiguous Day-Ahead SCUC Instructed Hours of Operation, sequentially. If the Resource fails this eligibility criterion, the Resource will be ineligible for RTORSGP for the given Hour.

(e) The offered Short-Term Reserve Dispatch Status for a Short-Term Reserve Qualified Resource must be Economic in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This criterion will be checked for each Hour of the contiguous Day-Ahead SCUC Instructed Hours of Operation, sequentially. If the Resource fails this eligibility criterion, the Resource will be ineligible for RTORSGP for the given Hour.

To be eligible for the RTORSGP, the Real-Time Must-Run committed Hours must meet the following requirements, provided that the specified Offer data shall include any overrides entered by the Transmission Provider at the request of the Market Participant that owns or represents the Resource:

(a) The Resource, excluding Demand Response Resources – Type I, must offer flexibly for the Hour, pursuant to the following criteria:

i. Ability to be dispatched by the unit dispatch system, as determined by the following: (1) Real-Time unit dispatch system control status is a 1 or 2; (2) Operating limits used by the unit dispatch system must have an operating range of greater than 1 MW; and, (3) Real-Time Ramp Rate is greater than 0 MW/minute, in the Real-Time Energy and Operating Reserve Market for the applicable Dispatch Interval.

ii. If four or more consecutive Dispatch Intervals fail eligibility in an Hour, the Resource will be ineligible for RTORSGP in that Hour.

(b) All Real-Time Offer data as specified below must be the same for each consecutive Real-Time Must-Run committed Hour within the Real-Time Must-Run SCUC Instructed Hours of Operation, pursuant to the following criteria:

i. The following Offer parameters must be the same for each consecutive Real-Time Must Run committed Hour.

1. Energy Offer curve

2. Regulating Capacity, Regulating Mileage, Spinning Reserve and Supplemental Reserve Offers

3. Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hour Regulation Minimum Limit

4. Targeted Demand Reduction Level

ii. This eligibility test will be performed for each Dispatch Interval within the Hour.

iii. This eligibility test is performed for each of the Real-Time Must-Run committed Hours sequentially, starting at the beginning of the day.

iv. This eligibility test will not apply to Hours outside the boundaries of the Operating Day.

(c) The Real-Time Offer data for the first Hour of Real-Time Must-Run SCUC Instructed Hours of Operation must be the same as those of the previous Hour if there was a commitment in the previous Hour, pursuant to the following criteria:

i. The same Offer data listed in Section 40.3.5.5(a) and (b) must be the same in the Hour prior to the first Real-Time Must-Run Committed Hour if there is commitment in the Hour prior to the first Hour in the Real-Time Must-Run SCUC Instructed Hours of Operation.

ii. This test will be performed for each Dispatch Interval within the Hour.

iii. This test is performed for each of the Real-Time Must-Run committed Hours sequentially, starting at the beginning of the day.

iv. These tests will not apply to Hours outside the boundaries of the Operating Day.

(d) The Resource Offer Up and Down Ramp Capability Dispatch Status must be Economic in the Real-Time Energy and Operating Reserve Markets. This criterion will be checked for each Dispatch Interval within the Hour and for each Hour of the contiguous Real-

Time Must-Run SCUC Instructed Hours of Operation, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet this criterion, the Resource will be ineligible for RTORSGP in that Hour.

(e) The offered Short-Term Reserve Dispatch Status for a Short-Term Reserve Qualified Resource must be Economic in the Real-Time Energy and Operating Reserve Market. This criterion will be checked for each Dispatch Interval within the Hour and for each Hour of the contiguous Real-Time Must-Run SCUC Instructed Hours of Operation, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet this criterion, the Resource will be ineligible for RTORSGP in that Hour.

Generation Resources, Electric Storage Resources, Demand Response Resources – Type II and External Asynchronous Resources that satisfy the eligibility criteria set forth above shall receive a RTORSGP calculated as follows:

(a) Calculation of RTORSGP for Day-Ahead SCUC Instructed Hours of Operations and Real-Time Must Run SCUC Instructed Hours of Operations

Resources that satisfy the eligibility criteria described above will have the calculation of the RTORSGP performed for each of the eligible Hours in accordance with Schedule 27. The calculation assesses whether the cost associated with following the Setpoint Instructions exceeds the value of the payments associated with following such dispatch, independently for each eligible Hour in the RTORSGP contiguous SCUC Instructed Hours of Operation. A Generation Resource, Electric Storage Resource, Demand Response Resource – Type II or External Asynchronous Resource will receive a RTORSGP in an eligible Hour if the Resource's cost of following dispatch exceeds the value of the payment for following dispatch including any net Operating Reserve revenue, Regulation Deployment Adjustment, Up Ramp Capability Credit and Down Ramp Capability Credit.

The calculation of the RTORSGP is performed in three steps for eligible unit Hours. The first step is the determination of the cost to the Resource of following the Setpoint Instructions. The second step is the determination of the value of the payment to the Resource for following Setpoint Instructions. The third step is the calculation of the RTORSGP. Each step of the calculation is described in Schedule 27.

The sum of the RTORSGP payments made in an Hour shall be funded through an assessment of debits on all Market Participants on a *prorata* basis, based on their Market Load Ratio Share.

If an eligible Market Participant buys out of a Day-Ahead Schedule for Energy, Day-Ahead Schedule for Regulating Reserve, Day-Ahead Schedule for Spinning Reserve, Day-Ahead Schedule for Supplemental Reserve, and/or Day-Ahead Schedule for Short-Term Reserve in a manner that reduces its Day-Ahead Margin it shall receive a DAMAP. The purpose of such payments is to protect Market Participants' Day-Ahead Margins associated with real-time reductions below Day-Ahead Schedules after accounting for any Market Participant requested real-time de-rates granted by Transmission Provider, real-time reductions below the Day-Ahead Schedule for Regulating Reserve of Stored Energy Resources as a result of dispatch limitations due to reduced Energy storage capability, and any offsetting Real-Time margins for Operating Reserve, Short-Term Reserve, Up Ramp Capability, and Down Ramp Capability cleared in excess of Day-Ahead Schedules for those products. The DAMAP does not include any compensation for Lost Opportunity Costs for Resources based on avoided Real-Time LMP revenues and/or avoided Real-Time MCP revenues. The Manual Redispatch of Generation Resources or Demand Response Resources-Type II shall be compensated pursuant to Section 33.8 of this Tariff, provided, that, if a Resource is dispatched below its Day-Ahead Schedule and afterwards is manually redispatched back to its Day-Ahead Schedule, the Resource's Day-Ahead Margin shall be deemed eroded, and the Resource shall retain its eligibility for DAMAP, during the intervals it needs to reach its Day-Ahead Schedule in accordance with its real-time ramp rate.

Market Participants that satisfy the eligibility criteria set forth in this Section 40.3.6 shall receive a DAMAP calculated pursuant to Section 40.3.6.5 with respect to the following Resources:

(a) Generation Resources and Electric Storage Resources, including Generation Resources and Electric Storage Resources, manually redispatched pursuant to Section 33.8 of the Tariff, and Demand Response Resources – Type II committed in the Day-Ahead Energy and Operating Reserve Market, or

(b) Demand Response Resources – Type I with Day-Ahead Schedules for Contingency Reserve, or

(c) External Asynchronous Resources for Import Schedules with Day-Ahead Schedules for Energy, or

(d) Stored Energy Resources with Day-Ahead Schedules for Regulating Reserve.

A Resource, including a Generation Resource or an Electric Storage Resource manually redispatched pursuant to Section 33.8 of this Tariff, is only eligible for DAMAP in Hours in which its Day-Ahead Margin has been eroded.

Eligibility is assessed on an hourly basis, utilizing both hourly data inputs and interval-level data inputs.

To be eligible for the DAMAP, each Hour's Offer data must comply with the following requirements, provided that the specified Offer data shall include any overrides entered by the Transmission Provider at the request of the Market Participant that owns or represents the Resource:

(a) A Generation Resource, Demand Response Resource-Type II, Stored Energy Resource, or External Asynchronous Resource must offer flexibly for the Hour, pursuant to the following criteria:

i. Ability to be dispatched by the unit dispatch system, as determined by the following: (1) Real-Time unit dispatch system control status is a 1 or 2; (2) Operating limits used by the unit dispatch system must have an operating range of greater than 1 MW; and, (3) Real-Time Ramp Rate is greater than 0 MW/minute, in the Real-Time Energy and Operating Reserve Market for the applicable Dispatch Interval.

ii. If four or more consecutive Dispatch Intervals fail eligibility in an Hour, the Resource will be ineligible for DAMAP for that Hour.

(b) A Demand Response Resource – Type I must submit a Targeted Demand Reduction Level greater than 1 MW.

(c) The Day-Ahead Offer must meet the following requirements, if there is a non-zero Day-Ahead Schedule for Energy in the prior Hour:

i. For the Day-Ahead Schedule for Energy in the current Hour, the price on the Day-Ahead Energy Offer in the current Hour must not decrease by greater than ten percent (10%) from the price on the Day-Ahead Energy Offer in the prior Hour.

ii. The Day-Ahead limit in the current Hour must not increase by greater than five times the day-ahead Hourly Ramp Rate from the Day-Ahead limit in the prior Hour.

The Day-Ahead limit in the current Hour is equal to: The maximum of: (1) the Day-Ahead Hourly Economic Minimum Limit in the current Hour; or (2) the as-committed self-schedule MW in the current Hour for instances where the Energy Dispatch Status in the current Hour is self-schedule.

The Day-Ahead limit in the prior Hour is equal to: The maximum of: (1) the Day-Ahead Schedule for Energy in the prior Hour; (2) the Day-Ahead Hourly Economic Minimum Limit in the prior Hour; or (3) the as-committed self-schedule MW in the prior Hour for instances where the Energy Dispatch Status in the prior Hour is self-schedule.

iii. If the Resource fails any of the above Day-Ahead Offer eligibility criteria, the Resource will be ineligible for DAMAP for the given Hour.

(d) The Resource Offer Up and Down Ramp Capability Dispatch Status must be Economic in the Day-Ahead and Real-Time Energy and Operating Reserve Markets. This criterion will be checked for each Dispatch Interval within the Hour and for each Hour of the Day-Ahead Transmission Provider Commitment Period, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet this criterion, the Resource will be ineligible for DAMAP in that Hour.

(e) The offered Short-Term Reserve Dispatch Status for a Short-Term Reserve Qualified Resource must be Economic in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This criterion will be checked for each Dispatch Interval within the Hour and for each Hour of the Day-Ahead Transmission Provider Commitment Period, sequentially. If four or more consecutive Dispatch Intervals in an Hour fail to meet this criterion, the Resource will be ineligible for DAMAP in that Hour.

Resources that satisfy the eligibility criteria set forth above shall receive a DAMAP in each eligible Hour that the Resource's Day-Ahead Margin has been eroded as calculated in accordance with Schedule 27. The calculation assesses whether any Day-Ahead Margins have been eroded through the following of Transmission Provider instructions independently for each eligible Hour. A Resource will receive a DAMAP in an eligible Hour if the Resource's Day-Ahead Margins have been eroded after including any positive real-time margins associated with real-time cleared Energy and/or Operating Reserve in excess of Day-Ahead Schedules for Energy and/or Operating Reserve, Short-Term Reserve credit, Up Ramp Capability Credit and Down Ramp Capability Credit in that eligible Hour.

The calculation of the DAMAP is performed in three steps for eligible Hours. The first step determines adjustments to Day-Ahead Schedules to account for real-time de-rates on a Dispatch Interval basis. The second step determines the Day-Ahead Margin reduction associated with the adjusted Day-Ahead Schedules for Energy, Regulating Reserve, Spinning Reserve and/or Supplemental Reserve associated with following dispatch, including any offsetting real-time margins associated with real-time cleared Energy and/or Operating Reserve in excess of the Day-Ahead Schedule for Energy and/or Operating Reserve, on a Dispatch Interval basis, Short-Term Reserve credit, Up Ramp Capability Credit and Down Ramp Capability Credit. The third step determines the DAMAP for an Hour. Each step of the calculation is described in Schedule 27.

The sum of the DAMAPs made in an Hour shall be funded through an assessment of debits on all Market Participants on a *pro-rata* basis, based on their Market Load Ratio Share.

Transmission Usage Charges in the Real-Time Energy and Operating Reserve Market:

a. Interchange Schedules submitted to be considered in the Real-Time Energy and Operating Reserve Market are subject to Interchange Schedule Charges based on the Real-Time Ex Post LMP at the Interface where they enter or exit the Transmission Provider Region. The Transmission Provider shall charge a Transmission Usage Charge to all Market Participants submitting new or Interchange Schedules after the 1030 hours EPT (after the deadline for submitting Interchange Schedules to be considered in the Day-Ahead Energy and Operating Reserve Market).

b. For Export Schedules or Import Schedules, the Transmission Usage Charge for each Hour will be the sum of products of: (i) the amount of Energy in MWh scheduled to be withdrawn by the Market Participant in each Dispatch Interval of the Real-Time Energy and Operating Reserve Market, minus the amount of Energy submitted to be considered in the Day-Ahead Energy and Operating Reserve Market through an Interchange Schedule (possibly zero (0)) to be withdrawn by that Market participant in that Hour, in MWh; and (ii) the Real-Time Ex Post LMP at the Commercial Pricing Node for the relevant Interface.

c. Interchange Schedules that represent Through Transactions are subject to Transmission Usage Charges based on the Real-Time Ex Post LMP at the Interface where they enter or exit the Transmission Provider Region. The Transmission Usage Charge for each Hour will be the sum of the products of: (i) the amount of Energy scheduled to be withdrawn by that Market Participant in each Dispatch Interval of the Real-Time Energy and Operating Reserve Market, minus the amount of Energy submitted to be considered in the Day-Ahead Energy and Operating Reserve Market (possibly zero (0) for new Real-Time Interchange Schedules) to be withdrawn by that Market Participant in that Hour, in MWh; and (ii) the Real-Time Ex Post LMP at the Commercial Pricing Node for the Interface relevant to the Interchange Schedule Delivery Point, minus the Real-Time Ex Post LMP at the Commercial Pricing Node of the Interface relevant to the Interchange Schedule Receipt Point.

d. The Transmission Provider shall divide each Transmission Usage Charge or the Real-Time Interchange Schedule Charges into separate components for Cost of Congestion and the Cost of Losses.

i. Cost of Congestion. The Cost of Congestion shall be calculated as the (a) MWh quantity multiplied by the (b) Marginal Congestion Component of the Real-Time Ex Post LMP at the Interface for the Interchange Schedule Delivery Point minus the Marginal Congestion Component of the Real-Time Ex Post LMP at the Commercial Pricing Node for the Interchange Schedule Receipt Point; or the MWh quantity multiplied by the Marginal Congestion Component of the Real-Time Ex Post LMP at the Interface for transactions that are not Through Transactions.

ii. Cost of Losses. The Cost of Losses shall be calculated as the (a) MWh quantity multiplied by the (b) Marginal Losses Component of the Real-Time Ex Post LMP at the Interface for the Interchange Schedule Delivery Point minus the Marginal Losses Component of the Real-Time Ex Post LMP at the Interface for the Interchange Schedule Receipt Point; or the MWh quantity multiplied by the Marginal Losses Component at the Interface for transactions that are not Through Transactions.

The Transmission Provider shall collect and disburse a Transmission Usage Charge for all Financial Schedules designated to be settled in the Real-Time Energy and Operating Reserve Market. The Transmission Usage Charge for the seller shall be the product of: (i) the amount of Energy scheduled, in MWh, and (ii) the Hourly Real-Time Ex Post LMP at the Delivery Point minus the Hourly Real-Time Ex Post LMP at the Source Point. The Transmission Usage Charges for the buyer on the Financial Schedule shall be the product of: (i) the amount of Energy scheduled, in MWh, and (ii) the Hourly Real-Time Ex Post LMP at Sink Point minus the Hourly Real-Time Ex Post LMP at the specified Delivery Point.

The Transmission Provider is not the Energy Market Counterparty to the sale of Energy under a Financial Schedule transaction and collects and disburses the Transmission Usage Charge for a Financial Schedule as agent for the buyer and seller.

The Transmission Provider shall calculate for each Hour of the Real-Time Energy and Operating Reserve Market the Real-Time Marginal Losses Surplus, as the Real-Time Energy and Operating Reserve Market Marginal Losses Surplus. The Real-Time Marginal Losses Surplus is summed with the Day-Ahead Marginal Losses Surplus, to determine the Marginal Losses Surplus, allocated to Market Participants as described in Section 40.6.

The Transmission Provider shall calculate for each Hour of the Real-Time Energy and Operating Reserve Market the Real-Time Marginal Losses Surplus as the Total Real-Time Charges for Energy and Operating Reserve Market Purchases, minus Total Real-Time Credits for Energy and Operating Reserve Market Sales, minus Total Real-Time Congestion Credits:

a. The total Real-Time Energy and Operating Reserve Market charges for Energy and Operating Reserve Market Purchases for each Hour of the Real-Time Energy and Operating Reserve Market will be the sum across all Commercial Pricing Nodes of the Hourly Real-Time Ex Post LMP multiplied by the difference between: (i) Actual Energy Withdrawals; and (ii) Scheduled Withdrawals.

b. The total Real-Time Energy and Operating Reserve Market credits for Energy and Operating Reserve Market Sales for each Hour of the Real-Time Energy and Operating Reserve Market will be the sum across all Nodes, Commercial Pricing Nodes, and Zones of the Hourly Real-Time Ex Post LMP multiplied by the difference between: (i) Actual Energy Injections; and (ii) Scheduled Injections.

c. The total Real-Time Energy and Operating Reserve Market congestion credits for each Hour of the Real-Time Energy and Operating Reserve Market will be the sum across all Nodes, Commercial Pricing Nodes, and Zones of:

    i. The Marginal Congestion Component multiplied by the difference between: (a) Actual Energy Withdrawals; and (b) Scheduled Withdrawals; minus

    ii. The Marginal Congestion Component multiplied by the difference between: (a) Actual Energy Injections; and (b) Scheduled Injections.

The Transmission Provider will refund to Load, the difference between Marginal Losses and average losses on a Local Balancing Authority basis as set forth in this Section 40.6.

The Transmission Provider shall calculate Marginal Losses Surplus as the sum of the Day-Ahead Marginal Losses Surplus calculated pursuant to Section 39.3.5 and the Real-Time Marginal Losses Surplus calculated pursuant to Section 40.5 minus the determined value of Inadvertent Energy calculated pursuant to Section 40.7. The Transmission Provider shall allocate the Marginal Losses Surplus to Load in a manner that reflects the difference between Marginal Losses and System Losses on a Local Balancing Authority Area basis as follows:

a. The Transmission Provider shall calculate the Local Balancing Authority Marginal Losses Surplus Share by allocating the Marginal Losses Surplus to each Local Balancing Authority on a *prorata* basis per the cost of supplying losses to Load scheduled by Market Participants within the Balancing Authority Area, excluding any Load scheduled by GFA Responsible Entities.

b. The Transmission Provider shall allocate the Local Balancing Authority Marginal Losses Surplus Share to Market Participants within each Local Balancing Authority Area on a *prorata* basis per their Market Load Ratio Share of the total Load in the Local Balancing Authority Area, excluding any Load scheduled and served by GFA

Responsible Entities.

The Transmission Provider shall track and settle for Inadvertent Energy between the MISO Balancing Authority Area and other Balancing Authority Areas in the Eastern Interconnection, pursuant to Applicable Reliability Standards. For the Inadvertent Energy flows between the MISO Balancing Authority Area and the PJM Interconnection, LLC, flows will be accounted for under the rates, terms and provisions of the Joint Operating Agreement as set forth in this Section, and shall report those amounts to the ERO and/or Applicable Reliability Entity.

The Transmission Provider will financially value Inadvertent Energy for the MISO Balancing Authority Area. Any such Inadvertent Energy will be calculated hourly on a financial basis through the determination of an Inadvertent Energy Value (either a surplus or shortage), the Transmission Provider will sum the Inadvertent Energy Value to determine a daily total. The daily total of the Inadvertent Energy Value will be charged or credited to each Market Participant based on their share of the same billing determinants used for those determining charges pursuant to Schedule 17 for the Operating Day. Each Market Participant's share of the daily total Inadvertent Energy Value will be expressed as a percentage based on their share of the Schedule 17 billing determinants as compared to the total Schedule 17 billing determinants for all Market Participants during the same Operating Day.

The settlement of Inadvertent Energy flows between the MISO Balancing Authority Area and the PJM Interconnection, LLC will be calculated and settled according to the rates, terms and conditions of the Joint Operating Agreement, MISO FERC Electric Tariff, Rate Schedule No. 5 and FERC Electric Tariff Rate Schedule No. 38.

The Transmission Provider shall prepare Settlement Statements for each Market Participant, detailing each Market Participant's cost responsibility. Settlement Statements shall provide sufficient detail to allow verification of the invoiced amounts and completion of the Market Participant's internal accounting.

Settlement Statement(s) will be made available for each Operating Day and will be published for Market Participants electronically on Business Days. The Market Participant is responsible for accessing the information once posted by the Transmission Provider. To issue a Settlement Statement, the Transmission Provider may use estimated, disputed or calculated Metered data and information in schedules. The Transmission Provider will create the applicable statements for each Operating Day.

When actual validated data and schedule information are available and all of the settlement and invoice disputes raised by Market Participants during the validation process have been resolved, the Transmission Provider shall recalculate the amounts payable and receivable by the affected Market Participant. Settlement Statements will break down credits and charges by charge type. A schedule for resettlement will be published electronically by the Transmission Provider indicating that a specific Operating Day will be resettled and the date the Settlement Statement will be issued.

It is the responsibility of each Market Participant to notify the Transmission Provider if it fails to receive Settlement Statements on the date specified for issuance of such Settlement Statement. Each Market Participant shall be deemed to have received its Settlement Statement on the dates specified, unless it notifies the Transmission Provider to the contrary. If the Transmission Provider receives notice that a Settlement Statement has not been received, it will make reasonable attempts to provide the Settlement Statement to such Market Participant(s). The Settlement schedule will not be modified for a Market Participant's failure to notify the Transmission Provider of a missing Settlement Statement.

The Transmission Provider shall make available Financial Transmission Rights (FTRs) within the Transmission Provider Region to provide a financial hedging mechanism for managing the risk of congestion charges reflected in Day-Ahead Ex Post LMPs. FTRs will not protect Market Participants from congestion charges related to Hourly Real-Time Ex Post LMPs. The Transmission Provider shall make available Auction Revenue Rights (ARRs) that will determine entitlements to a share of the revenues generated in the annual FTR Auction.

The Transmission Provider will provide FTR Obligations and, when feasible, FTR Options. The Transmission Provider shall maintain a list of possible FTR Receipt Points and FTR Delivery Points as specified in FTR Obligations and in FTR Options.

The Transmission Provider will provide ARR Obligations under this section, and administer MVP ARRs under Section 47. The Transmission Provider shall maintain a list of possible baseload and peak Reserved Source Points (RSPs) and ARR Zones as specified in the ARR Obligations. ARR Zones will include the following two general categories. Category 1 shall consist of Network Integration Transmission Service OASIS reservation Points of Delivery existing during the Reference Year, including external interface Commercial Nodes for Point-To-Point exports. Category 2 shall consist of subzones within the Network Integration Transmission Service Points of Delivery that will be established where required to support state jurisdictional accounting obligations or where supported by transmission and Energy supply arrangements during the Reference Year and that meet the qualification criteria as described in the following paragraphs.

A Market Participant will provide the Transmission Provider with the specific terms and conditions in such transmission and Energy supply arrangements to substantiate the designation of a Category 2 ARR Zone.

Category 2 ARR Zones requested by a single or multiple Market Participants to satisfy state statutory or regulatory jurisdictional requirements to separate Load according to state boundaries will be considered valid subzones within a single Category 1 ARR Zone. The requesting Market Participant(s) must specify the native Load delivery points and the qualifying Generation Resources associated with the Category 2 ARR Zone requested to separate Loads according to state boundaries. Requests for Category 2 ARR Zones for purposes other than to satisfy state jurisdictional requirements must be supported by i) Point-To-Point Transmission Service, Network Integration Transmission Service or GFA service agreements (including any relevant supporting documentation where transmission service agreements in effect are unclear) specifying delivery locations representing native Load delivery points and by ii) power supply contracts or specifying the set of qualifying supply resources and/or Generation Resources associated with those Load delivery locations. Market Participants must indicate the electrical representation of their native Load delivery points in terms of the Transmission Provider's Elemental Pricing Nodes (EPNodes), which may necessitate or involve the sharing of EPNodes by agreement between or among affected Market Participants. Requests to establish two or more ARR Zones that share identical or nearly identical EPNode definitions will not be permitted unless such definition is clearly supported by the effective transmission service agreements and any supporting documentation. Once the Transmission Provider has determined that a request to establish a Category 2 ARR Zone meets the criteria as defined in this Section, it will be adopted as such.

If the Transmission Provider determines that the request for a Category 2 ARR Zone definition does not meet the above criteria based on the data furnished by the requesting Market Participant, the corresponding Load delivery locations will be included in the qualifying ARR Zone where the native Load delivery points are electrically represented. If the Transmission Provider determines that the establishment of a requested Category 2 ARR Zone will preclude or limit a Market Participant(s) that otherwise qualifies to request and receive LTTRs, the request will be denied. Once defined, the ARR Zone definitions will not change over time to match changing Load Zone configurations, but will be modified to accommodate the retirement of, or addition of new, load EPNodes within the established ARR Zone. In addition, the Transmission Provider may terminate or redefine one or more existing Category 2 ARR Zones in connection with the integration of a new Transmission Owner when all of the following conditions are met: i) the new Transmission Owner or its customer requests such termination or redefinition for the integration; ii) the native Load delivery points of the Category 2 ARR Zones were part of other existing Transmission Owners prior to the integration of the new Transmission Owner; and iii) the native Load delivery points in (ii) have or will become part of the new Transmission Owner upon integration. Upon the satisfaction of all the conditions, the Transmission Provider may convert any such Category 2 ARR Zone into a Category 1 ARR Zone, or combine any such two or more Category 2 ARR Zones into a single Category 1 ARR Zone, when reasonably warranted by the integration of the new Transmission Owner.

The Reference Year for all initial ARR Zones at the start of the Annual ARR Allocation process shall be comprised of the four Seasons starting March 2004 and ending February 2005. For any ARR Zone added after the start of Annual ARR Allocation process as a result of an expansion of the Transmission Provider Region, the Reference Year shall be comprised of the four most recent complete Seasons just prior to the Annual ARR Registration associated with the integration of the applicable ARR Zone. When the expansion of the Transmission Provider Region becomes effective after the start of the allocation year, Transmission Customers in the newly integrated ARR Zones shall be eligible to participate in a partial-year allocation of FTRs for the remainder of such allocation year pursuant to Section 42.6 of this Tariff. The

Transmission Provider shall terminate all ARR Zones of a Transmission Owner upon its departure from the Transmission Provider Region.

For a given Hour that falls within the FTR Period and term, an FTR Obligation confers on its FTR Holder appropriate debits or credits. In an applicable Hour, an FTR Obligation will provide the FTR Holder with credits when the Marginal Congestion Component of the Day-Ahead Ex Post LMP at the FTR Delivery Points is greater than the Marginal Congestion Component of the Day-Ahead Ex Post LMP at the FTR Receipt Points. Conversely, in an applicable Hour, an FTR Obligation will impose on its FTR Holder charges when the Marginal Congestion Component of the Day-Ahead Ex Post LMP of the FTR Delivery Point is less than the Marginal Congestion Component of the Day-Ahead Ex Post LMP of the FTR Receipt Point. The settlement of FTRs shall be consistent with Section 39.3.4.

For a given Hour that falls within the FTR Period and Term, an FTR Option confers credits on the FTR Holder when the Marginal Congestion Component of the Day-Ahead Ex Post LMP at the FTR Delivery Points is greater than the Marginal Congestion Component of the Day-Ahead Ex Post LMP at the FTR Receipt Point. There will be no charge (financial obligation) to the FTR Holder when the Marginal Congestion Component of the Day-Ahead Ex Post LMP of the FTR Delivery Point is less than the Marginal Congestion Component of the Day-Ahead Ex Post LMP of the FTR Receipt Point. The set of FTR Receipt Points and the set of FTR Delivery Points that are specified for an FTR Option are a subset of those specified for FTR Obligations.

An FTR is specified by: (i) an FTR Receipt Point; (ii) an FTR Delivery Point; (iii) an FTR Quantity; (iv) whether the right is an Obligation or an Option; (v) an FTR Period (peak/off peak); and (vi) an FTR term. The FTR Receipt Point and FTR Delivery Point specified in a given FTR (Obligation or Option) may be any one of the following:

Node for the relevant Generation Resource.

Hub.

Load Zone.

Interface.

ARRs are settled based on the auction clearing prices from the annual FTR Auction. An ARR Obligation will provide the ARR Holder with credits when the value of the ARR Obligation is positive and will impose charges when the value of the ARR is negative. The value of the ARR Obligation is positive when the auction clearing price at the ARR Receipt Point (RSPs) is greater than the clearing price at the ARR Delivery Point (ARR Zone). Conversely, an ARR Obligation will impose charges on its ARR Holder when the clearing price of the ARR Delivery Point is greater than the clearing price of the ARR Receipt Point.

An ARR is specified by: (i) an ARR Receipt Point; (ii) an ARR Delivery Point; (iii) an ARR Quantity; (iv) an ARR Period (on-peak/off peak); (v) an ARR Term; (vi) whether the ARR is an LTTR; (viii) whether the ARR is feasible or infeasible; and (viii) whether the ARR is a year 1 counterflow LTTR. The ARR Receipt Point shall be the CPNode for the relevant RSP or an Interface. The ARR Delivery Point shall be a Category 1 or 2 ARR Zone or an Interface CPNode. The RSP shall be a designated Network Resource pursuant to Section 1.217 of this Tariff.

A Partial-Year FTR Allocation will be conducted for the Market Participant in the new ARR Zones added as a result of Transmission Provider Region expansion that becomes effective after the start of the Annual ARR Allocation period. The Partial-Year FTR Allocation will cover the period of time when the new ARR Zones become effective up to the start of the next Annual ARR Allocation. For the partial year period, the Market Participants in new ARR Zone(s) may request an allocation of FTRs, which will be in lieu of an allocation of ARRs.

As part of the integration of new ARR Zones, the Transmission Provider will conduct a mid-cycle Annual ARR Registration for the Market Participants in the new ARR Zone(s). The ARR registration process will be held according to Section 43.2.1 of the Tariff, with the Reference Year comprised of the four full seasons prior to the Annual ARR Registration associated with the integration of the applicable ARR Zones. Market Participants must provide data that satisfies the same requirements as laid out in Sections 42 and 43. The Partial-Year FTR Allocation and the ensuing Annual ARR Allocation will use the ARR Entitlements from the mid-cycle ARR registration. To meet the Generation Resource Qualification Requirements, Market Participants may request the exception described in Section 43.2.1.a.ii.

The Partial-Year FTR Allocation will consist of a single-round nomination and allocation using the Simultaneous Feasibility Test (SFT) similar to the Annual ARR Allocation process. Market Participants of Network Integration Transmission Service and Option A GFA Transmission Service may nominate up to the Forecasted Peak Load (less the portion of the Load served under Carved-Out or Option C GFAs) of the remaining seasons of the current ARR allocation period. Market Participants of Point-to-Point Transmission Service may nominate up to the eligible Point-to-Point Transmission Service MW amount. The Partial-Year FTR Allocation and the allocated FTRs will cover the peak and off-peak periods for each of the remaining seasons of the partial year. The process will be conducted with base loading from the latest Annual FTR Auction models to ensure the Simultaneous Feasibility of all existing FTRs. The Transmission Provider will build seasonal allocation models to be used in the Partial-Year FTR Allocation from data submitted for the Network and Commercial Models that includes the information submitted by Market Participants in the new ARR Zone(s). Transmission capacity resulting from updating the loopflow assumptions will also be used for allocating FTRs to the Market Participants in the new ARR Zone(s) during the Partial-Year FTR Allocation process. Market Participants in the new ARR Zone(s) may participate in the monthly FTR Auctions pursuant to Section 45 of the Tariff, following the Partial-Year FTR Allocation, for each complete month beginning with the integration date.

In subsequent Annual ARR Allocation periods, the Market Participants shall follow the nomination and allocation procedures specified in Section 43.2.4 for the allocation of ARRs. The Year 1 Annual ARR Allocation process for the Market Participants in the new ARR Zones will be the first full allocation period that begins immediately after the end of the partial year period.

The Transmission Provider will conduct an Annual ARR Registration prior to every Annual ARR Allocation. The ARR Registration will involve the definition of ARR Entitlements. ARR Entitlements will be defined using the RSPs and ARR Zones that qualified during the Reference Year. For each ARR Zone, the Transmission Provider shall determine the RSP set based on the historical Reference Year and assign a *pro rata* amount of MW capability from each RSP to each Transmission Customer in the ARR Zone based on its proportion of peak Load in the ARR Zone. ARRs shall be allocated to each Transmission Customer in an ARR Zone from each RSP in a MW amount equal to or less than the amount of the RSP that has been assigned to the Network Customer. The ARR Entitlements will determine Market Participants' Candidate ARRs (CARRs) that may be nominated and allocated during the Annual ARR Allocation. This process is further described in the Business Practices Manuals.

Transmission Customers taking Transmission Service under this Tariff must convert their transmission rights applicable during the Reference Year to ARR Entitlements consistent with the procedures described herein. Transmission Customers taking Transmission Service for Loads Pseudo-tied out of the Transmission Provider Region are included in this conversion requirement. LSEs with external Loads (loads outside Transmission Provider footprint) may request ARR Entitlements pursuant to Section 43.2.1.a, 43.6.1 or 43.6.2 if they have existing agreements with the Transmission Provider to pay a share of the embedded costs of the Transmission System on a long-term basis to support Loads out of the Transmission Provider Region.

a. **ARRs for Grandfathered Agreements.** Market Participants with Grandfathered Agreements must elect to schedule and settle for Cost of Congestion as provided in Section 38.8.3. Market Participants under Grandfathered Agreements that select Option A as described in Section 38.8.3 convert rights to Transmission Service under Grandfathered Agreements to ARR Entitlements.

Such converted Grandfathered Agreements shall be comparable to the transmission service received by such parties under their existing Grandfathered Agreements. Under Option A, transmission rights under Grandfathered Agreements are converted in their entirety to ARR Entitlements. Market Participants with Option A Grandfathered Agreements may be allocated ARRs and may self-schedule feasible ARRs in the annual FTR Auction to convert those ARRs to FTRs.

b. **Election of Conversion:** Market Participants intending to convert transmission rights contained in Grandfathered Agreements to ARR Entitlements during the Annual ARR Allocation shall notify the Transmission Provider of such intent during ARR Registration. Procedures for such notification are specified in the Business Practices Manuals. Market Participants requesting ARR Entitlements for Grandfathered Agreements must follow the nomination and allocation procedures established for service conversion under the Tariff and as further described in the Business Practices Manuals.

Market Participants that elect not to convert their existing rights under Grandfathered Agreements to ARR Entitlements may convert the GFA service at the following Annual ARR Allocation. Market Participants intending to convert Grandfathered Agreements to ARR Entitlements must follow the nomination and allocation procedures established for service conversion under the Tariff as set forth in the Business Practices Manuals.

a. All Point-To-Point Transmission Service of annual or longer duration and RSPs that meet the Resource Qualification Requirements and the RSPs valid for at least one full Season, but less than all four Seasons, and Option A Grandfathered Agreements as specified in Section 38.8.3.a, are eligible for conversion of their existing rights to ARRs in the Annual ARR Allocation process.

Point-To-Point Transmission Service starting with dates after the Reference Year will be eligible for conversion of existing rights to ARR Entitlements pursuant to Section 43.6 and Section 46 of this Tariff. The path which existed during the Reference Year will be used to define the LTTR and will not change in subsequent years. For Point-to-Point Transmission Service that has been granted different capacities in different months, the Transmission Provider will use the minimum granted capacity in an allocation Season as the ARR Entitlement for that Season.

When Point-To-Point Transmission Service with rollover rights expires during the Annual ARR Allocation period, Market Participants may elect to register ARR Entitlements for the rollover period. The Market Participant will then be eligible to nominate, and be allocated ARRs during the Annual ARR Allocation for such Transmission Service. If the Market Participant does not exercise rollover rights pertaining to that Transmission Service on the Transmission Provider's OASIS, the Transmission Provider shall terminate such allocated ARRs or the self-scheduled FTR of such Transmission Service when the Transmission Service terminates. All Market Participants that have existing rights and are eligible to nominate and hold ARRs must participate in the ARR registration procedures specified in this Section 43.2 to preserve their entitlements under the Service Agreement, or Grandfathered Agreements for Market Participants that elect Option A. During the Annual ARR Registration, Market Participants must register their existing rights by providing information requested by the Transmission Provider.

The ARR Entitlements from the first year of the Annual ARR Registration will only change if any Baseload Reserved Source Set (BRSS) or the Peak Reserved Source Set (PRSS) RSPs were terminated or replaced. ARR Entitlements for any newly added BRSS or PRSS RSPs will be created during the Annual ARR Registration.

i. Generation Resource Qualification Requirement. Under the Generation Resource Qualification Requirements, in order for a Generation Resource to qualify for inclusion as a Reserved Source Point in the BRSS or PRSS, a qualified Market Participant must have had a Capacity and Energy ownership interest in, or a Capacity and Energy contract with, the Generation Resource that either began in the Reference Year, ended in the Reference Year, or remained in effect throughout the Reference Year for the applicable ARR Zone. Only designated Network Resources are eligible for BRSS and PRSS designation in connection with Network Integration Transmission Service.

An ARR Zone may be a RSP under the following exceptions: (a) if the ARR Zone contains behind-the-meter generation specified as a GFA resource committed to in GFA proceedings before the FERC and (b) pursuant to exceptions set forth in Section 43.2.3.

If the Transmission Service for such owned Generation Resources or contracted for Generation Resources was approved, but is not yet in service during the Reference Year, or the Generation Resource was under construction, but was not yet in service during the Reference Year, the Generation Resource will qualify for inclusion in the BRSS or PRSS, provided that deliveries under the contracted for Generation Resource or owned Generation Resource began prior to December 31, 2005. In the event the entire MW capacity of the Generation Resource is greater than the Market Participant's owned MW amount or contracted for MW amount, only the Capacity and Energy MW amount owned or contracted for shall qualify.

This ownership or contractual relationship must be, or have been, for at least five (5) years, and that either relationship began in the Reference Year, ended in the Reference Year, or remained in effect throughout the Reference Year for the applicable ARR Zone, as verified by the Transmission Provider. Contracts qualify if they include rollover rights that were exercised in such a way that the duration of the contracts was effective for a minimum of five (5) years. Generation Resources shared by multiple Market Participants may be split between or among multiple ARR Zones of such Market Participants in proportion to their ownership or contractual interest in the Generation Resources, and the amount of Load each Market Participant actually serves with such Generation Resources. If two Market Participants have contracts that meet all of the above qualification requirements for the same Generation Resource, such that the exact same megawatts (MWs) from the Generation Resource would otherwise qualify as a Reserved Source Point for more than one ARR Zone, then the Market Participant that contracted with the Generation Resource most recently will be given priority in determining the ARR Zone for which the Generation Resource will serve as a Reserved Source Point.

ii. Generation Resource Qualification Requirement Exception for Insufficient PRSS to Meet Baseload Usage. To the extent that the qualification requirements result in any Market Participant having insufficient MWs in its PRSS to meet its Baseload Usage within a given ARR Zone, the Generation Resource Qualification Requirements for the ownership or contractual duration for that Market Participant within that ARR Zone will be reduced from the required five (5) year duration to a one (1) year duration for the PRSS up to the Market Participant's Baseload Usage. This exception will apply only to the initial determination of Reserved Source Sets during year 1 of the Annual ARR Registration and any Resources added to the PRSS under this exception are not eligible for nomination in Stage 1A of the Annual ARR Allocation and thus will not receive LTTR status. Any future additions or substitutions shall be required to meet the five (5) year ownership or contractual duration requirement. This Section does not permit a Market Participant with, ownership or contractual duration in a supply Resource of less than five (5) years, to participate under Stage 1A to receive LTTRs.

iii. Baseload Usage: Baseload Usage shall consist of fifty percent (50%) of Peak Usage. For Market Participants utilizing Point-To-Point Transmission Service fifty percent (50%) of the Point-

To-Point Transmission Service(s) MW amount will be assumed to be Baseload Usage.

iv. Peak Usage: Peak Usage shall be defined as a Market Participant's Total Forecasted Peak Load usage in a given ARR Zone for the upcoming Annual ARR Allocation period.

v. Generation Resource Qualification Requirement Exception for Insufficient BRSS to Meet Baseload Usage: To the extent that the Generation Resource Qualification Requirements result in any Market Participant having insufficient RSPs in its BRSS to meet its Baseload Usage for a given ARR Zone, the Market Participant may utilize the following rules to request the creation of additional BRSS entitlements, not to exceed its Baseload Usage. These supplemental rules will apply only: (1) to the initial determination of the BRSS for areas integrated into the Transmission Provider Region after the effective date of these supplemental rules and (2) during the first Annual ARR Registration following the effective date of these exceptions, for areas integrated into the Transmission Provider Region prior to the effective date of these supplemental rules. Each Market Participant in this category (2) is eligible to add BRSS entitlements up to at least its year 1 BRSS entitlement gap or the

BRSS gap existing in the first Annual Registration following the effectiveness of these supplemental rules.

If the Market Participant declines to accept an eligible Baseload RSP defined under the first supplemental rule, no further BRSS additions maybe made for that Market Participant under the second supplemental rule.

Supplemental BRSS entitlements may only be added in the order specified below. An RSP shall not under these provisions be subscribed above its maximum capacity.

1. Term Reduction: While maintaining the 50% capacity factor Generation Resource Qualification Requirement for Baseload Supply Resources, the Transmission Provider will implement requests by the Market Participant for a reduction of the ownership or contractual duration for that Market Participant from the required five (5) year duration to a one (1) year duration, for PPAs that serve load in the Market Participant's ARR Zone. Twelve rolling monthly firm transmission reservations, valid during the Reference Year, will be eligible if that monthly service is converted into a confirmed long-term firm transmission service and the conversion is evident at the time of initial ARR registration.

ARR Entitlements created under this rule will be defined commencing from the longest duration transmission service to the shortest duration transmission service. For entitlements based on ownership or contractual duration of three (3) years or less, Market Participants shall provide the capacity factor data for the RSP for the full length of the ownership or contract.

2. Heat Rate Stack: If the first supplemental rule, set forth in subsection v.1 above, does not provide sufficient RSPs to create BRSS entitlements satisfying a Market Participant's Baseload Usage, the Market Participant may then utilize the heat rate stack rule. While maintaining the Generation Resource Qualification Requirement ownership or contractual requirement of five (5) year duration, the Transmission Provider will allow the creation of BRSS entitlements for non-BRSS RSPs entitlements. BRSS entitlements created under this rule will be determined using the most recent annual average heat rate data available for the initial Annual ARR Registration. The remaining BRSS entitlement deficiency may be mitigated by adding these RSPs from the lowest to the highest heat rates to the applicable ARR Zone.

vi. A Market Participant may reject BRSS entitlements created under Section 43.2.1 (a)(v), provided that the rejection shall only be permitted in the reverse order of how the entitlements were created (i.e., shortest to longest duration under the first supplemental rule, and highest to lowest heat rate under the second supplemental rule, and provided further that a Market Participant that rejects BRSS entitlements under this Section is not precluded from including the applicable resources into the PRSS in accordance with Section 43.2.1(a)(ii).

b. The Transmission Provider shall verify such information as consistent with the terms of the Transmission Service for which the existing entitlement is claimed. Any Market Participant that fails to provide all of the information requested during the Annual ARR Registration period will be deemed to have waived any rights to nominate in the Annual ARR Allocation process but may remain subject to Counterflow ARR Assignment.

c. For year 1 of the implementation of the Annual ARR Allocation process, Market Participants will be required to provide information requested by the Transmission Provider that will establish the RSPs, ARR Zones, BRSS, and PRSS for the Point-To-Point, Network Integration Transmission Service and GFA rights. For year 2 and beyond, Market Participants will need to provide additional information to add or modify the original BRSS or PRSS. For Point-To-Point Transmission Service Market Participants will provide ARR Receipt Point and ARR Delivery Point information consistent with the confirmed transmission service request registered on OASIS and pursuant to Sections 42.5, 43.2.1.a and 43.2.3.

d. Year 1 of the Annual ARR Allocation will be defined as the first allocation year in which the Transmission Provider conducted the Annual ARR Allocation for an ARR Zone.

e. Prior to the start of every Annual ARR Allocation, Market Participants with Candidate Baseload or Candidate Peak ARR Rights may request the Transmission Provider to transfer ownership of such rights in its entirety to another Market Participant.

Any party to an agreement that remains in effect for transmission service, Energy, or a combination thereof, that was executed prior to September 16, 1998 and applicable during the Reference Year, has rights to participate in the annual ARR nomination process (Option A), or to request refunds of congestion costs in the Day-Ahead Energy and Operating Reserve Market (Option B). To protect such rights, parties to Grandfathered Agreements must participate in the Annual ARR Registration process. During the registration period, Market Participants must register their existing entitlements contained in Grandfathered Agreements by providing information requested by the Transmission Provider, including: information about contractual source, sink, term, MW quantity, and OASIS reservation numbers where appropriate. When registering Grandfathered Agreements, the parties may assign any MW value to their Grandfathered Agreement, not to exceed the maximum value of their existing entitlement contained in the Grandfathered Agreement. For purposes of this Section, a GFA Responsible Entity shall be entitled to specify multiple RSPs and ARR Zones, consistent with its existing entitlements. With regard to GFAs involving multiple RSPs and ARR Zones, the GFA Responsible Entity shall provide information identifying each RSP and ARR Zone combination. The Transmission Provider shall verify such information as consistent with the terms of the Grandfathered Agreement for which the existing entitlement is claimed.

During year 1 of the Annual ARR Registration, if the Points of Receipt for a Point-To-Point Transmission Service reservation, Network Integration Transmission Service reservation, or Grandfathered Agreements reservation are specified as a Local Balancing Authority Area, the existing entitlement shall be defined in terms of RSPs within that Local Balancing Authority Area.

The Transmission Provider shall define the ARR Receipt Point for the Network Integration Transmission Service entitlements as the default set of RSPs when the Point of Receipt of such entitlements is a Local Balancing Authority Area.

The Transmission Provider shall accommodate a definition of the ARR Receipt Point, for the Point-To-Point Transmission Service identified during the registration process and for all Grandfathered Agreements, as a specific set of RSPs when the Market Participant registering such existing entitlements and the Market Participant for the RSPs are in agreement as to the ARR Receipt Point definition.

When the Market Participant registering the existing entitlement and the Market Participant for the RSPs do not agree as to the ARR Receipt Point definition, then, for Point-To-Point Transmission Service identified during the registration process as supporting a generation Capacity transaction and for all Grandfathered Agreements, the use of that Local Balancing Authority Area shall be the default set of RSPs.

When the Market Participant registering the existing entitlement and the Market Participant for the source Commercial Pricing Nodes do not agree as to the ARR Receipt Point definition, then, for Point-To-Point Transmission Service not identified during the registration process as supporting generation capacity transactions, the use of the ARR Zone, within the Local Balancing Authority Area shall be the default ARR source. Multiple existing entitlements shall be defined when the Point of Receipt includes more than one (1) generation Commercial Pricing Node.

If the Transmission Provider determines that two or more existing entitlements represent hubbing transactions in which a set of existing entitlements are used to deliver power to the Local Balancing Authority Area while another set of existing entitlements are used to transport that power from the Local Balancing Authority Area, the Transmission Provider may use an ARR Zone or a Hub as the ARR Delivery Point corresponding to the first set of existing entitlements that deliver power to the Local Balancing Authority Area and as the ARR Receipt Point corresponding to the second set of existing entitlements that transport the power from the Local Balancing Authority Area.

The Transmission Provider shall make ARRs for existing entitlements registered through the Annual ARR Registration process available to Market Participants based on a multi-stage allocation/nomination methodology. In each stage, the Transmission Provider shall provide Market Participants with the opportunity to be allocated ARRs from RSPs as described in Section 43.2.4a, based on the Peak Usage. Market Participants representing LSEs with service obligations shall be entitled to participate in Stage 1A, provided, that, the Transmission Provider may give priority to LSEs with long-term power supply arrangements in Stage 1A when the Transmission Provider needs to limit the amount of existing transmission capacity available for Stage 1A to a level that is able to support the reasonable needs of all LSEs.

The Transmission Provider shall provide two (2) nomination and allocation stages for Network Integration Transmission Service plus all Option A and Option B Grandfathered Agreements and for all Point-To-Point Transmission Service. For each stage and each category, within each stage, ARR nomination eligibility will be equal to maximum nomination eligibility (total of forecast Peak Network Load served under Network Integration Transmission Service plus Grandfathered Service; or total Point-To-Point reservation amount multiplied by an ARR Stage Factor less the MW quantity of ARRs allocated in any previous stage; provided, that a Market Participant may aggregate the total MW of its Firm Point-To-Point Transmission Service reservations and allocate them between eligible Points of Delivery and Points of Receipt. The ARR Stage Factors shall be:

Stage 1A: Fifty percent (50%) of Peak Usage; otherwise the Candidate Baseload ARR Rights.

Stage 1B: One hundred percent (100%) of Peak Usage; otherwise the Candidate Peak ARR Rights.

These two stages constitute Stage 1.

The Transmission Provider shall allocate ARRs to Market Participants in each stage only to the extent that the Transmission Provider determines that such ARRs satisfy its Simultaneous Feasibility Test (SFT). The Transmission Provider will allocate infeasible ARRs only to the extent needed to ensure the full MW allocation of Stage 1A nominated LTTRs from the prior year's Annual ARR Allocation. Allocated ARRs are obligations.

a. Stage 1A – Nomination and Allocation Procedures.

i. The Transmission Provider will enter all LTTRs from the current Annual ARR Allocation period into this stage. Market Participants are eligible to nominate CARRs up to fifty percent (50%) of the sum of their forecasted Network Integration Transmission Service peak load in each ARR Zone in which they serve Load for the upcoming Annual ARR Allocation period, plus Option A and Option B Grandfathered Agreements. This will constitute the Candidate Baseload ARR Rights for each Market Participant. The source of the Candidate Baseload ARR Rights will be any of the RSPs in the BRSS for each of the corresponding ARR Zones up to the qualified Market Participant's pro rata Load share of the ARR Zone. Market Participants may request incremental or new nominations from Stage 1A ARR Entitlements. Market Participants eligible to submit LTTR termination requests pursuant to Section 43.2.5 may do so only during this stage.

In addition, Market Participants are eligible to nominate up to fifty percent (50%) of the reservation MW quantity for each of the applicable annual or longer Firm Point-To-Point Transmission Service entitlement.

(a) Baseload Resource Source Set. The BRSS shall consist of Baseload Supply Resources that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone and entitlements created pursuant to Section 43.2.1(a)(v). Interfaces are understood to serve as proxies for Baseload Supply Resources located external to the Transmission Provider Region and are eligible for inclusion in the BRSS.

(b) Baseload Supply Resources. Baseload Supply Resources shall consist of supply Resources with an average capacity factor of at least fifty percent (50%) over the Reference Year and the two (2) years previous to the Reference Year for a total of three (3) years, or the life of the unit to the extent the unit had not been in operation for three (3) years up to and including the Reference Year. In determining capacity factors for supply Generation Resources, data from the single month of the 36-month period with the lowest capacity factor for that supply Generation Resource will be excluded.

For Point-To-Point Transmission Service Network Resources external to the Transmission Provider Region, the holder of the service may opt to use the above process to the extent that the supply Resource behind the

Transmission Service can be identified, where the LSE has a Capacity and Energy interest through a contract or ownership and the Capacity factor of the Resource is at least fifty percent (50%).

The holder may also opt to use the scheduling factor of the Transmission Service. If the scheduling factor of the Transmission Service or comparable transmission service is used, that scheduling factor must also be at least fifty percent (50%) to qualify as a Baseload Supply Resource. For new Generation Resources, a class average for the technology type shall be used.

(c) Limitation to Baseload Usage. Since Candidate Baseload ARR Rights are based on Baseload Usage in a given ARR Zone, a Market Participant cannot request more ARRs sinking in a particular ARR Zone in Stage 1A than their Baseload Usage in that ARR Zone.

Candidate ARRs (CARRs) equal to one hundred percent (100%) of the Option B Grandfathered Agreements, that were registered with the Transmission Provider pursuant to Section 43.2.2, are automatically included in Stage 1A. The Transmission Provider shall not allocate to Market Participants ARRs representing Option B Grandfathered Agreements that are determined to be feasible.

Such ARRs are used by the Transmission Provider as an accounting mechanism to determine revenue adequacy of any congestion cost refunds to Option B Grandfathered Agreements. Stage 1A includes eight (8) independent nominations: one (1) of each of the four (4) Seasons and two (2) time periods (On-Peak and Off-Peak). The Transmission Provider shall perform an SFT for each season and time period for the Stage 1A Candidate ARRs ("CARRs"). CARRs are curtailed in each season and time period as required to achieve simultaneous feasibility, provided, that LTTRs already allocated in the prior year shall not be curtailed.

ii. CARRs for Option B Grandfathered Agreements shall be included in the Stage 1A nomination at the full MW quantity of the existing entitlement that was registered with the Transmission Provider pursuant to Section 43.2.2, even if these nominations exceed the Stage 1A cap for CARRs for Network Integration Transmission Service plus Grandfathered Agreements.

CARRs for service under the Tariff and for Option A Grandfathered Agreements may be nominated in addition to the Option B Grandfathered Agreements up to the Stage 1A cap for CARRs for Network Integration Transmission Service plus Grandfathered Agreements.

iii. Where the MW quantity of Option B Grandfathered Agreements exceeds the Stage 1A limit for CARRs for Network Integration Transmission Service plus Grandfathered Agreements, Stage 1A nominations for Network Integration Transmission Service plus Grandfathered Agreements will include only Option B Grandfathered Agreements. Any Option B Grandfathered Agreements over the Stage 1A limit for CARRs for Network Integration Transmission Service plus Grandfathered Agreements are taken into account in subsequent stages by reducing the size of subsequent stages for the purpose of determining nomination eligibility for CARRs for Network Integration Transmission Service plus Grandfathered Agreements.

iv. All new or incremental nominations in Stage 1A (i.e., nominations not associated with allocated LTTRs in the prior-year) will be subject to the Simultaneous Feasibility Test, and will be allocated only to the extent feasible. The Simultaneous Feasibility Test will be performed on a market-wide, non-ARR Zone basis.

v. In a Market Participant's year 2 and ensuing Annual ARR Allocations, the Market Participant is guaranteed the MW quantity for a Stage 1A CARR (candidate LTTR) up to the current Annual ARR Allocation period's corresponding LTTR MW quantity. Where the LTTR Restoration and Termination Stage is unable to fully allocate such CARR, the Transmission Provider will assign infeasible ARRs for the un-restored MW portion of the CARR. The infeasible ARRs shall be subject to the same settlement terms and conditions as other allocated ARRs. The cost, if any, of infeasible ARRs will be funded by all Stage 1A ARR Holders (i.e., Long Term Transmission Rights (LTTR) holders) in the ratio share of the MW quantity of LTTRs allocated in the current Annual ARR Allocation. The allocated LTTRs for each Market Participant will be the sum of the allocated LTTRs, the feasible and infeasible ARRs, assigned following the LTTR Restoration and Termination Stage pursuant to Section 43.2.5.

b. Stage 1B Nomination and Allocation Procedures. In Stage 1B, Market Participants are eligible to nominate CARRs up to one hundred percent (100%) of the sum of their forecasted Network Integration Transmission Service peak Load in each ARR Zone in which they serve Load for the upcoming Annual ARR Allocation period, plus Option A and Option B Grandfathered Agreements, less feasible LTTRs allocated in Stage 1A for Network Integration Transmission Service and Option A Grandfathered Agreements and less Option B Grandfathered Agreements. Any infeasible ARRs assigned following the LTTR Restoration and Termination Stage pursuant to Section 43.2.5 shall be deemed included in the Stage 1B Nomination. This will constitute the Candidate Peak ARR Rights for each Market Participant.

The source for the Candidate Peak ARR Rights will be any of the RSPs in the Peak Reserved Source Set (PRSS) for each of the corresponding ARR Zones up to the qualified Market Participant's pro rata Load share of the ARR Zone. The PRSS shall consist of all supply Resources, inclusive of Baseload Supply Resources, that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone, and entitlements created pursuant to Sections 43.2.1(a)(ii) and 43.2.1(a)(v). Interfaces shall serve as proxies for supply.

Resources located external to the Transmission Provider Region are eligible for inclusion in the PRSS. Since Candidate Peak ARR Rights are based on Peak Usage in a given ARR Zone, a Market Participant cannot request more ARRs sinking in a particular ARR Zone in this stage than their Peak Usage in that ARR Zone.

In addition, Market Participants are eligible to nominate CARRs up to one hundred percent (100%) of the reservation MW quantity for each annual or longer Firm Point-To-Point Transmission Service entitlement or aggregation thereof, less feasible LTTRs allocated in Stage 1A for Firm Point-To-Point Transmission Service entitlement or aggregation thereof. Stage 1B includes eight (8) independent nominations: one (1) for each of four (4) seasons and two (2) time periods (peak and off-peak). Any Option B Grandfathered Agreements rolled over from Stage 1A shall automatically reduce the Stage 1B nomination limit for Network Integration Transmission Service and Grandfathered Agreements. The Transmission Provider will also nominate the MVP ARR Entitlements in Stage 1B, as described in Section 47. The Transmission Provider shall perform an SFT for each season and time period for Stage 1B CARRs and Candidate MVP ARRs. The Transmission Provider shall curtail CARRs and Candidate MVP ARRs in each season and time period as required to achieve simultaneous feasibility. The feasible portions of LTTRs previously allocated in Stage 1A are fixed (not subject to Curtailment) in the Stage 1B process. Infeasible Stage 1A LTTRs remain LTTRs whether or not made feasible in Stage 1B. To the extent that infeasible LTTRs are not rendered feasible in Stage 1B, they shall remain infeasible LTTRs for the current Annual ARR Allocation period.

In Stage 2 of the Annual ARR Allocation, the Transmission Provider will inform each Market Participant of its Stage 2 allocation based on that Market Participant's Stage 1 allocation amounts and its Stage 1 nomination cap. The Transmission Provider will further inform each Market Participant of its Stage 2 allocation as a percentage of the Stage 2 allocation of all applicable Market Participants. Each Market Participant will then receive the corresponding percentage share of the dollar value of the system capability sold in the annual FTR Auction that was not otherwise disbursed to holders of ARRs, or pursuant to provisions governing MVP ARRs, allocated in Stage 1. MVP ARRs will not receive Stage 2 allocations.

The Transmission Provider will determine the Stage 2 allocation for each Market Participant after the completion of the Stage 1 allocation. The Stage 2 allocation will be calculated as described below:

i. For each Season and Period of the annual FTR Auction, the Stage 2 allocation for each Market Participant will be calculated as the difference between the Stage 1 nomination cap and the sum of ARRs allocated against Network Integration Transmission Service and Option A GFAs (including allocated infeasible ARRs in Stage

1) and Option B GFA entitlements. The Stage 1 nomination cap and the allocated ARRs will correspond to the forecasted Network Integration Transmission Service peak Load in each ARR Zone, plus Option A and Option B Grandfathered Agreements.

This calculation will include any quantity of Counterflow ARRs, and of the LTTR MWs whose termination was requested but not granted.

ii. Exception for Counterflow and HUFU ARRs: Counterflow and HUFU ARRs will not be included in the allocated Stage 1 ARRs when determining the MW amount to be allocated in Stage 2. (By definition, Counterflow and HUFU ARRs are assigned in a Market Participant's year 1 Annual ARR Allocation). This exception for Counterflow and HUFU ARRs will apply to year 2 and ensuing Annual ARR Allocations for the LTTR MW quantity whose termination was requested but not granted.

iii. The Stage 2 allocation will also be determined in a similar manner as described in (i) and (ii) above for the Point-To-Point Transmission Services

separately.

This Section describes: (1) the restoration of: (i) a Market Participant's Stage 1A CARRs curtailed in its year 1 Annual ARR Allocation ("year 1 Stage 1A CARRs"); and (ii) the candidate LTTRs curtailed in a Market Participant's year 2 and ensuing Annual ARR Allocations; (2) Counterflow ARR allocation; (3) HUFU ARR Entitlements and (4) the processing of a Market Participant's LTTR termination requests in its year 2 and ensuing Annual ARR Allocations. The curtailed candidate LTTRs will be eligible for restoration to their current Annual ARR Allocation period's MW quantity. The curtailed year 1 Stage 1A CARRs will be eligible for restoration to their CARR MW quantity. The Transmission Provider shall attempt such restoration based on any available Counterflow and HUFU ARR Entitlements, and in conjunction with its attempt to maximize, subject to simultaneous feasibility, the termination of the LTTRs for which LTTR termination requests were made during Stage 1A.

The Transmission Provider will terminate only the LTTRs, and not the underlying RSPs and ARR Entitlements, pursuant to this Section. The termination of RSPs, HUFU RSPs and ARR Entitlements shall be handled differently under the limited circumstances described in Section 43.6.4. The Transmission Provider will perform the restoration and termination processes described in this Section after Stage 1A is concluded and before the Stage 1B nominations are accepted.

a. In restoring the curtailed candidate LTTRs and a Market Participant's year 1 Stage 1A CARRs, the Transmission Provider will minimize an objective function that is the weighted sum of two components:

i. The first component of the objective function is the weighted sum of squares of the megawatt amount of the curtailed candidate LTTRs and a

Market Participant's curtailed year 1 Stage 1A CARRs that the Transmission Provider is unable to restore based on the inclusion of Counterflow and HUFU ARR Entitlements and processing of LTTR termination requests. The weights in the weighted sum of squares will be equal to the inverse of the MW of curtailed candidate LTTR and curtailed year 1 Stage 1A CARRs.

ii. The second component of the objective function is the weighted sum of squares of any LTTR megawatt amount whose termination was requested but not granted, and the Counterflow and HUFU ARRs that the Transmission Provider adds to restore curtailed candidate LTTRs and curtailed year 1 Stage 1A CARRs. The weights in the weighted sum of squares will be equal to the inverse of the MW of the corresponding LTTR termination requests and Counterflow and HUFU ARR Entitlements.

b. Counterflow and HUFU ARRs shall be allocated and assigned directly to the owner of the corresponding CARR(s). Counterflow and HUFU ARRs and any LTTR megawatt quantity whose termination was requested but not granted shall be subject to the same settlement terms and conditions as other allocated LTTRs.

c. Counterflow and HUFU ARRs and any LTTR megawatt quantity whose termination was requested but not granted will not be considered toward the Stage 1B ARR nomination eligibility cap of the Market Participant.

d. During a Market Participants year 1 Annual ARR Allocation, the Transmission Provider may assign Counterflow and HUFU ARRs to such Market Participant from any of its Counterflow and HUFU ARR Entitlements. In a Market Participant's year 2 and ensuing Annual ARR Allocation, the Market Participant can request the termination of LTTRs pursuant to this Section.

e. A Market Participant's LTTR whose termination was requested but not granted shall nonetheless expire after such termination requests are made for ten (10) consecutive allocation periods. The termination will take effect on the eleventh (11th) allocation period after: (i) the year when that LTTR was first requested for termination, or (ii) year 1 in the case of Counterflow and HUFU ARRs assigned to a Market Participant. This 10-year timeline shall be reset if the megawatt volume that remains un-terminated after the processing of an ensuing request is greater than the megawatt volume that remained un-terminated after the processing of the immediately preceding request. The MW quantity covered by a request for termination of an LTTR during the 2009-10 Annual ARR Allocation shall be deemed to constitute the un-nominated MW quantity of that LTTR (i.e., the difference between the 2008-09 LTTR MW and the 2009-10 Stage 1A CARR corresponding to that LTTR). Requests for LTTR termination for the 2010-11 allocation and beyond should be made pursuant to the LTTR termination procedure under this section.

f. HUFU ARR Entitlements cannot be nominated in the Stage 1A process in the year 1 allocation pursuant to Section 43.2.4.a, but may be nominated in the Stage 1B process to the extent HUFU ARRs are not assigned in the restoration stage. The MW quantity of the HUFU ARR Entitlements associated with the HUFU

RSPs eligible for nomination in Stage 1B, subject to the Stage 1B nomination cap, will be the difference between the full qualified capacity of the HUFU ARR Entitlements for the HUFU RSPs, less the MW of HUFU ARRs already assigned in the restoration stage. HUFU ARR Entitlements will only be used for counterflow assignment pursuant to this Section in year 1 of the Market Participant's Restoration Stage of the Annual ARR Allocation and shall not count towards the Stage 1A nomination cap. If the Market Participant elected to add a RSP that was deemed eligible for addition into the BRSS pursuant to the first or second supplemental rules of Section 43.2.1(a) (v), that RSP will be ineligible as a HUFU RSP. Once a HUFU ARR is terminated based on the Market Participant's request pursuant to Section 43.2.5 (e), the associated HUFU ARR Entitlement will be an eligible PRSS entitlement in subsequent years for Stage 1B nomination only up to its full qualified capacity. A Market Participant may utilize Section 43.6.1 to consider HUFU RSPs for potential eligibility for inclusion in the BRSS.

g. Candidate LTTRs are re-nominated into Stage 1A of the next Annual ARR Allocation period, where they may be allocated either as LTTRs or as Counterflow LTTRs.

The annual allocation performed by the Transmission Provider considers time period and season for entitlements (existing terms of Transmission Service or terms under the Grandfathered Agreement for Market Participants that elected Option A), irrespective of whether the existing entitlements vary by time period or season.

a. The annual allocation of ARRs shall be performed separately for On-Peak and Off-Peak periods in each of four (4) seasons prior to the start of each allocation period.

b. The four (4) seasons are:

   i. **Winter:** December, January, February

   ii. **Spring:** March, April, May

   iii. **Summer:** June, July, August

   iv. **Fall:** September, October, November

Replacement of Reserved Source Point or Firm Point-to-Point Transmission Service:

Megawatts from an existing Reserved Source Point may be removed from the BRSS or PRSS to free up system capability for the feasibility of ARRs from a replacement Reserved Source Point eligible to be added to the BRSS or PRSS based on a Baseload Supply Resource or non-Baseload Supply Resource, provided that a Baseload Supply Resource that replaces a non-Baseload Reserved Source Point is only eligible to be added to the non-BRSS part of the PRSS. The Market Participant may also request to replace an existing BRSS RSP with a non-Baseload Supply Resource in an ARR Zone in which the requesting Market Participant's total PRSS MW do not exceed 115% of the requesting Market Participant's Peak Usage, provided that no LTTRs have been allocated to the existing BRSS RSP for the portion to be replaced. Once allocated, the replacement RSP will be considered a non-BRSS RSP, and the replaced Baseload Supply Resource can only be submitted for subsequent re-inclusion in the BRSS pursuant to this section or section 43.6.2.

The replacement RSP must meet the Resource Qualification Requirements pursuant to Section 43.2.1.a with two exceptions: i) the Capacity and Energy Contract can also be with another entity that has a Capacity and Energy contract directly with the Generation Resource, provided that both contracts have the same termination date; and ii) the

Capacity and Energy ownership interest, or the Capacity and Energy contract should remain in effect throughout the Seasons for which the replacement RSP is requested in the upcoming Annual ARR Allocation for the applicable ARR Zone. For the purposes of determining Resource Qualification Requirements, the Reference Year shall be replaced by the Annual ARR Allocation period subsequent to the year of the request for the replacement RSP.

Megawatts from ARR Entitlements associated with an existing Firm Point-To-Point Transmission Service may be removed from Stage 1A or Stage 1B to free up system capability for the feasibility of the replacement Firm Point-To -Point Transmission Service with annual or longer duration that commences after the applicable Reference Year and will remain in effect throughout the upcoming Annual ARR Allocation. The replacement Firm Point-To-Point Transmission Service must be active by virtue of rollover provisions or extant in the upcoming Annual ARR Allocation period by the closing date provided by the Transmission Provider prior to each Annual ARR Registration. The Market Participant requesting to replace Stage 1A ARR Entitlements associated with an existing Firm Point-To-Point Transmission Service with the replacement Firm Point-To-Point Transmission Service in Stage 1A must also meet the following requirements: (a) the Market Participant must be an LSE serving load with the portion of the replacement Firm Point-To-Point

Transmission Service for which Stage 1A replacement is requested; (b) the Market Participant must demonstrate the existence of a firm network contract with the transmission provider for the network load; (c) the duration of the Market Participant's entitlement to service under the network contract (source and sink) by virtue of rollover rights or extant, in the upcoming Annual Allocation Period by the closing date provided by the Transmission Provider prior to each Annual ARR Registration, must be equal to or greater than that of the eligible Firm Point-To-Point Transmission Service; (d) the Point of Receipt of the replacement Firm Point-to-Point Transmission Service must correspond to a Local Balancing Authority Area, and the Point of Delivery must correspond to the Local Balancing Authority or external Balancing Authority Area for the load identified in the network contract; (e) the Market Participant must demonstrate a Capacity and Energy interest through a contract or ownership of the Resource corresponding to the source of the replacement Firm Point-To-Point Transmission Service and (f) the Resource or the replacement Firm Point-To-Point Transmission Service must meet the Baseload Supply Resource qualification requirements pursuant to Section 43.2.4.a.i.(b). The remainder of the replacement Firm Point-To-Point Transmission Service MW that did not pass the SFT shall be entitled to Stage 2 ARR compensation pursuant to Section 43.2.4A. The rollover provisions described in Section 43.2.1.a will also apply to the replacement Firm Point-To-Point Transmission Service.

The total MW subscription of the Generator associated with the replacement RSP and Firm Point-To-Point Transmission Service request, taking into consideration all existing ARR Entitlements and all other replacement requests, as well as all addition requests pursuant to Section 43.6.2, cannot exceed the rated Capacity of the corresponding Generator.

An SFT will be conducted to add the replacement Baseload Supply Resource and Stage 1A eligible Firm Point-To-Point Transmission Service into Stage 1A up to the quantity determined to be feasible using the Restoration and Termination Stage of the most recent Annual ARR Allocation without the infeasible ARRs. Similarly, an SFT will be conducted to add the replacement non-Baseload Supply Resource and non-Stage 1A eligible Firm Point-To-Point Transmission Service into Stage 1B up to the quantity determined to be feasible using Stage 1B of the most recent Annual ARR Allocation without the infeasible ARRs. These SFTs will be conducted on a market-wide, non-ARR Zone basis.

The SFT shall maximize the allocation sought by the replacement request, and the replacement of the existing ARR Entitlements. Market Participants shall submit the requests with the order in which those requests will need to be studied. The SFT determines the MW quantity of the replacement RSP for which ARR Entitlements can be defined, and the

MW quantity of the existing RSP that can be terminated. The SFT can result in ARR Entitlements for a MW quantity of the replacement RSP that is less than, equal to, or greater than the terminated MW quantity of the existing RSP. The requesting Market Participant must submit the Minimum Acceptance Ratio for the replacement request. If the ratio of the replacement ARR Entitlements to existing ARR Entitlements being replaced is less than the Minimum Acceptance Ratio, determined by the SFT, the Transmission Provider will deny the replacement request. The ensuing SFT results shall be binding, without any need for acceptance by the requesting Market Participants. The SFT will be performed sequentially, and the outcome of the replacement request will be fixed for the following addition and replacement requests. The study will be performed for the Stage 1A requests first and then for the Stage 1B requests, on a first-come, first request basis. The ARR Entitlements that the SFT determines to be feasible will set the ARR Entitlement MW for all future allocation periods. In each subsequent allocation period, the Market Participant will be able to request ARRs and/or LTTRs from the resulting ARR Entitlements.

The replacement RSP can either be an existing or new Generation Resource. If the request to designate a replacement RSP involves a new Generation Resource, then after it passes the SFT, the designation shall be effective in the next allocation year, for the first full Season at the start of which the new Generation Resource is commercially operational. Otherwise, if the new Generation Resource is not commercially operational by that time, the designated RSP and/or associated ARRs will be removed.

A Market Participant may increase the feasibility of ARRs from a new Baseload Supply Resource or replacement Firm Point-To-Point Transmission Service by utilizing the Feasibility Upgrade Process. In such case, the Market Participant will be eligible to receive LTTRs pursuant to Section 46. If the ARR Receipt Point and ARR Delivery Point of such ARRs and LTTRs match exactly with an associated Firm Point-To-Point Transmission Service that was approved based on construction of the new transmission capacity, then the remainder of the Firm Point-To-Point Transmission Service MW that did not pass the SFT for LTTRs shall be entitled to Stage 1B ARR Entitlements subject to a further SFT and, subsequently, the remainder that did not pass the SFT for Stage 1B Entitlements shall be entitled to Stage 2 ARRs .

A replacement Baseload Supply Resource or Stage 1A eligible Firm Point-To-Point Transmission Service that would otherwise have qualified for inclusion in Stage 1A but fails the SFT for such inclusion may, at the requesting Market Participant's option, be automatically included in Stage 1B without having to undergo or pass any further SFT, but only for the upcoming Annual ARR Allocation.

Designation of New Reserved Source Point or Firm Point-to-Point Transmission Service:

New Network Resources may, upon request, be added to the BRSS or PRSS, in the amount that the SFT determines to be feasible, to the extent that the total MW capacity of the requesting Market Participant's portion of the existing BRSS or PRSS in a given ARR Zone is less than 115% of the Baseload Usage or Peak Usage, respectively, of the requesting Market Participant in the given ARR Zone.

Firm Point-To-Point Transmission Service with annual or longer duration that commences after the Reference Year is eligible to be requested as an addition to Stage 1A or Stage 1B in the upcoming Annual ARR Allocation for the amount that is determined to be feasible by the SFT. The eligible Firm Point-To-Point Transmission Service must be active by virtue of rollover provisions or extant in the upcoming Annual ARR Allocation period by the closing date provided by the Transmission Provider prior to each Annual ARR Registration. The Market Participant requesting to add the eligible Firm Point-To-Point Transmission Service into Stage 1A must also meet the following requirements: (a) the Market Participant must be an LSE serving load with the portion of the eligible Firm Point-To-Point Transmission Service for which Stage 1A entitlement is requested, (b) the Market Participant must demonstrate the existence of a firm network contract with the transmission provider for the network load; (c) the duration of the Market Participant's entitlement to service under the network contract (source and sink) by virtue of rollover rights or extant, in the upcoming Annual ARR Allocation period by the closing date provided by the Transmission Provider prior to each Annual ARR Registration, must be equal to or greater than that of the eligible Firm Point-To-Point Transmission Service; (d) the Point of Receipt of the eligible Firm Point-to-Point Transmission Service must correspond to a Local Balancing Authority Area, and the Point of Delivery must correspond to the Local Balancing Authority Area or external Balancing Authority Area for the load identified in the network contract; (e) the Market Participant must demonstrate a Capacity and Energy interest through a contract or ownership of the Resource corresponding to the source of the eligible Firm Point-To-Point Transmission Service; and (f) the Resource or the Firm Point-To-Point Transmission Service must meet the Baseload Supply Resource qualification requirements pursuant to Section 43.2.4.a.i.(b). The remainder of the Firm Point-To -Point Transmission Service MW that did not pass the SFT shall be entitled to Stage 2 ARR compensation pursuant to Section 43.2.4A. The rollover provisions described in Section 43.2.1.a will also apply to these Firm Point-To-Point Transmission Services.

The designation of a new RSP must meet the Resource Qualification Requirements pursuant to Section 43.2.1.a with two exceptions: i) the Capacity and Energy Contract can also be with another entity that has a Capacity and Energy contract directly with the Generation Resource, provided that both contracts have the same termination date; and ii) the Capacity and Energy ownership interest in, or the Capacity and Energy contract should remain in effect throughout the Seasons for which the replacement RSP is requested in the upcoming Annual ARR Allocation for the applicable ARR Zone. For purposes of determining Resource Qualification Requirements, the Reference Year shall be replaced by the Annual ARR Allocation period subsequent to the year of the request to add a new RSP.

The total MW subscription of the Generator associated with the new RSP or Firm Point-To-Point Transmission Service request, taking into consideration all existing ARR Entitlements and all other addition requests, as well as replacement requests pursuant to Section 43.6.1, cannot exceed the rated Capacity of the corresponding Generator.

An SFT will be conducted to add the new Baseload Supply Resource and Stage 1A eligible Firm Point-To-Point Transmission Service into Stage 1A up to the quantity determined to be feasible using the Restoration and Termination Stage of the most recent Annual ARR Allocation without the infeasible ARRs. Similarly, an SFT will be conducted to add a new non-Baseload Supply Resource and non-Stage 1A eligible Firm Point-To -Point Transmission Service into Stage 1B up to the quantity determined to be feasible using Stage 1B of the most recent Annual ARR Allocation without the infeasible ARRs. The SFTs will be conducted on a market-wide, non-ARR Zone basis.

Market Participants shall submit requests with the order in which those requests will need to be studied. The ensuing SFT results shall be binding, without any need for acceptance by the requesting Market Participants.

The SFT will be performed sequentially and the outcome of the additions will be fixed for the following addition requests. The study will be performed on a first-come, first request basis, for the Stage 1A requests first and then for the Stage 1B requests. The outcome of the SFT will set the ARR Entitlement MW for all future allocation periods. Each following allocation period, the Market Participant will then be able to request ARRs and/or LTTRs from the resulting ARR Entitlements.

The newly designated RSP can either be an existing or new Generation Resource. If the request for RSP designation involves a new Generation Resource, then after it passes the SFT, the designation shall be effective in the next allocation year, for the first full Season at the start of which the new Generation Resource is commercially operational. Otherwise, if the new Generation Resource is not commercially operational by that time, the newly designated RSP and/or associated ARRs will be removed.

A Market Participant may increase the feasibility of ARRs from a new Baseload Supply Resource or a new Firm Point-To-Point Transmission Service by utilizing the Feasibility Upgrade Process. In such case, the Market Participant will be eligible to receive FTRs and LTTRs pursuant to Section 46. If the ARR Receipt Point and ARR Delivery Point of such FTRs and LTTRs match exactly with an associated Firm Point-To-Point Transmission Service that was approved based on construction of the new transmission capacity, then the remainder of the Firm Point-To-Point Transmission Service MW that did not pass the SFT for LTTRs shall be entitled to Stage 1B ARR Entitlements subject to a further SFT and, subsequently, the remainder that did not pass the SFT for Stage 1B ARR Entitlements shall be entitled to Stage 2 ARRs.

A Baseload Supply Resource or Stage 1A eligible Firm Point-To-Point Transmission Service that would otherwise have qualified for inclusion as an addition in Stage 1A but fails the SFT for such inclusion may, at the requesting Market Participant's option, be automatically included in Stage 1B without having to undergo or pass any further SFT, but only for the upcoming Annual ARR Allocation.

A Market Participant may request that an existing RSP that is in the PRSS but not in the BRSS be included in the BRSS if the RSP meets all the qualifications for inclusion in the BRSS and passes the SFT for such inclusion. In assessing such a request, the Transmission Provider shall reevaluate the baseload status of an RSP that it has previously determined to have that status. A Market Participant may not request that an RSP be removed from an ARR Zone and then later request that such RSP be re-included in the same ARR Zone, within the same year.

For Point-To-Point Transmission Service Agreements, any allocated ARRs terminate when such service agreement expires. Point-To-Point Transmission Service with annual service or longer that terminates during the allocation period is included in the annual allocation.

Retirement of Generation Resources and Expiration of Long-Term Power Purchase Agreement:

Market Participants can request the termination of an RSP that has associated year 1 Counterflow ARRs, and corresponds to a retiring (or retired) Generation Resource or an expiring (or expired) long-term power purchase agreement by submitting a termination request to the Transmission Provider at least 5 years before the expected retirement or expiration, provided that a shorter notice period shall be allowed under the circumstances set forth in sections 43.6.4.1 and 43.6.4.2 hereof. The Transmission Provider will review and verify the contract termination or resource retirement and, upon confirmation, will completely terminate the RSP, including any associated ARR Entitlements and LTTRs, from the corresponding ARR Zone, either immediately if the retirement or expiration has already occurred, or in the next full Season following the actual occurrence of such retirement or expiration.

The Market Participant requesting the termination of the RSP shall be the same Market Participant whose ownership or contractual relationship with the Generation Resource was the basis for the original inclusion of the RSP in the PRSS. If the retirement of the Generation Resource or the expiry of the long-term power purchase agreement occurs during an Annual ARR Allocation period, the corresponding FTRs acquired through self-scheduling shall remain in effect through the end of the current Annual ARR Allocation period.

A Market Participant may request the termination of an RSP that has associated year 1 Counterflow ARRs and that is tied to a Generation Resource that is retiring or has retired, or a long-term power purchase agreement that is expiring or has expired, prior to or during the 2010 Annual ARR Allocation period, and such termination shall be effective in the next full Season following such retirement or expiration.

A Market Participant may request the termination of an RSP that has associated year 1 Counterflow ARRs, allocated during the 2008-09 Annual ARR Allocation, and that is tied to a Generation Resource that is retiring or has retired, or a long-term power purchase agreement that is expiring or has expired, during any of the Annual ARR Allocation periods from 2011 through 2015, and such termination shall be effective in the next full Season following such retirement or expiration.

43.6.4.3 Termination of RSP Associated with Counterflow ARRs Allocated in 2009 and Future Annual ARR Allocated Periods.

A Market Participant may request the termination of an RSP that has associated year 1 Counterflow ARRs allocated during 2009 or future Annual ARR Allocation periods, or a HUFU RSP and its associated HUFU ARRs, and that is tied to a Generation Resource that is retiring or has retired, or a long-term power purchase agreement that is expiring or has expired. The Market Participant must submit a 5 year termination notice to the Transmission Provider. The termination of the RSP, including any associated ARR Entitlements and LTTRs, shall be effective in the next full Season following such generator retirement or PPA expiration. The 5 year notice may be waived and the RSP, or the HUFU RSP (including any associated HUFU ARRs) terminated immediately if the Generation Resource was rendered inoperable immediately and permanently due to a catastrophic failure of the Generation Resource.

A Market Participant may request the termination of an RSP, including a HUFU RSP and associated HUFU ARRs, tied to a Generation Resource that is retiring or retired, or a long-term power purchase agreement that is expiring or expired, and has no associated LTTRs in the current Annual ARR Allocation period, and such termination shall be effective in the next full Season following such retirement or expiration.

In the absence of timely termination notices from a Market Participant, the RSP or HUFU RSP (including any associated HUFU ARRs) associated with the retiring or retired Generation

Resource or expiring or expired long-term power purchase agreement will be retained in the subsequent Annual ARR Allocation periods.

The Transmission Provider shall provide in the appropriate Business Practices Manuals, the timeline and details of the procedure for requesting the termination of RSPs, including HUFU RSPs, HUFU ARRs, ARR Entitlements and LTTRs, associated with a retiring or retired Generation Resource or an expiring or expired long-term power purchase agreement.

ARRs may be awarded for the remainder of the current Annual ARR Allocation Period for the Point-To-Point transmission rights pursuant to the rollover requirements described in Section 43.2.1.a of this Tariff. The ARRs will be terminated if the renewal request is not confirmed by the Transmission Customer. The same renewal request will not be granted FTRs separately through the OASIS request for FTRs. Market Participants may convert the ARRs into FTRs by self-scheduling into Annual FTR Auction.

Market Participants shall be provided the opportunity to nominate additional CARRs in Stage 1A and Stage 1B to reflect incremental Load growth. Load growth shall be reflected in the Peak Usage. All available information will be used to determine the Peak Usage if less than three years of data is available.

The Transmission Provider shall consider the impact of ARRs and FTRs on external flowgates located outside the Transmission Provider Region. The Transmission Provider shall address such impacts consistent with any executed seams agreements with such parties.

ARR Entitlements will be reassigned at the registration process for an Annual ARR Allocation period, and ARR revenue will be re-assigned during an Annual ARR Allocation period, to reflect Load switching under state retail choice programs, such other state auction programs or other transactions under which Load switches between suppliers. On an annual basis, each Market Participant's nomination eligibility will be based on its Peak Usage within an ARR Zone for the upcoming Annual ARR Allocation period and will reflect Load switching between Annual ARR Allocation periods.

During an Annual ARR Allocation period, ARR revenue re-distributed pursuant to Load shifts will entitle the Market Participants gaining the Load to the revenue based on clearing prices from the annual FTR Auctions, based on the source, sink and MW value of the ARRs of the Market Participant losing the Load. Before making such a reallocation, the Transmission Provider shall verify the reported Load to have shifted between the Market Participants. The Market Participant losing the Load and the Market Participant gaining the Load must agree on and provide the Transmission Provider with due notice and adequate evidence, in the required format and in a timely manner, of the results of the state retail choice programs, other state auction programs or other transactions that caused Load shifting, as a condition for the Transmission Provider's reallocation of ARR revenue based on such Load shift. On a monthly basis, the Transmission Provider will then reassign ARR revenue based on Load reported to have shifted between Market Participants for the prior month, which reassignment will be either a net credit or a net charge.

Where there are multiple Market Participants serving or served Load under Network Integration Transmission Service in an ARR Zone, they should designate a single entity to report all Load shifts on their behalf in the required format and in a timely manner. The Transmission Provider shall be entitled to rely on the accuracy and completeness of a designated entity's report. If a report is submitted by an entity that has been designated by some but not all Market Participants seeking the revenue reassignment, the Load shift data for the covered month shall be deemed incomplete and shall not be used as a basis for reassigning ARR revenues. In the absence of an accurate report on Load shifts for the prior month, the Transmission Provider shall use data from the last accurate report on Load shifts, if any, *i.e.*, no Load will be deemed to have shifted in the ARR Zone since the last accurate report.

Market Participants within an ARR Zone that lose Load will receive an obligation to fund ARRs equal to a *pro rata* share of all their ARRs for Network Integration Transmission Service in the Annual ARR Allocation. Market Participants that acquire Load will receive a *pro rata* share of Load gained during the month multiplied by the total ARR funding obligations allocated to Market Participants that lost Load during the month.

The Transmission Provider shall not guarantee that new Transmission Customers are entitled to the same level of FTRs as existing Transmission Customers. Where a Market Participant has provided FTR data to the Transmission Provider by July 14, 2004, and has submitted an unconditional application to become a Market Participant prior to July 14, 2004, the Transmission Provider shall include such entities in the initial FTR allocations. The Transmission Provider shall make best efforts to have all Market Participants receive all eligible FTRs that might be available.

Effect of a Transmission Owner or Market Participants Withdrawal on LTTRs:

The Transmission Provider shall calculate the impact of the withdrawal of a Market Participant or the Transmission Owner on the feasibility of the existing LTTRs of the LTTR holders that will remain after the withdrawal, consistent with the procedures set forth in the Business Practices Manual for FTRs and ARRs. The impact study calculation shall be concluded within three months before the scheduled withdrawal date. The calculation shall use a reference case reflecting the feasibility of all existing LTTRs prior to the withdrawal; and a study case indicating whether and to what extent such feasibility would be affected by the withdrawal. The reference case shall consist of the Stage 1A and restoration steps of the last complete Annual ARR Allocation (if the withdrawal date falls at the end of the current ARR allocation period), or the last four consecutive seasonal allocations (if the withdrawal date falls before the end of the current ARR allocation period), in which the withdrawing Market Participants, including those in the ARR Zone of a withdrawing Transmission Owner, participated fully preceding the withdrawal.

In the case of a withdrawing Transmission Owner, the calculation shall include modeling revisions that:

(1) Remove: (a) LTTRs that source and sink in the withdrawing Transmission Owner's ARR Zone(s); (b) LTTRs that source in the withdrawing Transmission Owner's ARR Zone(s), sink outside the Transmission Provider Region and are not eligible for point-to-point conversion; and (c) LTTRs of all Market Participants that only hold LTTRs as customers of the withdrawing Transmission Owner, and that will not remain Market Participants under any other arrangements after such withdrawal;

(2) Convert to point-to-point LTTRs any LTTRs that source in the Transmission Provider Region or adjacent Balancing Authority Area and sink in the withdrawing Transmission Owner's ARR Zone, and update the sinks of such LTTRs to appropriate interfaces;

(3) Update to appropriate interfaces the sources of LTTRs that sink in the Transmission Provider Region and are sourced in the withdrawing Transmission Owner's ARR Zone(s); and

(4) Update loopflows to reflect the removal of the withdrawing Transmission Owner, which involves but is not limited to, updating the Reciprocal Coordinated Flowgates (RCFs) and Firm Flow Entitlements (FFEs) to reflect the impacts related to the Transmission Owner's withdrawal.

As applicable, the steps described above shall be used in the case of any Market Participant(s) withdrawing for reasons other than the withdrawal of its host Transmission Owner.

The calculation shall determine to what extent the withdrawal shall:

(1) Render existing LTTRs infeasible; and

(2) Render existing infeasible LTTRs feasible.

Where two or more Transmission Owners are scheduled to withdraw on the same date, or on withdrawal dates that otherwise warrant the use of the same reference case, the impact of each withdrawal shall be calculated independently of the other withdrawal(s). The cumulative impact of the withdrawals shall be determined through the discount factor described in section 43.7.4.5.

Where the withdrawal of a Transmission Owner, causing the withdrawal of Market Participants in its ARR Zone(s), or the withdrawal of a Market Participant for reasons other than the withdrawal of its host Transmission Owner, is calculated to have an overall negative net impact on (*i.e.*, increases) the infeasibility uplift of existing LTTRs of the LTTR holders that will remain after the withdrawal, the withdrawing Transmission Owner, or the Market Participant(s) withdrawing for reasons other than the withdrawal of its host Transmission Owner, will be assessed the costs as described in section 43.7.4.5.

The seasonal (peak/ off-peak) incremental infeasibility and feasibility of LTTRs due to the impacts of the withdrawal will be priced based on the corresponding seasonal (peak/ off-peak) average of the last three annual auction clearing prices for the relevant paths. When a particular path is not available for all of the last three ARR annual allocation periods, the prices will be determined based on the most recent historical prices available, or those on the electrically equivalent paths.

Where the withdrawal of a Transmission Owner, causing the withdrawal of Market Participants in its ARR Zone(s), is calculated to have an overall positive net impact on (*i.e.*, decreases) the infeasibility uplift of existing LTTRs of the LTTR holders that will remain after the withdrawal, the value of such positive net impact shall not be credited to the withdrawing Transmission Owner and the Market Participants in its ARR Zone(s).

Where the withdrawal of a Market Participant(s) for reasons other than the withdrawal of its host Transmission Owner, is calculated to have an overall positive net impact on the infeasibility uplift of existing LTTRs of the LTTR holders that will remain after the withdrawal, the value of such positive net impact shall not be credited to the Market Participants in that ARR Zone(s).

The total value of the annual net impact of the withdrawal of a Market Participant(s) or Transmission Owner(s) on the infeasibility uplift of the LTTRs of LTTR holders that will remain after the withdrawal shall constitute an annual gross charge to be imposed on the withdrawing Market Participant, if withdrawing for reasons other than the withdrawal of its host Transmission Owner; or on a withdrawing Transmission Owner, as part of its exit fee, up to ten years after the withdrawal. This annual gross charge will be adjusted for the following, as applicable, prior to applying the discount factor, to derive the net annual charge:

1) Credit for the withdrawing entity's[1] LTTRs that are scheduled to be terminated during the 10-year period based on previous and properly renewed LTTR termination requests.
2) Credit or charge accounting for the withdrawing entity's removal of infeasible LTTRs.
3) Credit or charge for the cessation of the withdrawing entity's contribution to the uplift of the cost of infeasible LTTRs after its withdrawal.

The net annual charge shall be reduced by a discount factor in each year where the overall LTTR infeasibility of the Transmission System is less than the infeasibility determined in the study case. There shall be no discount factor in years when the overall LTTR infeasibility of the Transmission System increases relative to the level of infeasibility determined in the study case. After each of and up to ten Annual ARR Allocations following the Market Participant(s)' or Transmission Owner's withdrawal, the Transmission Provider shall calculate the discount factor by dividing the percentage of infeasible LTTRs relative to all LTTRs in the particular

[1] The phrase "withdrawing entity" refers to Market Participants within the withdrawing Transmission Owner's LBA Area or Market Participants withdrawing for reasons other than the withdrawal of any Transmission Owner.

Annual ARR Allocation by the percentage of the infeasible LTTRs relative to all LTTRs in the study case.

The cost of calculating such LTTR impacts shall also be charged to the withdrawing Market Participant(s) or Transmission Owner (in the latter case, as part of its exit fee).

Upon receipt of the withdrawing or withdrawn Market Participants' or Transmission Owner's annual payment described in section 43.7.4.5, the Transmission Provider shall correspondingly reduce the uplift of the cost of infeasible LTTRs to all LTTR holders remaining after each such payment.

Upon providing a notice of withdrawal, the withdrawing Market Participant or withdrawing Transmission Owner may request a preliminary estimate of the LTTR impacts of its withdrawal. The estimate shall not be binding and will not serve as a substitute for the required impact study set forth in section 43.7.4 of this Tariff. All costs of such a preliminary estimate shall be charged to the withdrawing Market Participant or withdrawing Transmission Owner.

The Transmission Provider shall conduct FTR Auctions on an annual basis: (i) to allow the Market Participant to convert their feasible ARRs allocated in the most recent Annual ARR Allocation into FTRs by self-scheduling them; and (ii) to allow Market Participants to buy other FTRs through a competitive bidding process. The Transmission Provider shall conduct FTR Auctions in a manner consistent with this Tariff and the standards and procedures set forth in the Business Practices Manuals. The annual auction shall consist of eight (8) independent auctions for the peak and off-peak periods for four (4) seasons.

Transmission Provider shall offer for sale at the annual FTR Auctions the entire expected transfer capability of the Transmission Provider Region in three (3) rounds for each of the four (4) seasons in any upcoming annual auction. The transfer capability will be reduced by a proportion appropriate for each of the ARRs that were self-scheduled by the existing ARR Holders. The transfer capability is further reduced to account for the loopflow assumptions.

a. All FTRs acquired through the annual FTR Auctions shall have a term of one (1) Season as defined in Section 43.3.

b. The self-scheduling of FTRs and all bids to purchase FTRs must be submitted to the Transmission Provider during the annual bidding period, pursuant to the requirements contained in the Business Practices Manual.

c. The Transmission Provider shall post the results of the annual FTR Auction on the internet webpage. The posted results shall consist of: (i) FTR Receipt Point; (ii) FTR Delivery Point; (iii) FTR quantity; (iv) whether the right is an Obligation or an Option; (v) FTR Period (peak/off-peak); (vi) FTR term; (vii) whether the right is a Buy or Sell; (viii) name of the FTR Bidder/FTR Offeror; (ix) the round of the FTR Auction where each FTR was awarded; and (x) FTR Market Clearing Price for each FTR awarded in the annual FTR Auction.

The Transmission Provider shall develop and use auction rules and procedures as specified in this Section 44.2 and implement them through procedures consistent with the Business Practices Manuals.

The Transmission Provider shall ensure that each party submitting an FTR Bid is a Market Participant qualified to submit such a bid consistent with the creditworthiness provisions maintained by the Transmission Provider. As a result of this evaluation of creditworthiness, the Transmission Provider shall establish a limit before the auction on the value of the FTRs that the Market Participant may be awarded in the auction. Market Participants will not be permitted to submit FTR Bids that exceed this permissible amount.

To aid Market Participants' participation in the auction, the Transmission Provider will make available data to be used in the optimization model pursuant to the Business Practices Manual.

The Transmission Provider will establish an auditable information system to facilitate analysis and acceptance or rejection of FTR Bids, to provide a record of all FTR Bids and self-scheduled FTRs, and to provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, awarding and recording of FTR Bids and self-scheduled FTRs. The Transmission Provider will establish a system to communicate auction-related information to all auction participants. The Transmission Provider will receive FTR Bids and self-scheduled FTRs from any entity that meets the eligibility criteria established in this Tariff and will implement the auction bidding rules previously established by the Transmission Provider. The Transmission Provider will determine the set of Winning FTR Bids for each auction (as per Section 44.5.1) and calculate the FTR Market Clearing Price of all FTRs at the conclusion of the auction.

The aggregate value of the FTR Bids submitted by any Market Participant submitting FTR Bids (FTR Bidder) into the FTR Auction shall not exceed the portion of that Market Participant's Total Credit Limit allocated to the FTR Auction, as provided in the Credit Policy. Each FTR Bidder must pay the FTR Market Clearing Price for each FTR it is awarded in the auction, as calculated pursuant to Section 44.5.2.

a. Each FTR Bidder shall include the following information in its FTR Bid:

   i. The FTR bid will be an obligation type;

   ii. FTR Receipt Point, FTR Delivery Point, as applicable, provided, that, the FTR cannot be defined as having an FTR Receipt Point and an FTR Delivery Point within the same Bus;

   iii. The maximum MW desired;

   iv. The maximum acceptable price, in $/MW;

   v. Whether for On-Peak or Off-Peak; and

   vi. Season.

b. An FTR Bid for a specified MW quantity of FTRs shall constitute an FTR Bid to purchase a quantity of FTRs equal to or less than the specified quantity. An FTR Bid may not specify a minimum quantity of MW that the FTR Bidder wishes to purchase.

c. All FTR Bids and the actions of FTR Bidders shall be subject to the provisions of Module D.

d. An FTR Bid that defines the FTR source and sink within the same Bus in the FTR Auction model will be rejected.

a. Each FTR Holder desiring to sell an FTR following the annual FTR Auction shall include the following information in its FTR Offer:

   i. The FTR Offer will be an obligation type;

   ii. FTR Receipt Point or FTR Delivery Point, as applicable;

   iii. The MW quantity of the FTR offered, which cannot exceed the quantity of the FTR MW from which it is being offered;

   iv. The minimum acceptable price, if any (reserve price), in $/MW; and

   v. Whether for On-Peak or Off-Peak.

b. Each FTR Holder that Offers FTRs for sale must provide verification of its ownership of the FTRs offered. An FTR Offer for a specified MW quantity of FTRs shall constitute an Offer to sell a quantity of FTRs equal to or less than the specified quantity. An FTR Offer may not specify a minimum quantity offered but may specify a reserve price, below which the FTR Holder does not wish to sell the FTR.

c. All FTR Offers and the actions of FTR Holders submitting such offers shall be subject to the provisions of Module D.

a. Each ARR Holder desiring to self-schedule an FTR in an annual FTR Auction shall include and adhere to the following information, as applicable:

i. The self-scheduled FTR will be an FTR Obligation type;

ii. FTR Receipt Point and FTR Delivery Point will correspond to the originating ARR's Receipt Point and Delivery Point, respectively;

iii. The MW quantity cannot exceed the originating ARR MW;

iv. The self-scheduled FTR will be a price-taker, (*i.e.*, it will be price insensitive);

v. The On-Peak or Off-Peak type for the self-scheduled FTR will be determined from the originating ARR;

vi. The start and stop dates for the self-scheduled FTR will also be inherited from the originating ARR; and

vii. The self-scheduling of FTRs corresponding to allocated infeasible ARRs is not permitted.

b. Each ARR Holder that self-schedules FTRs must provide verification of its ownership of the originating ARR.

c. All self-scheduled FTRs and the actions of ARR Holders submitting such self-scheduled FTRs shall be subject to the provisions of Module D.

Independent auctions shall be held for the On-Peak period and Off-Peak Period in each of the four (4) seasons of the Year. The Transmission Provider shall use for each FTR Auction a linear programming model that considers all FTR Bids and self-scheduled FTRs submitted and selects a combination of the Winning FTR Bids that: (i) respects the transfer capability of the Transmission Provider Region over the period in the subject Season; and (ii) maximizes the combined net economic value (as expressed in the FTR Bids) of the Winning FTR Bids, recognizing any reserve price specified in FTR Offers. In order to maximize the net economic value of the Winning FTR Bids, the linear programming model shall automatically reconfigure the FTRs offered for sale in FTR Auctions by FTR Holders, consistent with the provisions herein. In the event that there are two (2) or more Winning FTR Bids that are identical in all material respects except for the quantity of MW sought, then each such Winning FTR Bid shall reflect its *prorata* share of the quantity of MW sought that can be awarded. Starting with planning year 2013/2014, any cleared FTR with its source and sink defined as within the same Bus will be rejected and resettled within the Annual ARR Allocation period where it cleared.

All Comparable FTRs sold in an FTR Auction shall be sold at the same FTR Market Clearing Price, expressed in $/MW. For a FTR Obligation, the FTR Market Clearing Price is the negative of the rate of change in the objective function value of the FTR Auction linear programming problem for an infinitesimal increment or decrement of flow from the FTR Receipt Point to the FTR Delivery Point. This can also be calculated from the difference in shadow price of the power flow balance at the FTR Receipt Point and at the FTR Delivery Point. For all FTR Options, the FTR Market Clearing Price is calculated from the shadow prices of the transmission constraints in the FTR Auction linear programming problem. The shadow price of a transmission constraint is the rate of change in the objective function value for an infinitesimal increment or decrement in the capacity of the constraint. The FTR Market Clearing Price for the FTR Option is the sum of the product of the PTDF (or OTDF) of the FTR Option on the constraint multiplied by the shadow price of the constraint limit in the direction of the corresponding PTDF (or OTDF) over all transmission constraints.

Each Market Participant that received a Winning FTR Bid shall pay or collect the FTR Market Clearing Price from the Transmission Provider for all FTRs awarded to it in accordance with the provisions of the Business Practices Manuals. The Transmission Provider shall pay or collect the FTR Auction Market Clearing Prices for each ARR that was allocated to the ARR Holder in the Annual ARR Allocation. Market Participants will pay for or collect the FTR Auction Clearing Price for their self-scheduled FTRs. All remaining revenues from the annual FTR Auction collected by the Transmission Provider shall be allocated among the ARR Holders pursuant to the provisions of Section 43.2.4.

The Transmission Provider shall release the Bid and Offer data ninety (90) days after the annual FTR Auction, except as required pursuant to the provisions of Section 38.9. The posted data shall consist of: (i) FTR Receipt Point; (ii) FTR Delivery Point; (iii) whether the right is an Obligation or an Option; (iv) FTR Period (peak/off-peak); (v) FTR term; (vi) whether the right is a Buy or Sell; (vii) anonymous identification code of FTR Bidder/FTR Offeror; (viii) FTR Bid curve/FTR Offer curve; and (ix) the round of the FTR Auction where each Bid or Offer was submitted. All Bid and Offer data will be provided rather than only cleared Bids and Offers. When these FTR Bids and Offers are posted, the names of the FTR Bidders and FTR Offerors shall not be publicly revealed, but they shall be posted in such a way as to allow the tracking of each individual entity's Bids and Offers over time.

The Transmission Provider shall conduct FTR Auctions on a monthly basis in a manner consistent with this Tariff and the standards and procedures set forth in the Business Practices Manuals.

The Transmission Provider shall make available for purchase in the monthly FTR Auctions the entire expected Adjusted FTR Capability for the relevant terms offered in the FTR Auctions.

a. The monthly FTR Auctions will offer the following FTR terms:

1) In May, the Transmission Provider will offer June;

2) In June, the Transmission Provider will offer July, August, Fall, Winter and Spring;

3) In July, the Transmission Provider will offer August, September, October, and November;

4) In August, the Transmission Provider will offer September, October, and November;

5) In September, the Transmission Provider will offer October, November, Winter and Spring;

6) In October, the Transmission Provider will offer November, December, January and February;

7) In November, the Transmission Provider will offer December, January and February;

8) In December, the Transmission Provider will offer, January, February; and Spring;

9) In January, the Transmission Provider will offer February, March, April; and May;

10) In February, the Transmission Provider will offer March, April, and May;

11) In March, the Transmission Provider will offer, April, and May;

12) In April, the Transmission Provider will offer May.

b. FTRs offered by the Transmission Provider through monthly FTR Auctions shall have a term of one (1) Month, beginning on the first Day of the Month, or one (1) Season, beginning the first Day of the Season.

c. All FTR Bids and Offers must be submitted to the Transmission Provider during the Monthly Bidding Period, pursuant to the requirements contained in the Business Practices Manuals.

d. The Transmission Provider shall post the results of the monthly FTR Auction on the internet webpage. The posted results shall consist of: (i) FTR Receipt Point; (ii) FTR Delivery Point; (iii) FTR quantity; (iv) whether the right is an Obligation or an Option; (v) FTR Period (peak/off-peak); (vi) FTR term; (vii) whether the right is a Buy or Sell; (viii) name of the FTR Bidder/FTR Offeror; (ix) the round of the FTR Auction where each FTR was awarded; and (x) FTR Market Clearing Price for each FTR awarded in the monthly FTR Auction.

The Transmission Provider shall develop and use auction rules and procedures as specified in this Section 45.2 and implement them through procedures consistent with the Business Practices Manuals.

The Transmission Provider shall ensure that each party submitting an FTR Bid is a Market Participant qualified to submit such a bid consistent with the creditworthiness provisions maintained by the Transmission Provider. As a result of this evaluation of creditworthiness, the Transmission Provider shall establish a limit before the auction on the value of the FTRs that the Market Participant may be awarded in the auction. Market Participants will not be permitted to submit FTR Bids that exceed this permissible amount.

To aid Market Participants’ participation in the auction, the Transmission Provider shall make available information on Marginal Congestion Components of Day-Ahead Ex Post LMPs and historical congestion before each FTR Auction. The Transmission Provider will also make available data to be used in the optimization model.

The Transmission Provider will establish an auditable information system to facilitate analysis and acceptance or rejection of FTR Bids, to provide a record of all FTR Bids, and to provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, awarding and recording of FTR Bids.

The Transmission Provider will establish a system to communicate auction-related information to all auction participants. The Transmission Provider will receive FTR Bids from any entity that meets the eligibility criteria established in this Tariff and will implement the auction bidding rules previously established by the Transmission Provider. The Transmission Provider will properly utilize an optimization process program to determine the set of Winning FTR Bids for each auction and calculate the FTR Market Clearing Price of all FTRs at the conclusion of the auction, in the manner described in this Tariff.

The aggregate value of the FTR Bids submitted by any Market Participant submitting FTR Bids (FTR Bidder) into the FTR Auction shall not exceed that Market Participant's ability to pay as determined by the Transmission Provider (based on an analysis of the FTR Bidder's creditworthiness). Each FTR Bidder must pay the FTR Market Clearing Price for each FTR it is awarded in the auction, as calculated pursuant to Section 45.5.2.

a. Each FTR Bidder shall include the following information in its FTR Bid:

i. The type of FTR (*i.e.* Receipt Point-To-Delivery Point FTR Obligation, Receipt Point-To-Delivery Point FTR Option);

ii. FTR Receipt Point, FTR Delivery Point, as applicable, provided, that, the FTR cannot be defined as having an FTR Receipt Point and an FTR Delivery Point within the same Bus;

iii. The maximum MW desired;

iv. The maximum acceptable price, in $/MW;

v. Whether for On-Peak or Off-Peak; and

vi. The Month or Season for which the FTR Bid is being submitted.

b. An FTR Bid for a specified MW quantity of FTRs shall constitute an FTR Bid to purchase a quantity of FTRs equal to or less than the specified quantity. An FTR Bid may not specify a minimum quantity of MW that the FTR Bidder wishes to purchase.

c. All FTR Bids and the actions of FTR Bidders shall be subject to the provisions of Module D.

d. An FTR Bid that defines the FTR source and sink within the same Bus in the FTR Auction model will be rejected.

a. Each FTR Holder desiring to sell an FTR in an FTR Auction shall include the following information in its FTR Offer:

i. The type of FTR (*i.e.* Receipt Point-To-Delivery Point FTR Obligation, or Receipt Point-To-Delivery Point FTR Option);

ii. FTR Receipt Point or FTR Delivery Point, as applicable;

iii. The MW quantity of the FTR offered, which cannot exceed the quantity of the FTR MW from which it is being offered;

iv. The minimum acceptable price, if any (reserve price), in $/MW;

v. Whether for On-Peak or Off-Peak; and

vi. The Month or Season for which the FTR Bid is being submitted.

b. Each FTR Holder that Offers FTRs for sale must provide verification of its ownership of the FTRs offered. An FTR Offer for a specified MW quantity of FTRs shall constitute an Offer to sell a quantity of FTRs equal to or less than the specified quantity. An FTR Offer may not specify a minimum quantity offered but may specify a reserve price, below which the FTR Holder does not wish to sell the FTR.

c. All FTR Offers and the actions of FTR Holders submitting such offers shall be subject to the provisions of Module D.

Independent auctions shall be held for the On-Peak and Off-Peak period in a given Month. The Transmission Provider shall use for each FTR Auction a linear programming model that considers all FTR Bids and FTR Offers (Winning FTR Bids and Winning FTR Offers, respectively) that: i) respects the transfer capability of the Transmission Provider Region over the Period in the subject Month or Season; and ii) maximizes the combined net economic value (as expressed in the FTR Bids) of the Winning FTR Bids. The linear programming model shall automatically reconfigure the FTRs offered for sale in FTR Auctions by FTR Holders, consistent with the provisions herein. In the event that there are two (2) or more Winning FTR Bids that are identical in all material respects except for the quantity of MW sought, then each such Winning FTR Bid shall reflect its *pro rata* share of the quantity of MW sought that can be awarded. Starting with the planning year 2013/2014, any cleared FTR with its source and sink defined as within the same Bus will be rejected and resettled within the Annual ARR Allocation period where it cleared.

All Comparable FTRs sold in an FTR Auction shall be sold at the same FTR Market Clearing Price, expressed in $/MW. For an FTR Obligation, the FTR Market Clearing Price is the negative of the rate of change in the objective function value of the FTR auction linear programming problem for an infinitesimal increment or decrement of flow from the FTR Receipt Point to the FTR Delivery Point. This can also be calculated from the difference in shadow price of the power flow balance at the FTR Receipt Point and at the FTR Delivery Point. For all FTR Options, the FTR Market Clearing Price is calculated from the shadow prices of the transmission constraints in the FTR auction linear programming problem.

The shadow price of a transmission constraint is the rate of change in the objective function value of the infinitesimal increment or decrement in the capacity of the constraint. The FTR Market Clearing Price for the FTR Option is the sum of the product of the Planned Transmission Distribution Factor (PTDF) of the FTR Option on the constraint multiplied by the shadow price at the constraint limit in the direction of the corresponding PTDF (or Outage Transmission Distribution Factor (OTDF)) over all transmission constraints.

Each Market Participant that submitted a Winning FTR Bid shall be charged the FTR Market Clearing Price for all FTRs awarded to it in accordance with the provisions of the Business Practices Manuals. The Transmission Provider shall credit to each FTR Holder the FTR Market Clearing Price for each FTR held by that FTR Holder that was sold in the FTR Auction. After all such credits are provided to sellers of existing FTRs, the net sum of the FTR Auction revenues shall be added to the Excess Congestion Charge Fund for the Month and shall be used in performing the true-up funding to FTR Holders for the Month as described in Section 39.3.4.c.i of this Tariff. Any amounts remaining in the Excess Congestion Charged Fund, including FTR Auction revenues for the Month, shall be carried forward to the end of the Year and distributed *pro rata* among Transmission Customers, as described in Section 39.3.4.c.ii of this Tariff.

The Transmission Provider shall release the Bid and Offer data ninety (90) days after the monthly FTR Auction, except as required pursuant to the provisions of Section 38.9. The posted data shall consist of: (i) FTR Receipt Point; (ii) FTR Delivery Point; (iii) whether the right is an Obligation or an Option; (iv) FTR Period (peak/off-peak); (v) FTR term; (vi) whether the right is a Buy or Sell; (vii) anonymous identification code of FTR Bidder/FTR Offeror; (viii) FTR Bid curve/FTR Offer curve; and (ix) the round of the FTR Auction where each Bid or Offer was submitted. All Bid and Offer data will be provided rather than only cleared Bids and Offers. When these FTR Bids and Offers are posted, the names of the FTR Bidders and Offerors shall not be publicly revealed, but they shall be posted in such a way as to allow the tracking of each individual entity's Bids and Offers over time.

To implement and facilitate the transition to ARRs and LTTRs, the Transmission Provider shall conduct in January 2008 the monthly FTR allocations, and the monthly FTR Auctions, for February, March, April and May 2008 ("Transitional Auction"). Market Participants shall be required to allocate enough credit to cover their total bids in such monthly FTR Auctions. Each such FTR Auction shall be settled on the first calendar day of the month to which they pertain. Pending settlement, the revenues from each FTR Auction shall be transferred to credit in the form of measured exposure. The transitional auction shall comply with and be subject to the provisions of Attachment L, Section III.B.5 of this Tariff, concerning the allocation of credits from FTR Auction activities, and Section 45.6 of this Tariff, concerning the allocation of surplus revenues from FTR Auction activities. The FTR Auction credit process in Attachment L, Section III.B.5 of this Tariff, provides for the reallocation of credit or refund of collateral in excess of gross bids or measured exposures from this transitional auction.

Section 45.6 of the EMT provides for the use of the FTR Auction revenues for FTR funding, and for the reallocation and/or refund of any revenue surplus.

From January through May 2008, the Transmission Provider may also manually administer the transfers of FTRs in the secondary market through service requests submitted to the Transmission Provider's portal at least two weeks in advance of the effective date of the secondary transfer. After the existing FTR system and software are terminated and taken offline, requests for

FTRs related to transmission requests shall be manually processed by the Transmission Provider.

These transitional activities are hereby authorized notwithstanding any other provisions of this Tariff to the contrary, including, section 1.104 ("FTR Auction"), section 1.203 ("Monthly Bidding Period"), and section 45 ("Monthly FTR Auctions"), which shall be deemed modified to the extent necessary to allow such transitional activities.

Market Participants that fund (pay for construction of) Network Upgrades and elect not to receive credits, if eligible, under Attachment FF of this Tariff shall be deemed eligible by the Transmission Provider to receive FTRs and LTTRs. Entities eligible to receive FTRs and LTTRs pursuant to the provisions of this Section shall be permitted to elect any set of ARR Receipt Points and Delivery Point, provided that the combination of such FTRs issued satisfy the two (2) conditions set forth in Section 46.1 of this Tariff. New Point-to-Point Transmission Services associated with construction of new transmission capacity and receiving FTRs and LTTRs pursuant to this Section will not be eligible to receive Stage 1B ARRs or Stage 2 compensation if the ARR Receipt Point and ARR Delivery Point of the LTTRs received do not match exactly with the Source and Sink of the Transmission Service. The in-service date of the network upgrades must coincide with the start date of the Point-To-Point Service for which the FTRs and LTTRs are requested pursuant to this Section.

A Market Participant funding a Network Upgrade can request the creation of new Commercial pricing node(s) (CPNodes) if the total cost of the Network Upgrade is in excess of one million dollars. The Market Participant can then use the newly created CPNodes that are requested, as the ARR Receipt Points and Delivery Points.

If a qualified Market Participant funds the Network Upgrades necessary to make feasible otherwise infeasible ARRs, the Transmission Provider will provide the qualified Market Participant with a detailed description of the upgrades necessary to achieve the desired ARR feasibility, to the extent that this description is not currently provided for under the Tariff or Transmission Provider procedures. The Market Participant may then utilize existing Tariff provisions in Attachment FF to be compensated for the upgrade or request FTRs and LTTRs in accordance with this Section.

Market Participants may request LTTRs for the incremental transmission capacity created by the Network Upgrade that they fund. Market Participants must follow the timeline set forth by the Transmission Provider to make such a request in order to obtain the LTTRs when the Network Upgrade becomes effective. The Transmission Provider will perform the SFT for the requested LTTR paths using the most recent Annual ARR Allocation models and by treating the previously allocated feasible LTTRs as fixed. The SFT will ensure that any previously allocated feasible LTTRs are not degraded. Any LTTRs associated with the Network Upgrade issued by the Transmission Provider will remain in effect from the time the network upgrade becomes effective to the end of the current allocation period and will be considered to be prior-year allocated LTTRs in the upcoming ARR Allocation. Any LTTRs issued by the Transmission Provider under this section will not be eligible for settlement for the remainder of the current annual allocation period.

Market Participants may request FTRs associated with the Network Upgrade for the balance of the current annual allocation period. The Transmission Provider will perform the SFT by inserting the Network Upgrade into the most recent FTR Auction models.

The SFT will ensure that the FTRs in the study models will be fixed. The FTRs resulting from the SFT will remain in effect from the time the Network Upgrade becomes effective to the end of the current annual allocation period.

The Transmission Provider will make Stage 1A ARR Entitlements available for the future Annual ARR Allocation periods. The ARR Entitlements' Receipt Point, Delivery Point and MW will match the LTTRs previously allocated. Market Participants shall follow and shall be applied the nomination procedures laid out in Section 43.2.4 to obtain ARRs, LTTRs and/or counterflow assignment.

Where multiple Market Participants fund a Network Upgrade, absent an agreement among such Market Participants to the contrary, the ARRs allocated pursuant to the provisions of Section 43 shall be allocated to such Market Participants in proportion to their financial contribution to the Network Upgrade (including construction, research, and development costs), as reported by the Market Participants to the Transmission Provider. Market Participants collectively funding a Network Upgrade are encouraged to agree in writing among themselves prior to any significant outlays, how such ARRs will be allocated following completion of the Network Upgrade

Market Participants that funded network upgrades in a different transmission provider region prior to integration with the Transmission Provider may be eligible for LTTRs beginning with the first full Annual ARR Allocation period following integration with the Transmission Provider. Market Participants may also be eligible for FTRs for the balance of the Annual ARR Allocation period if the integration occurred on a date other than June 1. In order to qualify under this Section, the costs of such upgrades shall have been deemed to be ineligible for wholesale transmission rate recovery and shall not have been included in transmission credits under the previous transmission provider's tariff, and shall be in-service prior to the end of the requesting Market Participant's year 1 of the Annual ARR Allocation. The Transmission Provider will coordinate with the prior transmission provider to identify the capacity created by the network upgrades, and net out any capacity (a) for which the party that funded the upgrade has been reimbursed through compensation mechanisms under the prior transmission provider's tariff, to the extent that the participant's right to additional compensation associated with the upgrades has been transferred or retired as a result of such reimbursement and (b) used to grant network, generator interconnection, or long-term point-to-point transmission service to the funding party or another transmission or interconnection customer, when such service is eligible for an allocation of ARRs. The Transmission Provider will convert the net incremental capacity to BRSS entitlements. The start date of the BRSS entitlements granted under this Section 46.3 will coincide with the first full Season following the in-service date of the network upgrade. These entitlements will not be considered as Counterflow ARR Entitlements. The Transmission Provider will create CPNodes on both sides of the network upgrade to represent the upgrade. The Market Participant can then use the newly created CPNodes as the ARR Receipt Points and

Delivery Points to establish BRSS entitlements. Incremental capacity that is not nominated or allocated in Stage 1A shall be eligible for nomination by the funding party in Stage 1B or for inclusion in Stage 2. Network Upgrades in-service after the end of the requesting Market Participant's year 1 of the Annual ARR Allocation shall be eligible for LTTRs in accordance with Section 46.1 of the Tariff.

Multi-Value Projects (MVP) are upgrades defined under Attachment FF of this Tariff. Entities that are subject to the MVP allocation charges will be eligible for a credit based on the value of the MVP ARRs associated with these projects.

The MVP ARR Entitlements are defined by: (i) an ARR Receipt Point; (ii) an ARR Delivery Point; (iii) an ARR Quantity; (iv) an ARR Period (on-peak/off peak); and (v) an ARR Term. Prior to the Annual ARR Registration, the Transmission Provider will perform an analysis to identify the incremental capacity created by the MVP upgrades planned to be in-service before the start of, or at any time during, the effective period of the upcoming Annual ARR Allocation. An MVP ARR analysis shall be performed for the first four consecutive full Seasons after an MVP comes into service. If such four full Seasons are partly within an upcoming Annual ARR Allocation period, and partly within the next Annual ARR Allocation period, the MVP ARR analysis shall initially be performed for such full Season(s) that are within the upcoming period, and thereafter shall be performed for such other full Season(s) that are within the next period. For each MVP upgrade covered by this section of the Tariff, the Transmission Provider will create new CPNodes that will be used as the ARR Receipt Point and ARR Delivery Point for the associated MVP ARR Entitlement. The Transmission Provider will perform the SFT to determine the incremental capacity created by the eligible upgrade using the most recent Stage 1B ARR allocation models and by treating the previously allocated feasible ARRs as fixed. The MVP ARR Entitlements will terminate at the end of the life of the associated MVP facility.

The nominated Candidate MVP ARRs, and allocated MVP ARRs, are defined by: (i) an ARR Receipt Point; (ii) an ARR Delivery Point; (iii) an ARR Quantity; (iv) an ARR Period (on-peak/off peak); and (v) an ARR Term. The Transmission Provider will fully nominate the MVP ARR Entitlements during Stage 1B of the Annual ARR Allocation. The allocation of MVP ARRs will be subject to the SFT in Stage 1B. MVP ARRs will not be self-scheduled in the Annual FTR Auction.

The allocated MVP ARRs will only be valued, based on clearing prices from the corresponding Annual FTR Auction, when the auction clearing price at the ARR Receipt Point is greater than the auction clearing price at the ARR Delivery Point. Therefore, MVP ARRs are in the nature of options, as their value will always be positive. At the end of each Month, the Transmission Provider will distribute that Month's share of the sum of the value of all MVP ARRs, *pro rata*, based on MVP allocation charges pursuant to Schedules 26-A and 39 of this Tariff.

The Transmission Provider, with the assistance of the IMM as appropriate, shall monitor for possible Market Implementation Errors and Emergency System Conditions in the Energy and Operating Reserve Markets. If Market Implementation Errors or Emergency System Conditions are identified, the Transmission Provider may impose corrective measures as specified below and take immediate action to remedy the Market Implementation Error or Emergency System Condition as soon as possible.

Market Implementation Errors and Emergency System Conditions do not include situations in which prices rise to levels based on demand and supply levels determined by efficient competition in periods of relative scarcity, or fall to levels based on demand and supply levels determined by efficient competition in times of relative surplus. The Transmission Provider shall, to the extent possible, avoid interfering with these competitive price signals.

When time permits, Market Implementation Errors and Emergency System Conditions shall be addressed in consultation and cooperation with Market Participants and jurisdictional agencies, as appropriate, through the process described in the ISO Agreement. The Transmission Provider is committed to ongoing consultation and cooperation with Market Participants and jurisdictional agencies.

a. The Transmission Provider may change LMPs or other prices cleared through the Energy and Operating Reserve Markets and the corresponding changes in Settlements or payments attributable to a Market Implementation Error or Emergency System Conditions only when: (i) one or more LMPs or any other prices or payments could not be developed; or (ii) LMPs or other prices cleared through the Energy and Operating Reserve Markets and the corresponding changes in Settlements deviate from what would have been produced absent an identified Market Implementation Error or Emergency System Conditions.

b. In any Hour for which the Transmission Provider reasonably believes that a Market Implementation Error or Emergency System Conditions will require changes to one or more LMPs or other prices clearing through the Energy and Operating Reserve Markets and the corresponding changes in Settlement prices, the Transmission Provider shall post on the OASIS and its website as soon as reasonably practicable, a notice that the Transmission Provider is considering a correction for the Hour. To the extent possible, the Transmission Provider will post a notice of a proposed correction, and if possible a description of the proposed action, before bids are to be submitted for such Hour. If the circumstances do not permit advance notice, the Transmission Provider shall endeavor to post such a notice on its OASIS and its website on or before one hour prior to the closing of Day-Ahead Energy and Operating Reserve Market bids for the next trading day, or prior to the closing of bids in the Real-Time Energy and Operating Reserve Market, but in no event later than 5:00 p.m. EST on the calendar day following the day in which the Hour occurs where changes in LMPs or other prices clearing through the Energy and Operating Reserve Markets and the corresponding changes in Settlement prices would be affected by the contemplated price correction.

c. Prior to making a price correction, if reasonably possible, but in no event later than five (5) calendar days after the date on which notice of a price correction is posted, the Transmission Provider must either post a description of its proposed price correction by posting the notice on the OASIS and its website or remove the notice of possible price correction from the OASIS and its website. Unless a price correction is posted within such period, the notice of possible price correction pertaining to the Hour shall be deemed to be withdrawn.

d. The Transmission Provider shall recalculate changes in LMPs or other prices cleared through the Energy and Operating Reserve Markets and the corresponding changes in Settlements in a manner that reflects, as closely as reasonably practicable, the LMPs or other prices that would have cleared through the Energy and Operating Reserve Markets but for the Market Implementation Error or Emergency System Conditions, and shall substitute the recalculated LMPs or other prices that would have cleared the Energy Markets absent the Market Implementation Error or Emergency System Conditions. Such changes in LMPs or other prices cleared through the Energy and Operating Reserve Markets shall serve as the basis for Settlement.

e. In any instance in which the Transmission Provider makes price corrections, it shall, as soon as possible thereafter, address the Market Implementation Errors, or Emergency System Conditions that resulted in incorrect prices. The Transmission Provider shall undertake this work in consultation and cooperation with Market Participants and jurisdictional agencies, as appropriate and as time permits, through the process described in the ISO Agreement.

For any infeasible ARRs established during the first five Annual ARR Allocations following the integration of the Second Planning Area, the Transmission Provider shall determine and settle LTTR infeasibility, as set forth in Section 43.2.4.a.v, separately for Market Participants in the First Planning Area and the Second Planning Area. If the applicable LTTR sources in one Planning Area and sinks in the same Planning Area, then the entire cost of settling the infeasibility shall be allocated to that Planning Area. If the applicable LTTR sources in one Planning Area and sinks in a different Planning Area, then the cost of settling infeasibility shall be allocated equally to the two Planning Areas.