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December 22, 2011

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First St., N.E.
Washington, D.C. 20426

Re: Midwest Independent Transmission System Operator, Inc.
Extended Locational Marginal Pricing Filing,
Docket No. ER12-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, Part 35 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35, *et. seq*., the Midwest Independent Transmission System Operator, Inc. ("MISO") respectfully submits an original and five (5) copies of proposed amendments to MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff") to improve the accuracy of Energy and Ancillary Services pricing provisions through a new methodology, Extended Locational Marginal Pricing ("ELMP")[1]. The proposed Tariff enhancements will, among other things, enable block loaded Generation Resources, Generation Resources[2] dispatched at limits, and Emergency Demand Response ("EDR") resources (all of which types of resources are currently unable to participate in setting Locational Marginal Prices ("LMP")) to be eligible to set Day-Ahead and/or Real-Time prices for Energy and Ancillary Services.

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1 ELMP was originally described during early stakeholder meetings as "convex hull pricing" due to its mathematical characteristics. *See, e.g.*, "Market-Clearing Electricity Prices and Energy Uplift" by Paul R. Gribik, William W. Hogan, and Susan L. Pope, pp 16-21 (2007). http://www.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf. MISO renamed this Energy pricing algorithm "Extended LMP" or "ELMP" in 2010 to emphasize its close relationship to existing LMP pricing.

2 Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the Tariff or the proposed Tariff provisions.

I. Background

MISO's approved LMP methodology for establishing locational prices currently does not permit Offers from block loaded units,[3] Offers from Generation Resources dispatched at their limits, and/or Offers from EDR resources, to set Energy or Ancillary Service prices. This limitation results from the fact that these types of resources are not able to move incrementally up or down in response to small changes in dispatch conditions. Although LMP is a relatively accurate pricing methodology, it may not always reflect the cost of the most expensive action that MISO must take to meet MISO's system requirements at a location.

For example, the most expensive Generation Resource that must be dispatched at times to meet system demand changes may be a combustion turbine ("CT") Generation Resource which may be block loaded (or may be dispatched at EconMin). Although MISO may require Energy from such a CT to meet its system demand, the Energy produced by the CT operating at its minimum limit may be more than the Energy desired, given other lower cost Resources that are on-line but not fully dispatched.[4] The dispatch algorithm requires that MISO "back down" a less expensive Resource in such a situation to make room for the CT. The resulting LMP would thus reflect the cost of the less expensive Resource that is backed down, rather than the cost of the more expensive CT that MISO actually committed and dispatched to meet system demand. In this simple example, LMP would not accurately reflect the cost of the last action needed to meet system demand.

In other instances, LMP and Ancillary Service Marginal Clearing Prices ("MCP") may reflect shortage prices, even though MISO is not actually short of capacity and could commit a CT to address the perceived shortage. In some instances, the perceived shortage is only transitory (*e.g.*, lasting only 5 or 10 minutes); thus, the shortage does not affect MISO's operations or reliability. In such situations, the high prices resulting from traditional LMP algorithms may disappear even before Market Participants can take actions in response to the prices. The resulting Energy prices also would not accurately reflect the cost of the actions that MISO would take to alleviate the shortage problem if such a condition were to persist. Such transient shortages may result, for example, when MISO runs out of ramping capacity from committed Resources. Such prices can be viewed as artificial because MISO often has available

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[3] An example of a "block loaded unit" is a Generation Resource that submits a fixed block Offer of Energy (*i.e.*, the Economic Minimum amount ("EconMin") in the offer is equal to the Economic Maximum amount ("EconMax") in the offer), so the Generation Unit does not submit a range in which the Resource can be dispatched. The Resource must be dispatched at a single level if it is committed. EconMin refers to the Economic Minimum Offer amount that a Generation Resource offers into the Market because the Resource does not want to be dispatched at a lower amount of MWs. EconMax refers to the maximum quantity of MWs that a Generation Resource wants to offer into the Market.

[4] Testimony of Dr. Paul R. Gribik ("Gribik Testimony") at 4-6.

Fast Start Resources[5] which MISO could commit at a cost that is less than the shortage cost used to set the Energy LMP or Ancillary Service MCPs. In such a situation, there is actually no shortage of capacity that could be committed to supply Energy or Ancillary Services at the location. The transient price spikes resulting from LMP calculations may sometimes confuse Market Participants and result in pricing unpredictability to Market Participants.

II. Overview of Proposed Tariff Changes to Implement ELMP

To address these and other pricing anomalies, MISO has been developing the proposed ELMP methodology to improve pricing signals, in part, by having Energy and Ancillary Service prices more accurately reflect the costs of actions that MISO would take to meet Energy and Ancillary Service requirements, or to reflect actions that MISO could take to alleviate transient shortages that MISO may encounter when the MISO system is not actually short of Resources. Adoption of the proposed ELMP pricing would tend to establish Energy and Ancillary Service prices that more accurately reflect the cost of the most expensive action that MISO would need to take to meet system requirements. Proposed ELMP pricing would tend to "smooth out" Energy and Ancillary Service prices by considering the actions that MISO could take to address transient problems by committing Resources that can respond quickly, even if such Resources are not yet on-line at the moment. In contrast to the existing LMP methodology, the ELMP proposal is designed to more accurately reflect the full cost of an action taken to meet requirements by taking into account the commitment of Fast Start Resources, as well as adjusting the incremental output of an on-line resource.[6] Under the proposal, EDR resources also would become eligible to set Energy prices, consistent with a Commission order.[7]

For the purposes of implementing ELMP, MISO is proposing to define a "Fast Start Resource" in proposed Section 1.220A of the Tariff, in part, as "a resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less". Some MISO stakeholders have suggested that the definition of "Fast Start Resource" should be expanded to include resources that are able to respond within 30 minutes of being notified.

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5 ELMP considers a "Fast Start Resource" to include all Resources that can respond to a Dispatch Instruction within 10 minutes or less and has a minimum run time of one hour or less. (Currently, Section 1.529 of the Tariff currently defines a "Quick Start Resource" to be "a Generation Resource or Demand Response Resource-Type II that can be started, synchronized and inject Energy within the Contingency Reserve Deployment Period.". The term "Fast Start Resources" is being used for ELMP, in part, to differentiate it from Quick Start Resources used for Contingency Reserve Deployment.)

6 Gribik Testimony at 7-9.

7 *Midwest Independent Transmission System Operator, Inc.*, 122 FERC ¶ 61,070, P 27, 57 (2008).

MISO will implement ELMP with a 10-minute definition of Fast Start Resources. In current Real-Time dispatch, MISO is looking 10 minutes ahead. The decision to commit a Resource with a 10-minute notification time is usually made contemporaneously with the time frame in which MISO makes dispatch decisions for all committed Resources. As such, the commitment costs for such a Resource will be considered when setting prices under the new methodology. Thus, if an off-line resource cannot be operationally available within the 10-minute window, the resource should not be considered to be an available resource for setting prices.[8] MISO will work with its stakeholders to consider extending the Fast Start Resource definition to 30 minutes after Look Ahead Commitment ("LAC") and Look Ahead Dispatch ("LAD") are in production, in part, because these initiatives will enhance the ability of MISO to utilize 30-minute resources.

Some stakeholders have suggested that MISO adopt different criteria for off-line and on-line resources. For example, a new term, "Short Minimum Runtime Resources", could pertain to on-line resources that have minimum run times of less than or equal to one hour, without any restrictions on notification time. The existing Fast Start Resource definition would be restricted to only off-line resources. Although MISO did not adopt such proposals in this filing, MISO will evaluate these concepts as a potential future improvement once there has been sufficient experience with the proposed methodology.

Under the proposed ELMP, when MISO must commit a Fast Start Resource that will operate at EconMin to meet system requirements, the proposed ELMP price would more accurately reflect such costs. When MISO encounters transient shortages and MISO is able to commit additional Fast Start Resources to alleviate the shortage condition, then the proposed ELMP would more accurately reflect the cost of the next action that MISO could take, something that LMP cannot reflect as accurately. In many instances, however, LMP and ELMP prices would be expected to be very close.

Under certain circumstances, dispatching down a less expensive Resource to bring on-line capacity from a more expensive off-line Resource that must be block loaded or operated at a limit, could also result in increased Real-Time Revenue Sufficiency Guarantee Charge ("RSG") or Make Whole Payments ("MWP") to Resources that are called upon.[9] A side benefit to adoption of the proposed ELMP methodology is that it would reduce some RSG costs. Reduced RSG payments to Resources, in some instances, may be achieved by providing a pricing signal that can incorporate the costs of committing and dispatching Fast Start Resources, including those at an operating limit, when such a Resource is the most expensive Resource needed at its location and where such costs may otherwise be recovered through an RSG charge.[10]

Initially, MISO developed approaches that would allow all Resources that were operated at limits to participate in setting prices. Also, the approach would allow all commitment related

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[8] Gribik Testimony at 24.

[9] Testimony of Kevin A. Vannoy ("Vannoy Testimony") at 4.

[10] Vannoy Testimony at 5-8.

costs for such Resources to be considered in setting prices. The approach also would allow MISO to consider inter-temporal effects when setting prices: that is, costs incurred in one time period (hour in the Day-Ahead Market or Dispatch Interval in the Real-Time Market) could be used in setting prices in another period. This approach was termed "full" ELMP.

MISO has carefully considered implementing either the full ELMP methodology or a somewhat simplified, "approximate" ELMP methodology. MISO has discussed both options with its stakeholders. MISO is proposing to take a staged approach by initially implementing an approximate method of incorporating ELMP.[11] This approach takes into account more of the Offer costs of Fast Start Resources and EDR Resources, without incurring the significant computational complexity of implementing full ELMP, by using available single-interval dispatch software. Inter-temporal effects and multiple-interval dispatch related costs also would not be reflected in the initial implementation of approximate ELMP. MISO, however, may incorporate this feature along with the planned implementation of LAD, in future stages of ELMP. As a result, many of the benefits of full ELMP initially can be obtained through the proposed approximation methodology, at a lower cost and within a shorter time frame than if MISO implemented a full ELMP methodology.

Finally, it is worth noting that the proposed ELMP methodology will not involve any changes to the current methodology and procedures that MISO uses to physically operate the MISO system and to dispatch resources to reliably meet load demands.[12] The proposed ELMP provisions will only improve the pricing signals for Energy and Ancillary Services; it will not modify MISO's Operations, or the order in which MISO will dispatch available resources.

III. Stakeholder Process

In July 2006, the Independent Market Monitor ("IMM") initially recommended that MISO incorporate changes to allow "inflexible units and demand" to set energy prices in the real-time market.[13] Based, in part, upon the IMM's recommendation, MISO commenced discussions with stakeholders through several of its stakeholder committees and through informal working groups.[14]

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11 Gribik Testimony at 8-10.

12 Gribik Testimony at 8.

13 *2005 State of the Market Report for the Midwest ISO*, at 51. https://www.midwestiso.org/Library/Repository/Report/IMM/2005%20State%20of%20the%20Market%20Report.pdf.

14 *See, e.g., Basic Principles of Convex Hull Pricing: Webinar # 1* October 30, 2009 (referencing the IMM's recommendations on slide 3) (available at: https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Workshop%20Materials/Convex%20Hull%20Pricing%20Workshop/20091030%20Convex%20Hull%20Pricing%20Workshop%201.pdf).

A. ELMP Task Team:

For more than 2 years, MISO has been working with its stakeholders and consultants through a series of workshops and through the ELMPTT to allow fixed block resources (as well as Generation Resources at "EconMin") to be able to set prices in MISO's markets.[15] As part of this effort, MISO also worked with its stakeholders to permit EDR resources to set Energy and Operating Reserve Market prices. During this period, MISO has been discussing the need for ELMP with its stakeholders, and MISO has been reviewing a variety of approaches that could be adopted. MISO has responded to many stakeholder questions during this period and has developed many examples of how ELMP might influence Energy and Operating Reserve pricing. MISO has discussed the status of its work with stakeholders in several different types of stakeholder meetings, particularly through a series of ELMPTT meetings.[16] MISO has also used these meetings to collect comments and suggestions from affected parties regarding ELMP.

Beginning early this year, MISO presented theoretical results as well as case studies of ELMP to the ELMPTT using the approximation methods, through a series of hypothetical examples. At the April 29, 2011 ELMPTT meeting, MISO presented a revised decision tree of potential approaches for developing ELMP for the Real-Time Energy Market ("RTM") and the Day-Ahead Energy Market ("DAM"), based upon stakeholder feedback from an April 8, 2011 ELMPTT meeting. At the May 23, 2011 ELMPTT Meeting, MISO reviewed the results of the ELMP ballots that stakeholders had cast; these results had previously been posted on MISO's website and also had been sent to the MISO Market Subcommittee exploder list. MISO sought additional stakeholder feedback and discussed how the results of the feedback related to MISO's proposal.

At the June 14, 2011 ELMPTT meeting, MISO reviewed the initial staged implementation approach for ELMP. This approach would be developed by extending existing software to the extent possible to minimize implementation costs, development time and risks. MISO then outlined the Resources and Offer costs that would participate in setting ELMPs in the RTM. MISO explained that Start-Up Offer costs, No-Load Offer costs and Incremental Energy Costs as well as Operating Reserve Offer Costs of On-Line and Off-Line Fast Start Resources would participate in setting Energy and Operating Reserve prices. EDR Resources that were scheduled could also participate in setting prices in the Real-Time Market. MISO also explained that in the DAM, On-Line and Off-Line Fast Start Resources and their Start-Up, No-Load and Incremental Energy Costs as well as Operating Reserve Offer Costs would participate in setting Energy and Operating Reserve prices. On-Line slow start resources and only their Incremental Energy Costs and Operating Reserve Offer Costs would participate in setting prices in both the Day-Ahead and Real-Time Markets.

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[15] Gribik Testimony at 11-21.

[16] Minutes documenting the work at the numerous ELMPTT meetings can be found on the MISO website: https://www.midwestiso.org/Library/MeetingMaterials/Pages/ELMPTT.aspx.

In addition, on June 14th MISO discussed the proposed treatment of Fast Start Resources and EDR resources in the approximate ELMP method with the ELMPTT. MISO summarized that the proposed staged implementation would improve pricing signals, but that multiple-interval dispatch related costs would not be reflected because the proposed implementation initially would be built upon existing single-interval dispatch software. In addition, MISO discussed the language of a proposed Market Subcommittee motion to support moving forward with ELMP work. The ELMPTT supported the proposed motion by a vote of 13 in favor, 1 against, and 13 abstentions.

Additional ELMPTT meetings were held on September 9, 2011, September 23, October 21, November 4, and November 18 at which additional examples of how ELMP would operate were provided and stakeholder questions regarding the procedures were answered. On October 28, 2011, MISO posted a copy of all of the proposed redline Tariff changes that would be entailed in implementing ELMP. Stakeholders provided MISO with written and oral comments and suggested edits to the proposed Tariff changes, and all of the stakeholder feedback was discussed during the November 18, 2011 ELMPTT meeting. Additional improvements to the comprehensive redline Tariff sheets were posted on the MISO website for stakeholders on November 23, 2011.

On December 2, 2011, the ELMPTT voted on an amended motion[17] to have MISO file the ELMP Tariff sheets. The motion passed the ELMPTT by a vote of 10 in favor, 3 against, and 16 abstentions.

On December 16, 2011, the ELMPTT discussed parallel testing as part of the ELMP implementation plans. Several stakeholders requested that MISO conduct parallel testing of ELMP before there is a "cut-over" from LMP pricing to ELMP pricing. MISO is currently planning to conduct such parallel testing for a period of about three (3) months prior to implementation of ELMP pricing. During this period, MISO will be posting indicative ELMP prices and indicative Settlement statements, including RSG billing determinants, which will not be binding. Posting these prices and Settlement statements will assist stakeholders in being able to compare the *status quo* pricing to ELMP pricing. However, Market Participant bidding behaviors may be different during parallel testing as opposed to after ELMP pricing is implemented. Once ELMP has been implemented, MISO will provide an estimate of RSG payments based upon *status quo* LMPs.[18]

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17 "The Extended LMP Task Team (ELMPTT) supports MISO filing Tariff language with FERC in 2011 that is substantially similar to Tariff language that was posted with the December 2, 2011 ELMPTT meeting materials, in order for MISO to implement a revised pricing approach that will be consistent with the pricing approach approved at the June 14, 2011 ELMPTT meeting. Such support is contingent on MISO including in the transmittal letter, a commitment to providing two settlement statements during parallel operations, one under LMP pricing and one under ELMP pricing."

18 The approved 12/16/11 ELMPTT motion stated: "MISO will track market-wide charge component data generated from the new ELMP and old LMP for the parallel testing period,

B. Market Subcommittee:

At the June 28, 2011 Market Subcommittee ("MSC") meeting, MISO reviewed the proposed ELMP staged approach which had been endorsed earlier by the ELMPTT. MISO discussed that it was developing draft Tariff language regarding the ELMP modifications. Once Tariff provisions were developed, MISO would be vetting additional details with the MSC over the coming months. Some stakeholders wanted to see defined Tariff language, these stakeholders also wanted to hear from MISO Real-Time Operations personnel on their interpretation of the proposed Tariff language, and what they thought it would mean in terms of MISO's operations. MISO acknowledged this request and encouraged stakeholders to remain available to work with MISO to develop and move through the next ELMP implementation steps. The Market Subcommittee approved a proposed ELMP motion[19] by a roll call vote of 41 in favor, 2 opposed, and 20 abstentions.[20]

The MSC again reviewed the conceptual design of ELMP and the proposed redlined Tariff sheets to implement ELMP, at its December 6, 2011 meeting. The MSC approved an amended MISO motion[21] to make an ELMP filing by a vote of 26 in favor, 2 opposed, and 21 abstentions.

IV. Proposed Tariff Amendments

Initial ELMP implementation would use existing software, to the extent possible, in order to minimize implementation costs, development time, and risks. The proposed approximate

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and additionally for the period covering the initial year of ELMP implementation will track day ahead and real time RSG charge component approximated data. MISO will timely report data results monthly to the MSC and either of the remaining ELMPTT or RSGTF. MISO will then submit a "ELMP First Year Implementation Report" illustrating analytical conclusions and recommendations reached by MISO staff. The IMM will also be given access to all ELMP data gathered by MISO and will be provided opportunity to add his analysis & recommendations to the same report."

19 "The Extended LMP Task Team (ELMPTT) recommends that the Market Subcommittee (MSC) support the following proposal to MISO: (1) to move forward with development of a revised pricing approach based on a staged implementation as outlined with the June 14, 2011 ELMPTT and June 28, 2011 MSC meeting materials; and (2) to develop cost estimates before proceeding with developing systems to implement the pricing approach".

20 Gribik Testimony at 18.

21 "The Market Subcommittee (MSC) supports MISO filing Tariff language with FERC in 2011 that is substantially similar to Tariff language that was posted with the December 2, 2011 ELMPTT meeting materials, in order for MISO to implement a revised pricing approach that will be consistent with the pricing approach approved at the June 14, 2011 ELMPTT meeting. Such support is contingent on MISO including in the transmittal letter, a commitment to providing two settlement statements during parallel operations, one under LMP pricing and a shadow settlement statement under ELMP pricing."

ELMP method would be implemented by extending existing DAM and RTM economic dispatch software. Existing dispatch software would treat single intervals in DAM (one hour) and RTM (5 minutes). Approximate ELMP would be calculated using a single interval in the initial implementation. A detailed discussion of how ELMP would be implemented through the Tariff can be found in the enclosed Testimony of Paul Gribik.[22]

A. New and Revised Tariff Definitions

Although the existing Tariff uses the term "LMP" and "MCP" throughout the Tariff to describe the procedures that MISO currently uses to calculate DAM and RTM prices for Energy and Ancillary Services, in most instances the Tariff refers to a particular variation of LMP or MCP (*e.g.*, Day-Ahead LMP, Ex Ante LMP, Ex Post LMP, or Hourly Ex Post LMP). MISO considered the advantages and disadvantages of simply modifying the Tariff by adding "E" before LMP to reflect the change from the existing LMP to a new ELMP methodology. MISO determined that it would be unnecessarily confusing to substitute "ELMP" for "LMP" in the Tariff, in large part because under ELMP many of the variations of LMP and MCP will continue to exist. Moreover, a wholesale replacement of "LMP" with "ELMP" would likely cause confusion in the electric industry given the large number of existing contracts which currently use the term "LMP". MISO discussed these proposed terminology changes with stakeholders at the November 4 and November 18 ELMPTT meetings.[23]

Although MISO is proposing to preserve many of the concepts that are currently used in the Tariff (as described in the table below) many of the terms used in the Tariff will be modified to clarify the concepts that are being addressed, as summarized below:

Existing Defined Tariff Terms	**Proposed ELMP Replacement Terms**
Ex Post LMP	Real-Time Ex Post LMP
Hourly Ex Post LMP	Hourly Real-Time Ex Post LMP
Day-Ahead LMP	Day-Ahead Ex Ante LMP
Ex Ante LMP	Real-Time Ex Ante LMP
Ex Post MCP	Real-Time Ex Post MCP
Hourly Ex Post MCP	Hourly Real-Time Ex Post MCP
Day-Ahead MCP	Day-Ahead Ex Ante MCP

22 Gribik Testimony at 21-29.
23 Gribik Testimony at 19.

Ex Ante MCP	Real-Time Ex Ante MCP

MISO is proposing to add the following new definitions into the Tariff to implement the ELMP proposal:

Proposed New Terms	**Proposed Tariff Definitions**
Extended Locational Marginal Price ("ELMP")	The Transmission Provider shall implement ELMP, an enhanced pricing mechanism expanding upon LMP and MCP in which additional resources, including resources that are scheduled to operate at limits, certain off-line resources, and the start-up or shut-down and no-load or curtailment costs of resources that may be included in the calculation of prices at the Commercial Pricing nodes located throughout the Transmission Provider region. Such prices shall be calculated per the process set forth in Schedule 29A.
Fast Start Resource	A Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less and that will participate in setting price as described in the process in Schedule 29A of this Tariff.
Day-Ahead Ex Post LMP	The LMP calculated for the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29A of this Tariff.
Day-Ahead Ex Ante LMP	The LMP calculated through the clearing of the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29 of this Tariff.
Day-Ahead Ex Post MCP	The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated for the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29A of this Tariff.
Day-Ahead Ex Ante MCP	The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated through the clearing of the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29 of this Tariff.

As described in more detail in the Testimonies of Paul Gribik[24] and Kevin Vannoy,[25] these revised definitions and new definitions will enable the Tariff to accurately describe the changes that will result from the proposed ELMP methodology.

B. Proposed Changes to the Day-Ahead Energy Market:

As described in Section 39 and Schedule 29 of the Tariff, MISO will continue to use the same Security-Constrained Economic Dispatch ("SCED") clearing algorithms to solve the DAM Energy and Operating Reserve schedules for Resources that will be used in Settlements. The resultant prices will be Ex Ante Energy and Operating Reserve prices that are for informational purposes only.[26]

Under the proposed ELMP pricing, MISO will use a new SCED-Pricing algorithm (as described in a new Schedule 29A) to establish the Ex Post pricing that will be used for DAM Settlements.[27] The new SCED-Pricing will allow Fast Start Resources to relax their dispatch minimums to zero by allowing the partial commitment of such resources for pricing purposes. The new SCED-Pricing can also partially commit offline Fast Start Resources during scarcity conditions or to address transmission constraint violations. ELMP will allow Start-Up and No-Load Costs for Fast Start Resources to be included in such pricing.

The proposed ELMP methodology will permit Start-Up, No-load and Incremental Energy Offer costs, as well as Operating Reserve Offer Costs, to participate in setting ELMPs for On-Line Fast Start Resources committed by MISO in the DAM, and for Off-Line Fast Start Resources only when there are shortages or transmission violations in the DAM dispatch, as described in Schedule 29A. On-Line slow start resources and on-line Must Run Fast Start Resources would participate in setting ELMP prices, however, only Incremental Energy Offer costs and Operating Reserve Offer costs would be considered.[28] MISO will calculate Ex Ante and Ex Post prices as described in Sections 39.2.9.i through 39.2.9.n. Sections 39.2.10 and 39.2.11 of the proposed Tariff discuss the pricing rules during shortage and surplus conditions. LMP and MCP will be capped at the Value of Lost Load in accordance with Section 39.2.9.o.

MISO will post both Ex Ante and Ex Post LMPs and MCPs for Commercial Pricing Nodes (including Resource, Load Zone, Hub, Interface types) that are calculated in accordance with Sections 39.2.9.d through 39.2.9.h. and Section 39.1.5. The Marginal Congestion Component and Marginal Loss Component of LMP will be calculated as described in Sections 39.2.9.b. of the Tariff.

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24 Gribik Testimony at 23.
25 Vannoy Testimony at 3-4.
26 Gribik Testimony at 23.
27 Gribik Testimony at 22.
28 Gribik Testimony at 28-29.

C. Proposed Changes to the Real-Time Energy Market:

The proposed ELMP methodology will permit Start-Up, No-load and Incremental Energy Offer costs, as well as Operating Reserve Offer Costs, to participate in setting ELMPs for On-Line Fast Start Resources committed by MISO in the Reliability Assessment Commitment process, and for Off-Line Fast Start Resources only when there are shortages or transmission violations in the RTM dispatch, as described in Schedule 29A. On-Line slow start resources and Fast Start Resources that are Must Run or committed by MISO in DAM would participate in setting ELMP prices, however, only Incremental Energy Offer costs and Operating Reserve Offer costs would be considered.[29] On-Line EDR resources would also participate in setting ELMPs in the RTM by consideration of Shut-Down Offer costs and reduction offer costs.[30]

D. Proposed Changes to Settlements Provisions

As described in more detail in the Testimony of Kevin A. Vannoy, ELMP generally will have the following impacts on Market Settlements: (1) change all Settlement-related LMPs and MCPs to ‘Ex Post’ definitions; and (2) update the Day-Ahead RSG Make Whole Payments to include provisions specific to differences in Day-Ahead Ex Ante and Day-Ahead Ex Post pricing.[31] As described in Section A above, all Settlement sections of the Tariff were updated to use either Day-Ahead Ex Post LMP or Day-Ahead Ex Post MCP, Hourly Real-Time Ex Post LMP, or Real-Time Ex Post MCP. In addition, all charges and credits associated with the Settlement of the Day-Ahead Energy and Operating Reserve and FTR Markets will use Ex Post pricing based on the SCED-Pricing Algorithm.[32]

Under the existing Tariff there are RSG provisions to keep parties whole under certain circumstances. Under the proposed ELMP methodology, certain Market Transactions may not be kept whole to their costs due to differences between the Ex Ante (SCED) process which generates cleared schedules and the Ex Post (SCED-Pricing) process which defines the prices.

The current Tariff keeps Resources whole via three MWP mechanisms: (1) RSG; (2) Day-Ahead Margin Assurance; and (3) Real-Time Offer RSG payments. As a result, no additional MWPs are required. Currently, MISO’s Day-Ahead RSG keeps Resources whole for MISO economic commitments. Other price sensitive Day-Ahead Market Transactions that do not require a MWP under the existing Tariff include: (1) Must-Run Resources; (2) Price Sensitive Demand Bids; (3) Virtual Transactions; and (4) Dispatchable and Up-to-Transmission Usage Charge (“TUC”) Interchange Schedules. As a result of potential differences between Ex Ante and Ex Post LMPs, such transactions may require a MWP under ELMP.

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29 Gribik Testimony at 26-28.
30 Gribik Testimony at 27.
31 Vannoy Testimony at 3-5.
32 Vannoy Testimony at 5.

Virtual Supply Offers, dispatchable Import Schedules, and Must Run Generation require Day-Ahead RSG when an Ex Ante to Ex Post decrease in price results in insufficient revenue to cover their offered costs. Virtual Demand Bids, Price Sensitive Demand Bids, Price Sensitive Exports require Day-Ahead RSG when an Ex Ante to Ex Post increase in price results in a charge that is greater than their willingness to pay. In addition, Up-to-TUC Interchange Transactions require Day-Ahead RSG when the TUC offer that cleared based on the Ex Ante LMP price spread between two Commercial Pricing Nodes is no longer satisfied based on the Ex Post prices.

After consideration, MISO has decided to not include Opportunity Costs in the ELMP MWP Tariff provisions, as described in the Testimony of Kevin Vannoy.[33] As a result, MISO will not keep any transactions whole for any opportunity costs associated with differences between Ex Ante and Ex Post prices.

E. Proposed Modifications to Schedules and Attachments

As discussed above, MISO is proposing to incorporate a new Schedule 29A to implement SCED-Pricing, the methodology that implements ELMP, into the Tariff. This new Schedule is comparable to existing Schedule 29, which contains the algorithms that will continue to be used to calculate LMPs. MISO is also proposing to modify Schedule 30, the Emergency Demand Response Initiative, by: (1) amending the Part II to clarify that EDR Offers can set Real-Time Ex Post LMP prices; and (2) amending Part V to use the new term Hourly Real-Time Ex Post LMP.

In addition, MISO is proposing to make conforming modifications to Attachments AA, DD, and RR that are consistent with the implementation of the ELMP methodology as described in Section IV.A herein.

V. DOCUMENTS SUBMITTED WITH THIS FILING

The following documents are submitted with this filing:

Tab A - Redlined Tariff sheets

Tab B - Clean Tariff sheets

Tab C - Testimony of Paul R. Gribik

Tab D - Testimony of Kevin A. Vannoy

VI. EFFECTIVE DATE

MISO respectfully requests an effective date of more than 120 days from the date of this filing for the subject Tariff sheets, and a waiver of any applicable provisions of the

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[33] Vannoy Testimony at 8-9.

Commission's rules and regulations to effectuate such a date. Given the complexity and significant costs entailed in developing the required ELMP systems, MISO proposes to not make the investments required to implement the ELMP systems until after the Commission has issued a favorable order regarding the subject filing. Within 120 days after the Commission issues a favorable order, MISO will file a status report with the Commission which will provide the date when MISO will be able to commence ELMP under the Tariff and implement the enclosed proposed new and revised Tariff provisions.

VII. NOTICE AND SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Open Access Transmission, Energy and Operating Reserve Markets Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, MISO's Advisory Committee participants, as well as all state commissions within the Region. In addition, the filing has been posted electronically on MISO's website at https://www.midwestiso.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx for other interested parties in this matter.

VIII. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary in this proceeding:

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IX. CONCLUSION

For all of the foregoing reasons, MISO respectfully requests that the Commission accept the proposed Tariff revisions, without modification or hearing.

Sincerely,

/s/ Arthur W. Iler

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December 22, 2011

Attachments

cc: Jeffrey Hitchings, FERC
Patrick Clarey, FERC
Christopher Miller, FERC
Penny Murrell, FERC
Melissa Lord, FERC
Michael Donnini, FERC
Natalie Tingle-Stewart, FERC

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Carmel, Indiana, this 22nd day of December, 2011.

Arthur W. Iler
Arthur W. Iler
MISO

Tab A

1.115a Day-Ahead Ex Ante LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated through the clearing of the Day--Ahead Energy and Operating Reserve Market using the process defined in Schedule 29 of this Tariff.

1.115b Day-Ahead Ex Ante MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated through the clearing of the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29 of this Tariff.

1.115c Day-Ahead Ex Post LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated for the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29A of this Tariff.

1.115d Day-Ahead Ex Post MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated for the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29A of this Tariff.

1.117 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.118 Day-Ahead Margin: Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

For an Hour,~~The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated through~~ the difference between~~clearing of~~ the Market Participant's accepted Day-Ahead Energy Offer and the Day-Ahead Ex Post LMP for that interval~~and Operating Reserve Market~~.

1.~~1~~20 RESERVED Version: 1~~0~~.0.0 Effective: 12/31/9998~~7/28/2010~~

~~The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated through the clearing of the Day Ahead Energy and Operating Reserve Market.~~

1.201 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.202 RESERVED Version: 1.0.0 Effective: 12/31/9998

~~The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated at the beginning of the Dispatch Interval, used for informational purposes in the Real-Time Energy and Operating Reserve Market.~~

1.203 RESERVED Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

~~The LMP calculated for each Dispatch Interval.~~

1.204 RESERVED Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

~~The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated for each Dispatch Interval.~~

1.213 Extended Locational Marginal Price (ELMP) Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

The Transmission Provider shall implement, ELMP, an enhanced pricing mechanism expanding upon LMP and MCP in which additional resources, including resources that are scheduled to operate at limits, certain off-line resources, and the start-up or shut-down and no-load or curtailment costs of resources that may be included in the calculation of prices at the Commercial Pricing nodes located throughout the Transmission Provider region. Such prices shall be calculated per the process set forth in Schedule 29A.

1.220a Fast Start Resource Version: 0.0.0 Effective: 12/31/9998

A Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less and that will participate in setting price as described in the process in Schedule 29A of this Tariff.

1.229 Financial Transmission Right (FTR): Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

A financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges that arise when the Transmission System is congested and differences in Marginal Congestion Components of Day-Ahead Ex Post LMPs result~~LMPs result from the redispatch of Resources out of economic merit order to relieve that congestion~~.

1.290 RESERVED Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

1.291 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.298a Hourly Real-Time Ex Post LMP Version: 0.0.0 Effective: 12/31/9998

The LMP derived through mathematical integration of the Dispatch Interval Real-Time Ex Post LMPs over the Hour, and used for purposes of Settlement of Energy transactions in the Real-Time Energy and Operating Reserve Market.

1.298b Hourly Real-Time Ex Post MCP~~291 RESERVED~~ Version: 0.0.0 Effective:

12/31/9998~~7/28/2010~~

The average MCPs for Regulating Reserve, Spinning Reserve and Supplemental Reserve applicable to a specific Resource derived through time and quantity weighting of the applicable Real-Time Ex Post MCPs over the Hour, and used for purposes of Settlement of Operating Reserves in the Real-Time Energy and Operating Reserve Market.

1.308a Inadvertent Energy Value: Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

For the Midwest ISO Balancing Authority Area within the Transmission System, the calculated monetary value for each Hour of the Inadvertent Energy expressed in MWh multiplied by the Midwest ISO Balancing Authority Area's average generation Hourly Real-Time Ex Post LMP for the Hour.

1.366 Locational Marginal Price (LMP): Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

A ~~The market clearing~~ price for Energy at a given Commercial Pricing Node in the Transmission Provider Region which is~~shall be equivalent to~~ the marginal cost of serving demand at the Commercial Pricing Node while meeting Zonal and Market-Wide Operating Reserve Requirements.

1.379 Market Clearing Price (MCP): Version: 1.0.0 Effective: 12/31/9998

A price for Regulating Reserves, Spinning Reserves, and Supplemental Reserves which is the marginal cost of meeting the particular reserve requirements while meeting locational Energy requirements.

1.379a Market Clearing Price Zonal Terms Version: 2~~1~~.0.0 Effective:

12/31/9998~~4/1/2011~~

The following subset of terms used in the Market Clearing Price calculation under Module C: the Shadow Prices of Reserve Zone Operating Reserve constraints, Reserve Zone Regulating and Spinning Reserve constraints, and Reserve Zone Regulating Reserve constraints, and beginning November 1, 2011, additional marginal cost for managing congestion in order to supply incremental regulating Reserve, Spinning Reserve, or 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.

1.381 Market Implementation Errors: Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

Flaws in the design or implementation of software resulting in changes in Ex Post LMPs or other prices cleared through the Energy and Operating Reserve Market and the corresponding changes in Settlements not accurately reflecting the application of the Market Rules.

1.517 Price Taker: Version: 2~~1~~.0.0 Effective: 12/31/9998~~10/1/2012~~

A Market Participant with an Energy and/~~Offer,~~ or Operating Reserve~~ZRC~~ Offer not capable of setting LMPs~~, ACPs,~~ or MCPs.

1.533a Real-Time Ex Ante LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated at the beginning of the Dispatch Interval, using the process defined in Schedule 29 of this Tariff, that is used for informational purposes in the Real-Time Energy and Operating Reserve Market.

1.533b Real-Time Ex Ante MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated at the beginning of the Dispatch Interval, using the process defined in Schedule 29 of this Tariff, that is used for informational purposes in the Real-Time Energy and Operating Reserve Market.

1.533c Real-Time Ex Post LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated for each Dispatch Interval using the process defined in Schedule 29A of this Tariff.

1.533d Real-Time Ex Post MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated for each Dispatch Interval using the process defined in Schedule 29A of this Tariff.

1.535 Real-Time Offer Revenue Sufficiency Guarantee Payment: Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP): The real-time make-whole payment provided under Section 40.3.5 of this Tariff to the Resources described therein, when sum of revenue from Hourly Real-Time Ex Post~~hourly real-time~~ LMPs and Hourly Real-Time Ex Post~~hourly real-time~~ MCPs do not fully cover the incremental Energy Offer costs and Operating Reserve Costs of such Resources.

1.598 Security Constrained Economic Dispatch (SCED): Version: 1.0.0 Effective: 12/31/9998

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The algorithm keeps the commitment of Resources fixed in the dispatch. The model is described in Schedule 29.

1.598a Security Constrained Economic Dispatch Pricing (SCED-Pricing Version: 0.0.0 Effective: 12/31/9998

Security Constrained Economic Dispatch Pricing (SCED-Pricing):

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The model is described in Schedule 29A.

1.626 State Estimator MWs: Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

The megawatts that are determined by the State Estimator to be generated at a given location for each Dispatch Interval~~Real Time LMP interval~~.

15.7 Marginal Losses Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

System Losses are associated with all Transmission Service including Transmission Service associated with Grandfathered Agreements. The Transmission Provider shall assess to Market Participants the Marginal Losses Component of Ex Post LMP, as specified in Sections 39.2.9~~.c.ii~~, 39.3.3.c.ii, 40.2.11, and 40.4.1.

28.5 Marginal Losses Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

System Losses are associated with all Transmission Service including Transmission Service associated with Grandfathered Agreements. The Transmission Provider shall assess to Market Participants the Marginal Losses Component of Ex Post LMP in Sections 39.2.9~~.c.ii~~, 39.3.3.c.ii, 40.2.11, and 40.4.1. The Transmission Provider, ITC, Transmission Owners, and ITC

Participant(s) are not obligated to provide Marginal Losses.

33.8.2 Manual Redispatch Compensation and Eligibility Version: 2~~1~~.0.0 Effective: 12/31/9998~~3/1/2011~~

As a result of following Manual Redispatch instructions, Generation Resources or Demand Response Resources–Type II that are manually redispatched by the Transmission Provider, either directly or as a Transmission Provider instruction communicated through a Local Balancing Authority, may not fully recover their real-time Incremental Energy Cost from the Hourly Real-Time Ex Post~~hourly real-time~~ LMP during the period the Transmission Provider has directed the Generation Resources or Demand Response Resources–Type II to operate at Energy levels above the Resource's Day-Ahead Schedule for Energy, or may have Day-Ahead Margins eroded during the period the Transmission Provider has directed the Generation Resource or Demand Response Resource-Type II to operate at Energy levels below the Resource's Day-Ahead Schedule for Energy. In such circumstances, the Market Participant owning the Generation Resource or Demand Response Resource– Type II shall be compensated pursuant to Schedule 27 of this Tariff only if the following eligibility criteria and requirements are satisfied.

a. A Generation Resource or Demand Response Resource-Type II manually redispatched pursuant to this Section of this Tariff, is only eligible for Real-Time Offer Revenue Sufficiency Guarantee Payments ("RT ORSGP") under Schedule 27 in Hours in which it has been committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market, or received a commitment from the Transmission Provider in the Real-Time Energy and Operating Reserve Market as must-run. In addition, the following requirements must be met for a Generation Resource or Demand Response Resource-Type II to be eligible for RTORSGP under Schedule 27:

1) Day-Ahead committed Hours must comply with the following

requirements:

(a) The Generation Resource or Demand Response Resource-Type II must offer flexibly for the Hour pursuant to the following criteria:

i. All limits used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must have a dispatch range of greater than one (1) MW;

ii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half MW per minute; and

iii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval 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, or of the Hourly Integrated Forecast Maximum Limit for a Dispatchable Intermittent Resource.

iv. If four or more consecutive Dispatch Intervals fail eligibility, the Resource will be ineligibile for compensation.

(b) The as-committed day-ahead Offers must remain unchanged when submitted as Real-Time Offers pursuant to the following criteria:

i. For a given day-ahead committed Hour, the following Offers must be the same as the Offers that the day-ahead commitment was based on, and the Real-Time Offers at the close of the Real-Time Energy and Operating Reserve Market Hour as submitted by the Market Participant:

1. 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.

2. The real-time Regulating Reserve Offer must be equal to the day-ahead Regulating Reserve 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.

3. Real-time must-run committed Hours must meet the following requirements:

   (a) The Generation Resource or Demand Response Resource-Type II must offer flexibly for the Hour, pursuant to the following criteria:

   i. All limits used in the Real-Time Energy and Operating Reserve Market within the

Dispatch Interval must have a dispatch range of greater than one (1) MW;

ii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half MW per minute; and

iii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval 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, or of the Hourly Integrated Forecast Maximum Limit for a Dispatchable Intermittent Resource.

iv. If four or more consecutive Dispatch Intervals fail eligibility, the Resource will be ineligibile for compensation.

(b) All Offers must be the same for each consecutive real-time must-run Hour within the Manual Redispatch period and the first Hour of the Manual Redispatch period must be the same as the previous Hour, if committed, pursuant to the following criteria:

i. The following Offer parameters must be the same for each consecutive real-time must-run committed Hour in the Manual Redispatch period:

1. Energy Offer curve;

2. Regulating Reserve, Spinning Reserve and Supplemental Reserve Offers; and

3. Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hourly Regulation Minimum Limit.

ii. The following Offer parameters must be the same for the first Hour of the real-time must-run committed Hour in the Manual Redispatch period, and the previous Hour, if committed:

1. Energy Offer curve;

2. Regulating Reserve, Spinning Reserve and Supplemental Reserve Offers; and

3. Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hourly Regulation Minimum Limit.

Failure to meet any of these requirements will result in the Generation Resource or Demand Response Resource-Type II being disqualified for RTORSGP in the Hour during which such failure occurs and each subsequent Hour of the Manual Redispatch period.

a. A Generation Resource or Demand Response Resource-Type II manually redispatched pursuant to this Section 33.8 is only eligible for DAMAP under Schedule 27 in Hours in which its Day-Ahead Margin has been eroded.

b. In addition, the following requirements must be met for a Generation Resource or Demand Response Resource-Type II to be eligible for DAMAP under Schedule 27:

The Generation Resource must offer flexibly for the Hour, pursuant to the following criteria:

i. All limits used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must have a dispatch range of greater than one (1) MW;

ii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the

Dispatch Interval must be greater than one-half MW per minute; and

iii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half of one percent (0.5%) of the real-time Hourly Economic Maximum Limit of the Generation Resource per minute, or of the Hourly Integrated Forecast Maximum Limit for a Dispatchable Intermittent Resource.

If four or more consecutive Dispatch Intervals fail eligibility, the Resource will be ineligible for compensation.

Failure to meet any of these requirements will result in the Generation Resource or Demand Response Resource-Type II being disqualified for DAMAP in the Hour during which such failure occurs.

a. During any period in which a Generation Resource is Manually Redispatched, the Generation Resource shall be exempt from paying Revenue Sufficiency Guarantee Distribution charges and shall be exempt from Excessive/Deficient Energy Deployment Charges under Section 40.3.4. If the period of Manual Redispatch includes any partial Hour, then that entire Hour will be exempt from paying Revenue Sufficiency Guarantee Charges and shall be exempt from Excessive/Deficient Energy Deployment Charges under Section 40.3.4.

37.3 Limitations on Charges and Cost Responsibilities Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

a. **Bundled Load:** Transmission Owners and ITC Participants taking Network Integration Transmission Service to serve their Bundled Load shall not pay charges pursuant to Schedules 1, 3 through 6 and Schedule 9. After the Transition Period ends, beginning February 1, 2008, the total Schedule 9 revenues to be distributed to Transmission Owners and ITC Participants under the ISO Agreement shall include the Schedule 9 charges that would be payable by any Transmission Owners and ITC Participants covered by the above exclusion or by a similar exclusion in a Service Agreement with the Transmission Provider ("imputed revenues"). In distributing Schedule 9 revenues to Transmission Owners and ITC Participants, the Transmission Provider shall deduct the imputed revenues attributed to each such Transmission Owner and ITC Participant from the total Schedule 9 revenues that are due to that Transmission Owner or ITC Participant. Notwithstanding the first sentence of this section, Ameren Service Company, acting as a

Transmission Customer taking Transmission Service to serve Ameren Energy, Inc., as agent for and on behalf of Union Electric Company (d/b/a AmerenUE and Ameren Energy Generating Company), for serving their Bundled Load in the State of Missouri shall not pay charges pursuant to Schedule 2.[1]

The Market Participant shall be financially responsible for payment of the Marginal Congestion Component of Ex Post LMP and Marginal Loss Component of Ex Post LMP related to their transactions as specified in Sections 39.2.9~~.c~~, 39.3.3.c, 40.2.11, and 40.4.1 for those Transmission Owners and ITC Participants taking Network Integration Service to serve their Bundled Load.

Notwithstanding the foregoing in this Section 37.3.a, the following rules apply in instances in which there are multiple Transmission Owners within a pricing zone or Local Balancing Authority Area. Specifically, a Transmission Owner located in a pricing zone or Local Balancing Authority Area with one or more other Transmission Owners shall remain obligated to pay for Transmission and/or Other Ancillary Services it receives within that pricing zone or Local Balancing Authority Area that it does not provide itself unless the transmission and/or ancillary services are provided pursuant to a Grandfathered Agreement. Any disputes as to the amount to be paid, or the services to be provided or received shall be resolved through the ADR process set forth in

Section 12 of this Tariff.

b. **Grandfathered Agreements for Load Inside of the ISO:** For the Transmission Service provided as a result of or pursuant to Grandfathered Agreements for Load inside of the ISO, each GFA Responsible Entity which is a party to that Grandfathered Agreement shall not be obligated to pay charges under Schedules 1 through 9, but it shall be responsible for Transmission Usage Charges as specified in Sections 40.2.11 and 40.4.1. Each GFA Responsible Entity shall remain responsible for payment of the applicable Schedule 10 charges for the services taken pursuant to Section 37.1 for its Load, which may include wholesale Loads under Grandfathered Agreements.

c. **Grandfathered Agreements for Load Outside of the ISO:** For the Transmission Service provided as a result of or pursuant to Grandfathered Agreements for Load outside of the ISO, the GFA Responsible Entity shall be exempt from rates under this Tariff for services provided pursuant to the existing agreements, except for charges under Schedule 10, and the Transmission Usage Charge as specified in Sections 40.2.11 and 40.4.1 to the Interface at the boundary of the Transmission System.

d. **Exception to Section 37.3 (b) and (c):** Notwithstanding the provisions of Section 37.3(b) and (c), (i) if ancillary services are not taken or provided under the Grandfathered Agreement, in whole or in part, then such Ancillary Services which are not provided under such Grandfathered Agreement shall be provided and charged for under this Tariff; and (ii) if Marginal Losses are not provided or paid for under the Grandfathered Agreement, then the Market Participant will be financially responsible for the charges attributable to Marginal Losses as assessed for these related transactions in accordance with the provisions of Module C, Sections 39.3.1, 39.3.3, 40.3 and 40.5.

e. Imputed Revenues Associated with Grandfathered Agreements. After the Transition Period ends, beginning February 1, 2008, the total Schedule 7, 8, and 9 revenues to be distributed to Transmission Owners and ITC Participants under the ISO Agreement shall include the Schedule 7, 8, and 9 charges that would otherwise be payable by any GFA Responsible Entity covered by the exclusions in Section 37.3(b) or Section 37.3(c) ("GFA imputed revenues"), provided, however, that GFA imputed revenues shall not include any Schedule 7, 8, and 9 charges associated with a Grandfathered Agreement with respect to which the revenues are reflected as a credit in the calculation of the Transmission Owner's or ITC Participant's revenue requirement pursuant to Attachment O. In distributing Schedule 7, 8, and 9 revenues to those Transmission Owners and ITC Participants, the Transmission Provider shall deduct the GFA imputed revenues attributed to each such Transmission Owner or ITC Participant from the total Schedule 7, 8, and 9 revenues that are due to that Transmission Owner or ITC Participant.

[1] *Midwest Independent Transmission System Operator, Inc.,* 106 FERC ¶ 61,293 (2004).

38.5 Load Aggregation Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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.

38.8.4.5 Settlement of Imbalances. Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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~~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.

39 Day-Ahead EORM Processes and Settlements Version: 1.0.0 Effective: 12/31/9998

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 and Supplemental 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 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 and Operating 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 and Operating 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 and/or Operating Reserve through economic clearing are greater than or equal to the corresponding Energy and/or Operating Reserve costs respectively when the resource is not scheduled at a limit. Such Energy and/or Operating Reserve costs are equal to the corresponding Energy and/or Operating 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 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.

39.1.3 Rules for Financial Schedules Version: 1.0.0 Effective: 12/31/9998

Financial Schedules may be submitted at any time prior to 1200 hours EST six (6) Calendar Days after the Operating Day. 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.

39.1.5 Posting of the Day-Ahead Schedules Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

By 1600 hours EST, 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 and Supplemental 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 shall consist of twenty-four (24) Hourly values for each Resource. Also at 1600 hours EST, 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 and Day-Ahead Ex Post LMP (including the Marginal Congestion Component and the Marginal Losses Component) for each Commercial Pricing Node; ~~and~~ the Day-Ahead Ex Ante Regulating Reserve MCP, Ex Ante Spinning Reserve MCP, and Ex Ante Supplemental Reserve MCP for each Resource; and the Day-Ahead Ex Post Regulating Reserve MCP, Ex Post Spinning Reserve MCP, and Ex Post Supplemental 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.

39.2.1 Transmission Provider Obligations Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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 and to supply Operating 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 and supply Operating Reserve in the Day-Ahead Energy and Operating Reserve Market

c. Provide the Settlement functions associated with the purchase and sale of Energy and Operating 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 and Zonal Regulating Reserve Requirements, the Market-Wide and Zonal Spinning Reserve Requirements and the Market-Wide and Zonal Supplemental Reserve Requirements at least 48 hours prior to the beginning of the Operating Day.

39.2.9 Day-Ahead Energy and Operating Reserve Market Process Version: 4~~3~~.0.0 Effective: 12/31/9998~~4/1/2011~~

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; ~~and~~ (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; and, (ii) Operating Reserve Schedules for Resources.

b. **Determination of ~~the~~ Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs~~LMP~~ 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 and, if applicable, 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~~. The Day-Ahead LMPs are established~~ 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 Demand Bids and (ix) Demand Curves.

i. Calculation of Marginal Congestion Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the~~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 the transmission congestion 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~~ The Marginal Congestion Component of a Day-Ahead~~ LMP reflects the marginal cost of managing the transmission congestion 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~~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 ~~Day-Ahead~~ LMPs for each Hour and Aggregate Price Node in the Day-Ahead Energy and Operating Reserve Market. The calculation of ~~Day-Ahead~~ 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 ~~Day-Ahead~~ 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 ~~Day-Ahead~~ LMPs for each Hour and Commercial Pricing Node in the Day-Ahead Energy and Operating Reserve Market. The ~~Day-Ahead~~ LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the ~~Day-Ahead~~ LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

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

The Transmission Provider shall determine the ~~Day-Ahead~~ LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the ~~Day-Ahead~~ LMP for the Resource Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ 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 ~~Day-Ahead~~ LMP for the Resource Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ 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 ~~the~~ Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs~~LMP~~ at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the~~a Day-Ahead~~ LMP for the Load Zone Commercial Pricing Node as follows:

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

ii. If the Load Zone consists of multiple Loads, the ~~Day-Ahead~~ LMP for the Load Zone Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ 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 ~~the~~ Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs~~LMP~~ at a Hub Commercial Pricing Node

The Transmission Provider shall determine the~~a Day-Ahead~~ LMP for a Hub Commercial

Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the ~~Day-Ahead~~ LMP for the Hub Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the ~~Day-Ahead~~ LMP for the Hub Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ 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.

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

The Transmission Provider shall determine the~~a Day-Ahead~~ LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the ~~Day-Ahead~~ LMP for the Interface Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the ~~Day-Ahead~~ LMP for the Interface Commercial Pricing Node is set equal to the calculated ~~Day-Ahead~~ 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~~Price~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources

On a day-ahead market basis, the~~The~~ Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Regulating Reserve ~~MCPs~~ 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~~based on~~ 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, 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) Reserve Zone Operating Reserve Constraint Shadow Price (v) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price (vi) Reserve Zone Regulating Reserve Constraint Shadow Price (vii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (viii) beginning November 1, 2011, additional marginal cost for managing congestion 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. ~~. Such Regulating Reserve MCPs for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources shall be calculated on a Day-Ahead basis for each Hour of the Day-Ahead Energy and Operating Reserve Market.~~

j. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Regulating

Reserve Market Clearing Price for Stored Energy Resources

On a day-ahead market basis, the~~The~~ Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Regulating Reserve ~~MCPs~~ for Stored Energy Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using~~based on~~ the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCP for~~. The~~ Regulating Reserve and Day-Ahead Ex Post MCP for Regulating Reserve~~MCP~~ for Stored Energy 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) Maximum Stored Energy Resource Regulation Constraint Shadow Price and (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price; all such Constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively. ~~. Such Regulating Reserve MCPs for Stored Energy Resources shall be calculated on a Day-Ahead basis for each Hour of the Day-Ahead Energy and Operating Reserve Market.~~

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, and External Asynchronous Resources

On a day-ahead market basis, the~~The~~ Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve ~~MCPs~~ 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~~based on~~ the SCED algorithm and SCED-Pricing algorithm, respectively.

The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for~~. The~~ Spinning Reserve ~~MCP~~ for Generation Resources, Demand Response 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) Reserve Zone Operating Reserve Constraint Shadow Price(iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion 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. ~~.~~ ~~Such Spinning Reserve MCPs for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources shall be calculated on a Day-Ahead basis for each Hour of the Day-Ahead Energy and Operating Reserve Market.~~

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~~The~~ Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve ~~MCPs~~ for Demand Response Resources – Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using~~based on~~ 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 ~~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, (iii) Reserve Zone Operating Reserve Constraint Shadow Price (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing congestion 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. ~~. Such Spinning Reserve MCPs for Demand Response Resources – Type I shall be calculated on a Day-Ahead basis for each Hour of the Day-Ahead Energy and Operating Reserve Market.~~

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, and External Asynchronous Resources

On a day-ahead market basis, the~~The~~ Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve ~~MCPs~~ 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~~based on~~ the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for~~. The~~ Supplemental Reserve ~~MCP~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Balance Constraint Shadow Price (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (iv) beginning November 1, 2011, additional marginal cost for managing congestion 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. ~~. Such Supplemental Reserve MCPs for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources shall be calculated on a Day-Ahead basis for each Hour of the Day-Ahead Energy and Operating Reserve Market.~~

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~~The~~ Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve ~~MCPs~~ for Demand Response Resources - Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using~~based on~~ the SCED algorithm and SCED-Pricing algorithm, respectively.~~,~~ The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve ~~MCP~~ for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price (ii) Reserve Zone Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost for managing congestion 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. ~~. Such Supplemental Reserve MCPs for Demand Response Resources – Type I shall be calculated on a Day-Ahead basis for each Hour of the Day-Ahead Energy and Operating Reserve Market.~~

o. 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.

p. 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.

39.2.10 Shortage Conditions in the Day-Ahead EORM Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

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 and External Asynchronous Resource up to the Emergency Maximum Limit except for Resources selected to provide Regulating Reserve, and (ii) the commitment of Generation Resources, Demand Response Resources - Type I, and Demand Response 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. Both SCED and SCED-Pricing algorithms will include Scarcity Pricing based on the Operating Reserve Demand Curves and Regulating Reserve Demand Curves if ~~and only sufficient~~ Operating Reserve is insufficient~~not cleared~~ to meet the Market-Wide and/or Zonal Operating 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 can not 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.

39.2.11 Surplus Conditions in the Day-Ahead EORM Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

If the non-Emergency minimum supply from Offers and Fixed Import Schedules exceed cleared Demand Bids plus cleared Export Schedules plus cleared Virtual Demand 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 and Demand Response 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~~Should~~ Regulating Reserve Scarcity occurs, then Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post~~occur, Energy~~ 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~~MCPs~~ shall include positive Regulating Reserve Scarcity Prices, based upon the Market-Wide and/or Zonal 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.

39.3.1 Charges for DA EORM Purchases Version: 2~~1~~.0.0 Effective: 12/31/9998

a. Market Participants that purchase Energy in the Day-Ahead Energy and Operating Reserve Market, other than Energy associated with a host Load Zone, 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 other than a host 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.

39.3.2 Payments for DA EORM Sales Version: 2~~1~~.0.0 Effective: 12/31/9998

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.

39.3.2A Day-Ahead Operating Reserve Procurement Credits Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

a. Market Participants scheduled to supply Regulating Reserve from Generation Resources, Demand Response Resources – Type II, Stored Energy Resources 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 ~~MCP~~.

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 ~~MCP~~.

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 ~~MCP~~.

39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments Version: 2~~1~~.0.0 Effective: 12/31/9998

The Transmission Provider shall determine, whether any Generation Resources, Demand Response Resources – Type I or Demand Response Resources – Type II 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, Demand Response Resource – Type I or Demand Response Resource – Type II 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. ~~When the Day-Ahead LMP is less than the Net Benefit Price Threshold for a given Demand Response Resource, then the applicable hourly Production Costs for the hour(s) in which the LMP is less than the Net Benefits Price Threshold will be equal to zero. If the Demand Response Resource is a BTMG then the applicable hourly production cost will be equal to zero. This payment shall be supported through revenue collected from the Day-Ahead Revenue Sufficiency Guarantee Charge as set forth in Section 39.3.1A.~~

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 and for Operating Reserves scheduled above Self Schedule MWs. 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 Demand Bid, 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 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.

All Market Participant Day-Ahead Revenue Sufficiency Guarantee Credits shall be funded in accordance with Section 39.3.1A.

39.3.2C Charges and Payments for Purchases and Sales for DRRs Version: 3~~2~~.0.0 Effective: 12/31/9998

a. Market Participants that purchase Energy associated with a Host Load Zone 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 at the Host Load Zone Commercial Pricing Node, net of Day-Ahead Financial Schedules, for each Hour in the Day-Ahead Energy and Operating Reserve Market.

b. ~~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 – Type I or Demand Response Resources – Type II~~(other than BTMG)~~ 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 Demand Response Resource – Type I and Demand Response Resource - Type II Offers cleared ~~. 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 a zero $/MW price. Market Participants with Day-Ahead Financial Schedules will be charged the applicable Day-Ahead LMP for Day-Ahead Financial Schedule sales and will be credited for Day-Ahead Financial Schedule purchases~~.

39.3.3 Payments and Charges for Financial and Interchange Schedules Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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 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.

39.3.5 Calculation of the Day-Ahead Marginal Losses Surplus Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

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).

40.2 Real-Time Energy and Operating Reserve Market Version: 1.0.0.~~0 Effective: 7/28/2010~~ Effective: 12/31/9998

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, and Supplemental Reserve, (ii) Real-Time Ex Ante LMPs and Real-Time Ex Post LMPs for Energy, and (iii) Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Regulating Reserve, Spinning Reserve, and Supplemental Reserve are calculated for each five (5) minute Dispatch Interval based on submitted Offers and using ~~a~~ SCED and SCED-Pricing algorithms~~algorithm~~ as set forth in this Section 40.2.

The clearing and pricing of Energy and Operating Reserve in the Real-Time Energy and Operating Reserve Market is based on ~~a~~ simultaneous co-optimization processes~~process~~ in which the total costs of Energy and Operating Reserve are minimized.

The SCED simultaneous co-optimization process ensures: (i) that all Real-Time Ex Ante~~Energy~~ LMPs and Operating Reserve Real-Time Ex Ante MCPs for each Resource supplying Energy and/or Operating Reserve through economic clearing are greater than or equal to the corresponding Energy and/or Operating Reserve costs respectively when the resource is not scheduled at a limit. Such ~~, where such~~ Energy and/or Operating Reserve costs are equal to the corresponding Energy and/or Operating 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 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 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.

40.2.2 Transmission Provider Obligations Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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 and Operating 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 and Operating 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 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 and Operating 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 and Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Operating Reserves for each five (5) minute Dispatch Interval.

40.2.8A Rules for Financial Schedules Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

Financial Schedules may be submitted at any time prior to 1200 hours EST six (6) Calendar Days after the Operating Day. 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.

40.2.15 Real-Time Energy and Operating Reserve Market Process Version: 3~~2~~.0.0 Effective: 12/31/9998~~4/1/2011~~

The Transmission Provider shall (i) use a SCED algorithm to clear Offers, Self-Schedules, and Interchange Schedules, (ii) determine the Midwest ISO 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, and Supplemental 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, and, if applicable, 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~~. The~~ 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~~any~~ Ex Ante LMP reflects the marginal cost of managing the transmission congestion 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~~any~~ 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~~Markets~~. 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 Node~~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~~Markets~~. 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 Real-Time 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.

~~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~~an~~ 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 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 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

~~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~~Operating~~ Day.

g. Determination of the Real-Time Ex Ante LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine the Real-Time~~an~~ 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.

h. Determination of the Real-Time Ex Ante LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine the Real-Time~~an~~ Ex Ante 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 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 ~~external~~ 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. ~~The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for 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 Real-Time Ex Ante Regulating Reserve Market Clearing Prices~~Price~~ for Generation Resources, Demand Response Resources – Type

II, External Asynchronous Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Regulating Reserve ~~MCPs~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using~~based on~~ the SCED algorithm. The Real-Time Ex Ante MCP for Regulating Reserve ~~MCP~~ for Generation Resources, Demand Response 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) Reserve Zone Operating Reserve Constraint Shadow Price, (v) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, if applicable, (vi) Reserve Zone Regulating Reserve Balance Constraint Shadow Price, if applicable, (vii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (viii) beginning November 1, 2011, additional marginal cost for managing congestion 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~~. Such Regulating Reserve 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.~~

j. Determining the Real-Time Ex Ante Regulating Reserve Market Clearing

Prices~~Price~~ for Stored Energy Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Regulating Reserve ~~MCPs~~ for Stored Energy Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using~~based on~~ the SCED algorithm. The Real-Time Ex Ante MCP for Regulating Reserve ~~MCP~~ 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, and (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price; all such Constraints noted herein are as set forth in Schedule 29. ~~Such Regulating Reserve MCPs for Stored Energy Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.~~

k. Determining the Real-Time Ex Ante Spinning Reserve Market Clearing Prices~~Price~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Spinning Reserve ~~MCPs~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using~~based on~~ the SCED algorithm. The Real-Time Ex Ante MCP for

Spinning Reserve ~~MCP~~ for Generation Resources, Demand Response 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) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion 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.

l. Determining the Real-Time Ex Ante 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 Ante MCPs for Spinning Reserve for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Real-Time Ex Ante 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, (iii) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, and (v ~~(vi) Market-Wide Non-DRR1 Operating Reserve Constraint~~

~~Shadow Price, and (vii~~) beginning November 1, 2011, additional marginal cost for managing congestion 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.~~

m. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Prices~~Price~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve ~~MCPs~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using~~based on~~ the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve ~~MCP~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1~~Generation-based~~ Operating Reserve Constraint Shadow Price, and (iv) beginning November 1, 2011, additional marginal cost for managing congestion 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.~~ Such Supplemental Reserve 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.~~

n. Determining the Real-Time Ex Ante 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 Ante MCPs for Supplemental Reserve ~~Market Clearing Price~~ for Demand Response Resources - Type I for each Dispatch Interval in

~~The Transmission Provider shall calculate~~ the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve ~~MCPs for Demand Response Resources – Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, based on the SCED algorithm. The Supplemental Reserve MCP~~ for Demand Response Resources - Type I is the sum of the: (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost for managing congestion 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.~~ Such Supplemental Reserve MCPs for Demand Response Resources – Type I shall be calculated on a Real-Time basis for each~~

~~Dispatch Interval of the Real-Time Energy and Operating Reserve Market~~.

o. 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.

40.2.17 Calculation of Real-Time Ex Post LMPs and Ex Post MCPs Version: 5~~4~~.0.0 Effective: 12/31/9998~~4/1/2011~~

For each Dispatch Interval, the Transmission Provider shall use the SCED-Pricing algorithm~~an ex post pricing process~~ to establish Real-Time Ex Post LMPs and Real-Time Ex Post MCPs. The Real-Time ~~based on the same input data and SCED algorithm used to clear the Real-Time Energy and Operating Reserve Market. The~~ Ex Post LMPs and Real-Time Ex Post MCPs will be subject to input data validation and adherence to the price calculation requirements.~~, specified in this Tariff.~~ Input data validation corrections will be made pursuant to Section 40.2.18 of this Tariff.~~, and the Business Practices Manuals.~~ The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs are used to settle Real-Time Energy and Operating 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.~~ex post process described in this Tariff and the Business Practices Manuals.~~ The Real-Time Ex Post LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, and, if applicable, Reserve Scarcity costs to supply Energy to ~~a~~ Load at the Elemental Pricing Node during the Dispatch Interval using the SCED-Pricing algorithm. The Real-Time Ex Post LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource Offers, (iii) External Asynchronous Resource Offers, and (iv) Emergency Demand Response resource Offers.~~.~~

~~The Ex Post 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 Post LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Real-Time~~any~~ Ex Post LMP reflects the marginal cost of managing the transmission congestion 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 the 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~~Markets~~. 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~~Markets~~. 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 ~~Ex Post LMP~~ or Aggregate Price Node ~~Ex Post LMP~~ 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 the Real-Time~~an~~ 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~~Operating~~ Day.

f. Determination of the Real-Time Ex Post LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine the Real-Time~~an~~ 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.

g. Determination of the Real-Time Ex Post LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine the Real-Time~~an~~ 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~~Price~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Post MCPs for Regulating Reserve ~~MCPs~~ for Generation Resources, Demand Response 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 ~~. The~~ Ex Post MCP for Regulating Reserve ~~MCP~~ for Generation Resources, Demand Response 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) Reserve Zone Operating Reserve Constraint Shadow Price, (v) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, (vi) Reserve Zone Regulating Reserve Balance Constraint Shadow Price (vii) Market-Wide ~~-~~Non-DRR1 Operating Reserve Constraint Shadow Price, and (viii) beginning November 1, 2011, additional marginal cost for managing congestion in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone; all such Constraints~~constraints~~ noted herein are as set forth in Schedule 29A. ~~29. Such Ex Post Regulating Reserve 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.~~

i. Determining the Real-Time Ex Post Regulating Reserve Market Clearing Prices~~Price~~ for Stored Energy Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Post MCPs for Regulating Reserve ~~MCPs~~ for Stored Energy Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using~~based on~~ the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Regulating Reserve ~~MCP~~ 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, and (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price; all such Constraints noted herein are as set forth in Schedule 29A. ~~29. Such Regulating Reserve MCPs for Stored Energy Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.~~

j. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices~~Price~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve ~~MCPs~~ for Generation Resources, Demand Response 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~~. The~~ Ex Post MCP for Spinning Reserve ~~MCP~~ for Generation Resources, Demand Response 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) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion 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, using the SCED-Pricing algorithm, 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, (iii) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing congestion 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~~29. Such Ex Post 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~~.

~~k~~l. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices~~Price~~ for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources

The Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve ~~MCPs~~ for Generation Resources, Demand Response 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 ~~MCP~~ for Generation Resources, Demand Response Resources – Type II, External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, if applicable, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, if applicable, and (iv) beginning November 1, 2011, additional marginal cost for managing congestion 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~~29~~.

m. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices~~Price~~ for Demand Response Resources - Type I

On a real-time market basis, the~~The~~ Transmission Provider shall calculate the Real-Time

Ex Post MCPs for Supplemental Reserve ~~MCPs~~ 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~~. The~~ Ex Post MCP for Supplemental Reserve ~~MCP~~ for Demand Response Resources - Type I is the sum of the: (i) Market-Wide Operating Reserve Constraint Shadow Price,~~ and~~ (ii) Reserve Zone Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost for managing congestion 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 ~~29. Such Ex Post Supplemental Reserve MCPs for Demand Response Resources - Type I shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.~~

n. 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.

40.2.18 Price Verification Version: 1.0.0

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 and Operating 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 and/or Operating 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 Intervals and then integrated and weighted in accordance with the standard procedure.

c. Real-Time Ex Post MCPs and Hourly 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 Hourly 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 Hourly Real-Time Ex Post LMPs exceeding five (5) Business Days from the applicable Operating Day shall require approval by the Transmission Provider Board.

40.2.20 Capacity Shortage Conditions in the Real-Time EORM Version: 2~~1~~.0.0 Effective: 12/31/9998~~3/1/2011~~

The Transmission Provider shall take the measures set forth below during Capacity shortage conditions to maintain reliability within the Midwest ISO 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 Midwest ISO 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: (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource - Type II and External Asynchronous Resource up to the 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, and Demand Response Resources - Type II that are designated as available for Emergency conditions only, and (iii) the curtailment of Export Schedules, in amounts required to relieve the shortage condition in an economic manner.

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 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, 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 in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post~~LMPs and~~ MCPs which will reflect Scarcity Pricing based upon Demand Curves, if sufficient Operating Reserve is not cleared to meet the Market-Wide and/or Zonal Operating Reserve Requirement.

ii. 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 Midwest ISO Balancing Authority Area basis, or a on a Sub-Area basis if limited by transmission 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 Midwest ISO Balancing Authority Area, as applicable. During Emergency conditions, Real-Time Ex Ante LMPs, Real-Time Ex Ante MCPs, Real-Time Ex Post LMPs and Real-Time Ex Post~~LMPs and~~ MCPs will be set to the VOLL, either on a Midwest ISO 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 OASIS notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section

40.2.20.

40.2.21 Capacity Surplus under Minimum Load Conditions in RT EORM Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

The Transmission Provider shall take the measures set forth below during Capacity surplus conditions under minimum Load conditions to maintain reliability within the Midwest ISO Balancing Authority Area.

a. RAC

If during any RAC process, the Transmission Provider's forecast of Real-Time demand less Regulating Reserve within the Midwest ISO 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 and Demand Response 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 when setting prices.

ii. If Real-Time demand less Regulating Reserve within the Midwest ISO 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 ~~and~~ 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~~MCPs~~ 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 OASIS notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.21.

40.3 Real-Time Energy and Operating Reserve Market Settlement Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

The Transmission Provider shall provide timely Settlement of purchases and sales of Energy, Regulating Reserve, Spinning Reserves, and Supplemental Reserves in the Real-Time Energy and Operating Reserve Market. Settlement of the Real-Time Energy and Operating Reserve Market will be conducted on an hourly basis 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 applicable Hourly Real-Time Ex Post LMPs and Metered MWh values, and applicable Hourly Real-Time Ex Post MCPs and Dispatch Targets for Operating Reserve. Settlement is performed on quantity deviations from Day-Ahead Energy and Operating Reserve Schedules.

40.3.1 Hourly Ex Post LMPs and MCPs Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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 EORM Market Settlement Calculations Version: 3~~2~~.0.0 Effective: 12/31/9998

Real-Time Energy and Operating Reserve Market Market Settlement Calculations

The Real-Time Energy and Operating Reserve Market shall be settled on quantity deviations from the Day-Ahead Energy and Operating Reserve Schedules, with consideration for Real-Time Financial Schedules. Settlement for the Real-Time Energy and Operating Reserve Market uses applicable Hourly Real-Time Ex Post LMPs and reported MWh values, and applicable Hourly Real-Time Ex Post MCPs and Dispatch Targets for Operating 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:

a. Charges and Credits for Real-Time Energy and Operating Reserve Market Purchases.

i. Energy Charges and Credits. Market Participants shall be charged the applicable Hourly Real-Time Ex Post LMP for any Actual Energy Withdrawals other than Actual Energy Withdrawals associated with a host Load Zone, 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. Real-Time Revenue Sufficiency Guarantee Constraint Management Charge: For deviations occurring prior to the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the following deviations adjusted for the applicable

Commercial Pricing Node Constraint Contribution Factor:

(1) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any positive difference between: (a) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (b) the Day-Ahead Schedule (excluding Resources committed in any RAC processes conducted for the Operating Day);

(2) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any negative difference between:

(a) the Real-Time Hourly Economic Maximum Limit in effect at the Notification Deadline and (b) the Day-Ahead Schedule (excluding Resources committed in any RAC processes conducted for the Operating Day);

(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 Virtual Transaction resulting from a cleared Virtual Supply Offer or the negative of any Virtual Transaction resulting from a cleared Virtual Bid;

(5) any difference between: (a) the real-time Import Schedule in effect at the Notification Deadline and (b) the day-ahead Import Schedule;

(6) any difference between:

(a) the day-ahead Export Schedule and (b) the real-time Export Schedule in effect at the Notification Deadline;

(7) the negative of 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).

For deviations occurring after the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the maximum of: (1) the following deviations adjusted for the applicable Commercial

Pricing Node Constraint Contribution Factor and (2) zero:

(1) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any positive 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: (1) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (ii) the Day-Ahead Schedule and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day); (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day);

(2) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any negative difference between: (a) the real-time hourly Economic Maximum 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 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 (4) for Day-Ahead committed Resources, the Day-Ahead Schedule for Supplemental Reserve and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day);

(3) for Resources, Excessive Energy or the negative of Deficient Energy pursuant to Section 40.3.4;

(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;

(5) any difference between:

(a) the real-time Import Schedule and (b) the real-time Import Schedule in effect at the Notification Deadline;

(6) any difference between: (a) the real-time Export Schedule in effect at the Notification Deadline and (b) the real-time Export Schedule; and

(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.

The sum, by Asset Owner, of: (1) the net positive sum of the Asset Owner's deviations pursuant to Section 40.3.3.a.ii and (2) the sum of such Asset Owner's deviations pursuant to Section 40.3.3.a.iii, shall be multiplied by the per unit Real-Time Revenue Sufficiency Guarantee Constraint Management Charge deviation rate to determine the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge to be paid by the Market Participant.

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 aggregate Real-Time Revenue Sufficiency Guarantee Credit in that Hour attributed to Resources committed in any RAC processes and (2) the greater of: (a) the sum of: (i) the aggregate net positive sum, by Asset Owner, for such amounts pursuant to Sections 40.3.3.a.ii and 40.3.3.a.iii and (ii) any Topology Adjustment or Transmission De-rate adjusted for the applicable Constraint Contribution Factor and (b) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes, adjusted for the applicable Constraint Contribution Factor.

In the event that the aggregate Real-Time Revenue Sufficiency Guarantee Credit in any Hour attributed to Resources committed in any RAC processes for the given Active Transmission Constraint 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 excess shall be funded through the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation and Headroom Charges.

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.

v. RSG Intra-Hour Demand Change Charge

(a) Any Real-Time Revenue Sufficiency Guarantee Make Whole Payments paid to Resources committed for a purpose other than constraint management and any residual Real-Time Revenue Sufficiency Guarantee Charge Make Whole Payments not recovered under the RSG Constraint Management Charge including RSG Second Pass Charge assignment will be determined under the RSG Intra-Hour Demand Change Charge, described below.

(b) The RSG Intra-Hour Demand Change Charge will be the product of: (1) the amount set forth in Section 40.3.3.a.iv (a), and; (2) the minimum of (a) the Real-Time Headroom for the Hour, over the sum of the Real-Time Economic Maximum Dispatch that were not used in support of transmission constraint management, plus the sum of the residual of the Real-Time Economic Maximum Dispatch for Resources used in support of transmission constraint management after reduction by the Capacity allocated under the RSG Constraint Management Charge. This residual shall equal the total Real-Time Economic Maximum Dispatch attributable to Resources committed to manage a transmission constraint, multiplied by the percentage of the Real-Time Revenue Sufficiency Guarantee Charges attributable to Resources committed to manage a transmission constraint not recovered under the RSG Constraint Management Charge, or; (b) the value of 1.

The Real-Time Headroom shall be equal to the sum of the differences between the Real-Time Economic Maximum Dispatch and Actual Injections of Resources committed by the Transmission Provider in any RAC processes conducted for the Operating Day.

(c) The aggregate Real-Time Revenue Sufficiency Guarantee Charge in an Hour calculated under the RSG Intra-Hour Demand Change Charge shall be assessed to Market Participants through the RSG Second Pass Charge.

(d) In the event that the aggregate Real-Time Revenue Sufficiency Guarantee Charge described in Section 40.3.3.a.iv (b) in that Hour exceeds the aggregate of the RSG Intra-Hour Demand Change Charges to Market Participants and the RSG Constraint Management Charge, any excess shall be recovered under the RSG Day-Ahead Schedule Deviations Charge.

v. **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 the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge or 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.

(a) **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.a.vi, 40.3.3.a.vii and 40.3.3.a.viii.

(b) **Real-Time Revenue Sufficiency Guarantee Headroom Charge**: The Real-Time Revenue Sufficiency Guarantee Headroom Charge in an Hour will be calculated by multiplying 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 and by the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation and Headroom Rate determined in section 40.3.3.a.viii. The Real-Time Revenue Sufficiency Guarantee Headroom Charge will be allocated pro rata, to Market Participants based on their Market Load Ratio Share.

vi. 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 and External Asynchronous Resources, 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 (iv) for Day-Ahead committed Resources, the Day-Ahead Schedule for Supplemental Reserve and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day);

(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) any difference between (a) the day-ahead

Import Schedule and (b) the real-time Import Schedule in effect at the Notification Deadline;

(4) 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);

(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.

vii. 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 and External Asynchronous Resources committed in any RAC processes conducted for the Operating Day, any positive difference between (a) the real-time Hourly Economic Maximum Limit at the time the Generation Resource, Demand Response Resource – 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 and External

Asynchronous Resources committed in any RAC processes conducted for the Operating Day, 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 and External Asynchronous Resource is committed by the Transmission Provider;

(3) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources not committed in any RAC processes 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;

(3) for Resources, Deficient Energy pursuant to Section 40.3.4;

(4) for Load Zones, any positive difference

between (a) the Actual Energy Withdrawal and (b) the Real-Time Load Zone Demand Forecast in effect at the Notification Deadline**;**

(5) any positive difference between (a) the real-time Import Schedule in effect at the Notification Deadline and (b) the real-time Import Schedule;

(6) any positive difference between (a) the real-time Export Schedule and (b) the real-time Export Schedule in effect at the Notification Deadline; and

(7) for Demand Response Resources – Type I, any positive difference between: (a) the Targeted Demand Reduction Level in effect at the Notification Deadline and (b) the Dispatch Target for Energy.

(8) 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; and

(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;

(10) for Intermittent Resources, the positive value of any 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.a.vi and (2) the sum of such Asset Owner's deviations pursuant to Section 40.3.3.a.vii shall be multiplied by the per unit Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation and Headroom Charge rate to determine the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge to be paid by the Market Participant.

viii. **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 equal the quotient of: (1) the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge or otherwise attributable to Topology Adjustment or Transmission De-rate 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.a.vi and 40.3.3.a.vii and (ii) 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 and (b) the difference between: (i) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes and (ii) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes adjusted for the applicable

Constraint Contribution Factor.

ix. In the event that the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge or 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.

x. 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) Resource deviations 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; or (4) Intermittent Resource deviations caused by or occurring as a result of Transmission Provider manual curtailment instructions.

xi. ***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.

xii. **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.a.xi, *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.

xiii. **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.

xiv. **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.

xv. **Revenue Neutrality.** The Transmission Provider shall distribute the revenue inadequacy or surplus adequacy from the Settlement of Excessive Energy *pro rata*, to Market Participant Loads based on their Market Load Ratio Share.

xvi. **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 Hourly Real-time Ex Post LMP and the Resource's Offer Price at the average Dispatch Target for Energy during the Dispatch Interval. Market Participants, excluding Stored Energy Resources, with 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 Hourly 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.

xvii. Reserve Zone Demand Response Resource Compensation Recovery Charge: For each Reserve Zone and each Hour, the Transmission Provider shall recover the total Demand Response Resource compensation based on the total Demand Response Resource monetary benefit. The total Demand Response Resource monetary benefit is equal to the sum of all Market Participant benefits from: (1) a decreased Hourly Ex Post LMP, and (2) avoided losses on retail sales.

Demand Response Resource compensation: For a given Demand Response Resource, the Demand Response Resource compensation is equal to the sum of:

(1) the product of:

(A) the minimum of (i) the Day-Ahead Schedule for Energy or (ii) the Real-Time Non-Excessive Energy; and

(B) the Hourly Ex Post LMP for the Load Zone(s) associated with the Demand Response Resource; and

(2) the product of:

(A) the maximum of (i) zero or (ii) the difference between (a) the Real-Time Non-Excessive Energy and (b) the Day-Ahead Schedule for Energy; and

(B) the Hourly Ex Post LMP for the Demand Response Resource; and

(3) the Real-Time Excessive Energy times the Demand Response Resource Excessive Energy Price.

Monetary Benefit from Decreased Hourly Ex Post LMP: The Market Participant monetary benefit from decreased Hourly Ex Post LMP is equal to the product of: (i) the MWs purchased by all buyers (including cleared Virtual Supply Offers) in the Real-Time EORM at the Hourly Ex Post LMP and (ii) the difference between:

(1) the price point on the Net Benefits Supply Curve corresponding to the MW quantity equal to the sum of:

(A) the MW quantity on the Net Benefits Supply Curve corresponding to the Reserve Zone Hourly Ex Post LMP; plus

(B) the quantity of Real-Time Non-Excessive Energy for Demand Response Resources; and

(2) the applicable Hourly Ex Post LMP.

Monetary Benefits from Avoided Losses on Retail Sales: For each Demand Response Resource and associated Load Zone and each Hour, the Market Participant monetary benefit from avoided losses on retail sales is equal to the product of: (1) the maximum of (i) the difference between the Hourly Ex Post LMP for the Load Zone and the MFRR, or (ii) zero; and (2) the Demand Response Resource Actual Energy Injection.

If the total Demand Response Resource monetary benefit for an Hour is greater than the total Demand Response Resource compensation, then Market Participants who benefited shall receive a charge equal to the product of: (1) their respective monetary benefit; and (2) the quotient of (i) the total Demand Response Resource compensation and (ii) the total Demand Response Resource monetary benefit.

If the total Demand Response Resource monetary benefit for an Hour is less than or equal to the total Demand Response Resource compensation, then Market Participants who benefitted shall receive a charge equal to their respective Demand Response Resource monetary benefit.

If the total Demand Response Resource compensation is greater than the total Demand Response Resource monetary benefit, then the excess Demand Response Resource compensation shall be allocated, *pro rata*, based on Market Participant Load Ratio Share.

b. Credits for Real-Time Energy and Operating Reserve Market Sales.

i. Non-Excessive Energy Credits. Market Participants are credited the applicable Hourly Real-Time Ex Post LMP for Non-Excessive Energy injection for Generation Resources, Stored Energy Resources and External Asynchronous Resources 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 Hourly Real-

Time Ex Post LMP is the LMP at the Commercial Pricing Node at which the injection occurs.

ii. Excessive Energy Credits. Market Participants are credited the lesser of the Hourly Real-Time Ex Post LMP and the Hourly Excessive Energy Price for Excessive Energy associated with Generation Resources, and External Asynchronous Resources where such Excessive Energy is calculated pursuant to Section 40.3.4. Excessive Energy associated with Stored Energy Resources is settled at the Hourly Real-Time Ex Post LMP.

iii. Regulating Reserve Credit. Market Participants are credited the Hourly Real-Time Ex Post MCP for any positive difference between the time-weighted average of the Real-Time cleared amounts for Regulating Reserve in an Hour and their Day-Ahead Schedule for Regulating Reserve in that Hour (and will be charged the Hourly Real-Time Ex Post MCP for any negative difference between the time-weighted average of the Real-Time cleared amounts for Regulating Reserve in an Hour and their Day-Ahead Schedule for Regulating Reserve in that Hour). The applicable Hourly Real-Time Ex

Post MCP for Regulating Reserve is for the Commercial Pricing Node at which the procurement occurs.

iv. Spinning Reserve Credits. Market Participants are credited the Hourly Real-Time Ex Post MCP for any positive difference between the time-weighted average of the Real-Time cleared amounts for Spinning Reserve in that Hour and their Day-Ahead Schedule for Spinning Reserve in that Hour (and will be charged the Hourly Real-Time Ex Post MCP for any negative difference between the time-weighted average of the Real-Time cleared amounts for Spinning Reserve and their Day-Ahead Schedule for Spinning Reserve in that Hour). The applicable Hourly Real-Time Ex Post MCP for Spinning Reserve is for the Commercial Pricing Node at which the procurement occurs.

v. Supplemental Reserve Credits. Market Participants are credited the Hourly Real-Time Ex Post MCP for any positive difference between the time-weighted average of the Real-Time cleared amounts for Supplemental Reserve in an Hour and their Day-Ahead Schedule for Supplemental Reserve in that

Hour (and will be charged for any negative difference between the time-weighted average of the Real-Time cleared amounts for Supplemental Reserve in the Hour less their Day-Ahead Schedule for Supplemental Reserve in that Hour). The applicable Hourly Real-Time Ex Post MCP for Supplemental Reserve is for the Commercial Pricing Node at which the procurement occurs.

vi. Real-Time Revenue Sufficiency Guarantee Credit. The Transmission Provider shall determine, on a daily basis, whether any Generation Resources, ~~or~~ Demand Response Resources committed by the Transmission Provider in the Real-Time Energy and Operating Reserve Market did not recover the sum of the Resource's 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. If the sum of the Generation Resource's ~~and~~ Demand Response Resource's Production Cost (based on Non-Excessive Energy) and Operating Reserve Cost is greater than the sum of (a) for Generation Resources, ~~or~~ Demand Response

Resources, Non-Excessive Energy multiplied by the applicable Hourly Real-Time ~~Hourly~~ Ex Post LMP, (b) Real-Time Operating Reserve Revenue as determined by the sum, for all Dispatch Intervals in an Hour, of the products of the (i) cleared Real-time Operating Reserve for a Dispatch Interval and (ii) applicable Real-Time Ex Post MCP for a Dispatch Interval and (iii) the duration of the Dispatch Interval expressed in Hours, (c) and the sum of the Dispatch Interval net Regulating Reserve Deployment charge/credit as determined pursuant to Section 40.3.3.a.xi for the Hour, 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 shortfall spread over all the Hours in that contiguous commitment period. ~~When the Hourly Ex Post LMP is less than the Net Benefit Price Threshold for a given Demand Response Resource, applicable hourly Production Costs will be equal to zero for those hour(s) in which the Real~~

~~Time LMP is less than the Net Benefits Price Threshold. If the Demand Response Resource is a BTMG then the applicable hourly production cost will be equal to zero.~~ This credit shall be supported through revenue collected from the Real-Time Revenue Sufficiency Guarantee Charge.

vii. 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.

c. Charges and Credits for Real-Time Energy and Operating Reserve Market Energy Purchases and Sales Associated with Demand Response Resources.

i. **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 Host Load Zone or Demand Response Resource – Type I, net of Real-Time Financial Schedules that exceed their Day-Ahead Scheduled Withdrawals associated with a Host Load Zone or Demand Response Resource – Type I (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 Host Load Zone or Demand Response Resource-Type I). 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. **Demand Response Resource Non-Excessive Energy Charges and Credits.** ~~When the Hourly Ex Post LMP is greater than or equal to the Net Benefit Price Threshold,~~ Market Participants are~~will be~~ credited the applicable Hourly Real-Time Ex Post LMP for Non-Excessive Energy injection for Demand Response Resources – Type I and Demand Response Resources – Type II~~(that are not BTMG)~~ pursuant to Section 40.3.4, net of Real-Time Financial Schedules, that exceeds their Day-Ahead Scheduled Injections (and will be charged ~~. When the Hourly Ex Post LMP is less than the Net Benefit Price Threshold, then Market Participants will be credited at a price of zero dollars per MWh ($0/MWh)~~ for Non-Excessive Energy, net of Real-Time Financial Schedules, deviations ~~injection for~~

~~Demand Response Resources pursuant to Section 40.3.4, that exceeds their Day-Ahead Scheduled Injections. Market Participants will be charged the applicable Hourly Ex Post LMP for Non-Excessive Energy~~ below their Day-Ahead Scheduled Injections). The applicable Hourly Real-Time ~~. Market Participants with Real Time Financial Schedules will be charged the applicable Hourly Ex Post LMP for Real Time Financial Schedule sales and will be credited for Real Time Financial Schedule purchases. The applicable Hourly~~ Ex Post LMP is the LMP at the Commercial Pricing Node.

iii. **Demand Response Resource Excessive Energy Credits.** ~~When the Hourly Ex Post LMP is greater than or equal to the Net Benefit Price Threshold,~~ Market Participants are credited the lesser of the applicable Hourly Real-Time Ex Post LMP and the Hourly Excessive Energy Price for Excessive Energy associated with Demand Response Resources – Type I and Demand Response Resources – Type II~~(other than BTMG)~~ where such Excessive Energy is calculated pursuant to Section 40.3.4. ~~When the Hourly Ex Post LMP is less than the Net Benefit Price Threshold,. Market Participants will be credited at a price of zero dollars per MWh ($0/MWh) for Excessive Energy.~~

The applicable Hourly Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node.

d. Charges and Credits for Midwest ISO Balancing Authority Compliance with NERC/RRO Standards and Participation in Reserve Sharing Group.

i. Administrative Charges/Credits. Revenue received by the Midwest ISO 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 Rate Schedule 17 of the Tariff. Fees to be paid by the Midwest ISO Balancing Authority associated with the provision of such administrative services shall be recovered from Market Participants pursuant to Rate Schedule 17 of the Tariff.

ii. Other Charges/Revenue. Charges owed, other than charges owed under Sections 40.3.3.d.i and 40.2.22, by the Midwest ISO 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.d.i, received by the Midwest ISO 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.

40.3.4 Charge for Excessive/Deficient Energy and Reserve Deployment Version: ~~3.~~5.0.0
Effective: 12/31/9998~~4/19/2011~~

Settlement of deviations from Setpoint Instructions is conducted hourly 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. 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. 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, Demand Response Resource – Type II and External Asynchronous Resource Tolerance Band. The upper limit of a Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource specific Tolerance Band, or Excessive Energy Threshold, shall be equal to the sum of: (1) one hundred and eight percent (108%) of 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 for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate; and (2) the product of (a) the ramp rate used for energy and regulation and (b) the duration of the Dispatch Interval, in minutes. The lower limit of a Generation Resource, Demand Response Resource – Type II, or External Asynchronous Resource specific Tolerance Band, or Deficient Energy Threshold, shall be equal to the sum of: (1) ninety-two percent (92%) of 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 for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate; and (2) the negative product of (a) the ramp rate used for Energy and regulation and (b) the duration of the 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.iv, 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. Demand Response Resource – Type I Tolerance Band.

The upper limit of a Demand Response Resource – Type I specific Tolerance Band, or Excessive Energy Threshold, for Demand Response Resources – Type I that have been committed for Energy, shall be equal to one hundred and eight percent (108%) of the Targeted Demand Reduction Level for that Dispatch Interval and, the lower limit of a Demand Response Resource - Type I specific Tolerance Band, or Deficient Energy Threshold, for Demand Response Resources – Type I that have been committed for Energy, shall be equal to ninety-two percent (92%) 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.iv. 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.

iii. Stored Energy Resource Tolerance Band. The upper limit of a Stored Energy Resource specific Tolerance Band, or Excessive Energy Threshold, 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) 8% 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 lower limit of a Stored Energy Resource specific Tolerance Band, or Deficient Energy Threshold, 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 8% of the absolute value of (i) the Dispatch Target for Energy and (ii) the average Regulating Reserve Deployment instruction for that Dispatch Interval.

iv. 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.

v. Hourly Excessive Energy for Generation Resource, and Stored Energy Resource and External Asynchronous Resource. Hourly Excessive Energy for a Generation Resource, Stored Energy Resource, or External Asynchronous Resource is equal to the sum of the Excessive Energy amounts in each Dispatch Interval for that Generation Resource, Stored Energy Resource, or External Asynchronous Resource in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. 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 average telemetered output of the Generation Resource, expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output of the External Asynchronous Resource, expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output of the Stored Energy Resource, expressed in MW and scaled by Actual Energy Injection, and the Excessive Energy Threshold for that Stored Energy Resource, or (b) zero.

vi. Hourly Excessive Energy for Demand Response Resource-Type I. Hourly Excessive Energy for one or more Demand Response Resources-Type I equal to the sum of the Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type I in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. Excessive Energy for such one or more a Demand Response Resources - 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 such one or more Demand Response Resources -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).

vii. Hourly Excessive Energy for Demand Response Resource-Type II. Hourly Excessive Energy for one or more Demand Response Resources-Type II is equal to the sum of the Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type II in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. Excessive Energy for such one or more Demand Response Resources - 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 one or more Demand Response Resource -Type II, expressed in MW, and the Excessive Energy Threshold for such one or more Demand Response Resource -Type II, or (b) zero. The Calculated DRR -Type II Output for a Dispatch Interval, scaled by Actual Energy Injection, is equal to the host Load Zone Dispatch Interval Demand Forecast (positive value) in a Dispatch Interval, expressed in MW, minus the host Load Zone average net telemetered demand amount (withdrawal positive, injection negative) for that Dispatch Interval, expressed in MW; where such total amount is allocated to specific Demand Response Resources – Type II in any proportion as determined by the Market Participants. If the Dispatch Interval Demand

Forecast is equal to zero or is not submitted to the Transmission Provider, the Calculated DRR-Type II Output shall be equal to zero (0).

viii. Hourly Deficient Energy for Generation Resource, Stored Energy Resource, or External Asynchronous Resource. Hourly Deficient Energy for a Generation Resource, Stored Energy Resource or External Asynchronous Resource is equal to the sum of the Deficient Energy amounts in each Dispatch Interval for that Generation Resource, Stored Energy Resource or External Asynchronous Resource in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. 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 average telemetered output for that Generation Resource expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output for that External Asynchronous Resource, expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output for that Stored Energy Resource, expressed in MW and scaled by Actual Energy Injection, or (b) zero (0) MW.

ix. Hourly Deficient Energy for Demand Response Resource-Type I. Hourly Deficient Energy for one or more Demand Response Resource-Type I is equal to the sum of the Deficient Energy amounts for such one or more Demand Response Resources – Type I in each Dispatch Interval in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. Deficient Energy in a Dispatch Interval for such one or more Demand Response Resources-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 such one or more Demand Response Resources-Type I and the Calculated DRR-Type I Output of such one or more Demand Response Resources -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.

x. Hourly Deficient Energy for Demand Response Resource-Type II. Hourly Deficient Energy for one or more Demand Response Resources-

Type II is equal to the sum of the Deficient Energy amounts for such one or more Demand Response Resources – Type II in each Dispatch Interval in a specific Hour with Excessive Energy, Deficient Energy of any combination thereof in four (4) or more consecutive Dispatch Intervals. Deficient Energy in a Dispatch Interval for such one or more Demand Response Resources-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 one or more Demand Response Resources-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. The Calculated DRR -Type II Output, scaled by Actual Energy Injection, for a Dispatch Interval is equal to the host Load Zone Dispatch Interval Demand Forecast (positive value) in a Dispatch Interval, expressed in MW, minus the host Load Zone average net telemetered demand amount (withdrawal positive, injection negative) for that Dispatch Interval, expressed in MW; where such total amount is allocated to specific Demand Response Resources – Type II in any proportion as determined by the Market Participant. If the Dispatch Interval Demand Forecast is equal to zero or is not submitted to the Transmission Provider, the Calculated DRR-Type II Output shall be equal to zero (0) MW.

xi. Hourly Non-Excessive Energy for Generation Resource, Stored Energy Resource, or External Asynchronous Resource. Hourly Non-Excessive Energy for a Generation Resource, Stored Energy Resource, or

External Asynchronous Resource is equal to the sum of Non-Excessive Energy amounts in each Dispatch Interval for the Generation Resource, Stored Energy Resource, or External Asynchronous Resource in a specific Hour. 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, of the Stored Energy Resource.

xii. Hourly Non-Excessive Energy for Demand Response Resource-Type I. Hourly Non-Excessive Energy for one or more Demand Response Resources-Type I is equal to the sum of Non-Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type I in a specific Hour. 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 such one or more 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 one or more Demand Response Resource-Type I, or such one or more Demand Response Resources'-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 such one or more Demand Response Resources 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 the Measurement and Verification procedures. 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.

xiii. Hourly Non-Excessive Energy for Demand Response Resource-Type II. Hourly Non-Excessive Energy for one or more Demand Response Resource-Type II is equal to the sum of Non-Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type II in a specific Hour. 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 such one or more Demand Response Resources-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 one or more Demand Response Resources-Type II, or such one or more Demand Response Resources-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 such one or more Demand Response Resources-Type II is equal to the product of the Dispatch Interval duration in Hours and the Calculated DRR-Type II Output of such one or more Demand Response Resources-Type II.

For Demand Response Resources - Type II that are Regulation Qualified resources, the Calculated DRR-Type II Output, scaled by Actual Energy Injection, for a Dispatch Interval is equal to the host Load Zone Dispatch Interval Demand Forecast (positive value) in a Dispatch Interval, expressed in MW, minus the host Load Zone average net telemetered demand amount (withdrawal positive, injection negative) for that Dispatch Interval, expressed in MW; where such total amount is allocated to specific Demand Response Resources – Type II in any proportion as determined by the Market Participant. If the Dispatch Interval Demand Forecast is equal to zero or is not submitted to the Transmission Provider, the Calculated DRR-Type II Output shall be equal to zero (0) MW.

For Demand Response Resources - Type II that are not Regulation Qualified, the Calculated DRR-Type II Output is calculated in accordance with the Measurement and Verification procedures.

xiv. 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 and (ii) the Regulating Reserve credits/charges calculated pursuant to Section 40.3.3.b.iii 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 and (ii) the Real-Time Regulating Reserve charges/credits calculated pursuant to Section 40.3.3.b.iii 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.

Not withstanding 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.

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 II, Demand Response Resources-Type II, and Stored Energy Resources 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 or Stored Energy Resource; or

(4) The Hour when a Generation Resource or Stored Energy Resource 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 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 Hourly Real-Time Ex Post LMP of the Resource Commercial Pricing Node for the Hour 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~~Spinning~~ Reserve available for payment on that

Resource shall be restricted to the amount actually deployed in the Hour of failure and for every Hour thereafter until the Resource achieves a higher level of output in a subsequent test or actual deployment; and~~the remaining Hours in the Operating Day; 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. Revenue Distribution from Contingency Reserve Deployment Failure Charge and Excessive/Deficient Energy Deployment Charge. Credits resulting from Contingency Reserve Deployment Failure Charges shall be allocated to all Market Participants pro rata~~prorata~~, 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~~prorata~~, based on their Market Load Ratio Share, excluding Export schedules.

g. 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 ove 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 eith percent (108%) 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) ninety-two percent (92%) 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.

h. 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. As Contingency Reserve Deployment Failure Charge that is equal to the Resource's Shortfall Amount(s) multiplied by the Hourly Ex Post LMP of the Resource Commercial Pricing Node for the Hour 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.

40.3.5.1 Rationale for RTORSGP Version: 2~~1~~.0.0 Effective: 12/31/9998

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~~hourly~~ Real-Time Ex Post LMP revenue and hourly net Operating 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 in accordance with the eligibility and other requirements as stated in Section 33.8.

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, Demand Response Resources – Type I committed for the deployment of Spinning Reserve, and External Asynchronous Resources are eligible for the RTORSGP. The RTORSGP provides a Market Participant following Setpoint Instructions with a method to recover incremental Energy~~energy~~ costs thereby incurred that are not otherwise collected from the Hourly Real-Time Ex Post LMP and net Operating Reserve revenue. 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.~~. for a Resource based on avoided Real-Time LMP revenues and/or avoided Real-Time MCP revenues.~~ 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.

40.3.6.1 Rationale for DAMAP Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

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 and/or Day-

Ahead Schedule for Supplemental 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 the Midwest ISO, 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 cleared in excess of Day-Ahead Schedules for Operating Reserve. 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 in accordance with the eligibility and other requirements stated in Section 33.8 of this Tariff.

40.4.1 Transmission Usage Charges in the Real-Time EORM Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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 Hourly 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 1100 hours EST (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 will be the product of: (i) the amount of Energy scheduled to be withdrawn by the Market Participant in each Hour 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 Hourly Real-Time Ex Post LMP at the Commercial Pricing Node for the relevant Interface in $/MWh.

c. Interchange Schedules that represent Through Transactions are subject to Transmission Usage Charges based on the Hourly Real-Time Ex Post LMP at the Interface where they enter or exit the Transmission Provider Region. The Transmission Usage Charge will be the product of: (i) the amount of Energy scheduled to be withdrawn by that Market Participant in each Hour 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 Hourly Real-Time Ex Post LMP at the Commercial Pricing Node for the Interface relevant to the Interchange Schedule Delivery Point, minus the Hourly Real-Time Ex Post LMP at the Commercial Pricing Node of the Interface relevant to the Interchange Schedule Receipt Point, in $/MWh.

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 Hourly Real-Time Ex Post LMP at the Interface for the Interchange Schedule Delivery Point minus the

Marginal Congestion Component of the Hourly 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 Hourly 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 Hourly Real-Time Ex Post LMP at the Interface for the Interchange Schedule Delivery Point minus the Marginal Losses Component of the Hourly 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.

40.4.2 Financial Schedule Settlements Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

The Transmission Provider shall collect 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.

40.5.1 Hourly Real-Time Marginal Loss Surplus Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

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.

IV. FINANCIAL TRANSMISSION RIGHTS AND AUCTION REVENUE RIGHTS Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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.

42.1 FTR Obligations Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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.

42.2 FTR Options Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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.

45.2.3 Information to be Made Available to FTR Bidders and Offerors Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

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~~ pursuant to the Business Practices Manuals~~.

69.3.5 Demand Resource Eligibility Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can request accreditation for a Demand Resource as an LMR by registering such resource with the Transmission Provider as documented in the BPM for Resource Adequacy and by meeting the following requirements:

i. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources that can reduce Demand may qualify in meeting this standard).

ii. The Demand Resource must be available to be scheduled for a Demand reduction at the targeted Demand reduction level or by moving to a specified firm service level with no more than 12 Hours advance notice from the Transmission Provider.

iii. Once Scheduling Instructions are given by the Transmission Provider that require a Demand reduction, the Demand Resource must be capable of ramping down to meet the targeted Demand reduction level or achieve the firm service level by the Hour designated by the Transmission Provider's Scheduling Instructions.

iv. Once the targeted level of Demand reduction or firm service level is achieved, the Demand Resource must be able to maintain the targeted level of Demand reduction or firm service level for at least four (4) continuous Hours.

v. The Demand Resource must be capable of being interrupted at least five (5) times during the Summer Season (when called upon by the Transmission Provider) during any Planning Year for which the Demand Resource receives credit as a Planning Resource.

vi. Unless the Demand Resource is unavailable as a result of maintenance requirements or for reasons of Force Majeure, when a Demand reduction is requested by the Transmission Provider, the resultant reduction must be a reduction that would not have otherwise occurred within the next twenty four (24) hour period. There shall be no penalties assessed to a Market Participant representing the entity that has designated the PRCs from the LMR if the Demand Resource is unavailable for interruption as a result of maintenance requirements or for reasons of Force Majeure, or in the event the specified Demand reduction had already been accomplished for other reasons (e.g., economic considerations, self-scheduling at or above the credited level of Demand Resource, or local reliability concerns in accordance with instructions from the LBA).

vii. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures will not qualify as an LMR.

viii. The Transmission Provider will use the MECT to ensure that there can be only one LSE using PRCs from a Demand Resource or netting the MW associated with the Demand Resource from its forecasted Demand.

ix. Demand Resources that are offered into the Day-Ahead and/or Real-Time Energy and Operating Reserve Markets as price sensitive Bids are obligated to be interrupted during an Emergency pursuant to the Transmission Provider emergency operating procedures regardless of the projected or actual ~~Real-Time Energy Market~~ LMP.

x. A Market Participant must provide written documentation to the Transmission Provider from the state having jurisdiction over the Market Participant, or from customers represented by the LMR MP, with the amount and type of Demand Resource and the procedures for achieving the Demand reduction. For a Market Participant without state accreditation procedures for a Demand Resource, the Market Participant must secure verification from a third party auditor that is unaffiliated with the Market Participant to provide documentation of the Demand Resource's ability to reduce to the targeted Demand reduction level or to a specified firm service level when called upon by the Transmission Provider, or provide past performance data that demonstrates the Demand Resource is able to reduce to the targeted Demand reduction level or to the specified firm service level. If performance data does not exist from the previous Planning Year, at least one mock test must be used to support the validity of the Demand Resource, in accordance with the Business Practices Manual for Resource Adequacy. The mock test should employ all systems necessary to initiate a Demand reduction short of actual Demand reduction. The Transmission Provider will periodically review such procedures with the operator of the Demand

Resource to confirm that, among other things, adequate training has occurred to comply with such procedures.

69.3.9 Penalty Provisions for LMRs Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

Unless an LMR is unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Market Participant representing the entity which has designated the PRCs from the LMR will be subject (except as otherwise provided in Section 69.3.7.b) to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to achieve its Scheduling Instructions. The penalties defined below will only apply to the portion of the Scheduling Instruction that is not achieved during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties.

There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (i.e., for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the LBA) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (i.e., a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

a. The Transmission Provider shall assess the responsible Market Participant in Section 69.3.9 the costs that were otherwise incurred to replace the deficient Resource at the time the

LMR is called upon by the Transmission Provider and does not respond in full or in part. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any RSG charges. The Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand, and may, if deemed appropriate by the Transmission Provider, disqualify the Demand Resource or BTMG from further utilization as an LMR for the remainder of the Planning Year when the LMR was unavailable.

b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69.3.9.a above, and the Demand Resource or BTMG will no longer be eligible for utilization as an LMR by any Market Participant in meeting its PRMR or being used to net against forecasted Demand for the remainder of the current Planning Year and for the next Planning Year.

83.4.2 Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

For each occasion that the Congestion Management Customer increases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3, and does not simultaneously decrease the output of one or more Congestion Management Customer units on the opposite side of the constraint to match at least the increased output of the incremented units, the Transmission Provider shall arrange, for and on behalf of the Midwest ISO Market Participants, the delivery of a quantity of Energy~~energy~~ from the Congestion Management Customer equal to the megawatt hour quantity of the net increase in output for the duration of the net increase in output. The price for such delivery shall be the Day-Ahead Ex Post LMP or the Hourly Real-Time Ex Post LMP at the Congestion Management Customer-Transmission Provider interface node at the time of each occasion. If the Operating Procedure referred to in the preceding Section 83.4.1 is followed for a redispatch request, the Congestion Management Customer shall not be required to pay any Revenue Sufficiency Guarantee charges for quantity deviations from Day-Ahead Schedules as specified in Section 40.3.3.a.ii that would otherwise be associated with purchases under this Section 83.4.2 to comply with that redispatch request.

83.5.2 Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

For redispatch of generation requiring transfers of Energy~~energy~~ in the Real-Time Energy and Operating Reserve Market, the Congestion Management Customer will receive charges or credits associated with such transfers that will be settled at the Hourly Real-Time Ex Post LMP at the Congestion Management Customer-Transmission Provider interface node, including any applicable Revenue Sufficiency Guarantee Charges for quantity deviations from Day-Ahead Schedules as specified in Section 40.3.3.a.ii. Where re-dispatch of generation includes the additional commitment of Midwest ISO Resources, the Congestion Management Customer shall pay, in addition to previously specified charges, an amount equal to the applicable Start-Up costs and the No-Load Production Costs for the Resource.

SCHEDULE 2-A Reactive Supply and Voltage Control From Generation or Other Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

SCHEDULE 2-A

Reactive Supply And Voltage Control From

Generation or Other Sources Service

(For Zones Electing Schedule 2-A)

I. GENERAL

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, Generation Resources and non-generation resources capable of providing this service need to produce or absorb reactive power. Thus, service under Schedule 2 Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided to support all transactions on the Transmission System. The amount of Reactive Supply Service that must be supplied with respect to a Transmission Customer's transaction will be determined by the Transmission Provider based on the reactive power support necessary to maintain transmission voltages within the voltage range and the resulting reactive power ranges that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided by the Transmission Provider by making arrangements with the Local Balancing Authority (s) who acquire this service for the Transmission Provider's Transmission System, except that, in the case of ITC Reactive Supply and Voltage Control from Generation Sources Service, the service may, at the election of the ITC, be acquired by the ITC in accordance with the ITC Control Area Services and Operations Tariff and the standards for qualification of Generation Resources set out in this Schedule 2-A. The Transmission Customer must purchase this service from the Transmission Provider or from the ITC, as appropriate. The charges for such service by the Transmission Provider or the ITC will be based on the rates set forth below.

The Transmission Owner(s) within each Zone may elect to use this Schedule 2-A in lieu of Schedule 2. Any Zone that does not elect to utilize this Schedule 2-A and all qualified Generation within the Zone shall be governed by Schedule 2 and not by the terms of this Schedule 2-A. Any Zone that elects to use this Schedule 2-A and all Qualified Generation within that Zone shall be governed by the terms of this Schedule 2-A and not by the terms of Schedule 2. The Transmission Owner(s) electing this Schedule 2-A shall provide the Transmission Provider with sixty (60) days notice of such election. Transmission Owner(s) within each Zone also may choose to terminate the participation of a Zone in this Schedule 2-A upon sixty (60) days notice to the Transmission Provider. The Transmission Provider shall post the Zones to which this Schedule 2-A applies. If there are multiple Transmission Owners within a Zone and there is a disagreement between those Transmission Owners regarding any election, such disagreements shall be resolved pursuant to the dispute resolution provisions of the Tariff.

As detailed in Section III, Qualified Generators interconnected with the Transmission System are expected to operate within a range of 0.95 leading to 0.95 lagging power factor (or, the range specified in the interconnection agreement with the Qualified Generator, if different) based on full rated megawatt output at the Point of Interconnection (the “Deadband”) and, therefore, will not receive compensation for providing Reactive Supply and Voltage Control from Generation Sources Service within that range. The Transmission Provider shall establish a Deadband for each Qualified Generator and notify the Qualified Generator of its Deadband. If a Qualified Generator satisfies the requirements of this Schedule 2-A and is directed to provide Reactive Supply and Voltage Control from Generation Sources Service outside of the Deadband, then the Transmission Provider shall compensate the generator as provided in Section III.

II. QUALIFIED GENERATOR

A. General Qualifications: All existing Generation Resources collecting charges for Reactive Supply and Voltage Control from Generation Sources Service under a Commission approved cost-based rate schedule as of December 1, 2007, are deemed to be Qualified Generators. Any other Generation Resource may collect charges associated with Reactive Supply and Voltage Control from Generation Sources Service under this Schedule 2-A, where the Transmission Provider determines that the Generation Resource is a Qualified Generator based on the requirements of this Section II. The Transmission Provider shall have the right to review the Qualified Generator status of any Generation Resource at a subsequent time and revoke the Qualified Generator status of Generation Resources that do not meet the requirements of this Section II.

B. Technical Qualifications: If a Generation Resource meets the qualifications as stated below, it shall be recognized as a Qualified Generator.

1. The Generation Resource (i) operates with its voltage regulators in automatic mode and responds to voltage schedules of the Transmission Provider or Local Balancing Authority for the pricing zone in which the Generation Resource is located; (ii) is able to maintain voltage support within its design

limits; and (iii) is capable of a reactive power range of 95% leading to 95% lagging at the Point of Interconnection unless otherwise stated in the Generation Resource's Generator Interconnection and Operating Agreement;

2. The Generation Resource (i) can respond to changes in voltage on the system and to changes in voltage schedules if the facility is operating; or (ii) will provide voltage control specified by the Transmission Provider or Local Balancing Authority immediately, if intra-day system conditions require additional reactive power supply to maintain reliability, or as instructed by the Transmission Provider prior to the Operating Day based on forecasted system conditions, taking into consideration the unit's operating characteristics, and whether the Generation Resource is expected to be available for operation during the time of the request;

3. The Generation Resource has met the testing requirements for voltage control capability required by the Regional Reliability Council where the Generation Resource is located within the past five years; and

4. The Generation Resource has submitted a request to the Transmission Provider for Qualified Generator status as outlined in Section II.C below.

C. Notification to Transmission Provider of Qualified Generator Status: To be eligible to receive compensation for its voltage control capability, all Generation Resources shall submit a request to the Transmission Provider certifying compliance with this Section II. The Transmission Provider shall notify the Local Balancing Authority upon receiving a certification request from a Generation Resource. Such certification of compliance must include the following information about the Generation Resource:

1. Name and Position/Title of party providing certification;
2. Name of Company;
3. Name of Generation Resource;
4. Full rated megawatt output of Generation Resource at Deadband;
5. Commercial Pricing Nodes by unit;
6. Four Character NERC ID (for settlement purposes);
7. Reactive Minimum and Maximum limits at rated summer maximum power output, including Unit Name, production maximum (summer), MVAR maximum and MVAR minimum; and
8. Signature and date from the party providing certification.

The executed Certification Statement should be returned to:

Midwest ISO

Attn: Manager Interconnection Planning

701 City Center Drive

Carmel, IN 46032

or sent by e-mail to ginterconnection@midwestiso.org.

If after receiving a completed request, the Transmission Provider does not notify the Generation Resource of a deficiency to the certification within fifteen (15) days, Qualified Generator status is effective on the first day of the month immediately following the end of the fifteen-day notice period.

III. RATES, CHARGES, AND REVENUE DISTRIBUTION

A. Within Deadband

The Transmission Provider shall provide no compensation to any Qualified Generator for Reactive Supply and Voltage Control from Generation Sources Service within the Deadband. No Qualified Generator shall maintain a service schedule or tariff provision pertaining to the production of reactive power that imposes or may impose charges associated with the supply of reactive power within the Deadband.

B. Outside of Deadband

Each Qualified Generator shall be compensated for providing Reactive Supply and Voltage Control from Generation Sources Service outside of the Deadband provided that it is supplying such service at the explicit direction of the Local Balancing Authority. A Qualified Generator appropriately following voltages schedules shall not be compensated for service outside the Deadband unless the Local Balancing Authority directed it to do so. The revenues that each such Qualified Generator receives shall be based upon the following:

1. Compensation shall be the higher of lost opportunity costs or cost. Cost shall be $2.20 per MVARhr.

2. Lost opportunity costs shall be the Hourly Real-Time Ex Post~~hourly~~ LMP less the generator's incremental cost savings of producing less real power and more reactive power times the reduction in MW output requested by the Local Balancing Authority. In order to receive lost opportunity costs, a Qualified Generator must be directed to reduce real power output and must be producing in excess of the calculated MVAR output at .95 power factor (or the power factor specified in the generator interconnection agreement if different) pertaining to full

real power output at the interconnection point (less station service use). A Qualified Generator will not be compensated for a reduction in real power output for MW produced above its rated capability. A Qualified Generator must submit its monthly lost opportunity cost calculation to the Transmission Provider no later than 20 days following the end of a month.

3. The MVARhrs outside the deadband shall be the total MVARhrs provided in an hour less the MVARhrs that would be produced at the full rated MW output at .95 power factor (or the power factor specified in the generator interconnection agreement if different) at the Point of Interconnection (i.e., a 900 MW generator with 50 MW of station service use would produce 850 MW at the Point of Interconnection; and produce 279 MVARs at .95 power factor.).

4. On a monthly basis, the Transmission Provider shall determine the Reactive Supply and Voltage Control from Generation Sources Service that each Qualified Generator produced outside of the Deadband pursuant to directions of the Local Balancing Authority in MVARhr. For each such Qualified Generator, the Transmission Provider shall multiply the MVARhrs by the cost of reactive power set forth in paragraph 1. The Transmission Provider will not include the MVARhrs for any period in which the Qualified Generator has requested lost opportunity costs.

5. The "Reactive Power Cost," which will be set forth on a monthly basis, will be the sum of the lost opportunity costs and the MVARhr costs. The Transmission Provider shall then for each Qualified Generator develop a percentage based on that Qualified Generator's Reactive Power Cost under this

paragraph 5 divided by the total Reactive Power Costs under this paragraph (“Zonal Percentage”).

C. Development of the Schedule 2 Charge

Beginning on the first day of the third month after ___[the effective date of these Tariff sheets], there shall be a Schedule 2 charge developed for each Zone to be developed as follows:

1. There will be a two month lag in imposing charges with no true-up. This means that the Reactive Power Costs for January of a particular year, for example, will be used as the basis for charges in March of that same year, and the Reactive Power Costs for February of that year will be used as the basis for charges in April of that same year and so on.

2. For each Zone, the charge shall be calculated based upon the following formula:

   a. The Reactive Power Costs for each Qualified Generator in each Zone shall be added together. The Reactive Power Costs used shall be monthly costs. These Reactive Power Costs for each Zone shall be reduced by the portion of through and out reactive revenue distributed to each Zone for that month. This means that a March reactive power charge will be developed based upon January costs and revenues. This shall be considered the “Monthly Revenue Requirement” for each Zone. If the through and out reactive revenues distributed to a Zone exceed the Reactive Power Costs in any month, the Monthly Revenue

Requirement for that Zone shall equal zero.

b. Dividing the Monthly Revenue Requirement determined in step (a) above by the Attachment O, Page 1, Line 15 rate divisor for each Zone to derive a monthly rate; and deriving from that monthly rate the rates for weekly, daily and hourly service consistent with Attachment O, page 2 of 2. For those Zones not utilizing Attachment O to derive rates for base Transmission Service, the Transmission Provider shall use the same rate divisor used in calculating base transmission rates for Schedule 7, the Midwest ISO Single System-Wide Rates, or use a divisor specified by Commission order as the Schedule 2 rate divisor.

3. Rates for Reactive Supply and Voltage Control from Generation Sources Service for transactions exiting the Transmission System

The rate for Reactive Supply and Voltage Control from Generation Sources Service for Transmission Customers with loads located outside the Transmission Provider's Transmission System shall be calculated using an average rate. The average rate shall be calculated as provided in Section III of Schedule 2 except that the revenue requirements reflected for each Zone which has elected to use this Schedule 2-A shall be the revenue requirements established by this Schedule 2-A.

D. Collection of Charges and Distribution of Revenues

1. For each Zone under this Schedule 2-A, each Transmission Customer taking Transmission Service which sinks in that Zone shall pay the Transmission

Provider a charge for Reactive Supply and Voltage Control from Generation Sources Service determined by multiplying the applicable rate as calculated above by the Reserved Capacity for the Transmission Customer taking Point-To-Point Transmission Service or by the Network Load for a Transmission Customer taking Network Integration Transmission Service. Each Transmission Customer taking Transmission Service which is provided to Points of Delivery of loads sinking in a Zone which is not under this Schedule 2-A shall pay the applicable rate under Schedule 2. For Transmission Service provided to Points of Delivery or loads located outside of the Transmission System, the Transmission Customer shall pay the applicable charge under Schedule 2, subject to using the revenue requirements calculated under this Schedule 2-A for Zones electing to use this Schedule 2-A.

2. Each month for Point-to-Point Transmission Service or Network Integration Transmission Service provided to load within a Zone covered by this Schedule 2-A, the Transmission Provider shall distribute to each Qualified Generator owner a pro rata allocation of the amounts collected under this Schedule 2-A for that Zone based upon the Zonal Percentage calculated in Section III.B.5. The revenue distribution associated with Transmission Service sinking in a Zone which did not elect this Schedule 2-A shall be as provided by the revenue distribution provision in Schedule 2 (which shall only reflect the distribution of revenues to Zones which are not under this Schedule 2-A).

3. Each month for Transmission Service provided to Points of Delivery or loads located outside the Transmission System, the Transmission Provider shall

distribute to each Qualified Generation owner a pro rata allocation of the amounts collected as provided in Section III.C.3 of Schedule 2 with the revenue requirement reflected in such revenue distribution for Zones electing this Schedule 2-A calculated pursuant to this Schedule 2-A.

IV. QUALIFIED GENERATOR STATUS

A. Re-Evaluation of Qualified Generator Status

1. If a Qualified Generator fails to comply with the Local Balancing Authority's voltage control requirements three or more times in a calendar month for reasons other than planned or unscheduled outages, the Transmission Provider shall determine whether the Generation Resource should continue to be a Qualified Generator based on the criteria established in Section II.B of this Schedule 2-A.

2. In making a determination of whether a Generation Resource should continue to be a Qualified Generator, the Transmission Provider will evaluate, among other factors, whether the Generation Resource was operated consistently with its design characteristics, and whether system conditions prevented it from responding as required by the Local Balancing Authority.

SCHEDULE 3 Regulating Reserve Version: 2~~1~~.0.0 Effective: 12/31/9998~~7/28/2010~~

SCHEDULE 3

REGULATING RESERVE

I. GENERAL

Regulating Reserve is necessary to i) continuously balance the total output of all Resources within the Midwest ISO Balancing Authority Area with the total demand of all loads (including losses) within the Midwest ISO Balancing Authority Area plus the Net Scheduled Interchange of the Midwest ISO Balancing Authority Area and ii) assist in maintaining the difference between scheduled Interconnection frequency and actual Interconnection frequency within acceptable limits based on Applicable Reliability Standards. Regulation Deployment is accomplished by using automatic control equipment to raise or lower the output of on-line Resources as necessary to follow the moment-by-moment changes in demand and frequency. The obligation to maintain this balance between supply and demand lies with the Midwest ISO Balancing Authority. The Midwest ISO Balancing Authority will procure this service on behalf of the Load Serving Entities from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets, as provided for in Sections 39.2 and 40.2 of this Tariff. A Load Serving Entity must either purchase this service from the Midwest ISO Balancing Authority or make alternative comparable arrangements to satisfy its Regulating Reserve Obligation, where such Obligation is defined below. The Midwest ISO Balancing Authority shall determine whether alternative arrangements proposed by the Load Serving Entity are comparable to the provision of this service by the Midwest ISO Balancing Authority.

II. DESCRIPTION OF SERVICE

Regulating Reserve is unloaded and loaded Resource capacity utilized by the Midwest ISO Balancing Authority to manage the area control error as necessary to comply with Applicable Reliability Standards. Regulating Reserve is cleared and priced every Hour in the Day-Ahead Energy and Operating Reserve Market and every Dispatch Interval in the Real-Time Energy and Operating Reserve Market. Regulating Reserve is settled on an Hourly basis in both the Day-Ahead Energy and Operating Reserve Market and Real-Time Energy and Operating Reserve Markets. Regulating Reserve can only be supplied by Regulation Qualified Resources.

III. PURCHASE OBLIGATIONS WITHIN THE MIDWEST ISO BALANCING AUTHORITY AREA AND RATES

Day-Ahead and Real-Time Regulating Reserve procurement costs are collected from Load Serving Entities on a zonal basis using the following rate methodology:

A. Binding Settlement Zone Regulating Reserve Charges

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals within a Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants ("MP") for Resources providing Regulating Reserve within that Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Regulating Reserve Charge = GFA Regulating Reserve Procurement Rate multiplied by MP Carved-Out GFA Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Regulating Reserve ~~MCP~~ multiplied by the Minimum of [Regulating Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for the Binding Settlement Zone,

Where:

GFA Regulating Reserve Procurement Rate = Regulating Reserve Procurement Cost / Total Actual Energy Withdrawal in the Non-Binding Settlement Zone;

Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve within the Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Binding Settlement Zone;

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Binding Settlement Zone; and

MP Carved-Out GFA Regulating Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all

Regulating Reserve schedules within the Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Regulating Reserve Charge non-GFA = Non-GFA Regulating Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Regulating Reserve Procurement Rate = The difference between the Non-GFA Regulating Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Regulating Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Binding Settlement Zone;

Non-GFA Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve minus the aggregate sum of the <u>Hourly Real-Time Ex Post MCP for</u> Regulating Reserve ~~MCP~~ multiplied by the Minimum of [~~-~~Regulating Reserve schedules associated with the Carved-Out

GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for all GFA billing entities within the Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Binding Settlement Zone.

B. Non-Binding Settlement Zone Regulating Reserve Charge

Market Participants, other than Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals within a Non-Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Regulating Reserve within that Non-Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Regulating Reserve Charge = GFA Regulating Reserve Procurement Rate multiplied by the MP Carved-Out GFA Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Regulating Reserve ~~MCP~~ multiplied by the Minimum of [Regulating Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for the Non-Binding Settlement Zone,

Where:

GFA Regulating Reserve Procurement Rate = Regulating Reserve Procurement Cost / Total Actual Energy Withdraw in the Non-Binding Settlement Zone;

Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve within the Non-Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules,

within the Non-Binding Settlement Zone;

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Non-Binding Settlement Zone; and

MP Carved-Out GFA Regulating Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Regulating Reserve schedules within the Non-Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Regulating Reserve Charge non-GFA = Non-GFA Regulating Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Regulating Reserve Procurement Rate = the difference between the Non-GFA Regulating Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Regulating Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals

within the Non-Binding Settlement Zone;

Non-GFA Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Regulating Reserve ~~MCP~~ multiplied by the Minimum of [Regulating Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for all GFA billing entities within the Non-Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Non-Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules,

within the Non-Binding Settlement Zone;

IV. PROVISIONS TO SATISFY REGULATING RESERVE OBLIGATIONS VIA SELF-SCHEDULES

A Market Participant may Self-Schedule from their Regulation Qualified Resources in the Energy and Operating Reserve Markets to meet their hourly Market-Wide Regulating Reserve Obligation. A Market Participant's hourly Market-Wide Regulating Reserve Obligation shall be equal to the Market-Wide Regulating Reserve Requirement multiplied by the ratio of the Market Participant's Actual Energy Withdrawals, excluding real-time Export Schedules to Midwest ISO Balancing Authority Load, excluding real-time Export Schedules. Such Self-Scheduled Regulating Reserve shall be compensated at the applicable Regulating Reserve Market Clearing Price for that Resource pursuant to Sections 39 and 40 of this Tariff.

SCHEDULE 5 Spinning Reserve Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

SCHEDULE 5
Spinning Reserve

I. GENERAL

Spinning Reserve is required to immediately offset deficiencies in Energy supply that result from a Resource contingency or other abnormal event. Spinning Reserve may be provided by Resources that are Spin Qualified Resources available to provide Spinning Reserve. The obligation to maintain this immediate response capability to contingency events lies with the Midwest ISO Balancing Authority. The Midwest ISO Balancing Authority will procure Spinning Reserve on behalf of the Load Serving Entities, and Exporting Entities from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets as provided for in Sections 39.2 and 40.2 of this Tariff. Load Serving Entities, and

Exporting Entities must either purchase this service from the Midwest ISO Balancing Authority or make alternative comparable arrangements to satisfy its Spinning Reserve Obligation, where such Obligation is defined below. The Midwest ISO Balancing Authority shall determine whether alternative arrangements proposed by Load Serving Entities, and Exporting Entities are comparable to the provision of this service by the Midwest ISO Balancing Authority.

II. DESCRIPTION OF SERVICE

Spinning Reserve is synchronized unloaded resource capacity set aside to be available to immediately offset abnormal supply deficiencies. Spinning Reserve must be immediately available and must be fully deployable within the Contingency Reserve Deployment Period. Spinning Reserve is a specified percentage of the Contingency Reserve requirements of the Midwest ISO Balancing Authority that must be provided by Spin Qualified Resources. Spinning Reserve is cleared and priced every Hour in the Day-Ahead Energy and Operating Reserve Market and every Dispatch Interval in the Real-Time Energy and Operating Reserve Market. Spinning Reserve is settled on an hourly basis in both the Day--Ahead and Real-Time Energy and Operating Reserve Markets.

III. PURCHASE OBLIGATIONS WITHIN THE MIDWEST ISO BALANCING AUTHORITY AREA AND RATES

Day-Ahead and Real-Time Spinning Reserve procurement costs are collected from Load Serving Entities and Exporting Entities on a zonal basis using the following rate methodology:

A. Binding Settlement Zone Spinning Reserve Charges

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market

Participants for Resources providing Spinning Reserve within that Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Spinning Reserve Charge = GFA Spinning Reserve Procurement Rate multiplied by the MP Carved-Out GFA Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Spinning Reserve ~~MCP~~ multiplied by the Minimum of [Spinning Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Spinning Reserve Obligation] for the Binding Settlement Zone,

Where:

GFA Spinning Reserve Procurement Rate = Spinning Reserve Procurement Cost / Total Actual Energy Withdrawal in the Binding Settlement Zone;

Spinning Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve within the Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone; and

MP Carved-Out GFA Spinning Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Spinning Reserve schedules within the Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Spinning Reserve Charge non-GFA = Non-GFA Spinning Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Spinning Reserve Procurement Rate = The difference between the Non-GFA Spinning Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Spinning Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Binding Settlement Zone;

Non-GFA Spinning Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Spinning Reserve ~~MCP~~ multiplied by

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone.

B. Non-Binding Settlement Zone Spinning Reserve Charge

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out

GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Non-Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Spinning Reserve within that Non-Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Spinning Reserve Charge =	GFA Spinning Reserve Procurement Rate multiplied by the MP Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Spinning Reserve ~~MCP~~ multiplied by the Minimum of [~~-~~Spinning Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Spinning Reserve Obligation] for the Non-Binding Settlement Zone,

Where:

GFA Spinning Reserve Procurement Rate =	Spinning Reserve Procurement Cost / Total Actual Energy Withdraw in the Non-Binding Settlement Zone;
Spinning Reserve Procurement Cost =	The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve within the Non-Binding

Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone;

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

MP Carved-Out GFA Spinning Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Non-Binding Settlement Zone multiplied by the sum of all Spinning Reserve schedules within the Non-Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Spinning Reserve Charge non-GFA = Non-GFA Spinning Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Spinning Reserve Procurement Rate = The difference between the Non-

GFA Spinning Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Spinning Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Non-Binding Settlement Zone;

Non-GFA Spinning Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Spinning Reserve ~~MCP~~ multiplied by the Minimum of [Spinning Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Spinning Reserve Obligation] for all GFA billing entities within the Non-Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual

Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone.

IV. PROVISIONS TO SATISFY SPINNING RESERVE OBLIGATIONS VIA SELF-SCHEDULES

A Market Participant may Self-~~-~~Schedule from their Spin Qualified Resources in the Energy and Operating Reserve Markets to meet their hourly Market-Wide Spinning Reserve Obligation. A Market Participant's hourly Market-Wide Spinning Reserve Obligation shall be equal to the Market-Wide Spinning Reserve Requirement multiplied by the ratio of the Market Participant's Actual Energy Withdrawals, including real-time Export Schedules to Midwest ISO Balancing Authority Load, including real-time Export Schedules. Such Self-~~-~~Scheduled Spinning Reserve shall be compensated at the applicable Spinning Reserve Market Clearing Price for that Resource pursuant to Sections 39 and 40 of this Tariff.

SCHEDULE 6 Supplemental Reserve Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

SCHEDULE 6
Supplemental Reserve

I. GENERAL

Supplemental Reserve is required to offset deficiencies in Energy supply that result from a Resource contingency or other abnormal event. Supplemental Reserve may be provided by Resources that are Supplemental Qualified Resources that are available to supply Supplemental Reserve. The obligation to maintain this response capability to contingency events lies with the Midwest ISO Balancing Authority. The Midwest ISO Balancing Authority will procure

Supplemental Reserve on behalf of the Load Serving Entities and Exporting Entities from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets as provided for in Sections 39.2 and 40.2 of this Tariff. Load Serving Entities and Exporting Entities must either purchase this service from the Midwest ISO Balancing Authority or make alternative comparable arrangements to satisfy its Supplemental Reserve Obligation, where such Obligation is defined below. The Midwest ISO Balancing Authority shall determine whether alternative arrangements proposed by the Load Serving Entities and Exporting Entities are comparable to the provision of this service by the Midwest ISO Balancing Authority.

II. DESCRIPTION OF SERVICE

Supplemental Reserve is unloaded resource capacity set aside to be available to offset abnormal supply deficiencies. Supplemental Reserve must be fully deployable within the Contingency Reserve Deployment Period. Supplemental Reserve is a specified percentage of the Contingency Reserve requirement of the Midwest ISO Balancing Authority that is provided by Supplemental Qualified Resources. Supplemental Reserve is cleared and priced every Hour in the Day-Ahead Energy and Operating Reserve Market and every Dispatch Interval in the Real-Time Energy and Operating Reserve Market. Supplemental Reserve is settled on an hourly basis in both the Day--Ahead and Real-Time Energy and Operating Reserve Markets.

III. PURCHASE OBLIGATIONS WITHIN THE MIDWEST ISO BALANCING AUTHORITY AREA AND RATES

Day-Ahead and Real-Time Supplemental Reserve procurement costs are collected from Load Serving Entities and Exporting Entities on a zonal basis using the following rate methodology:

A. **Binding Settlement Zone Supplemental Reserve Charges**

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Supplemental Reserve within that Binding Settlement Zone for that Hour as follows:

Cost allocated to Carved-Out GFAs:

Carved-Out GFA Supplemental Reserve Charge = GFA Supplemental Reserve Procurement Rate multiplied by the MP Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Supplemental Reserve ~~MCP~~ multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for the Binding Settlement Zone,

Where:

GFA Supplemental Reserve Procurement Rate = Supplemental Reserve Procurement Cost / Total Actual Energy Withdrawal in the Binding Settlement Zone;

Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve within the Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Energy Withdrawal = the sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone; and

MP Carved-Out GFA Supplemental Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Supplemental Reserve schedules within the Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Supplemental Reserve Charge non-GFA = Non-GFA Supplemental Reserve Procurement Rate * MP Actual Energy

Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Supplemental Reserve Procurement Rate = The difference between the Non-GFA Supplemental Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Supplemental Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Binding Settlement Zone;

Non-GFA Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Supplemental Reserve ~~MCP~~ multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for all GFA billing entities within the Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone.

B. Non-Binding Settlement Zone Supplemental Reserve Charge

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Non-Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Supplemental Reserve within that Non-Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Supplemental Reserve Charge = GFA Supplemental Reserve Procurement Rate multiplied by the MP Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Supplemental Reserve ~~MCP~~ multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for the Non-Binding Settlement Zone,

Where:

GFA Supplemental Reserve Procurement Rate = Supplemental Reserve Procurement Cost / Total Actual Energy Withdraw in the Non-Binding Settlement Zone;

Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve within the Non-Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone;

Total Actual Energy Withdrawal = the sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

MP Carved-Out GFA Supplemental Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Non-Binding Settlement Zone multiplied by the sum of all Supplemental Reserve schedules within the Non-Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Supplemental Reserve Charge non-GFA = Non-GFA Supplemental Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Supplemental Reserve Procurement Rate = The difference between the Non-GFA Supplemental Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Supplemental Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Non-Binding Settlement Zone;

Non-GFA Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section

40.3.3.b.v specific to Resources providing Supplemental Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Supplemental Reserve ~~MCP~~ multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for all GFA billing entities within the Non-Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone.

IV. PROVISIONS TO SATISFY SUPPLEMENTAL RESERVE OBLIGATIONS VIA SELF-SCHEDULES

A Market Participant may Self-~~-~~Schedule from their Supplemental Qualified Resources in the Energy and Operating Reserve Markets to meet their hourly Market-Wide Supplemental Reserve Obligation. A Market Participant's hourly Market-Wide Supplemental Reserve Obligation shall be equal to the Market-Wide Supplemental Reserve Requirement multiplied by the ratio of the Market Participant's Actual Energy Withdrawals, including real-time Export Schedules to Midwest ISO Balancing Authority Load, including real-time Export Schedules. Such Self-~~-~~Scheduled Supplemental Reserve shall be compensated at the applicable Supplemental Reserve Market Clearing Price for that Resource pursuant to Sections 39 and 40 of this Tariff.

SCHEDULE 20 Treatment of Station Power Version: 1.0.0~~.0~~ Effective: 12/31/9999~~7/28/2010~~

SCHEDULE 20

Treatment of Station Power

I. RECOGNIZED MEANS OF PROVIDING FOR STATION POWER

A Generation Owner may arrange to provide for Station Power of a Facility:

1) Through On-Site Self-Supply, Remote Self-Supply, or Third-Party Supply (pursuant to Section II of this Schedule); or

2) By procuring Transmission Service under Module B of the Tariff (pursuant to Section III of this Schedule) in instances of Remote Self-Supply or Third-Party Supply.

II. ON-SITE SELF-SUPPLY, REMOTE SELF-SUPPLY AND THIRD-PARTY SUPPLY OF STATION POWER

1) A Generation Owner may obtain Station Power for its Facility through any of the following sources: a) from the same Facility (*i.e.*, On-Site Self-Supply); b) from a remote Facility owned by the same entity that owns

such Facility (*i.e*., Remote Self-Supply); *provided that*, if an entity owns a portion of a jointly-owned Facility, it may remotely self-supply its other Facility up to the amount of Energy from such jointly-owned Facility if: i) the entity has the right to call upon that Energy for its own use; and (ii) such Energy entitlement is not characterized as a sale from the jointly-owned Facility to any of its owners; or c) from a third party pursuant to an applicable retail rate or tariff (*i.e*., Third-Party Supply).

2) During any Month when the Net Output of a Facility is positive as a result of either the On-Site Self-Supply or Remote Self-Supply of Station Power, Generation Owner shall be deemed not to have engaged in the retail purchase of electric Energy with respect to Station Power service hereunder.

3) The determination of Net Output under paragraph (2) of this subsection will apply only to determine whether the Facility self-supplied Station Power during the Month and will not affect the price of Energy sold or consumed by the Generation Owner at any Bus during any Hour during the Month. ~~-~~For each Hour when a Facility has positive net output and delivers Energy into the Transmission System, Generation Owner will be paid the Hourly Real-Time Ex Post ~~locational marginal price (“~~LMP~~”)~~ at its Bus for that Hour for the net Energy delivered (i.e., minus On-Site Self-Supply of Station Power).~~-~~ Conversely, for each Hour when a Facility has negative net output and has received Station Power from the Transmission System, Generation Owner will pay the Hourly Real-Time Ex Post LMP

at its Bus for that Hour for all of the Energy consumed.

4) Transmission Provider will determine the extent to which each affected Facility during the Month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the Month. Generation Owner must provide the Transmission Provider with sufficient information to allow the Transmission Provider to implement Schedule 20. To the extent that a Transmission Owner or the Transmission Provider has primary access to relevant meter data, it must cooperate with Generation Owners regarding metering arrangements and verification of data to implement Schedule 20.

5) A Generation Owner may remotely self-supply Station Power from its generation facilities located outside the Transmission Provider Region during any Month only if such generation facilities in fact run during such Month and Generation Owner separately has reserved transmission service and scheduled delivery of the Energy from such resource in advance into the Transmission Provider Region.

III. TRANSMISSION SERVICE CHARGES FOR STATION POWER SUPPLY

1) **General** - A Generation Owner that supplies its Facility with Station Power via On-Site Self-Supply will be deemed not to have used, and will not incur any charges for, Transmission Service to provide such Station Power. In the event, and to the extent, that a Generation Owner obtains Station Power for its Facility through Remote Self-Supply or Third-Party Supply during any Month, Generation

Owner shall use and pay for hourly Non-Firm Point-To-Point Transmission Service for the transmission of Energy in an amount equal to the Facility's negative Net Output from Generation Owner's Facility(ies) having positive Net Output. Unless the Generation Owner makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under and subject to the charges and other terms and conditions of Non-Firm Point-To-Point Transmission Service specified in Module B of the Tariff and Part III of this Schedule 20 with an obligation to pay congestion charges and losses; provided, however, that no reservation shall be necessary for such Transmission Service and the terms and charges under Schedules 1 through 6 of this Tariff shall not apply. In the event a Generation Owner has other permissible transmission arrangements that involve a Transmission Owner providing for use of transmission facilities directly by the Generation Owner, the Transmission Owner shall be responsible for taking Transmission Service under the Tariff to satisfy its obligations to provide for delivery of Station Power and shall pay any applicable zonal Transmission Service rate under Schedules 7, 8 or 9 and all other charges applicable to such Transmission Service under this Tariff. In the event the Generation Owner has existing rights to use an ITC's facilities, the Generation Owner shall be responsible for taking Transmission Service under the Tariff but shall not be liable for any applicable zonal Transmission Service rate under Schedules 7, 8 or 9 of the Tariff. Such Generation Owner, with existing rights to use an ITC's facilities, shall be responsible for all other charges under the Tariff applicable to such Transmission Service. The amount of Energy that a

Generation Owner transmits in conjunction with the Remote Self-Supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or Energy by or for such Generation Owner under any other provisions of the Tariff.

IV. RETAIL PURCHASE OF STATION POWER

Nothing in this Schedule 20 is intended to: 1) preclude a Generation Owner from purchasing Station Power pursuant to an applicable retail rate or tariff; or 2) supercede otherwise applicable jurisdiction of a state regulatory commission, except in the event of a conflict between Federal and state tariff provisions, in which case the Federal tariff provisions will control.

V. METERING REQUIREMENTS

Generation Owners shall be responsible for making all appropriate metering arrangements for Station Power Transmission Service requirements to enable the Transmission Provider to implement Schedule 20. The Generation Owner shall also be responsible for timely submission of accurate, complete and verified metering information to the Transmission Provider, which shall have the right to audit such submissions. The Transmission Provider shall determine whether a Generation Owner's metering information is sufficiently accurate, complete and verifiable for purposes of implementing Schedule 20. The Transmission Provider shall have the sole responsibility of determining whether a facility self-supplied Station Power during a Month.

SCHEDULE 27 RTORSGP and DAMAP Version: 5~~4~~.0.0 Effective: 12/31/9998~~5/14/2011~~

SCHEDULE 27

Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP) and Day-Ahead Margin Assurance Payment (DAMAP)

The RTORSGP under Section 40.3.5 and the DAMAP under Section 40.3.6 of this Tariff shall be calculated as set forth below.

A. Calculation of RTORSGP for Day-Ahead Committed and Real-Time Must-Run Committed Resources

The RTORSGP for Day-Ahead committed and Real-Time Must-Run committed Generation Resources and Demand-Response Resources – Type II with Non-Excessive Energy levels greater than their Day-Ahead Schedules for Energy and the RTORSGP for External Asynchronous Resources with Non-Excessive Energy levels greater than their Day-Ahead Schedules for Energy shall be calculated in three steps. The first step shall determine the cost of following dispatch, *i.e.*, the cost to the Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource of following the Transmission Provider's Setpoint Instructions. The second step shall determine the payment for following dispatch, *i.e.*, the value of the payment to the Generation Resources, Demand Response Resources – Type II or External Asynchronous Resources for following the Transmission Provider Setpoint Instructions. The third step shall determine the RTORSGP.

1. Step One: Cost of Following Dispatch

a. Two intermediate quantities must be derived to properly calculate Incremental Energy Costs associated with following the Transmission Provider Setpoint Instructions for both Day-Ahead committed and Real-Time Must-Run committed Generation Resources and Demand Response Resources – Type II and for External Asynchronous Resources.

i. Determination of base output:

1. For Real-Time Must-Run committed Generation Resource and Demand Response Resource – Type II, the base output is equal to the Economic Minimum Dispatch for a given Dispatch Interval ("i"). For External Asynchronous Resource's with Day-Ahead Schedules for Energy that are equal to zero, the base output is equal to zero.

2. For Day-Ahead committed Generation Resources and Demand Response Resources – Type II or External Asynchronous Resources with Day-Ahead Schedules for Energy, the base output MW is equal to the Day-Ahead cleared MW, and will be the same for all intervals in an Hour.

3. The base output shall be calculated for every Dispatch interval ("i") in each eligible Hour as provided for in Section 40.3.5 of this Tariff.

ii. Determination of pay output:

1. The pay output shall be derived in the same way for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources for each Hour in the contiguous Day-Ahead Commitment Period.

2. The pay output shall be calculated for every eligible Hour and shall be equal to the Generation Resource's, Demand Response Resource's – Type II or External Asynchronous Resource's Non-Excessive Energy.

b. The base output and pay output are inputs into the calculation of the cost of following dispatch.

i. The cost of following dispatch for each eligible Hour is equal to the sum of the hourly integration of incremental Energy~~energy~~ costs from base output up to Pay Output (as defined below) in each interval ("i").

1. Cost of following dispatch is performed for every interval ("i") within each eligible Hour, and integrated to an hourly value, as specified below.

$$EnergyCost_h^{RT} = \sum_{Hour} \int^{POi} RTOen_i - \int^{BOi} RTOen_i \times S_i / 3600$$

Where:

$EnergyCost_h^{RT}$ = Additional cost for Non-Excessive Energy produced in real-time above the Base Output within Hour *h* in the contiguous Day-Ahead Commitment Period.

n = Number of intervals in the Hour *h* in the commitment period.

BO_i = Base Output for interval *i* in Hour *h* as defined above.

PO_i = Pay Output for interval *i* in Hour *h* as defined above.

$RTOen_i$ = RT Offer for Energy for interval *i*.

s_i = Number of seconds in interval *i*.

2. Step Two: Payment for Following Dispatch:

a. The Energy related payment (Energy ~~LMP~~ revenues) for following dispatch shall be calculated as follows:

$$LMPRev_h^{RT} = LMP_h^{RT} \times (NXE_h - EI_h^{DA})$$

Where:

$LMPRev_h^{RT}$ = The Energy~~LMP~~ revenue in an Hour h within the contiguous Day-Ahead Commitment Period.

LMP_h^{RT} = Hourly Real-Time Ex ~~-~~Post LMP for Hour h.

EI_h^{DA} = Day-Ahead Schedule for Energy in Hour h

NXE_h= Non-Excessive Energy for Hour h.

b. The Spinning Reserve related payment (Spinning Reserve net revenues) for following dispatch shall be calculated as:

$$NetSpinRev_h^{RT} = (\text{Max} ((ClrSpin_h^{RT} - ClrSpin_h^{DA}) \times (SpinMCP_h^{RT} - SpinOffer_h^{RT}) , 0)$$

Where:

$NetSpinRev_h^{RT}$ = Real-Time Spinning Reserve revenue credit for Hour h within the contiguous Day-Ahead Commitment Period.

$ClrSpin_h^{RT}$ = Cleared Real-Time Spinning Reserve for Hour h.

$ClrSpin_h^{DA}$ = Cleared Day-Ahead Spinning Reserve for Hour h.

$SpinMCP_h^{RT}$ = Hourly ~~Spinning Reserve~~ Real-Time Ex Post MCP for Spinning Reserve for Hour~~hour~~ h.

$SpinOffer_h^{RT}$ = Real-Time Offer for Spinning Reserve for Hour~~hour~~ h.

c. The Supplemental Reserve related payment (Supplemental Reserve net revenues) supplied from synchronized Resources for following dispatch shall be calculated as follows:

$$NetSynSuRev_h^{RT} =$$
$$MAX\left(\left(ClrSynSu_h^{RT} - ClrSynSu_h^{DA} \right) \times \left(SynSuMCP_h^{RT} - SynSuOffer_h^{RT} \right), 0 \right)$$

Where:

$NetSynSuRev_h^{RT}$ = Real-Time synchronized Supplemental Reserve revenue credit for Hour h within the contiguous Day-Ahead Commitment Period.

$ClrSynSu_h^{RT}$ = Cleared Real-Time synchronized Supplemental Reserve for Hour h.

$ClrSynSu_h^{DA}$ = Cleared Day-Ahead synchronized Supplemental Reserve for Hour h.

$SynSuMCP_h^{RT}$ = Hourly Real-Time Ex Post MCP for synchronized~~Synchronized~~ Supplemental Reserve ~~Ex-Post MCP~~ for Hour h.

$SynSuOffer_h^{RT}$ = Real-Time Offer for synchronized Supplemental Reserve for hour *h*.

d. The Regulating Reserve related payment (Regulating Reserve net revenues) for following dispatch shall be calculated as follows:

$$NetRegRev_h^{RT} = MAX((ClrReg_h^{RT} - ClrReg_h^{DA}) \times (RegMCP_h^{RT} - RegOffer_h^{RT}), 0)$$

Where:

$NetRegRev_h^{RT}$ = Real-Time Regulating Reserve revenue credit for Hour *h* within the contiguous Day-Ahead Commitment Period.

$ClrReg_h^{RT}$ = Cleared Real-Time Regulating Reserve for Hour *h*.

$ClrReg_h^{DA}$ = Cleared Day-Ahead Regulating Reserve for hour *h*.

$RegMCP_h^{RT}$ = Hourly Real-Time Ex Post MCP for Regulating Reserve ~~Ex-Post MCP~~ for Hour *h*.

$RegOffer_h^{RT}$ = Real-Time Offer for Regulating Reserve for hour *h*.

e. The net Operating Reserve related payment (Operating Reserve net revenues) shall be calculated as follows:

$$NetORRev_h^{RT} = NetSpinRev_h^{RT} + NetSynSuRev_h^{RT} + NetRegRev_h^{RT}$$

Where:

$NetORRev_h^{RT}$ = Net Operating Reserve revenue for Hour *h* within the contiguous Day-Ahead Commitment Period.

f. The total Energy and Operating Reserve related payment (total net revenue) in Hour h for following dispatch shall be calculated as follows:

$$Rev_h^{RT} = LMPRev_h^{RT} + NetORRev_h^{RT} + RDA_h$$

Where:

$Rev_h^{RT} =$ Total Real-Time net revenue in Hour h within the contiguous Day-Ahead Commitment Period.

$RDA_h =$ Regulation Deployment Adjustment in Hour h within the contiguous Day-Ahead Commitment Period as calculated pursuant to Section 40.3.3.a.xi of this Tariff.

$$Payment\_for\_Following\_Dispatch_t = Expost\_LMP_t \times (Metered\_MWH_t - Base\_Output_t)$$

3. Step Three: Real-Time Offer Revenue Sufficiency Guarantee Payment:

a. If the eligible Generation Resource's, Demand Response Resource's Type II or External Asynchronous Resource's cost of following dispatch exceeds the value of its payment for following dispatch in an eligible Hour, then the Resource will receive a RTORSGP in that Hour. The RTORSGP shall be calculated at an hourly level as a credit as specified below.

$$RTORSGP_h^{RT} = MAX (EnergyCost_h^{RT} - Rev_h^{RT}, 0)$$

Where:

$RTORSGP_h^{RT} =$ RTORSGP for Hour h within the contiguous Day-Ahead Commitment Period.

$EnergyCost_h^{RT}$ = Additional cost for Non-Excessive Energy produced above the Day-Ahead Schedule for Hour *h* within the contiguous Day-Ahead Commitment Period.

Rev_h^{RT} = Total Real-Time net revenue in Hour *h* within the contiguous Day-Ahead Commitment Period.

B. Calculation of DAMAP for Day-Ahead Committed Resources and External Asynchronous Resources

The DAMAP for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources with Day-Ahead Schedules for Regulating Reserve, External Asynchronous Resources with Day-Ahead Schedules for Energy, and Demand Response Resources-Type I with Day-Ahead Schedules for Contingency Reserve shall be calculated for each Hour in three steps. The first step shall determine adjustments to Day-Ahead Schedules to account for real-time de-rates for Generation Resources and Demand Response Resources – Type II or an adjustment to Day-Ahead Schedules for Regulating Reserve to the Real-Time cleared Regulating Reserve for Stored Energy Resources if the real-time decrease is the result of dispatch limitations due to reduced Energy storage capability for Dispatch Interval *i*. The second step shall determine 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, *i.e.*, the reduction in Day-Ahead Margin to the Generation Resource, Demand Response Resource – Type II, Stored Energy Resource or External Asynchronous Resource for following the Transmission Provider instructions for Dispatch Interval *i,* including any offsetting real-time margins associated with real-time cleared Energy and/or Operating Reserve in excess of Day-Ahead Schedules for Operating Reserve. The third step shall determine the DAMAP for an Hour.

1. Step One: Calculate Day-Ahead Schedule Adjustments

Prior to the determination of eligible amounts of Energy, Regulating Reserve, Spinning Reserve and/or Supplemental Reserve for use in DAMAP calculations, the Day-Ahead Schedules for Energy, Regulating Reserve, Spinning Reserve and/or Supplemental Reserve associated with Resources, are adjusted to account for Midwest ISO approved real-time reductions in Resource capability caused by physical operating restrictions. For Stored Energy Resources, if the real-time reduction is the result of dispatch limitations due to reduced Energy storage capability, the Adjusted Day-Ahead Schedule for Regulating Reserve for the given Dispatch Interval will be set equal to the Real-Time cleared Regulating Reserve. These Day-Ahead Schedule adjustments are calculated as follows for Dispatch Interval *i*.

$$AdjDASen_i = DASen_h - REDen_i$$

$$AdjDASreg_i = DASreg_h - REDreg_i$$

$$AdjDAScr_{ip} = DAScr_{hp} - REDcr_{ip}$$

Where:

$$REDen_i = (POTREDen_i / (POTREDen_i + POTREDreg_i + \sum_p POTREDcr_{ip})) \times REDtot_i$$

$$REDreg_i = (POTREDreg_i / (POTREDen_i + POTREDreg_i + \sum_p POTREDcr_{ip})) \times REDtot_i$$

$$REDcr_{ip} = (POTREDcr_{ip} / (POTREDen_i + POTREDreg_i + \sum_p POTREDcr_{ip})) \times REDtot_i$$

and where:

$$POTREDen_i = MAX (DASen_h - RTSen_i , 0)$$

$POTREDreg_i = MAX\,(\,DASreg_h - RTSreg_i\,,\,0\,)$

$POTREDcr_{ip} = MAX\,(\,DAScr_{hp} - RTScr_{ip}\,,\,0\,)$

and where:

$$REDtot_i = MAX(\,DASen_h + DASreg_h + \sum_p DAScr_{hp} - RTEcoMax_i\,,\,0\,)$$

Where:

$REDtot_i$ = Total MW reduction of Day-Ahead Schedules for interval *i*.

$DASen_h$ = Day-Ahead Schedule for Energy for hour *h* containing interval *i*.

$DASreg_h$ = Day-Ahead Schedule for Regulating Reserve for hour *h* containing interval *i*.

$DAScr_{hp}$ = Day-Ahead Schedule for Contingency Reserve product *p* for hour *h* containing interval *i*.

$RTEcoMax_i$ = Real-Time Economic Maximum Dispatch for interval *i*.

$POTREDen_i$ = Potential reduction in the Day-Ahead Schedule for Energy schedule for interval *i*.

$RTSen_i$ = Average Dispatch Target for Energy for interval *i*.

$POTREDreg_i$ = Potential reduction in the Day-Ahead Schedule for Regulating Reserve or interval *i*.

$RTSreg_i$ = Real-Time cleared Regulating Reserve for interval *i*.

$POTREDcr_{ip}$ = Potential reduction in the Day-Ahead Schedule for Contingency Reserve, product *p*, for interval *i*.

$RTScr_{ip}$ = Real-Time cleared Contingency Reserve, product p, for interval *i*.

$REDen_i =$ Actual reduction in the Day-Ahead Schedule for Energy for interval i.

$REDreg_i =$ Actual reduction in Day-Ahead Schedule for Regulating Reserve for interval i.

$REDcr_{ip} =$ Actual reduction in the Day-Ahead Schedule for Contingency Reserve, product p, for interval i.

$AdjDASen_i =$ Adjusted Day-Ahead Schedule for Energy for interval i.

$AdjDASreg_i =$ Adjusted Day-Ahead Schedule for Regulating Reserve for interval i.

$AdjDAScr_{ip} =$ Adjusted Day-Ahead Schedule for Contingency Reserve, product p, for interval i.

2. Step Two: Calculate Energy and Operating Reserve Contributions to DAMAP.

a. The Energy contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource for Dispatch Interval i is then calculated as follows. The Energy contribution to the DAMAP for a Stored Energy Resource is always set equal to zero.

i. If

$$RTSen_i < AdjDASen_h \text{ and } NXE_i < AdjDASen_h$$

Then:

$$CDAMAPen_i = (AdjDASen_h – MAX(Act_i ,DET_i)) \times LMP_h^{RT} –$$

$$MAX (\int^{AdjDASen} DAOen_h - \int^{MAX (NXE, DE T)} DAOen_h ,$$

$$(\int^{AdjDASen} RTOen_h - \int^{MAX(NXE, DE T)} RTOen_h)$$

ii. If $RTSen_i >= AdjDASen_h$ and $NXE_i >= AdjDASen_h$

$$CDAMAPen_i = MIN((AdjDASen_h – Act_i) \times LMP_h^{RT} +$$

$$(\int^{NXE} RTOen_h – \int^{AdjDASen} RTOen_h), 0)$$

Where:

$RTSen_i =$ average Dispatch Target for Energy for interval i.

$AdjDASen_i =$ Adjusted Day-Ahead Schedule for Energy for interval i.

$CDAMAPen_i =$ Energy contribution to DAMAP for interval i.

$NXE_i =$ Non-Excessive Energy for interval i.

$DET_i =$ Resource Deficient Energy Threshold for interval i.

$LMP_h^{RT} =$ Hourly Real-Time Ex Post LMP at the Resource bus for hour h containing interval i.

$RTOen_h =$ Real-Time Offer for Energy for hour h

containing interval i.

$DAOen_h$ = Day-Ahead Offer for Energy for hour h containing interval i.

b. The Contingency Reserve contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource for Dispatch Interval i is calculated as follows. The Contingency Reserve contribution to the DAMAP for a Stored Energy Resource is always set equal to zero.

i. If $RTScr_{ip} < AdjDAScr_{hp}$

Then:

$$CDAMAPcr_{ip} = (AdjDAScr_{hp} - RTScr_{ip}) \times (RTMCPcr_{hp} - DAOcr_{hp})$$

ii. If $RTScr_{ip} >= AdjDAScr_{hp}$

$$CDAMAPcr_{ip} = (AdjDAScr_{hp} - RTScr_{ip}) \times MAX((RTMCPcr_{hp} - RTOcr_{hp}), 0)$$

Where:

$RTScr_{ip}$ = Real-Time cleared Contingency Reserve, product p, for interval i.

$AdjDAScr_{hp}$ = Adjusted Day-Ahead Schedule for Contingency Reserve, product p, for interval i.

$CDAMAPcr_{ip}$ = Contingency Reserve, product p, contribution to DAMAP for interval i.

$RTMCPcr_{hp}$ = Hourly Real-Time Ex Post MCP~~Marginal Clearing Price~~ for Contingency Reserve, product p, for Hour h containing interval i.

$DAOcr_{hp}$ = Day-Ahead Offer for Contingency Reserve, product p, for Hour h containing interval i.

$RTOcr_{hp}$ = Real-Time Offer for Contingency Reserve, product p, for Hour h containing interval i.

c. The Regulating Reserve contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II, Stored Energy Resources, or External Asynchronous Resource for Dispatch Interval i is calculated as follows.

i. If $RTSreg_i < AdjDASreg_h$

Then:

$$CDAMAPreg_i = (AdjDASreg_h - RTSreg_i) \times (RTMCPreg_i - DAOreg_h)$$

ii. If $RTSreg_i >= AdjDASreg_h$

$$CDAMAPreg_i = (AdjDASreg_h - RTSreg_i) \times MAX((RTMCPreg_i - RTOreg_h), 0)$$

Where:

$RTSreg_i$ = Real-Time cleared Regulating Reserve for interval i.

$AdjDASreg_h$ = Adjusted Day-Ahead Schedule for Regulating Reserve for interval i.

$CDAMAPreg_i$ = Regulating Reserve contribution to DAMAP for interval i.

$RTMCPreg_i$ = Real-Time Ex Post MCP~~Market Clearing Price~~ for Regulating Reserve for hour h containing interval i.

$DAOreg_h$ = Day-Ahead Offer for Regulating Reserve for hour h containing interval i.

$RTOreg_h$ = Real-Time Offer for Regulating Reserve for hour h containing interval i.

d. The total contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II, Stored Energy Resource, or External Asynchronous Resource for Dispatch Interval i is calculated as follows.

$$CDAMAP_i = (CDAMAPen_i + \sum_p CDAMAPcr_{ip} + CDAMAPreg_i) \times s_i / 3600$$

Where:

$CDAMAP_i$ = Dispatch interval i contribution to DAMAP for hour h.

$CDAMAPen_i$ = Energy contribution to DAMAP for interval i.

$CDAMAPcr_{ip}$ = Contingency Reserve, product p, contribution to DAMAP for interval i.

$CDAMAPreg_i$ = Regulating Reserve contribution to DAMAP for interval i.

s_i = Length of dispatch interval i in seconds.

3. Step Three: Calculation of Hourly DAMAP:

a. If the sum of the eligible Generation Resource's, Demand Response Resource's Type II, Stored Energy Resource's, or External Asynchronous Resource's Dispatch Interval contribution to DAMAP is greater than zero, then the Resource will receive a DAMAP credit for the Hour.

b. The DAMAP shall be calculated at an hourly level as specified below.

$$\mathrm{DAMAP_h} = MAX\left(\sum\nolimits_{\mathrm{Hour}} \mathrm{CDAMAP_i}\ ,\ 0 \right)$$

Where:

$DAMAP_h$ = Day--Ahead Margin Assurance Payment to a Resource for hour h.

n = Number of intervals in hour h.

$CDAMAP_{\mathrm{i}}$ = Dispatch interval i contribution to DAMAP for hour h.

SCHEDULE 29A

ELMP for Energy and Operating Reserve Market:

Ex-Post Pricing Formulations

I. INTRODUCTION

The Transmission Provider utilizes an extension of the simultaneously co-optimized Security Constrained Economic Dispatch (SCED) algorithm to calculate prices for Energy and Operating Reserves. The SCED-Pricing algorithm utilizes a linear programming solver to minimize objective costs represented by a linear objective function subject to linear or linearized physical, reliability and Good Utility Practice constraints as in the simultaneously co-optimized SCED algorithm described in Schedule 29. The SCED-Pricing objective function includes total Energy costs, Regulating Reserve costs, Spinning Reserve costs, Supplemental Reserve costs, Market-Wide Operating Reserve value, Market-Wide Regulating Reserve value, Reserve Zone Operating Reserve value and Reserve Zone Regulating Reserve value. The SCED-Pricing algorithm is solved on an Hourly basis for the Day-Ahead Energy and Operating Reserve Market and for each five (5) minute Dispatch Interval for the Real-Time Energy and Operating Reserve Market. The SCED-Pricing algorithm extends the concept of LMP and MCP by allowing the cost of committing Fast Start Resources, the Energy cost of Fast Start Resources dispatched at limits, and Emergency Demand Response Resources to set Energy and reserve prices. This process is known as Extended LMP (ELMP). The SCED-Pricing algorithm in Schedule 29A is the same as the SCED algorithm in Schedule 29 with the exception of its treatment of Fast Start

Resources and Emergency Demand Response Resources.

II. DAY-AHEAD PRICING FORMULATIONS

The Day-Ahead Pricing formulation considers the cost of Energy, Regulating Reserves, and Spinning Reserves from Resources committed in the Hour. It also considers the costs of Supplemental Reserves from off-line or uncommitted Resources. In addition, the Day-Ahead Pricing formulation considers the costs of committing and the costs of keeping on-line those Fast-Start Resources that are committed by the Transmission Provider to be on line in the Hour. It also considers the costs of committing and dispatching off-line Fast Start Resources that are available for the Transmission Provider to commit in the Hour under conditions of Energy or Ancillary Service scarcity or that could alleviate transmission constraint violations, except for the Surplus Conditions in the Day-Ahead EORM described in section 39.2.11.c.

If an on-line Resource that is not a Fast Start Resource committed by the Transmission Provider in the Day-Ahead Market processes described in Section 39.2.9, the costs in the objective function for the Resource and the constraints on the Resource's Energy and Ancillary Service Schedules in the SCED-Pricing problem are the same as those for the Resource in the simultaneously co-optimized SCED algorithm described in Schedule 29.

For a Fast Start Resource committed by the Transmission Provider in the Day-Ahead market processes described in Section 39.2.9 to be on-line in the Hour, the SCED-Pricing algorithm considers the cost of committing and dispatching the Resource when setting prices. The SCED-Pricing algorithm considers the Resource eligible to set prices even if the Resource was scheduled to operate at its minimum or maximum limit. It also considers Start-Up Costs and No-Load Costs for the Fast Start Resource when setting prices. To achieve this, the SCED-Pricing algorithm allows fractional commitment of a Fast Start Resource for purposes of setting prices, even though fractional commitment is not a physically achievable outcome. SCED-Pricing represents the fraction of the Fast Start Resource committed in the Hour by a continuous decision variable, on_{hour}. The SCED-Pricing algorithm requires that on_{hour} satisfy

$$0 \leq on_{hour} \leq 1$$

The SCED-Pricing algorithm allocates a share of the Start-Up Cost for the Fast Start Resource to the Hour for which prices are being calculated. In the following N is the Minimum Run Time offered by the Fast Start Resource in hours.

$AllocatedShareStartUpCost_{hour}$ *= StartUpCost / N if hour is within N hours of the time the Resource was committed, or 0 if hour is later than N hours after the Resource was committed.*

The SCED-Pricing algorithm allocates the No-Load Cost for the Hour to the Hour for which prices are being calculated.

If the Fast-Start Resource was not committed to provide Regulation Reserves, the constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing will include the following. Let $DispatchSchedule_{hour}$ be the dispatch scheduled for the Resource in Hour *hour* and $SpinningReservesSchedule_{hour}$ be the Spinning Reserve Schedule for the Resource in Hour *hour* in SCED-Pricing.

$$on_{hour} \times EconMin_{hour} \leq EnergyDispatchSchedule_{hour}$$

$$0 \leq SpinningReservesSchedule_{hour}$$

$$EnergyDispatchSchedule_{hour} + SpinningReservesSchedule_{hour} \leq on_{hour} \times EconMax_{hour}$$

The ramping constraints affecting Energy and Spinning Reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$$on_{hour} \times (AllocatedShareStartUpCost_{hour} + NoLoadCost_{hour})$$

$$+ \int_{0}^{EnergyDispatchSchedule_{hour}} IncrementalEnergyCost_{hour}(x)dx$$

$$+ SpinningOfferCost_{hour} \times SpinningReservesSchedule_{hour}$$

If the Fast-Start Resource was committed to provide Regulating Reserves, the constraints for the Energy, Spinning Reserves, and Regulating Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_{hour}$ be the dispatch scheduled for the Resource in Hour *hour*, $SpinningReservesSchedule_{hour}$ be the Spinning Reserve Schedule for the Resource in Hour *hour*, and $RegulatingReservesSchedule_{hour}$ be the Regulating Reserve Schedule for the Resource in Hour *hour* in SCED-Pricing.

$$on_{hour} \times RegMin_{hour} \leq EnergyDispatchSchedule_{hour}$$

$$0 \leq SpinningReservesSchedule_{hour}$$

$$0 \leq RegulatingReservesSchedule_{hour}$$

$on_{hour} \times RegMin_{hour} \leq EnergyDispatchSchedule_{hour} - RegulatingReservesSchedule_{hour}$

$EnergyDispatchSchedule_{hour} + SpinningReservesSchedule_{hour} + RegulatingReservesSchedule_{hour} \leq on_{hour} \times RegMax_{hour}$

The ramping constraints affecting Energy and reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$on_{hour} \times (AllocatedShareStartUpCost_{hour} + NoLoadCost_{hour})$

$+ \int_{0}^{EnergyDispatchSchedule_{hour}} IncrementalEnergyCost_{hour}(x)dx$

$+SpinningOfferCost_{hour} \times SpinningReservesSchedule_{hour}$

$+ RegulatingOfferCost_{hour} \times RegulatingReservesSchedule_{hour}$

Off-line Fast Start Resources that are available to be committed in the Day-Ahead Market by the Transmission Provider participate in SCED-Pricing if either or both of the following conditions hold:

The SCED algorithm finds a solution that does not meet energy and/or reserve requirements in the Hour except for the Surplus Conditions in the Day-Ahead EORM described in section 39.2.11.c; and/or

The SCED algorithm finds a solution that violates a transmission constraint and the Transmission Provider determines that commitment of the Fast Start Resource provides relief to the violation.

In these scenarios, committing and dispatching off-line Fast Start Resource is an action that the Transmission Provider could take to address the shortage or violation. Rather than set price using a shortage cost or a transmission penalty price, the SCED-Pricing algorithm determines prices based on the action that the Transmission Provider could take to address the problem. The constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_{hour}$ be the dispatch scheduled for the Resource in Hour *hour* and let $OffLineSupplementalReservesSchedule_{hour}$ be the Off Line Supplemental Reserve Schedule for the Resource in Hour *hour* in SCED-Pricing.

$$on_{hour} \times EconMin_{hour} \leq EnergyDispatchSchedule_{hour} \leq on_{hour} \times EconMax_{hour}$$

$$0 \leq OffLineSupplementalReservesSchedule_{hour}$$

$$\leq (1 - on_{hour}) \times \min\{EconMax_{hour}, MaxOfflineResponseLimit_{hour}\}$$

The objective function elements for the Fast Start Resource includes:

$$on_{hour} \times (AllocatedShareStartUpCost_{hour} + NoLoadCost_{hour})$$

$$+ \int_{0}^{EnergyDispatchSchedule_{hour}} IncrementalEnergyCost_{hour}(x)dx$$

$+ \mathit{OffLineSupplementalOfferCost}_{hour} \times \mathit{OffLineSupplementalReservesSchedule}_{hour}$

The SCED-Pricing algorithm is the same as the SCED algorithm, with the exceptions for treatment of Fast Start Resources described above.

Objective Function:

Minimize {Total Hourly Energy Costs

+ Total Hourly Commitment Costs for Fast Start Resources

+ Total Hourly Regulating Reserve Costs

+ Total Hourly Spinning Reserve Costs

+ Total Hourly Supplemental Reserve Costs

- Total Hourly Market-Wide Operating Reserve Value

- Total Hourly Market-Wide Regulating Reserve Value

- Total Hourly Zonal Operating Reserve Value

- Total Hourly Zonal Regulating Reserve Value}

Where:

Total Hourly Energy Costs

= The sum of the hourly Energy costs that would be incurred by all Resources supplying dispatchable Energy, based on their submitted Energy offer curves, if they were to operate according to the schedule produced by SCED-Pricing for the given Hour.

Total Hourly Commitment Costs for Fast Start Resources

= The sum of the hourly Start-Up Costs and No-Load Costs that would be incurred by all Fast Start Resources available for commitment by the Transmission Provider, based on their submitted Start-Up and No-Load Offer Costs, if they were to operate according to the commitment produced by SCED-Pricing for the given Hour.

Total Hourly Regulating Reserve Costs

= The sum of the hourly Regulating Reserve costs, based on the Regulating Reserve offer prices, that would be incurred by all Resources supplying dispatchable Regulating Reserve, if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Hour.

Total Hourly Spinning Reserve Costs

= The sum of the hourly Spinning Reserve costs, based on the Spinning Reserve offer prices, that would be incurred by all Resources supplying dispatchable Spinning Reserve, if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Hour.

Total Hourly Supplemental Reserve Availability Costs

= The sum of the hourly Supplemental Reserve availability costs, based on the Supplemental Reserve offer prices, that would be incurred by all Resources supplying dispatchable Supplemental Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Hour.

Total Hourly Market-Wide Operating Reserve Value

= The hourly value of the Market-Wide Operating Reserve cleared by SCED-Pricing to the Load Serving Entities and Market Participant with Exports on whose behalf the Transmission Provider is procuring Operating Reserves based on the Market-Wide Operating Reserve Demand Curve.

Total Hourly Market-Wide Regulating Reserve Value

= The hourly value of the Market-Wide Regulating Reserve cleared by SCED-Pricing to the Load Serving Entities on whose behalf the Transmission Provider is procuring Regulating Reserves based on the Market-Wide Regulating Reserve Demand Curve.

Total Hourly Zonal Operating Reserve Value

= The hourly zonal value of the Operating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities and Market Participants with Exports on whose behalf the Transmission Provider is procuring Operating Reserves based on the Zonal Operating Reserve Demand Curves.

Total Hourly Zonal Regulating Reserve Value

= The hourly zonal value of the Regulating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities on whose behalf the Transmission Provider is procuring Regulating Reserves based on the Zonal Regulating Reserve Demand Curves.

Constraints:

Subject to

Nodal Power Balance Constraint

Market-Wide Operating Reserve Constraint

Market-Wide Regulating and Spinning Reserve Constraint

Market-Wide Regulating Reserve Constraint

Reserve Zone Operating Reserve Constraints

Reserve Zone Regulating and Spinning Reserve Constraints

Reserve Zone Regulating Reserve Constraints

Maximum Stored Energy Resource Regulation Constraints

Market-Wide Non-DRR1 Operating Reserve Constraint

Resource Limit Constraints

Resource Ramping Constraints

Transmission Constraints

Where:

The Nodal Power Balance Constraint ensures that the net Energy injected at an electrical Node to equal the net Energy flowing out of the same electrical Node on connected branches.

The Market-Wide Operating Reserve Constraint ensures the supply of Market-Wide Operating Reserve is greater than or equal to the Market-Wide Operating Reserve cleared by SCED-Pricing.

The Market-Wide Regulating and Spinning Reserve Constraint ensures that the supply of Market-Wide Regulating and Spinning Reserve is greater than or equal to the Market-Wide Regulating and Spinning Reserve requirement.

The Market-Wide Regulating Reserve Constraint ensures the supply of Market-Wide Regulating Reserve is greater than or equal to the Market-Wide Regulating Reserve cleared by SCED-Pricing.

The Reserve Zone Operating Reserve Constraints ensure the supply of Operating Reserve within a specific Reserve Zone is greater than or equal to the Operating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Reserve Zone Regulating and Spinning Reserve Constraints ensure that the supply of Regulating and Spinning Reserve within a specific Reserve Zone is greater than or equal to the Zonal Regulating and Spinning Reserve requirement.

The Reserve Zone Regulating Reserve Constraints ensure~~s~~ the supply of Regulating Reserve within a specific Reserve Zone is greater than or equal to the Regulating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Maximum Stored Energy Resource Regulation Constraints ensure that the supply of Regulating Reserve that is cleared by SCED-Pricing on Stored Energy Resources is less than or equal to the Market-Wide Regulating Reserve Requirement.

The Market-Wide Non-DRR1 Operating Reserve Constraint ensures the percentage of Market-Wide Operating Reserve that is cleared by SCED-Pricing on Generation Resources, Demand Response Resources – Type II, Stored Energy Resources, and/or External Asynchronous Resources complies with Applicable Reliability Standards.

The Resource Limit Constraints ensure that each Resource has the Capacity, based on submitted limits, to simultaneously supply cleared Energy, deploy one hundred percent (100%) of cleared Regulating Reserve in the upward direction, deploy one hundred percent (100%) of cleared Spinning Reserve and deploy one hundred percent (100%) of cleared Supplemental Reserve. In addition, the Resource Limit Constraints ensure that each Resource has the ability to simultaneously supply cleared Energy and deploy one hundred percent (100%) of the cleared Regulating Reserve in the downward direction with no Spinning Reserve or Supplemental Reserve deployment. For Fast Start Resources, the upper limits and lower limits on capacity available to provide energy and reserves are adjusted by the fractional commitment level for the Resource determined by SCED-Pricing.

The Resource Ramping Constraints ensure that each Resource is cleared by SCED-Pricing in a manner to follow load based on cleared Energy levels in adjacent dispatch intervals and deploy Regulating Reserve and Contingency Reserve in a manner that will comply with Applicable Reliability Standards.

The Transmission Constraints ensure that Energy is cleared by SCED-Pricing on Resources and Loads in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility. In addition, beginning November 1, 2011, the Transmission Constraints shall also ensure that Operating Reserves can be deployed in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility.

Under Shortage Condition in the Day-Ahead EORM described in section 39.2.10, Emergency Maximum Limits are used in SCED-Pricing for Resources available to be dispatched up to Emergency Maximum Limits in SCED. Under Surplus Condition in the Day-Ahead EORM described in section 39.2.11, Emergency Minimum Limits are used in SCED-Pricing for Resources available to be dispatched down to Emergency Minimum Limits in SCED. In addition, during a Surplus Condition, the commitment variable for all Fast Start Resource that were physically committed by the Transmission Provider are held at the value 1 in SCED-Pricing.

III. REAL-TIME FORMULATIONS

The Real-Time Pricing formulation considers the cost of Energy, Regulating Reserves, and Spinning Reserves from Resources committed in the Dispatch Interval. It also considers the costs of Supplemental Reserves from off-line or uncommitted Resources. In addition, the Real-Time Pricing formulation considers the costs of committing and the costs of keeping on-line those Fast-Start Resources that are committed in the RAC processes by the Transmission Provider to be on line in the Dispatch Interval. It also considers the costs of committing and dispatching off-line Fast Start Resources that are available for the Transmission Provider to commit in the Dispatch Interval under conditions of Energy or Ancillary Service scarcity or that could alleviate transmission constraint violations, except for the Capacity Surplus under Minimum Load Conditions in RT EORM described in section 40.2.21.b. If the Transmission Provider called upon Emergency Demand Response, the SCED-Pricing algorithm will also consider the cost of the Emergency Demand Response scheduled by the Transmission Provider.

If an on-line Resource that is not a Fast Start Resource is committed in the RAC processes by the Transmission Provider, the costs in the objective function for the Resource and the constraints on the Resource’s Energy and Ancillary Service Schedules in the SCED-Pricing problem are the same as those for the Resource in the simultaneously co-optimized SCED algorithm described in Schedule 29.

For a Fast Start Resource that was committed in the RAC processes by the Transmission Provider to be on-line in the Dispatch Interval, the SCED-Pricing algorithm considers the cost of committing and dispatching the Resource when setting prices. The SCED-Pricing algorithm considers the Resource eligible to set prices even if the Resource was scheduled to operate at its minimum or maximum limit. It also considers Start-Up Costs and No-Load Costs for the Fast Start Resource when setting prices. To achieve this, the SCED-Pricing algorithm allows fractional commitment of a Fast Start Resource for purposes of setting prices, even though this is not a physically achievable outcome. SCED-Pricing represents the fraction of the Fast Start Resource that is committed in the Dispatch Interval, t, for which prices are being calculated by the continuous decision variable on_t. The SCED-Pricing algorithm requires that on_t satisfy

$$0 \leq on_t \leq 1$$

The SCED-Pricing algorithm allocates a share of the Start-Up Cost for the Fast Start Resource to the interval for which prices are being calculated. In the following N is the minimum run time offered by the Fast Start Resource in hours.

$AllocatedShareStartUpCost_t = StartUpCost / (N \times Intervals\ per\ Hour)$ *if t is within N hours of the time the Resource was committed, or 0 if t is later than N hours after the Resource was committed.*

The SCED-Pricing algorithm allocates the No-Load Cost for the Dispatch Interval to the Dispatch Interval for which prices are being calculated.

If the Fast-Start Resource was not committed to provide Regulation Reserves, the constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing includes the following. Let $DispatchSchedule_t$ be the dispatch scheduled for the Resource in Dispatch Interval t and $SpinningReservesSchedule_t$ be the Spinning Reserve Schedule for the Resource in Dispatch Interval t in SCED-Pricing.

$$on_t \times EconMin_t \leq EnergyDispatchSchedule_t$$

$$0 \leq SpinningReservesSchedule_t$$

$$EnergyDispatchSchedule_t + SpinningReservesSchedule_t \leq on_t \times EconMax_t$$

The ramping constraints affecting Energy and Spinning Reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$$on_t \times (AllocatedShareStartUpCost_t + ({}^{NoLoadCost_t}/_{(Intervals\ per\ Hour)}))$$

$$+ \left(\int_0^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t(x)dx\right) / (Intervals\ per\ Hour)$$

$$+ (SpinningOfferCost_t \times SpinningReservesSchedules_t) / (Intervals\ per\ Hour)$$

If the Fast-Start Resource was committed to provide Regulation Reserves, the constraints for the Energy, Spinning Reserves, and Regulating Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_t$ be the dispatch level for the Resource in Dispatch Interval t, $SpinningReservesSchedule_t$ be the Spinning Reserve Schedule for the Resource in Dispatch Interval t, and $RegulatingReservesSchedule_t$ be the Regulating Reserve Schedule for the Resource in Dispatch Interval t in SCED-Pricing.

$on_t \times RegMin_t \leq EnergyDisptachSchedule_t$

$on_t \times RegMin_t \leq EnergyDispatchSchedule_t - RegulatingReservesSchedule_t$

$0 \leq SpinningReservesSchedule_t$

$0 \leq RegulatingReservesSchedule_t$

$Energy_t + SpinningReservesSchedule_t + RegulatingReservesSchedule_t \leq on_t \times RegMax_t$

The ramping constraints affecting Energy and Reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$on_t \times (AllocatedShareStartUpCost_t + ({}^{NoLoadCost_t}/_{(Intervals\ per\ Hour)}))$

$+ (\int^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t\,(x)dx) / (Intervals\ per\ Hour)$

$_0$

$+ (SpinningOfferCost_t \times SpinningReservesSchedules_t) / (Intervals\ per\ Hour)$

$+ (RegulatingOfferCost_t \times RegulatingReservesSchedules_t) / (Intervals\ per\ Hour)$

Off-line Fast Start Resources that are available to be committed by the Transmission Provider participate in SCED-Pricing if either or both of the following conditions hold:

a) The SCED algorithm finds a solution that does not meet energy and/or reserve requirements in the hour, except for the Capacity Surplus under Minimum Load Conditions in RT EORM described in section 40.2.21.b;

b) The SCED algorithm finds a solution that violates a transmission constraint and the Transmission
Provider determines that commitment of the Fast Start Resource provides relief to the violation.

In these scenarios, committing and dispatching an off-line Fast Start Resource is an action that the Transmission Provider could take to address the shortage or violation. Rather than set price using a shortage cost or a transmission penalty price, the SCED-Pricing algorithm determines prices based on the action that the Transmission Provider could take to address the problem. The constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_t$ be the dispatch scheduled for the Resource in Dispatch Interval t and $OffLineSupplementalReservesSchedule_t$ be the Off Line Supplemental Reserve Schedule for the Resource in Dispatch Interval t in SCED-Pricing.

$on_t \times EconMin_t \leq EnergyDispatchSchedule_t \leq on_t \times EconMax_t$

$0 \leq OffLineSupplementalReservesSchedule_t$

$\leq (1 - on_t) \times min\{EconMax_t, MaxOfflineResponseLimit_t\}$

The objective function elements for the Fast Start Resource includes:

$on_t \times (AllocatedShareStartUpCost_t + (NoLoadCost_t / (Intervals\ per\ Hour)))$

$+ (\int_0^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t(x)dx) / (Intervals\ per\ Hour)$

$+ (OffLineSupplementalOfferCost_t \times OffLineSupplementalReservesSchedules_t) / (Intervals\ per\ Hour)$

For an Emergency Demand Response Resource that was scheduled by the Transmission Provider to provide Energy by reduction in Load (or increase in behind the meter generation) in the Dispatch Interval, the SCED-Pricing algorithm will consider the cost of committing the Resource to reduce Energy consumption and the incremental cost of Energy reduction from the Resource when setting prices. To achieve this, the SCED-Pricing algorithm allows the reduction of Energy consumption by the Emergency Demand Response Resource to be adjusted for pricing purposes. SCED-Pricing represents the fraction of the Emergency Demand Response Resource that committed by the SCED-Pricing algorithm in the Dispatch Interval *t* by the continuous decision variable on_t. SCED-Pricing algorithm requires that on_t satisfy

$0 \leq on_t \leq 1$

The SCED-Pricing algorithm allocates a share of the Shut-Down Cost for the Emergency Demand Response Resource to the interval for which prices are being calculated. In the following, N is the period of time in Hours for which the Transmission Provider scheduled reduction in Energy consumption from the Emergency Demand Resource, $EconMax_t$ is the maximum reduction in power consumption in Dispatch Interval *t* that can be scheduled from the Emergency Demand Response Resource if called upon to reduce consumption in Dispatch Interval t, and $EconMin_t$ is the minimum reduction in power consumption in Dispatch Interval *t* that can be scheduled from the Emergency Demand Response Resource if called upon to provide reduce consumption in Dispatch Interval *t*. The allocation of Shut-Down Cost is then given by the following:

$AllocatedShareShutDownCost_t = ShutDownCost/N \times (Intervals\ per\ Hour)$

The constraints for the scheduled reduction from the Emergency Demand Response Resource in SCED-Pricing include the following:

$on_t \times EconMin_t \leq EnergyReduction_t \leq on_t \times EconMax_t$

The objective function elements for the Emergency Demand Response Resource includes:

$on_t \times AllocatedShareShutDownCost_t$

$$+ \left(\int_{0}^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t(x)dx\right) / (Intervals\ per\ Hour)$$

The SCED-Pricing algorithm is the same as the SCED algorithm, with the exceptions for treatment of Fast Start Resources and Emergency Demand Response Resources described above.

Objective Function:

Minimize {Total Dispatch Interval Energy Costs

+ Total Dispatch Interval Commitment Costs for Fast Start Resources

+Total Dispatch Interval Commitment Costs and Energy Reduction Costs for Emergency Demand Response Resources

+ Total Dispatch Interval Regulating Reserve Costs

+ Total Dispatch Interval Spinning Reserve Costs

+ Total Dispatch Interval Supplemental Reserve Costs

- Total Dispatch Interval Market-Wide Operating Reserve Value

- Total Dispatch Interval Market-Wide Regulating Reserve Value

- Total Dispatch Interval Zonal Operating Reserve Value

- Total Dispatch Interval Zonal Regulating Reserve Value}

Where

Total Dispatch Interval Energy Costs

= The sum of the Dispatch Interval Energy costs that would be incurred by all Resources supplying dispatchable Energy, based on their submitted Energy offer curves, if they were to operate according to the schedule produced by SCED-Pricing for the given Dispatch Interval.

Total Dispatch Interval Commitment Costs for Fast Start Resources

= The sum of the Dispatch Interval Start-Up Costs and No-Load Costs that would be incurred by all Fast Start Resources available for commitment by the Transmission Provider, based on their submitted Start-Up and No-Load Offer Costs, if they were to operate according to the commitment produced by SCED-Pricing for the given Dispatch Interval.

Total Dispatch Interval Commitment Costs and Energy Reduction Costs for Emergency Demand Response Resources

= The sum of the Dispatch Interval Shut-Down Costs and Energy Reduction Costs that would be incurred by Emergency Demand Response Resources, based on their submitted Shut-Down and Incremental Energy Reduction Offer Costs, if they were to operate according to the schedule produced by SCED-Pricing for the given Dispatch Interval.

Total Dispatch Interval Regulating Reserve Costs

= The sum of the Dispatch Interval Regulating Reserve costs, based on the Regulating Reserve offer prices, that would be incurred by all Resources supplying dispatchable Regulating Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Dispatch Interval.

Total Dispatch Interval Spinning Reserve Costs

= The sum of the Dispatch Interval Spinning Reserve costs, based on the Spinning Reserve offer prices, that would be incurred by all Resources supplying dispatchable Spinning Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Dispatch Interval.

Total Dispatch Interval Supplemental Reserve Availability Costs

= The sum of the Dispatch Interval Supplemental Reserve availability costs, based on the Supplemental Reserve offer prices, that would be incurred by all Resources supplying dispatchable Supplemental Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Dispatch Interval.

Total Dispatch Interval Market-Wide Operating Reserve Value

= The Dispatch Interval value of the Market-Wide Operating

Reserve cleared by SCED-Pricing to the Load Serving Entities and Market Participant with Exports on whose behalf the Transmission Provider is procuring Operating Reserves based on the Market-Wide Operating Reserve Demand Curve.

Total Dispatch Interval Market-Wide Regulating Reserve Value

= The Dispatch Interval value of the Market-Wide Regulating Reserve cleared by SCED-Pricing to the Load Serving Entities on whose behalf the Transmission Provider is procuring Regulating Reserve based on the Market-Wide Regulating Reserve Demand Curve.

Total Dispatch Interval Zonal Operating Reserve Value

= The Dispatch Interval zonal value of the Operating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities and Market Participants with Exports on whose behalf the Transmission Provider is procuring Operating Reserve based on the Zonal Operating Reserve Demand Curves.

Total Dispatch Interval Zonal Regulating Reserve Value

= The Dispatch Interval zonal value of the Regulating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities on whose behalf the Transmission Provider is procuring Operating Reserve based on the Zonal Regulating Reserve Demand Curves.

Constraints:

Subject to

Global Power Balance Constraint

Market-Wide Operating Reserve Constraint

Market-Wide Regulating and Spinning Reserve Constraint

Market-Wide Regulating Reserve Constraint

Reserve Zone Operating Reserve Constraints

Reserve Zone Regulating and Spinning Reserve Constraints

Reserve Zone Regulating Reserve Constraints

Maximum Stored Energy Resource Regulation Constraints

Market-Wide Non-DRR1 Operating Reserve Constraint

Resource Limit Constraints

Resource Ramping Constraints

Transmission Constraints

Where

The Global Power Balance Constraint ensures that the net Energy injected into the Eastern Interconnection model equals the net Energy withdrawn from the Eastern Interconnection model plus losses.

The Market-Wide Operating Reserve Constraint ensures the supply of Market-Wide Operating Reserve is greater than or equal to the Market-Wide Operating Reserve cleared by SCED-

Pricing.

The Market-Wide Regulating and Spinning Reserve Constraint ensures that the supply of Market-Wide Regulating and Spinning Reserve is greater than or equal to the Market-Wide Regulating and Spinning Reserve requirement.

The Market-Wide Regulating Reserve Constraint ensures the supply of Market-Wide Regulating Reserve is greater than or equal to the Market-Wide Regulating Reserve cleared by SCED-Pricing.

The Reserve Zone Operating Reserve Constraints ensure the supply of Operating Reserve within a specific Reserve Zone is greater than or equal to the Operating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Reserve Zone Regulating and Spinning Reserve Constraint ensures that the supply of Regulating and Spinning Reserve within a specific Reserve Zone is greater than or equal to the Zonal Regulating and Spinning Reserve requirement.

The Reserve Zone Regulating Reserve Constraint ensures the supply of Regulating Reserve within a specific Reserve Zone is greater than or equal to the Regulating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Maximum Stored Energy Resource Regulation Constraints ensure that the supply of Regulating Reserve that is cleared by SCED-Pricing on Stored Energy Resources is less than or equal to the Market-Wide Regulating Reserve Requirement

The Market-Wide Non-DDR1 Operating Reserve Constraint ensures the percentage of Market-Wide Operating Reserve that is cleared by SCED-Pricing on Generation Resources, Demand Response Resources – Type II, Stored Energy Resources, and/or External Asynchronous Resources complies with Applicable Reliability Standards.

The Resource Limit Constraints ensure that each Resource has the Capacity, based on submitted limits, to simultaneously supply cleared Energy, deploy one hundred percent (100%) of cleared Regulating Reserve in the upward direction, deploy one hundred percent (100%) of cleared Spinning Reserve and deploy one hundred percent (100%) of cleared Supplemental Reserve. In addition, the Resource Limit Constraints ensure that each Resource has the ability to simultaneously supply cleared Energy and deploy one hundred percent (100%) of the cleared Regulating Reserve in the downward direction with no Spinning Reserve or Supplemental Reserve deployment. For Fast Start Resources, the upper limits and lower limits on capacity available to provide energy and reserves are adjusted by the partial commitment level for the Resource determined by SCED-Pricing. For Emergency Demand Resources, the upper and lower limits on energy reduction are adjusted by the partial commitment level for the Resource as determined by SCED-Pricing.

The Resource Ramping Constraints ensure that each Resource is cleared in a manner to follow load based on cleared Energy levels in adjacent Dispatch Intervals and deploy Regulating Reserve and Contingency Reserve in a manner that will comply with Applicable Reliability Standards.

The Transmission Constraints ensure that Energy is cleared by SCED-Pricing on Resources and Loads in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility. In addition, beginning November 1, 2011, the Transmission Constraints shall also ensure that Operating Reserves can be deployed in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility.

Under Capacity Shortage Conditions in the Real-Time EORM described in section 40.2.20.b, Emergency Maximum Limits are used in SCED-Pricing for Resources available to be dispatched up to Emergency Maximum Limits in SCED. Under Capacity Surplus Condition under Minimum Load Conditions in RT EORM described in section 40.2.21.b, Emergency Minimum Limits are used in SCED-Pricing for Resources available to be dispatched down to Emergency Minimum Limits in SCED. In addition, during a Capacity Surplus Condition , the commitment variable for all Fast Start Resource that were physically committed by the Transmission Provider are held at the value 1 in SCED-Pricing.

SCHEDULE 30 Emergency Demand Response Initiative Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

SCHEDULE 30

EMERGENCY DEMAND RESPONSE INITIATIVE

I. GENERAL

Schedule 30 provides for the commitment and dispatch of interruptible demand, behind-the-meter generation and other demand resources that are capable of helping meet the energy balance during NERC Energy Emergency Alert 2 ("EEA2") or Alert 3 ("EEA3") events. Schedule 30 provides procedures for the Transmission Provider to be able to dispatch such resources ("Emergency Demand Response" or "EDR") only during EEA2 or EEA3 events. Such procedures provide for reductions in Load and/or increased behind-the-meter generation (*i.e.*, "demand reduction") to be compensated under the conditions specified below (*i.e.*, "EDR Initiative"). Schedule 30 does not pertain to demand reductions during non-EEA2 or EEA3 events. These EDR procedures: (i) enhance the Transmission Provider's ability to utilize demand response during EEA2 or EEA3 events; (ii) enable the Transmission Provider to establish curtailment priorities; (iii) reflect varying costs of EDR options; and (iv) allow the Transmission Provider to evaluate and dispatch EDR Offers in merit order by location and by priority status.

II. EMERGENCY DEMAND RESPONSE PARTICIPATION

A Market Participant within the Transmission Provider Region may become an EDR Participant by complying with these Schedule 30 requirements if it: (i) has the ability to cause a reduction in demand in response to receiving an EDR Dispatch Instruction from the Transmission Provider either because the Market Participant is the operator of a facility capable of reducing demand, or the Market Participant is a Load Serving Entity ("LSE") or ARC with a contract that entitles the Market Participant to reduce Load at such facility; or (ii) has the ability to cause an increase in output from a Behind the Meter generation resource to enable a net demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Only a Market Participant is allowed to register to become an EDR Participant on behalf of an asset owner and be an eligible EDR Participant by submitting EDR Offers to the Transmission Provider to reduce demand during an EEA2 or EEA3 event.

Prior to participating in the EDR Initiative, a Market Participant must complete the EDR registration form posted on the Transmission Provider's website and submit it to the Transmission Provider. An EDR Participant and its associated load asset or Behind the Meter Generation asset must be defined in the EDR registration form.

The Transmission Provider shall notify the Market Participant when it has met all required qualifications to become an eligible EDR Participant and that the Market Participant is eligible to submit EDR Offers.

EDR Participants must be able to receive an EDR Dispatch Instruction from the Transmission Provider via XML. EDR Participants must utilize metering equipment that meets the requirements, including, but not limited to, the ability to provide integrated hourly kWh values on a Commercial Price Node ("CPNode") basis. EDR Participants may provide hourly kWh values for non-interval metered demand reductions (*e.g.*, direct Load control) using the alternative Measurements and Verification Procedures provided in Sections 6 through 8 of this Schedule 30. Measurement of demand reductions shall be made on an aggregated applicable CPNode basis to enable the EDR Participant's demand reduction to be identified with an LMP; ~~however~~ EDR Offers can~~cannot~~ set the Real-Time Ex Post LMP.

An EDR Participant that intends to use a Behind the Meter Generation Resource for the purpose of reducing demand during an EEA2 or EEA3 event shall confirm to the Transmission Provider in writing that: (1) it holds all necessary permits (including, but not limited to, environmental permits) applicable to the operation of the Generation Resource; (2) it possesses rights to operate the Generation Resource that are equivalent to ownership of such unit; and (3) the Generation Resource is not a designated Network Resource. Unless notified otherwise, the Transmission Provider shall deem such representation applies each time the Generation Resource is used to reduce demand during an EEA2 or EEA3 event and that the generation resource is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits. The EDR Participant shall be solely liable for identification of and compliance with all such applicable permits.

If the Generation Resource designated by an EDR Participant historically is operated during non-Emergency conditions, the Energy that can be offered under the EDR Initiative is the increase in output from a Behind the Meter generation resource to enable a net Demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Determination of such output shall be based on the EDR Offer and the amount of load reduction provided, which is more fully described in the Business Practices Manuals. If a Demand reduction is subject to a contractual agreement with an LSE, then the operator of the facility will be entitled to submit an EDR Offer for the specified Demand reduction to the Transmission Provider only if, and to the extent that, an EDR Offer is consistent with the terms and conditions of the contract with such LSE and the operator of the facility is a Market Participant.

EDR Participants shall be required to identify if the Demand reduction can be variable or alternatively provide a specific level of Demand reduction. Upon receipt of an EDR Dispatch Instruction, an EDR Participant shall either: 1) curtail to the firm service level specified in their EDR Offer; or 2) provide a specific level of Demand reduction as specified in their EDR Offer. EDR Participants electing the first option shall be required to identify an expected peak Load in their EDR Offer.

An EDR Participant shall verify in writing to the Transmission Provider that it has received any required approvals from all applicable state regulatory agencies to enable the entity to participate in the EDR Initiative.

EDR Participants are responsible for maintaining Demand reduction information, including the amount in MWh of reduced Demand during EEA2 or EEA3 events whenever the EDR Participant responds to an EDR Dispatch Instruction from the Transmission Provider. The EDR Participant shall provide this information to the Transmission Provider in accordance with the procedures specified in the appropriate Business Practices Manuals.

III. EDR OFFER

An EDR Participant seeking to reduce Demand during an EEA2 or EEA3 event and receive compensation under this Schedule 30 must submit an EDR Offer to reduce Load to the Transmission Provider no later than 1100 EST on the day prior to the next Operating Day and will be in effect for the next Operating Day. If an EDR Participant is unable to reduce Demand in accordance with an EDR Offer due to exigent circumstances, then the EDR Participant shall promptly notify the Transmission Provider in accordance with the procedures in the Business Practices Manuals. Such notification must be made prior to the issuance of EDR Dispatch Instructions.

The EDR Offer shall specify: (i) the minimum and maximum amount of the offered Demand reduction (in minimum increments of 0.1 MWh) or; specify the firm service level to which the EDR Participant will curtail Demand and specify the EDR Participant's peak Load; (ii) the applicable minimum and maximum number of contiguous Hours for which the Demand reduction must be committed for such curtailments; (iii) shutdown costs associated with a demand reduction, including direct labor and equipment costs and/or opportunity costs; (iv) the number of Hours of advance notice from the Transmission Provider that the EDR Participant requires to reduce Demand; (v) the daily availability of the Demand reduction; (vi) an hourly curtailment offer for such Demand reduction specified in dollars per MWh, not to exceed $3,500/MWh.

The hourly curtailment Offer is a single dollar per MWh value that is applicable to every Hour of the day. Any EDR Offer shall remain valid until it is modified or revoked by the EDR Participant. EDR Offers must be made for a minimum period of one (1) Operating Day and may not be modified after 1100 EST on the day prior to the next Operating Day. EDR Offers must be consistent with any applicable contractual agreements with an LSE.

At the time of EDR registration, an EDR Participant shall provide complete details regarding any limitations on the EDR Participant's ability to reduce Demand, including, but not limited to: (i) information regarding the total number of times that the EDR Participant is able to reduce Demand during the year; (ii) the number of times that the EDR Participant has already reduced Demand during the current year; and (iii) any and all restrictions (including, but not limited to, contractual restrictions) that may preclude the EDR Participant from reducing Demand in the future. These limitations provided at the time of registration but not included in the EDR Offer will have no impact on the Transmission Provider's decision to commit the EDR. It is the responsibility of the EDR Participant to ensure the limitations that exist outside of the parameters outlined in the EDR Offer are not violated.

IV. ISSUANCE OF EMERGENCY DEMAND RESPONSE DISPATCH INSTRUCTIONS

The Transmission Provider may issue EDR Dispatch Instructions to EDR Participants, in accordance with the Business Practices Manuals, based upon factors, including, but not limited to, consideration of: (i) terms and conditions of the EDR Offer; (ii) anticipated need for Demand reduction during the EEA2 or EEA3 event; (iii) availability of other EDR Demand reductions; (iv) the location of the Demand reduction; and (v) anticipated future Emergency conditions. EDR Dispatch Instructions shall detail: (i) the commencement of such Demand reductions; (ii) the amount of Demand reduction that the EDR Participant shall reduce, including a schedule for modified Demand reductions, if appropriate; and (iii) the duration for such Demand reductions. The Transmission Provider may also issue updates to EDR Dispatch Instructions if changing system conditions warrant such action. Any updates to EDR Dispatch Instructions will be consistent with the EDR Offer. The Transmission Provider's Emergency operating procedures documentation shall provide further detailed information on EDR Dispatch Instructions during EEA2 or EEA3 events.

EDR Participants shall be entitled to receive compensation for reducing Demand only to the extent that the EDR Participants comply with the Transmission Provider's EDR Dispatch Instructions. EDR Participants shall not be entitled to compensation for Demand reductions in excess of the EDR Dispatch Instruction amounts (*i.e.*, if Demand was reduced by more than that requested by the Transmission Provider in an EDR Dispatch Instruction), provided that EDR Participants shall be entitled to proportionate compensation if they reduced Demand by a fraction of the EDR Dispatch Instruction. If an EDR Participant reduces Demand by more than the EDR Dispatch Instruction during an EEA2 or EEA3 event, the EDR Participant will not be allocated Real-Time Revenue Sufficiency Guarantee Charges for deviations in Load, pursuant to Section 40.3.3.a.iv. To the extent that an EDR Demand reduction would have occurred during the EDR Dispatch Instruction time period absent the Transmission Provider issuing an EDR Dispatch Instruction to the EDR Participant, then the EDR Participant will not be entitled to compensation for such Demand reduction.

V. COMPENSATION

EDR Participants that reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider shall receive the higher of the applicable Hourly Real-Time Ex Post~~real-time~~ LMP revenue for the associated CPNode of the EDR Participant or the EDR Production Costs during the period of actual Demand reductions. For EDR Participants that are ARCs, the provisions of Section 38.6, part 2(a), (b), or (c) will apply, for purpose of billing and settlement with adjustment for the applicable MFRR. EDR Production Costs are the sum of (i) the shutdown cost and (ii) the lesser of (a) the amount of hourly verifiable Demand reduction or (b) the hourly Dispatch Instruction for each hour multiplied by the EDR Offer during the period of actual Demand reductions.

EDR Participants must submit documentation of Demand reductions made in response to EDR Dispatch Instructions to enable the EDR Participant to verify in writing under oath to the Transmission Provider that the Demand reductions actually occurred during an EEA2 or EEA3 event. EDR Participants must verify in writing to the Transmission Provider that the amount of Demand reductions were made in direct response to the Transmission Provider's EDR Dispatch Instruction and that the Demand reductions otherwise would not have been made.

EDR Participants that receive EDR Dispatch Instructions in response to submitted EDR Offers but do not reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider to the levels specified in the EDR Dispatch Instruction, and adjusted for the Demand Reduction Tolerance, shall not be guaranteed cost recovery for such failure to make Demand reductions. The Demand Reduction Tolerance is equal to (i) the EDR Dispatch Instruction MWhs multiplied by ninety-five percent (95%). EDR Participants that reduce Demand in response to an EDR Dispatch Instruction between the levels specified in the EDR Dispatch Instruction and the Demand Reduction Tolerance will be guaranteed cost recovery for provision of Demand reductions. In addition, such EDR Participants failing to reduce Demand shall be charged an amount equal to the Demand Reduction Shortfall multiplied by the Hourly Real-Time Ex Post LMP of the host load zone. The Demand Reduction Shortfall is calculated as: (i) the Demand Reduction Tolerance minus the actual Demand reduction; or (ii) zero (0), whichever is greater.

Any reductions in Demand by an EDR Participant shall be subject to verification and potential investigation by the Transmission Provider and the Federal Energy Regulatory Commission to confirm the validity of all EDR Participant assertions.

VI. PAYMENTS

The sum of the EDR Initiative payments made in an Hour in excess of market revenues shall be funded through an assessment of debits on Market Participants on a *pro rata* basis, based on the metered Load Ratio Share in the local Balancing Authority Area(s) where the EEA2 or EEA3 events occurred that served Load during the EDR Dispatch Instruction period in that same Hour. For the purposes of this calculation, the Load Ratio Share shall be the factor calculated as the withdrawal reported at a given CPNode divided by the sum of all the withdrawals at all CPNodes in the local Balancing Authority Area(s) where the EEA2 or EEA3 conditions occurred that served Load during the EDR Dispatch Instruction period. Any credits that result from EDR Participant(s) failure to reduce Demand as described in Section V shall be allocated in the same *pro rata* basis as costs are allocated in Section VI.

VII. METER DATA

Unless an alternate approach is agreed upon by the Transmission Provider and an EDR Participant and such alternate approach is documented in the Business Practices Manuals, measurement and verification for hourly interval metered EDR Participants will be based upon actual hourly usage in the Hour immediately preceding notification to the EDR Participant of the EDR Dispatch Instruction by the Transmission Provider. If EEA2 or EEA3 events occur during sequential days, the relevant data will be based upon the actual hourly usage prior to the first of the sequential EEA2 or EEA3 event days.

Except as may otherwise be agreed to, EDR Participants must provide the Transmission Provider with meter information for the Hour prior to notification of the EDR Dispatch Instruction, as well as every Hour during the Demand reduction, except under the following circumstances. When on-site generation is deployed exclusively to support the Demand reduction, the EDR Participant may provide qualified meter data from the on-site generation for each Hour of the EEA2 or EEA3 event day. Provision of hourly meter data from the on-site generation will be deemed a certification by the EDR Participant that the on-site generation was not used for any purpose other than to support the Demand reduction during the EEA2 or EEA3 event day.

VIII. MEASUREMENT AND VERIFICATION PROCEDURES

An EDR Participant that achieves Demand reduction through the use of direct load control procedures must provide the Transmission Provider with proposed Measurement and Verification Procedures. Proposed Measurement and Verification Procedures must include: (1) a description of the direct Load control system, including communication technology, type of Load(s) which are controlled, proposed control scheme (*e.g*. cycling or complete Load shed), number of participants, geographic location of participants and other relevant information; (2) a description of Load research data that is used in the analysis; (3) a description of the formulae used to produce the estimate, including all assumptions; and (4) a description of all source information for variables used in the analysis, such as a schedule of Demand reductions according to the time of day and weather conditions (*e.g*., temperature and humidity index). The Transmission Provider may request additional information from such EDR Participant and/or request appropriate revisions to the proposed Measurement and Verification Procedures.

For all Demand reductions that are not metered directly by the Transmission Provider, EDR Participants must forward the meter data and/or the results of the direct Load control Measurement and Verification Procedures, as specified in the Business Practices Manuals, to the Transmission Provider within fifty-three (53) calendar days after the Demand reduction, in order to be eligible to receive compensation.

ATTACHMENT AA

COMPENSATION AND COST RECOVERY

FOR ACTIONS DURING EMERGENCY CONDITION

A. GENERAL

Pursuant to Sections 3.4 and 3.6 of the Operating Protocol for Existing Generators, Article 7 of the IOA, Article 13 of the LGIA, and pursuant to Article III, Section I and Appendix E of the ISO Agreement, the Transmission Provider has the authority to direct Generation Resources to provide any of the following services during an Emergency or Emergency System Conditions including: (1) shut down, start up, and increase or decrease real or reactive power output of the Generation Resource; (2) implement a reduction or disconnection pursuant to Articles 7.7 and 7.8 of the IOA and Article 13.5.2 of the LGIA; (3) assist with black start (if available) or restoration efforts; and/or (4) defer a scheduled outage. In addition, during an Emergency or Emergency System Condition, the Transmission Provider has the authority to address shortage conditions in the Real-Time Energy Markets and during a Maximum Generation Emergency under Sections 40.2.15, 40.2.17, and 48 of the Tariff, as may be further set forth in the Business Practices Manuals.

B. COMPENSATION FOR EMERGENCY CONDITION SERVICES

If the Transmission Provider requests or directs the Generation Resource, either directly or through a Local Balancing Authority, to provide such services during an Emergency or Emergency System Conditions, the Market Participant owning the Generation Resource shall be compensated in accordance with the provisions of Sections 40.2.15, 40.2.17 or 48 of this Tariff.

Where a Generation Resource has cleared the Day-Ahead Energy Market, is directed by the Transmission Provider to reduce production below the Day-Ahead cleared level, and is required to settle the associated negative Day-Ahead imbalance at a higher Hourly Real-Time Ex Post LMP, the Generation Resource shall be reimbursed for such cost based on the difference in Real-Time output from that cleared Day-Ahead multiplied by the difference between Hourly~~in~~ Real-Time Ex Post LMP and Day-Ahead Ex Post LMP. Costs associated with such reimbursements will be allocated to all Load on a Load Ratio Share basis.

C. EMERGENCY REDISPATCH COST RECOVERY

The Transmission Provider reserves the right to assign all costs of Emergency or Emergency System Conditions to an individual Transmission Customer(s), or a Market Participant(s) owning a Resource(s) where circumstances conclusively demonstrate that the actions or inactions of one or more such Transmission Customer(s) or Market Participant(s), which were in violation of a Transmission Provider directive and Good Utility Practices, proximately caused the Emergency or Emergency System Conditions to arise, provided that, prior to any such direct assignment of costs, the Transmission Provider must receive approval from the Commission pursuant to a filing under Section 205 of the Federal Power Act. To the extent that any costs are directly assigned hereunder, the cost allocation set forth in Section 40.2.17(e) would not then apply

D. BILLING

The Transmission Provider shall submit invoices to the Market Participant or Transmission Customer for the charges incurred under this Attachment AA pursuant to Section 7.6 of this Tariff.

E. INFORMATION

1. Information in Support of Emergency Condition Services

Generation Resource will provide the Transmission Provider with information sufficient to permit the Transmission Provider to verify Generation Resource's invoice for service under this Attachment AA. Unless otherwise mutually agreed, Generation Resource will provide such information within 15 days of Generation Resource's provision of Emergency Condition Services. Upon written request of Generation Resource, the Transmission Provider will provide Generation Resource with information sufficient to permit Generation Resource to verify that the Transmission Provider's request for services under this Attachment AA was consistent with the purposes for which such services may be requested, as set forth herein. Unless otherwise mutually agreed, such information will be provided within 15 days by the Transmission Provider.

2. Verification of Emergency Condition

Upon written request of Generation Resource, the Transmission Provider will provide within 15 days of such written request, all documentation supporting the existence of an Emergency Condition. Disputes about the existence of an Emergency Condition shall be submitted for resolution in accordance with the dispute resolution procedures of the Tariff. If the Transmission Provider orders the provision of Emergency Condition Services through a Balancing Authority, the Transmission Provider will direct the Balancing Authority to advise the Generation Resource that the redispatch is at the direction of the Transmission Provider and shall provide confirmation of such direction within seventy-~~-~~two (72) hours of issuance of the redispatch order.

3. Confidential Information

Generation Resource will indicate and mark any such Confidential Information that is provided to the Transmission Provider that is not publicly available or of a proprietary nature.

The Transmission Provider will keep such information confidential in accordance with the Standards of Conduct, Appendix A of the ISO Agreement, on file with the Commission, and the relevant provisions of the Tariff.

ATTACHMENT DD Day-Ahead Locational Marginal Prices Version: 1.0.0.~~0~~ Effective: 12/31/9998~~7/28/2010~~

ATTACHMENT DD

Day-Ahead Locational Marginal Prices

The following procedures apply to both Day-Ahead Ex Ante ~~(~~LMPs and Day-Ahead Ex Post LMPs.~~)~~

The Transmission Provider calculates the price of Energy at the Load buses and Resource buses in the Transmission Provider's Market Footprint and at the External Interfaces between the Transmission Provider's Market Footprint and adjacent BAs on the basis of LMPs. LMPs can be set by Offers to sell or Bids to purchase Energy, including Physical Bilateral Transactions. The Transmission Provider establishes Hubs and Load Zones based on a pre-defined set of buses. The LMPs, Hub prices, External Interface prices, and Load Zone prices include separate components for the marginal costs of energy, congestion, and losses. Day-Ahead Market LMPs are calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Energy Market at 1600 hours EST, or such later time as may be required from time to time due to unanticipated events.

A. LMP Components

In each hour of the Day-Ahead Energy Market, the Transmission Provider calculates the LMP for each CPNode, which is equal to the marginal cost of Energy available at the CPNode in the hour, based on the Offers of sellers and Bids of buyers selected in the Day-Ahead Energy Market. The Transmission Provider designates a Reference Bus, *r*, for all other buses in the power system. The Marginal Energy Component (MEC_r) is the marginal cost of energy available to the Reference Bus, based on Offers and Bids selected in the Day-Ahead Energy Market. For each bus other than the Reference Bus, the Transmission Provider determines separate components of the LMP for the marginal costs of energy, congestion, and losses relative to the Reference Bus, consistent with the following equation:

$$LMP_i = MEC_r + MCC_i + MLC_i$$

$$LMP_r = MEC_r$$

where:

- MEC_r is the LMP component representing the marginal cost of Energy (also referred to as λ) at the Reference Bus, *r*.

- MCC_i is the LMP component representing the marginal cost of congestion (also referred to as ρ) at bus *i* relative to the Reference Bus.

- MLC_i is the LMP component representing the marginal cost of losses (also referred to as γ) at bus *i* relative to the Reference Bus.

B. Marginal Congestion Component Calculation

The Transmission Provider calculates the marginal costs of congestion at each bus as a component of the bus-level LMP. The Marginal Congestion Component (MCC_i) of the LMP at bus i is calculated using the equation:

$$MCC_i = -\left(\sum_{k=1}^{k} GSF_{ik} * FSP_k\right)$$

where:

- K is the number of thermal or interface transmission constraints (also called Flowgate).

- GSF_{ik} is the Generation Shift Factor for the generator at bus i on Flowgate k which limits flows across that constraint when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The industry convention is to ignore the effect of losses in the determination of GSFs.

- FSP_k is the Flowgate Shadow Price on Flowgate k and is equivalent to the reduction in system cost expressed in \$/MWh that results from an increase of 1MW of the capacity on Flowgate k.

C. Marginal Losses Component Calculation

The Transmission Provider calculates the Marginal Losses Component (MLC_i) at each bus i. The MLC of the LMP at any bus i within the Transmission Provider's Market Footprint is calculated using the equation:

$$MLC_i = (DF_i - 1) * MEC_r$$

where:

- DF_i is the Delivery Factor for bus i to the system Reference Bus.

- DF_i is equal to $(1 - \partial L/\partial G_i)$, where: L is system losses, G_i is "generation injection" at bus i, $\partial L/\partial G_i$ is the partial derivative of system losses with respect to generation injection at bus i, that is, the incremental change in system losses associated with an incremental change in the generation injections at bus i holding constant other injection and withdrawals at all buses other than the Reference Bus and bus i.

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

D. Hub Price Calculation

The Transmission Provider calculates a hub price based on the LMPs for a set of buses that comprise the hub. These hub prices are the weighted average of the LMPs at the buses that comprise the hub. The weights are pre-determined by the Transmission Provider and remain fixed.

The price for Hub j is:

$$\text{Hub Price}_j = \sum_{i=1}^{NH} (W_{Hi} * LMP_i)$$

where:

- NH is the number of buses in Hub j.
- W_{Hi} is the weighting factor for bus i in Hub j. The sum of the weighting factors must add up to 1.

E. Load Zone Price Calculation

The Transmission Provider calculates a Load Zone price based on the LMPs for a set of buses that comprise the Load Zone. These Load Zone prices are the weighted average of the LMPs at the set of buses that comprise the Load Zone. The Load Zone bus weight is equal to the fractional share of each Load bus in the total Load in the Load Zone in the hour.

The price for Load Zone *j* is:

$$\text{Load Zone Price}_j = \sum_{i=1}^{NZ} (W_{Zi} * LMP_i)$$

where:

- *NZ* is the number of Load buses in Load Zone *j*.

- W_{Zi} is the load-weighting factor for bus *i* in Load Zone *j*. The sum of the weighting factors must add up to 1. These weights are based on State Estimator results from the 24-hour period, seven days prior to the Operating Day.

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

- Each Load Zone includes only the buses of Asset Owners who are in the zone and who have Load that is represented by that zone's definition. Asset Owners that have metered Load must either be settled at a zone defined by their Load points (zonal settlement) or must have a separate Load Zone created for each Load point (nodal settlement). Asset owners in retail choice areas where profiling, rather than metering is used, can be settled at an aggregate of all Load buses in the BA area.

- MPs who want to be billed at a zonal price must include in their zone all of the buses where energy deliveries are billed at the zonal price.

- **Multi-Element Flowgate Shadow Price Calculation**

The Transmission Provider, in addition to the calculation of the LMPs, calculates Flowgate Shadow Prices (FSPs) on sets of transmission constraints. The Transmission Provider calculates the FSP on the set of transmission elements designated as a Flowgate, based on a weighted average of the transmission FSPs that comprise the Flowgate:

$$\text{Flowgate Shadow Price}\, f = \sum_{k=1}^{M} (W_k * FSP_k)$$

where:

f is the index of Flowgates.

- *k* is a transmission element in the Flowgate *f*.

- *M* is the set of the transmission elements that comprise Flowgate *f*.

- W_k is the weights attached to each of the *M* transmission elements that comprise Flowgate *f*. The sum of the weighting factors adds up to 1. For Flowgates comprised of one transmission element, the W_k for that element is equal to 1. The Transmission Provider determines the W_k for transmission elements defined as Flowgates.

- FSP_k is the Flowgate Shadow Price on transmission element *k* and is equivalent to the reduction in system cost expressed in \$/MWh that results from an increase of 1MW of the capacity on transmission element *k*.

F. External Interface Price Calculation

The Transmission Provider calculates an External Interface price for all non-Transmission Provider Balancing Authorities. These prices are based on the LMPs for a set of generator buses that exist in external Balancing Authorities. Generally speaking, the set of buses used for an External Interface price is the set of generators in the external Balancing Authority for which the calculation is being done. If the external Balancing Authority is not in the Transmission Provider Network model, then an electrically equivalent Balancing Authority will be assigned for the Balancing Authority and the interface price for that non-modeled Balancing Authority will use the same interface price as is used for the electrical equivalent. The Transmission Provider may need to change, which EPNodes are used in the External Interface price calculations as operational experience dictates.

The price for an External Interface *j* is:

$$\text{External Interface Price} = \left[\sum_{j=1}^{NE} LMP_i \right] / \textit{NE average of LMPs}$$

where:

- *NE* is the number of buses in External Interface *j*

ATTACHMENT RR Real-Time Reserve Service Available to Balancing Authorities Version: 1.0.0~~.0~~ Effective: 12/31/9998~~7/28/2010~~

ATTACHMENT RR

Real-Time Reserve Services Available to Balancing Authorities During Phased Integration

A. Availability

If a Transmission Owner has signed the Transmission Owners Agreement, but will not integrate its transmission facilities with the Transmission System until a later date, a Balancing Authority whose loads and resources are connected to the Transmission Owner's facilities will be eligible to obtain Spinning Reserve Service and Supplemental Reserve Service from the Energy and Operating Reserves Market during the phased integration on the following terms and conditions. The Transmission Provider will assume responsibility for the valid single contingencies of the eligible Balancing Authority, and the Transmission Provider will set its Contingency Reserve Requirement to comply with NERC Standard, inclusive of these contingencies.

B. Eligibility

To be eligible to obtain Spinning Reserve Service and Supplemental Reserve Service under this Attachment RR:

1. The Transmission Owner that provides transmission service for the loads and resources of the Balancing Authority must have executed the signature page

of the Transmission Owners Agreement, and the application for membership must have been accepted by the Transmission Provider's Board of Directors.

2. The Transmission Owner has committed in writing to integrate its transmission facilities into the Transmission System not later than nine (9) months from the date that Real-Time Reserve Service first begins pursuant to an executed service agreement as shown in Attachment RR-1.

3. The Balancing Authority has executed the Balancing Authority Agreement and will become, upon final integration, a Local Balancing Authority as defined in that agreement.

4. The Balancing Authority or the Transmission Owner has executed a service agreement as shown in Attachment KK-1 to obtain Reliability Coordination Service from the Transmission Provider during the phased integration period; provided however, that the effective date of the Service Agreement may be extended by mutual agreement as necessary to accommodate the installation of communication systems and the completion of necessary training.

5. The Balancing Authority is a registered Market Participant, or is represented by an agent that is a registered Market Participant.

6. The Balancing Authority requesting service under this Attachment RR will not be a member of a contingency reserves sharing group during the phased integration period.

7. The Balancing Authority has executed a service agreement as shown in Attachment RR-1 to obtain Reserve Services from the Transmission Provider during the phased integration period.

C. Rate for Spinning Reserve Service and Supplemental Reserve Service

1. Notwithstanding any other provision of the Transmission Provider's Tariff, a Balancing Authority eligible for service under this Attachment RR will pay for obtained Spinning Reserve Service at the rate set forth in Schedule 5 of the Tariff, as set forth in Section C.3 of this Attachment RR.

2. Notwithstanding any other provision of the Transmission Provider's Tariff, a Balancing Authority eligible for service under this Attachment RR will pay for obtained Supplemental Reserve Service at the rate set forth in Schedule 6 of the Tariff as set forth in Section C.3 of this Attachment RR.

3. For the sole purposes of calculating the charges to be paid under Schedule 5 and Schedule 6 of the Tariff, the hourly load of the eligible Balancing Authority shall be reported to the Transmission Provider. The eligible Balancing Authority and the Transmission Provider shall mutually agree upon a representative Reserve Zone to be designated in the applicable service agreement as shown in Attachment RR-1 for the purpose of determining the Regulation and Spinning Reserves Distribution Rate used to calculate charges under this Section C.3.

4. The rate to be charged for energy delivered to the eligible Balancing Authority pursuant to this Attachment RR shall be the Hourly Real-Time Ex Post LMP at

the point of delivery to the eligible Balancing Authority, all applicable charges under the Tariff, including Revenue Sufficiency Guarantee charges, and charges pursuant to Schedules 1, 2, 10, and 17.

5. The terms and conditions of the Energy and Operating Reserves Market Tariff, including the settlement and payment terms of the Tariff, apply to all transactions under this Attachment RR.

D. Procedure to Supply Reserve Services

During the phased integration, the Transmission Provider will meet its Balancing Authority obligations to supply reserves by using its Energy and Operating Reserves Market. The Transmission Provider will assume responsibility for the valid NERC criteria single contingencies of the eligible Balancing Authority, and the Transmission Provider will set its Contingency Reserve Requirement to comply with NERC Standard, inclusive of these contingencies. The eligible Balancing Authority will not be obligated to supply reserves to the Transmission Provider. The following procedures shall be used by the eligible Balancing Authority to obtain Reserves pursuant to this Attachment RR.

1. When reserves are required by the eligible Balancing Authority to maintain compliance with applicable reliability standards, the eligible Balancing Authority will enter a zero-minute ramp schedule between the Transmission Provider and the eligible Balancing Authority that will be implemented immediately by the Transmission Provider.

2. The resulting emergency energy flow to serve the eligible Balancing Authority's load will be used by the eligible Balancing Authority to offset the Real Time demand on its generation resources, in response to Disturbances, and in a fashion consistent with BAL-002-0. The eligible Balancing Authority will satisfy its requirements to carry Contingency Reserves, and comply with the NERC Disturbance Control standard by having access to the Contingency Reserves of the Transmission Provider.

2.1 When the eligible Balancing Authority requests Contingency Reserves assistance from the Transmission Provider, compliance to the NERC Disturbance Control standard BAL-002-0 shall be calculated using the combined ACE of the eligible Balancing Authority and the Midwest ISO Balancing Authority and DCS Compliance shall be reported against the Transmission Provider Reportable Disturbance level.

2.2 If the Transmission Provider is contractually obligated to share reserves, the Midwest ISO Balancing Authority ACE for purposes of compliance to NERC Disturbance Control standard BAL-002-0 under that agreement shall be calculated as the sum of the Midwest ISO Balancing Authority ACE plus the ACE of each eligible Balancing Authority under this Attachment RR involved in a coincident contingency reserve event.

2.3 If the eligible Balancing Authority does not request Contingency Reserve activation from the Transmission Provider, the eligible Balancing Authority shall report NERC Disturbance Control Compliance as a stand alone Balancing Authority against its own DCS Compliance reporting threshold.

2.4 Combined ACE shall be calculated by aligning frequency deviation of time stamped ACE and frequency deviation data from all participating parties to ensure accuracy of aligned ACE data.

3. The Transmission Service Reservation for this transfer will indicate a "Normal" Point-to-Point export transaction from the Transmission Provider as "Source" to the eligible Balancing Authority as "Sink".

4. The eligible Balancing Authority, as the Receiving Balancing Authority, shall ensure that a request for an Arranged Interchange is submitted by creating an Electronic Tag (e-Tag) designating the Transmission Provider, (the Delivery Balancing Authority) as "Source" with a start time no more than 60 minutes beyond the resource loss or initiation of the event. The following requirements will apply to the e-Tag:

4.1 Transaction type of "Normal".

4.2 Transmission allocation designation of "Non-Firm" or NN-6 for every listed transmission provider.

4.3 Transmission Reservations shall be done after the fact for point to point deliveries from the Transmission Provider.

4.4 Receiving Balancing Authority, the Scheduler, and any intermediate transmission providers shall approve the e-Tag.

4.5 The appropriate Transmission Provider Control Center staff shall communicate and coordinate necessary operations with the Transmission Provider's Local Balancing Authorities and any affected Balancing Authorities.

4.6 This process will be performed for every event, regardless of duration.

E. Termination

The availability of Reserve Services pursuant to this Attachment RR terminates automatically upon the earliest of:

1. Full integration of the Transmission Owner's facilities into the Transmission System, and the integration of the eligible Balancing Authority into the Midwest ISO Balancing Authority;

2. The failure by the Transmission Owner to achieve final integration on the date established in the phased integration plan approved by FERC;

3. Receipt by the Transmission Provider of written notice, provided by the Transmission Owner prior to the final integration date approved by FERC, that the Transmission Owner intends to withdraw from the Midwest ISO; or

4. A determination by the Transmission Provider that the Balancing Authority has initiated a transaction under this Attachment RR for a purpose other than the ability to meet its reserves obligations as set forth in the applicable NERC and regional reliability standards.

ATTACHMENT RR-1

Form of Service Agreement for Real-Time Reserve Services During Phased Integration

1.0 This Service Agreement, dated as of the ___day of _________, _____ is entered into, by and between the Midwest ISO ("Transmission Provider") and ___________________________________ ("Reserve Services Customer"), (also hereafter referred to as Party or Parties as the context requires).

2.0 The Reserve Services Customer has been determined by the Transmission Provider to be eligible for Reserve Services as set forth in Attachment RR of the Tariff, and the Transmission Provider agrees to provide service upon the request of an authorized representative of the Reserve Services Customer.

3.0 The Reserve Services Customer: (i) agrees to supply information as set forth in Attachment RR of this Tariff , and such other information, data, and specifications reasonably necessary, in accordance with Good Utility Practice, to permit the Transmission Provider to provide the requested service; (ii) agrees to perform the obligations required of Reserve Services Customers set forth in the Tariff; and, (iii) agrees to take and pay for the requested service in accordance with the provisions of the Tariff and this Service Agreement.

4.0 Service under this Service Agreement shall commence on the later of: (1) the requested service commencement date, (2) the date on which all required technical data has been received and entered into the Transmission Provider models, or (3) a date that may be established by the Commission. Service under this Service Agreement shall terminate as required by Attachment RR of the Tariff, or as otherwise required by Commission orders or regulations.

5.0 Any notice required or authorized by Attachment RR or this Service Agreement ("Notice") or a request made by a Party regarding this Service Agreement shall be in writing. Notice shall be personally delivered, transmitted by facsimile (with receipt verbally or electronically confirmed), emailed, delivered by overnight courier or mailed, postage prepaid, to the other Party at the address designated below. A Party may change its designated address upon Notice to the other Party.

	Transmission Provider	Reserve Services Customer
Name	Stephen G. Kozey	____________________
Title:	General Counsel	____________________
Address:	PO Box 4202	____________________
	Carmel, IN 46082-4202	____________________

Fax: 317-249-5912 ____________________

Email@ skozey@midwestiso.org ____________________

5.0 The Tariff is incorporated herein and made a part hereof.

6.0 Description of Reserve Services Customer points of interconnection, via the Transmission Owner's facilities, with the Transmission System:

[Attach a separate sheet if necessary, listing points of interconnection]

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7.0 Upon meeting all other conditions required by Attachment RR and the Tariff, the Reserve Services Customer and Transmission Provider agree to commence service at midnight, on the _________day of _____________ 20__. Service under this Service Agreement shall terminate automatically upon the earlier of: (i) failure by the Transmission Owner to achieve final integration on the date established in the phased integration plan approved by FERC; (ii) the integration of the Reserve Services Customer's Balancing Authority into the Midwest ISO Balancing Authority Area; (iii) receipt by the Transmission Provider of written notice, provided by the Transmission Owner prior to the final integration date approved by FERC, that the Transmission Owner intends to withdraw from the Midwest ISO; or (iv) determination by the Transmission Provider that the Balancing Authority has initiated a transaction under this Attachment RR for a purpose other than the ability to meet its reserves obligations as set forth in the applicable NERC and regional reliability standards.

8.0 The Parties mutually agree to use _________________________________ as a representative Reserve Zone for the purpose of determining the Regulation and Spinning Reserves Distribution rate to be used in the calculation of charges under Section C.3 of Attachment RR. This representative Reserve Zone may be changed only by mutual consent of the Parties, and will remain in effect until termination of this Service Agreement.

9.0 Representations and Warranties. Each Party represents and warrants to the other that, as of the date it executes this Service Agreement:

9.1 The Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

9.2 The execution and delivery by the Party of this Service Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict, based on present knowledge and information, with any applicable law or with any other agreement binding upon the Party; this Service Agreement has been duly executed and delivered by the Party, and, upon receipt of any necessary regulatory approvals, this Service Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity;

9.3 There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder; and

9.4 It is in compliance with all NERC and Regional Entity standards applicable to its operations and facilities.

10. Assignment. Neither Party may assign this Service Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be

unreasonably withheld, except in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. Notwithstanding anything to the contrary herein, the following conditions shall apply to assignment of this Service Agreement by the Reserve Services Customer: (1) assignment may be made to only another eligible Reserve Services Customer; (2) if any change is requested by the assignee, it may be approved by the Transmission Provider only if such change does not impair reliability; and (3) the assignee must agree to be subject to and bound by all applicable terms and conditions of the Service Agreement and the Tariff. .

11. Third Party Beneficiaries. There are no intended third-party beneficiaries of this Service Agreement. Nothing in this Service Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any person not a Party to this Service Agreement.

12. Entire Agreement. This Service Agreement, which incorporates the Tariff, constitutes the entire understanding and agreement of the Parties, and supersedes any and all previous communications, representations, understandings, and agreements (oral or written) between the Parties with respect to the subject matter hereof. The headings used in this Service Agreement are for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

13. No Joint Venture. Nothing contained in this Service Agreement shall be construed to imply the existence of a joint venture, principal and agent relationship, or employment

relationship between the Parties, and no Party shall have any right, power or authority to create any obligation, express or implied, on behalf of the other Party without the express written consent of the other.

14. Governing Law. This Service Agreement, to the extent not subject to the jurisdiction of the FERC, shall be governed by and construed in accordance with applicable State laws.

15. Additional Terms. If the Reserve Services Customer is the United States of America or an agency thereof, the terms and conditions found in Section 12B of the Tariff applicable to participation by the United State of America shall be incorporated in this Service Agreement and shall become a part hereof by this reference. If the Reserve Services Customer is a public-power entity, the terms and conditions found in Section 12E of the Tariff applicable to participation by public power entities shall be incorporated in this Service Agreement and shall become a part hereof by this reference.

16. No Waiver of Jurisdictional Immunity. If the Reserve Services Customer is not subject to the jurisdiction of the FERC as a "public utility" under the Federal Power Act, the Reserve Services Customer shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over the Reserve Services Customer. Nothing in this Service Agreement waives any objection to, or otherwise constitutes consent to, the jurisdiction by FERC over the Reserve Services Customer or its transmission service, facilities and rates.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider		Reserve Services Customer	
By:	____________________	By:	________________________
Name:	____________________	Name:	________________________
Title:	____________________	Title:	________________________
Date:	____________________	Date:	________________________

TAB B

1.115a Day-Ahead Ex Ante LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated through the clearing of the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29 of this Tariff.

1.115b Day-Ahead Ex Ante MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated through the clearing of the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29 of this Tariff.

1.115c Day-Ahead Ex Post LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated for the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29A of this Tariff.

1.115d Day-Ahead Ex Post MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated for the Day-Ahead Energy and Operating Reserve Market using the process defined in Schedule 29A of this Tariff.

1.117 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.118 Day-Ahead Margin: Version: 1.0.0 Effective: 12/31/9998

For an Hour, the difference between the Market Participant's accepted Day-Ahead Energy Offer and the Day-Ahead Ex Post LMP for that interval.

1.120 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.201 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.202 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.203 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.204 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.213 Extended Locational Marginal Price (ELMP) Version: 1.0.0 Effective: 12/31/9998

The Transmission Provider shall implement, ELMP, an enhanced pricing mechanism expanding upon LMP and MCP in which additional resources, including resources that are scheduled to operate at limits, certain off-line resources, and the start-up or shut-down and no-load or curtailment costs of resources that may be included in the calculation of prices at the Commercial Pricing nodes located throughout the Transmission Provider region. Such prices shall be calculated per the process set forth in Schedule 29A.

1.220a Fast Start Resource Version: 0.0.0 Effective: 12/31/9998

A Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less and that will participate in setting price as described in the process in Schedule 29A of this Tariff.

1.229 Financial Transmission Right (FTR): Version: 1.0.0 Effective: 12/31/9998

A financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges that arise when the Transmission System is congested and differences in Marginal Congestion Components of Day-Ahead Ex Post LMPs result.

1.290 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.291 RESERVED Version: 1.0.0 Effective: 12/31/9998

1.298a Hourly Real-Time Ex Post LMP Version: 0.0.0 Effective: 12/31/9998

The LMP derived through mathematical integration of the Dispatch Interval Real-Time Ex Post LMPs over the Hour, and used for purposes of Settlement of Energy transactions in the Real-Time Energy and Operating Reserve Market.

1.298b Hourly Real-Time Ex Post MCP Version: 0.0.0 Effective: 12/31/9998

The average MCPs for Regulating Reserve, Spinning Reserve and Supplemental Reserve applicable to a specific Resource derived through time and quantity weighting of the applicable Real-Time Ex Post MCPs over the Hour, and used for purposes of Settlement of Operating Reserves in the Real-Time Energy and Operating Reserve Market.

1.308a Inadvertent Energy Value: Version: 1.0.0 Effective: 12/31/9998

For the Midwest ISO Balancing Authority Area within the Transmission System, the calculated monetary value for each Hour of the Inadvertent Energy expressed in MWh multiplied by the Midwest ISO Balancing Authority Area's average generation Hourly Real-Time Ex Post LMP for the Hour.

1.366 Locational Marginal Price (LMP): Version: 1.0.0 Effective: 12/31/9998

A price for Energy at a given Commercial Pricing Node in the Transmission Provider Region which is the marginal cost of serving demand at the Commercial Pricing Node while meeting Zonal and Market-Wide Operating Reserve Requirements.

1.379 Market Clearing Price (MCP): Version: 1.0.0 Effective: 12/31/9998

A price for Regulating Reserves, Spinning Reserves, and Supplemental Reserves which is the marginal cost of meeting the particular reserve requirements while meeting locational Energy requirements.

1.379a Market Clearing Price Zonal Terms Version: 2.0.0 Effective: 12/31/9998

The following subset of terms used in the Market Clearing Price calculation under Module C: the Shadow Prices of Reserve Zone Operating Reserve constraints, Reserve Zone Regulating and Spinning Reserve constraints, and Reserve Zone Regulating Reserve constraints, and beginning November 1, 2011, additional marginal cost for managing congestion in order to supply incremental regulating Reserve, Spinning Reserve, or 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.

1.381 Market Implementation Errors: Version: 1.0.0 Effective: 12/31/9998

Flaws in the design or implementation of software resulting in changes in Ex Post LMPs or other prices cleared through the Energy and Operating Reserve Market and the corresponding changes in Settlements not accurately reflecting the application of the Market Rules.

1.517 Price Taker: Version: 2.0.0 Effective: 12/31/9998

A Market Participant with an Energy and/or Operating Reserve Offer not capable of setting LMPs or MCPs.

1.533a Real-Time Ex Ante LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated at the beginning of the Dispatch Interval, using the process defined in Schedule 29 of this Tariff, that is used for informational purposes in the Real-Time Energy and Operating Reserve Market.

1.533b Real-Time Ex Ante MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated at the beginning of the Dispatch Interval, using the process defined in Schedule 29 of this Tariff, that is used for informational purposes in the Real-Time Energy and Operating Reserve Market.

1.533c Real-Time Ex Post LMP Version: 0.0.0 Effective: 12/31/9998

The LMP calculated for each Dispatch Interval using the process defined in Schedule 29A of this Tariff.

1.533d Real-Time Ex Post MCP Version: 0.0.0 Effective: 12/31/9998

The MCP for Regulating Reserve, Spinning Reserve and Supplemental Reserve calculated for each Dispatch Interval using the process defined in Schedule 29A of this Tariff.

1.535 Real-Time Offer Revenue Sufficiency Guarantee Payment: Version: 1.0.0 Effective: 12/31/9998

Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP): The real-time make-whole payment provided under Section 40.3.5 of this Tariff to the Resources described therein, when sum of revenue from Hourly Real-Time Ex Post LMPs and Hourly Real-Time Ex Post MCPs do not fully cover the incremental Energy Offer costs and Operating Reserve Costs of such Resources.

1.598 Security Constrained Economic Dispatch (SCED): Version: 1.0.0 Effective: 12/31/9998

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The algorithm keeps the commitment of Resources fixed in the dispatch. The model is described in Schedule 29.

1.598a Security Constrained Economic Dispatch Pricing (SCED-Pricing Version: 0.0.0 Effective: 12/31/9998

Security Constrained Economic Dispatch Pricing (SCED-Pricing):

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The model is described in Schedule 29A.

1.626 State Estimator MWs: Version: 1.0.0 Effective: 12/31/9998

The megawatts that are determined by the State Estimator to be generated at a given location for each Dispatch Interval.

15.7 Marginal Losses Version: 1.0.0 Effective: 12/31/9998

System Losses are associated with all Transmission Service including Transmission Service associated with Grandfathered Agreements. The Transmission Provider shall assess to Market Participants the Marginal Losses Component of Ex Post LMP, as specified in Sections 39.2.9, 39.3.3.c.ii, 40.2.11, and 40.4.1.

28.5 Marginal Losses Version: 1.0.0 Effective: 12/31/9998

System Losses are associated with all Transmission Service including Transmission Service associated with Grandfathered Agreements. The Transmission Provider shall assess to Market Participants the Marginal Losses Component of Ex Post LMP in Sections 39.2.9, 39.3.3.c.ii, 40.2.11, and 40.4.1. The Transmission Provider, ITC, Transmission Owners, and ITC Participant(s) are not obligated to provide Marginal Losses.

33.8.2 Manual Redispatch Compensation and Eligibility Version: 2.0.0 Effective: 12/31/9998

As a result of following Manual Redispatch instructions, Generation Resources or Demand Response Resources–Type II that are manually redispatched by the Transmission Provider, either directly or as a Transmission Provider instruction communicated through a Local Balancing Authority, may not fully recover their real-time Incremental Energy Cost from the Hourly Real-Time Ex Post LMP during the period the Transmission Provider has directed the Generation Resources or Demand Response Resources–Type II to operate at Energy levels above the Resource's Day-Ahead Schedule for Energy, or may have Day-Ahead Margins eroded during the period the Transmission Provider has directed the Generation Resource or Demand Response Resource-Type II to operate at Energy levels below the Resource's Day-Ahead Schedule for Energy. In such circumstances, the Market Participant owning the Generation Resource or Demand Response Resource– Type II shall be compensated pursuant to Schedule 27 of this Tariff only if the following eligibility criteria and requirements are satisfied.

a. A Generation Resource or Demand Response Resource-Type II manually redispatched pursuant to this Section of this Tariff, is only eligible for Real-Time Offer Revenue Sufficiency Guarantee Payments ("RT ORSGP") under Schedule 27 in Hours in which it has been committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market, or received a commitment from the Transmission Provider in the Real-Time Energy and Operating Reserve Market as must-run. In addition, the following requirements must be met for a Generation Resource or Demand Response Resource-Type II to be eligible for RTORSGP under Schedule 27:

1) Day-Ahead committed Hours must comply with the following requirements:

   (a) The Generation Resource or Demand Response Resource-Type II must offer flexibly for the Hour pursuant to the following criteria:

      i. All limits used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must have a dispatch range of greater than one (1) MW;

      ii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half MW per minute; and

      iii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval 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, or of the Hourly Integrated Forecast Maximum Limit for a Dispatchable Intermittent Resource.

      iv. If four or more consecutive Dispatch Intervals fail eligibility, the Resource will be ineligibile for compensation.

(b) The as-committed day-ahead Offers must remain unchanged when submitted as Real-Time Offers pursuant to the following criteria:

i. For a given day-ahead committed Hour, the following Offers must be the same as the Offers that the day-ahead commitment was based on, and the Real-Time Offers at the close of the Real-Time Energy and Operating Reserve Market Hour as submitted by the Market Participant:

1. 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.

2. The real-time Regulating Reserve Offer must be equal to the day-ahead Regulating Reserve 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.

3. Real-time must-run committed Hours must meet the following requirements:

(a) The Generation Resource or Demand Response Resource-Type II must offer flexibly for the Hour, pursuant to the following criteria:

i. All limits used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must have a dispatch range of greater than one (1) MW;

ii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half MW per minute; and

iii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval 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, or of the Hourly Integrated Forecast Maximum Limit for a Dispatchable Intermittent Resource.

iv. If four or more consecutive Dispatch Intervals fail eligibility, the Resource will be ineligibile for compensation.

(b) All Offers must be the same for each consecutive real-time must-run Hour within the Manual Redispatch period and the first Hour of the Manual Redispatch period must be the same as the previous Hour, if committed, pursuant to the following criteria:

i. The following Offer parameters must be the same for each consecutive real-time must-run committed Hour in the Manual Redispatch period:

1. Energy Offer curve;
2. Regulating Reserve, Spinning Reserve and Supplemental Reserve Offers; and
3. Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hourly Regulation Minimum Limit.

ii. The following Offer parameters must be the same for the first Hour of the real-time must-run committed Hour in the Manual

Redispatch period, and the previous Hour, if committed:

1. Energy Offer curve;
2. Regulating Reserve, Spinning Reserve and Supplemental Reserve Offers; and
3. Hourly Economic Minimum Limit, Hourly Emergency Minimum Limit and Hourly Regulation Minimum Limit.

Failure to meet any of these requirements will result in the Generation Resource or Demand Response Resource-Type II being disqualified for RTORSGP in the Hour during which such failure occurs and each subsequent Hour of the Manual Redispatch period.

a. A Generation Resource or Demand Response Resource-Type II manually redispatched pursuant to this Section 33.8 is only eligible for DAMAP under Schedule 27 in Hours in which its Day-Ahead Margin has been eroded.

b. In addition, the following requirements must be met for a Generation Resource or Demand Response Resource-Type II to be eligible for DAMAP under Schedule 27:

The Generation Resource must offer flexibly for the Hour, pursuant to the following criteria:

i. All limits used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must have a dispatch range of greater than one (1) MW;

ii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half MW per minute; and

iii. All ramp rates used in the Real-Time Energy and Operating Reserve Market within the Dispatch Interval must be greater than one-half of one percent (0.5%) of the real-time Hourly Economic Maximum Limit of the Generation Resource per minute, or of the Hourly Integrated Forecast Maximum Limit for a Dispatchable Intermittent Resource.

If four or more consecutive Dispatch Intervals fail eligibility, the Resource will be ineligible for compensation.

Failure to meet any of these requirements will result in the Generation Resource or Demand Response Resource-Type II being disqualified for DAMAP in the Hour during which such failure occurs.

a. During any period in which a Generation Resource is Manually Redispatched, the Generation Resource shall be exempt from paying Revenue Sufficiency Guarantee Distribution charges and shall be exempt from Excessive/Deficient Energy Deployment Charges under Section 40.3.4. If the period of Manual Redispatch includes any partial Hour, then that entire Hour will be exempt from paying Revenue Sufficiency Guarantee Charges and shall be exempt from Excessive/Deficient Energy Deployment Charges under Section 40.3.4.

37.3 Limitations on Charges and Cost Responsibilities Version: 1.0.0 Effective: 12/31/9998

a. **Bundled Load:** Transmission Owners and ITC Participants taking Network Integration Transmission Service to serve their Bundled Load shall not pay charges pursuant to Schedules 1, 3 through 6 and Schedule 9. After the Transition Period ends, beginning February 1, 2008, the total Schedule 9 revenues to be distributed to Transmission Owners and ITC Participants under the ISO Agreement shall include the Schedule 9 charges that would be payable by any Transmission Owners and ITC Participants covered by the above exclusion or by a similar exclusion in a Service Agreement with the Transmission Provider ("imputed revenues").

In distributing Schedule 9 revenues to Transmission Owners and ITC Participants, the Transmission Provider shall deduct the imputed revenues attributed to each such Transmission Owner and ITC Participant from the total Schedule 9 revenues that are due to that Transmission Owner or ITC Participant. Notwithstanding the first sentence of this section, Ameren Service Company, acting as a Transmission Customer taking Transmission Service to serve Ameren Energy, Inc., as agent for and on behalf of Union Electric Company (d/b/a AmerenUE and Ameren Energy Generating Company), for serving their Bundled Load in the State of Missouri shall not pay charges pursuant to Schedule 2.[1]

The Market Participant shall be financially responsible for payment of the Marginal Congestion Component of Ex Post LMP and Marginal Loss Component of Ex Post LMP related to their transactions as specified in Sections 39.2.9, 39.3.3.c, 40.2.11, and 40.4.1 for those Transmission Owners and ITC Participants taking Network Integration Service to serve their Bundled Load.

Notwithstanding the foregoing in this Section 37.3.a, the following rules apply in instances in which there are multiple Transmission Owners within a pricing zone or Local Balancing Authority Area. Specifically, a Transmission Owner located in a pricing zone or Local Balancing Authority Area with one or more other Transmission Owners shall remain obligated to pay for

Transmission and/or Other Ancillary Services it receives within that pricing zone or Local Balancing Authority Area that it does not provide itself unless the transmission and/or ancillary services are provided pursuant to a Grandfathered Agreement. Any disputes as to the amount to be paid, or the services to be provided or received shall be resolved through the ADR process set forth in Section 12 of this Tariff.

b. **Grandfathered Agreements for Load Inside of the ISO:** For the Transmission Service provided as a result of or pursuant to Grandfathered Agreements for Load inside of the ISO, each GFA Responsible Entity which is a party to that Grandfathered Agreement shall not be obligated to pay charges under Schedules 1 through 9, but it shall be responsible for Transmission Usage Charges as specified in Sections 40.2.11 and 40.4.1. Each GFA Responsible Entity shall remain responsible for payment of the applicable Schedule 10 charges for the services taken pursuant to Section 37.1 for its Load, which may include wholesale Loads under Grandfathered Agreements.

c. **Grandfathered Agreements for Load Outside of the ISO:** For the Transmission Service provided as a result of or pursuant to Grandfathered Agreements for Load outside of the ISO, the GFA Responsible Entity shall be exempt from rates under this Tariff for services provided pursuant to the existing agreements, except for charges under Schedule 10, and the Transmission Usage Charge as specified in Sections 40.2.11 and 40.4.1 to the Interface at the boundary of the Transmission System.

d. **Exception to Section 37.3 (b) and (c):** Notwithstanding the provisions of Section 37.3(b) and (c), (i) if ancillary services are not taken or provided under the Grandfathered Agreement, in whole or in part, then such Ancillary Services which are not provided under such Grandfathered Agreement shall be provided and charged for under this Tariff; and (ii) if Marginal Losses are not provided or paid for under the Grandfathered Agreement, then the Market Participant will be financially responsible for the charges attributable to Marginal Losses as assessed for these related transactions in accordance with the provisions of Module C, Sections 39.3.1, 39.3.3, 40.3 and 40.5.

e. **Imputed Revenues Associated with Grandfathered Agreements.** After the Transition Period ends, beginning February 1, 2008, the total Schedule 7, 8, and 9 revenues to be distributed to Transmission Owners and ITC Participants under the ISO Agreement shall include the Schedule 7, 8, and 9 charges that would otherwise be payable by any GFA Responsible Entity covered by the exclusions in Section 37.3(b) or Section 37.3(c) ("GFA imputed revenues"), provided, however, that GFA imputed revenues shall not include any Schedule 7, 8, and 9 charges associated with a Grandfathered Agreement with respect to which the revenues are reflected as a credit in the calculation of the Transmission Owner's or ITC Participant's revenue requirement pursuant to Attachment O. In distributing Schedule 7, 8, and 9 revenues to those Transmission Owners and ITC Participants, the Transmission Provider shall deduct the GFA imputed revenues attributed to each such Transmission Owner or ITC Participant from the total Schedule 7, 8, and 9 revenues that are due to that Transmission Owner or ITC Participant.

[1] *Midwest Independent Transmission System Operator, Inc.,* 106 FERC ¶ 61,293 (2004).

38.5 Load Aggregation Version: 1.0.0 Effective: 12/31/9998

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.

38.8.4.5 Settlement of Imbalances. Version: 1.0.0 Effective: 12/31/9998

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.

39 Day-Ahead EORM Processes and Settlements Version: 1.0.0 Effective: 12/31/9998

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 and Supplemental 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 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 and Operating 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 and Operating 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 and/or Operating Reserve through economic clearing are greater than or equal to the corresponding Energy and/or Operating Reserve costs respectively when the resource is not scheduled at a limit. Such Energy and/or Operating Reserve costs are equal to the corresponding Energy and/or Operating 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 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.

39.1.3 Rules for Financial Schedules Version: 1.0.0 Effective: 12/31/9998

Financial Schedules may be submitted at any time prior to 1200 hours EST six (6) Calendar Days after the Operating Day. 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.

39.1.5 Posting of the Day-Ahead Schedules Version: 1.0.0 Effective: 12/31/9998

By 1600 hours EST, 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 and Supplemental 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 shall consist of twenty-four (24) Hourly values for each Resource. Also at 1600 hours EST, 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 and Day-Ahead Ex Post 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, and Ex Ante Supplemental Reserve MCP for each Resource; and the Day-Ahead Ex Post Regulating Reserve MCP, Ex Post Spinning Reserve MCP, and Ex Post Supplemental 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.

39.2.1 Transmission Provider Obligations Version: 1.0.0 Effective: 12/31/9998

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 and to supply Operating 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 and supply Operating Reserve in the Day-Ahead Energy and Operating Reserve Market

c. Provide the Settlement functions associated with the purchase and sale of Energy and Operating 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 and Zonal Regulating Reserve Requirements, the Market-Wide and Zonal Spinning Reserve Requirements and the Market-Wide and Zonal Supplemental Reserve Requirements at least 48 hours prior to the beginning of the Operating Day.

39.2.9 Day-Ahead Energy and Operating Reserve Market Process Version: 4.0.0 Effective: 12/31/9998

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; and, (ii) Operating 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 and, if applicable, 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 Demand Bids and (ix) Demand Curves.

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 the transmission congestion 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 the transmission congestion 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 LMPs for each Hour and Commercial Pricing Node in the Day-Ahead Energy and Operating Reserve Market. The LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the 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 LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the LMP for the Resource Commercial Pricing Node is set equal to the calculated 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 LMP for the Resource Commercial Pricing Node is set equal to the calculated 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 LMP for the Load Zone Commercial Pricing Node as follows:

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

ii. If the Load Zone consists of multiple Loads, the LMP for the Load Zone Commercial Pricing Node is set equal to the calculated 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 LMP for a Hub Commercial Pricing Node as follows:

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

ii. If the Hub consists of multiple Elemental Pricing Nodes, the LMP for the Hub Commercial Pricing Node is set equal to the calculated 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.

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 LMP for an Interface Commercial Pricing Node as follows:

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

ii. If the Interface consists of multiple Elemental Pricing Nodes, the LMP for the Interface Commercial Pricing Node is set equal to the calculated 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, 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, 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, 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) Reserve Zone Operating Reserve Constraint Shadow Price (v) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price (vi) Reserve Zone Regulating Reserve Constraint Shadow Price (vii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (viii) beginning November 1, 2011, additional marginal cost for managing congestion 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

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 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 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 and (v) Market-Wide Non-DRR1 Operating 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, 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, 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) Reserve Zone Operating Reserve Constraint Shadow Price(iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion 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, (iii) Reserve Zone Operating Reserve Constraint Shadow Price (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing congestion 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, 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, 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, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Balance Constraint Shadow Price (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (iv) beginning November 1, 2011, additional marginal cost for managing congestion 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 (ii) Reserve Zone Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost for managing congestion 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. 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.

p. 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.

39.2.10 Shortage Conditions in the Day-Ahead EORM Version: 1.0.0 Effective: 12/31/9998

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 and External Asynchronous Resource up to the Emergency Maximum Limit except for Resources selected to provide Regulating Reserve, and (ii) the commitment of Generation Resources, Demand Response Resources - Type I, and Demand Response 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. Both SCED and SCED-Pricing algorithms will include Scarcity Pricing based on the Operating Reserve Demand Curves and Regulating Reserve Demand Curves if Operating Reserve is insufficient to meet the Market-Wide and/or Zonal Operating 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 can not 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.

39.2.11 Surplus Conditions in the Day-Ahead EORM Version: 1.0.0 Effective: 12/31/9998

If the non-Emergency minimum supply from Offers and Fixed Import Schedules exceed cleared Demand Bids plus cleared Export Schedules plus cleared Virtual Demand 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 and Demand Response 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 and/or Zonal 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.

39.3.1 Charges for DA EORM Purchases Version: 2.0.0 Effective: 12/31/9998

a. Market Participants that purchase Energy in the Day-Ahead Energy and Operating Reserve Market, other than Energy associated with a host Load Zone, 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 other than a host 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.

39.3.2 Payments for DA EORM Sales Version: 2.0.0 Effective: 12/31/9998

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.

39.3.2A Day-Ahead Operating Reserve Procurement Credits Version: 1.0.0 Effective: 12/31/9998

a. Market Participants scheduled to supply Regulating Reserve from Generation Resources, Demand Response Resources – Type II, Stored Energy Resources 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.

39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments Version: 2.0.0 Effective: 12/31/9998

The Transmission Provider shall determine, whether any Generation Resources, Demand Response Resources – Type I or Demand Response Resources – Type II 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, Demand Response Resource – Type I or Demand Response Resource – Type II 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 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 and for Operating Reserves scheduled above Self Schedule MWs. 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 Demand Bid, 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 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.

All Market Participant Day-Ahead Revenue Sufficiency Guarantee Credits shall be funded in accordance with Section 39.3.1A.

39.3.2C Charges and Payments for Purchases and Sales for DRRs Version: 3.0.0 Effective: 12/31/9998

a. Market Participants that purchase Energy associated with a Host Load Zone 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 at the Host Load Zone Commercial Pricing Node, net of Day-Ahead Financial Schedules, for each Hour in the Day-Ahead Energy and Operating Reserve Market.

b. Market Participants that sell Energy in the Day-Ahead Energy and Operating Reserve Market from Demand Response Resources – Type I or Demand Response Resources – Type II 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 Demand Response Resource – Type I and Demand Response Resource - Type II Offers cleared in the Day-Ahead Energy and Operating Reserve Market.

39.3.3 Payments and Charges for Financial and Interchange Schedules Version: 1.0.0 Effective: 12/31/9998

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 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.

39.3.5 Calculation of the Day-Ahead Marginal Losses Surplus Version: 1.0.0 Effective: 12/31/9998

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).

40.2 Real-Time Energy and Operating Reserve Market Version: 1.0.0 Effective: 12/31/9998

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, and Supplemental Reserve, (ii) Real-Time Ex Ante LMPs and Real-Time Ex Post LMPs for Energy, and (iii) Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Regulating Reserve, Spinning Reserve, and Supplemental Reserve 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 and Operating Reserve in the Real-Time Energy and Operating Reserve Market is based on simultaneous co-optimization processes in which the total costs of Energy and Operating Reserve are minimized.

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

40.2.2 Transmission Provider Obligations Version: 1.0.0 Effective: 12/31/9998

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 and Operating 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 and Operating 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 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 and Operating 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 and Real-Time Ex Ante MCPs and Real-Time Ex Post MCPs for Operating Reserves for each five (5) minute Dispatch Interval.

40.2.8A Rules for Financial Schedules Version: 1.0.0 Effective: 12/31/9998

Financial Schedules may be submitted at any time prior to 1200 hours EST six (6) Calendar Days after the Operating Day. 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.

40.2.15 Real-Time Energy and Operating Reserve Market Process Version: 3.0.0 Effective: 12/31/9998

The Transmission Provider shall (i) use a SCED algorithm to clear Offers, Self-Schedules, and Interchange Schedules, (ii) determine the Midwest ISO 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, and Supplemental 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, and, if applicable, Reserve Scarcity costs to supply Energy to 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 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 Node 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 Real-Time 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 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.

g. Determination of the Real-Time Ex Ante LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine the 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.

h. Determination of the Real-Time Ex Ante LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine the 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. 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 Real-Time Ex Ante Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response 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, 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, 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) Reserve Zone Operating Reserve Constraint Shadow Price, (v) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, if applicable, (vi) Reserve Zone Regulating Reserve Balance Constraint Shadow Price, if applicable, (vii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (viii) beginning November 1, 2011, additional marginal cost for managing congestion 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, and (v) Market-Wide Non-DRR1 Operating 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, 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, 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, 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) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion 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.

l. Determining the Real-Time Ex Ante 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 Ante MCPs for Spinning Reserve for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Real-Time Ex Ante 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, (iii) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing congestion 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, 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, 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, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (iv) beginning November 1, 2011, additional marginal cost for managing congestion 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 Prices 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, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost for managing congestion 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. 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.

40.2.17 Calculation of Real-Time Ex Post LMPs and Ex Post MCPs Version: 5.0.0 Effective: 12/31/9998

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 and Operating 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, and, if applicable, Reserve Scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Dispatch Interval using the SCED-Pricing algorithm. The Real-Time Ex Post LMPs are established based on (i) Generation Offers, (ii) Demand

Response Resource Offers, (iii) External Asynchronous Resource Offers, and (iv) Emergency Demand Response 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 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 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 the 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 the 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 the 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.

g. Determination of the Real-Time Ex Post LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine the 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, 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, 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, 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) Reserve Zone Operating Reserve Constraint Shadow Price, (v) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, (vi) Reserve Zone Regulating Reserve Balance Constraint Shadow Price (vii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (viii) beginning November 1, 2011, additional marginal cost for managing congestion 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 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, and (v) Market-Wide Non-DRR1 Operating 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, 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, 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 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) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, (v) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion 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, using the SCED-Pricing algorithm, 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, (iii) Reserve Zone Operating Reserve Constraint Shadow Price, (iv) Reserve Zone Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing congestion 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, 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, 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, External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, if applicable, (iii) Market-Wide Non-DRR1 Operating

Reserve Constraint Shadow Price, if applicable, and (iv) beginning November 1, 2011, additional marginal cost for managing congestion 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, (ii) Reserve Zone Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost for managing congestion 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. 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.

40.2.18 Price Verification Version: 1.0.0

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 and Operating 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 and/or Operating 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 Intervals and then integrated and weighted in accordance with the standard procedure.

c. Real-Time Ex Post MCPs and Hourly 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 Hourly 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 Hourly Real-Time Ex Post LMPs exceeding five (5) Business Days from the applicable Operating Day shall require approval by the Transmission Provider Board.

40.2.20 Capacity Shortage Conditions in the Real-Time EORM Version: 2.0.0 Effective: 12/31/9998

The Transmission Provider shall take the measures set forth below during Capacity shortage conditions to maintain reliability within the Midwest ISO 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 Midwest ISO 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: (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource - Type II and External Asynchronous Resource up to the 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, and Demand Response Resources - Type II that are designated as available for Emergency conditions only, and (iii) the curtailment of Export Schedules, in amounts required to relieve the shortage condition in an economic manner.

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 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, 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 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 and/or Zonal Operating Reserve Requirement.

ii. 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 Midwest ISO Balancing Authority Area basis, or a on a Sub-Area basis if limited by transmission 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 Midwest ISO Balancing Authority Area, as applicable. During Emergency conditions, Real-Time Ex Ante LMPs, Real-Time Ex Ante MCPs, Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be set to the VOLL, either on a Midwest ISO 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 OASIS notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.20.

40.2.21 Capacity Surplus under Minimum Load Conditions in RT EORM Version: 1.0.0 Effective: 12/31/9998

The Transmission Provider shall take the measures set forth below during Capacity surplus conditions under minimum Load conditions to maintain reliability within the Midwest ISO Balancing Authority Area.

a. RAC

If during any RAC process, the Transmission Provider's forecast of Real-Time demand less Regulating Reserve within the Midwest ISO 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 and Demand Response

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 when setting prices.

ii. If Real-Time demand less Regulating Reserve within the Midwest ISO 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 OASIS notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.21.

40.3 Real-Time Energy and Operating Reserve Market Settlement Version: 1.0.0

Effective: 12/31/9998

The Transmission Provider shall provide timely Settlement of purchases and sales of Energy, Regulating Reserve, Spinning Reserves, and Supplemental Reserves in the Real-Time Energy and Operating Reserve Market. Settlement of the Real-Time Energy and Operating Reserve Market will be conducted on an hourly basis 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 applicable Hourly Real-Time Ex Post LMPs and Metered MWh values, and applicable Hourly Real-Time Ex Post MCPs and Dispatch Targets for Operating Reserve. Settlement is performed on quantity deviations from Day-Ahead Energy and Operating Reserve Schedules.

40.3.1 Hourly Ex Post LMPs and MCPs Version: 1.0.0 Effective: 12/31/9998

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 EORM Market Settlement Calculations Version: 3.0.0 Effective: 12/31/9998

Real-Time Energy and Operating Reserve Market Market Settlement Calculations

The Real-Time Energy and Operating Reserve Market shall be settled on quantity deviations from the Day-Ahead Energy and Operating Reserve Schedules, with consideration for Real-Time Financial Schedules. Settlement for the Real-Time Energy and Operating Reserve Market uses applicable Hourly Real-Time Ex Post LMPs and reported MWh values, and applicable Hourly Real-Time Ex Post MCPs and Dispatch Targets for Operating 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:

a. Charges and Credits for Real-Time Energy and Operating Reserve Market Purchases.

i. Energy Charges and Credits. Market Participants shall be charged the applicable Hourly Real-Time Ex Post LMP for any Actual Energy Withdrawals other than Actual Energy Withdrawals associated with a host Load Zone, 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. Real-Time Revenue Sufficiency Guarantee Constraint Management Charge: For deviations occurring prior to the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the following deviations adjusted for the applicable Commercial Pricing Node Constraint Contribution Factor:

(1) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any positive difference between: (a) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (b) the Day-Ahead Schedule (excluding Resources committed in any RAC processes conducted for the Operating Day);

(2) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any negative difference between:

(a) the Real-Time Hourly Economic Maximum Limit in effect at the Notification Deadline and (b) the Day-Ahead Schedule (excluding Resources committed in any RAC processes conducted for the Operating Day);

(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 Virtual Transaction resulting from a cleared Virtual Supply Offer or the negative of any Virtual Transaction resulting from a cleared Virtual Bid;

(5) any difference between: (a) the real-time Import Schedule in effect at the Notification Deadline and (b) the day-ahead Import Schedule;

(6) any difference between: (a) the day-ahead Export Schedule and (b) the real-time

Export Schedule in effect at the Notification Deadline;

(7) the negative of 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).

For deviations occurring after the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the maximum of: (1) the following deviations adjusted for the applicable Commercial Pricing Node Constraint Contribution Factor and (2) zero:

(1) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any positive 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: (1) the real-time Hourly Economic Minimum Limit in effect at the Notification Deadline and (ii) the Day-Ahead Schedule and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating

Day); (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day);

(2) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources, any negative difference between: (a) the real-time hourly Economic Maximum 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 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 (4) for Day-Ahead committed Resources, the Day-Ahead Schedule for

Supplemental Reserve and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes conducted for the Operating Day);

(3) for Resources, Excessive Energy or the negative of Deficient Energy pursuant to Section 40.3.4;

(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;

(5) any difference between:

(a) the real-time Import Schedule and (b) the real-time Import Schedule in effect at the Notification Deadline;

(6) any difference between: (a) the real-time Export Schedule in effect at the Notification Deadline and (b) the real-time Export Schedule; and

(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.

The sum, by Asset Owner, of: (1) the net positive sum of the Asset Owner's deviations pursuant to Section 40.3.3.a.ii and (2) the sum of such Asset Owner's deviations pursuant to Section 40.3.3.a.iii, shall be multiplied by the per unit Real-Time Revenue Sufficiency Guarantee Constraint Management Charge deviation rate to determine the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge to be paid by the Market Participant.

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 aggregate Real-Time Revenue Sufficiency Guarantee Credit in that Hour attributed to Resources committed in any RAC processes and (2) the greater of: (a) the sum of: (i) the aggregate net positive sum, by Asset Owner, for such amounts pursuant to Sections 40.3.3.a.ii and 40.3.3.a.iii and (ii) any Topology Adjustment or Transmission De-rate adjusted for the applicable Constraint Contribution Factor and (b) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes, adjusted for the applicable Constraint Contribution Factor.

In the event that the aggregate Real-Time Revenue Sufficiency Guarantee Credit in any Hour attributed to Resources committed in any RAC processes for the given Active Transmission Constraint 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 excess shall be funded through the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation and Headroom Charges.

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.

v. RSG Intra-Hour Demand Change Charge

(a) Any Real-Time Revenue Sufficiency Guarantee Make Whole Payments paid to Resources committed for a purpose other than constraint management and any residual Real-Time Revenue Sufficiency Guarantee Charge Make Whole Payments not recovered under the RSG Constraint Management Charge including RSG Second Pass Charge assignment will be determined under the RSG Intra-Hour Demand Change Charge, described below.

(b) The RSG Intra-Hour Demand Change Charge will be the product of: (1) the amount set forth in Section 40.3.3.a.iv (a), and; (2) the minimum of (a) the Real-Time Headroom for the Hour, over the sum of the Real-Time Economic Maximum Dispatch that were not used in support of transmission constraint management, plus the sum of the residual of the Real-Time Economic Maximum Dispatch for Resources used in support of transmission constraint management after reduction by the Capacity allocated under the RSG Constraint Management Charge. This residual shall equal the total Real-Time Economic Maximum Dispatch attributable to Resources committed to manage a transmission constraint, multiplied by the percentage of the Real-Time Revenue Sufficiency Guarantee Charges attributable to Resources committed to manage a transmission constraint not recovered under the RSG Constraint Management Charge, or; (b) the value of 1.

The Real-Time Headroom shall be equal to the sum of the differences between the Real-Time Economic Maximum Dispatch and Actual Injections of

Resources committed by the Transmission Provider in any RAC processes conducted for the Operating Day.

(c) The aggregate Real-Time Revenue Sufficiency Guarantee Charge in an Hour calculated under the RSG Intra-Hour Demand Change Charge shall be assessed to Market Participants through the RSG Second Pass Charge.

(d) In the event that the aggregate Real-Time Revenue Sufficiency Guarantee Charge described in Section 40.3.3.a.iv (b) in that Hour exceeds the aggregate of the RSG Intra-Hour Demand Change Charges to Market Participants and the RSG Constraint Management Charge, any excess shall be recovered under the RSG Day-Ahead Schedule Deviations Charge.

v. **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 the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge or 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.

(a) **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.a.vi, 40.3.3.a.vii and 40.3.3.a.viii.

(b) **Real-Time Revenue Sufficiency Guarantee Headroom Charge**: The Real-Time Revenue Sufficiency Guarantee Headroom Charge in an Hour will be calculated by multiplying 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 and by the Real-Time Revenue Sufficiency Guarantee Day-Ahead

Schedule Deviation and Headroom Rate determined in section 40.3.3.a.viii. The Real-Time Revenue Sufficiency Guarantee Headroom Charge will be allocated pro rata, to Market Participants based on their Market Load Ratio Share.

vi. 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 and External Asynchronous Resources, 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 (iv) for Day-Ahead committed Resources, the Day-Ahead Schedule for Supplemental Reserve and (b) the real-time Hourly Economic Maximum Limit in effect at the Notification Deadline (excluding Resources committed in any RAC processes

conducted for the Operating Day);

(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) any difference between (a) the day-ahead Import Schedule and (b) the real-time Import Schedule in effect at the Notification Deadline;

(4) 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);

(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.

vii. 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 and External Asynchronous Resources committed in any RAC processes conducted for the Operating Day, any positive difference between (a) the real-time Hourly Economic Maximum Limit at the time the Generation Resource, Demand Response Resource – 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 and External Asynchronous Resources committed in any RAC processes conducted for the Operating Day, 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 and External Asynchronous Resource is committed by the Transmission Provider;

(3) for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources not committed in any RAC processes 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;

(3) for Resources, Deficient Energy pursuant to Section 40.3.4;

(4) for Load Zones, any positive difference between (a) the Actual Energy Withdrawal and (b) the Real-Time Load Zone Demand Forecast in effect at the Notification Deadline**;**

(5) any positive difference between (a) the real-time Import Schedule in effect at the Notification Deadline and (b) the real-time Import Schedule;

(6) any positive difference between (a) the real-time Export Schedule and (b) the real-time Export Schedule in effect at the Notification Deadline; and

(7) for Demand Response Resources – Type I, any positive difference between: (a) the Targeted Demand Reduction Level in effect at the Notification Deadline and (b) the Dispatch Target for Energy.

(8) 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; and

(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;

(10) for Intermittent Resources, the positive value of any 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.a.vi and (2) the sum of such Asset Owner's deviations pursuant to Section 40.3.3.a.vii shall be multiplied by the per unit Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation and Headroom Charge rate to determine the Real-Time

Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge to be paid by the Market Participant.

viii. **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 equal the quotient of: (1) the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge or otherwise attributable to Topology Adjustment or Transmission De-rate 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.a.vi and 40.3.3.a.vii and (ii) 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 and (b) the difference between: (i) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes and (ii) the aggregate of the hourly Economic Maximum Dispatch amounts of all Resources committed in any RAC processes adjusted for the applicable Constraint Contribution Factor.

ix. In the event that the aggregate residual Real-Time Revenue Sufficiency Guarantee Credit amount not funded through the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge or 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.

x. 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) Resource deviations 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; or (4) Intermittent Resource deviations caused by or occurring as a result of Transmission Provider manual curtailment instructions.

xi. ***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.

xii. **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.a.xi, *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.

xiii. **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.

xiv. **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.

xv. **Revenue Neutrality.** The Transmission Provider shall distribute the revenue inadequacy or surplus adequacy from the Settlement of Excessive Energy *pro rata*, to Market Participant Loads based on their Market Load Ratio Share.

xvi. **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 Hourly Real-time Ex Post LMP and the Resource's Offer Price at the average Dispatch Target for Energy during the Dispatch Interval. Market Participants, excluding Stored Energy Resources, with 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 Hourly 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.

xvii. Reserve Zone Demand Response Resource Compensation Recovery Charge: For each Reserve Zone and each Hour, the Transmission Provider shall recover the total Demand Response Resource compensation based on the total Demand Response Resource monetary benefit. The total Demand Response Resource monetary benefit is equal to the sum of all Market Participant benefits from: (1) a decreased Hourly Ex Post LMP, and (2) avoided losses on retail sales.

Demand Response Resource compensation: For a given Demand Response Resource, the Demand Response Resource compensation is equal to the sum of:

(1) the product of:

(A) the minimum of (i) the Day-Ahead Schedule for Energy or (ii) the Real-Time Non-Excessive Energy; and

(B) the Hourly Ex Post LMP for the Load Zone(s) associated with the Demand Response Resource; and

(2) the product of:

(A) the maximum of (i) zero or (ii) the difference between (a) the Real-Time Non-Excessive Energy and (b) the Day-Ahead Schedule for Energy; and

(B) the Hourly Ex Post LMP for the Demand Response Resource; and

(3) the Real-Time Excessive Energy times the Demand Response Resource Excessive Energy Price.

Monetary Benefit from Decreased Hourly Ex Post LMP: The Market Participant monetary benefit from decreased Hourly Ex Post LMP is equal to the product of: (i) the MWs purchased by all buyers (including cleared Virtual Supply Offers) in the Real-Time EORM at the Hourly Ex Post LMP and (ii) the difference between:

(1) the price point on the Net Benefits Supply Curve corresponding to the MW quantity equal to the sum of:

(A) the MW quantity on the Net Benefits Supply Curve corresponding to the Reserve Zone Hourly Ex Post LMP; plus

(B) the quantity of Real-Time Non-Excessive Energy for Demand Response Resources; and

(2) the applicable Hourly Ex Post LMP.

Monetary Benefits from Avoided Losses on Retail Sales: For each Demand Response Resource and associated Load Zone and each Hour, the Market Participant monetary benefit from avoided losses on retail sales is equal to the product of: (1) the maximum of (i) the difference between the Hourly Ex Post LMP for the Load Zone and the MFRR, or (ii) zero; and (2) the Demand Response Resource Actual Energy Injection.

If the total Demand Response Resource monetary benefit for an Hour is greater than the total Demand Response Resource compensation, then Market Participants who benefited shall receive a charge equal to the product of: (1) their respective monetary benefit; and (2) the quotient of (i) the total Demand Response Resource compensation and (ii) the total Demand Response Resource monetary benefit.

If the total Demand Response Resource monetary benefit for an Hour is less than or equal to the total Demand Response Resource compensation, then Market Participants who benefitted shall receive a charge equal to their respective Demand Response Resource monetary benefit.

If the total Demand Response Resource compensation is greater than the total Demand Response Resource monetary benefit, then the excess Demand Response Resource compensation shall be allocated, *pro rata*, based on Market Participant Load Ratio Share.

b. Credits for Real-Time Energy and Operating Reserve Market Sales.

i. Non-Excessive Energy Credits. Market Participants are credited the applicable Hourly Real-Time Ex Post LMP for Non-Excessive Energy injection for Generation Resources, Stored Energy Resources and External Asynchronous Resources 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 Hourly Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node at which the injection occurs.

ii. Excessive Energy Credits. Market Participants are credited the lesser of the Hourly Real-Time Ex Post LMP and the Hourly Excessive Energy Price for Excessive Energy associated with Generation Resources, and External Asynchronous Resources where such Excessive Energy is calculated pursuant to Section 40.3.4. Excessive Energy associated with Stored Energy Resources is settled at the Hourly Real-Time Ex Post LMP.

iii. Regulating Reserve Credit. Market Participants are credited the Hourly Real-Time Ex Post MCP for any positive difference between the time-weighted average of the Real-Time cleared amounts for Regulating Reserve in an Hour and their Day-Ahead Schedule for Regulating Reserve in that Hour (and will be charged the Hourly Real-Time Ex Post MCP for any negative difference between the time-weighted average of the Real-Time cleared amounts for Regulating Reserve in an Hour and their Day-Ahead Schedule for Regulating Reserve in that Hour). The applicable Hourly Real-Time Ex Post MCP for Regulating Reserve is for the Commercial Pricing Node at which the procurement occurs.

iv. Spinning Reserve Credits. Market Participants are credited the Hourly Real-Time Ex Post MCP for any positive difference between the time-weighted average of the Real-Time cleared amounts for Spinning Reserve in that Hour and their Day-Ahead Schedule for Spinning Reserve in that Hour (and will be charged the Hourly Real-Time Ex Post MCP for any negative difference between the time-weighted average of the Real-Time cleared amounts for Spinning Reserve and their Day-Ahead Schedule for Spinning Reserve in that Hour). The applicable Hourly Real-Time Ex Post MCP for Spinning Reserve is for the Commercial Pricing Node at which the procurement occurs.

v. Supplemental Reserve Credits. Market Participants are credited the Hourly Real-Time Ex Post MCP for any positive difference between the time-weighted average of the Real-Time cleared amounts for Supplemental Reserve in an Hour and their Day-Ahead Schedule for Supplemental Reserve in that Hour (and will be charged for any negative difference between the time-weighted average of the Real-Time cleared amounts for Supplemental Reserve in the Hour less their Day-Ahead Schedule for Supplemental Reserve in that Hour). The applicable Hourly Real-Time Ex Post MCP for Supplemental Reserve is for the Commercial Pricing Node at which the procurement occurs.

vi. Real-Time Revenue Sufficiency Guarantee Credit. The Transmission Provider shall determine, on a daily basis, whether any Generation Resources, Demand Response Resources committed by the Transmission Provider in the Real-Time Energy and Operating Reserve Market did not recover the sum of the Resource's 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. If the sum of the Generation Resource's Demand Response Resource's Production Cost (based on Non-Excessive Energy) and Operating Reserve Cost is greater than the sum of (a) for Generation Resources, Demand Response Resources, Non-Excessive Energy multiplied by the applicable Hourly Real-Time Ex Post LMP, (b) Real-Time Operating Reserve Revenue as determined by the sum, for all Dispatch Intervals in an Hour, of the products of the (i) cleared Real-time Operating Reserve for a Dispatch Interval and (ii) applicable Real-Time Ex Post MCP for a Dispatch Interval and (iii) the duration of the Dispatch Interval expressed in Hours, (c) and the sum of the Dispatch Interval net Regulating Reserve Deployment charge/credit as determined pursuant to Section 40.3.3.a.xi for the Hour, 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 shortfall spread over all the Hours in that contiguous commitment period. This credit shall be supported through revenue collected from the Real-Time Revenue Sufficiency Guarantee Charge.

vii. 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.

c. Charges and Credits for Real-Time Energy and Operating Reserve Market Energy Purchases and Sales Associated with Demand Response Resources.

i. **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 Host Load Zone or Demand Response Resource – Type I, net of Real-Time Financial Schedules that exceed their Day-Ahead Scheduled Withdrawals associated with a Host Load Zone or Demand Response Resource – Type I (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 Host Load Zone or Demand Response Resource-Type I). 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. **Demand Response Resource Non-Excessive Energy Charges and Credits.** Market Participants are credited the applicable Hourly Real-Time Ex Post LMP for Non-Excessive Energy injection for Demand Response Resources – Type I and Demand Response 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 Hourly Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node.

iii. **Demand Response Resource Excessive Energy Credits.** Market Participants are credited the lesser of the applicable Hourly Real-Time Ex Post LMP and the Hourly Excessive Energy Price for Excessive Energy associated with Demand Response Resources – Type I and Demand Response Resources – Type II where such

Excessive Energy is calculated pursuant to Section 40.3.4. The applicable Hourly Real-Time Ex Post LMP is the LMP at the Commercial Pricing Node.

d. Charges and Credits for Midwest ISO Balancing Authority Compliance with NERC/RRO Standards and Participation in Reserve Sharing Group.

i. Administrative Charges/Credits. Revenue received by the Midwest ISO 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 Rate Schedule 17 of the Tariff. Fees to be paid by the Midwest ISO Balancing Authority associated with the provision of such administrative services shall be recovered from Market Participants pursuant to Rate Schedule 17 of the Tariff.

ii. Other Charges/Revenue. Charges owed, other than charges owed under Sections 40.3.3.d.i and 40.2.22, by the Midwest ISO 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.d.i, received by the Midwest ISO 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.

40.3.4 Charge for Excessive/Deficient Energy and Reserve Deployment Version: 5.0.0 Effective: 12/31/9998

Settlement of deviations from Setpoint Instructions is conducted hourly 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. 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. 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, Demand Response Resource – Type II and External Asynchronous Resource Tolerance Band. The upper limit of a Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource specific Tolerance Band, or Excessive Energy Threshold, shall be equal to the sum of: (1) one hundred and eight percent (108%) of 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 for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate; and (2) the product of (a) the ramp rate used for energy and regulation and (b) the duration of the Dispatch Interval, in minutes. The lower limit of a Generation Resource, Demand Response

Resource – Type II, or External Asynchronous Resource specific Tolerance Band, or Deficient Energy Threshold, shall be equal to the sum of: (1) ninety-two percent (92%) of 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 for that Dispatch Interval for that Resource accounting for the Resource's applicable ramp rate; and (2) the negative product of (a) the ramp rate used for Energy and regulation and (b) the duration of the 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.iv, 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. Demand Response Resource – Type I Tolerance Band.

The upper limit of a Demand Response Resource – Type I specific Tolerance Band, or Excessive Energy Threshold, for Demand Response Resources – Type I that have been committed for Energy, shall be equal to one hundred and eight percent (108%) of the Targeted Demand Reduction Level for that Dispatch Interval and, the lower limit of a Demand Response Resource - Type I specific Tolerance Band, or Deficient Energy

Threshold, for Demand Response Resources – Type I that have been committed for Energy, shall be equal to ninety-two percent (92%) 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.iv. 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.

iii. Stored Energy Resource Tolerance Band. The upper limit of a Stored Energy Resource specific Tolerance Band, or Excessive Energy Threshold, 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) 8% 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 lower limit of a Stored Energy Resource specific Tolerance Band, or Deficient Energy Threshold, 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 8% of the absolute value of (i) the Dispatch Target for Energy and (ii) the average Regulating Reserve Deployment instruction for that Dispatch Interval.

iv. 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.

v. Hourly Excessive Energy for Generation Resource, and Stored Energy Resource and External Asynchronous Resource. Hourly Excessive Energy for a Generation Resource, Stored Energy Resource, or External Asynchronous Resource is equal to the sum of the Excessive Energy amounts in each Dispatch Interval for that Generation Resource, Stored Energy Resource, or External Asynchronous Resource in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. 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 average telemetered output of the Generation Resource, expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output of the External Asynchronous Resource, expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output of the Stored Energy Resource, expressed in MW and scaled by Actual Energy Injection, and the Excessive Energy Threshold for that Stored Energy Resource, or (b) zero.

vi. Hourly Excessive Energy for Demand Response Resource-Type I. Hourly Excessive Energy for one or more Demand Response Resources-Type I equal to the sum of the Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type I in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. Excessive Energy for such one or more a Demand Response Resources -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 such one or more Demand Response Resources -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).

vii. Hourly Excessive Energy for Demand Response Resource-Type II. Hourly Excessive Energy for one or more Demand Response Resources-Type II is equal to the sum of the Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type II in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. Excessive Energy for such one or more Demand Response Resources - 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 one or more Demand Response Resource -Type II, expressed in MW, and the Excessive Energy Threshold for such one or more Demand Response Resource -Type II, or (b) zero. The Calculated DRR -Type II Output for a Dispatch Interval, scaled by Actual Energy Injection, is equal to the host Load Zone Dispatch Interval Demand Forecast (positive value) in a Dispatch Interval, expressed in MW, minus the host Load Zone average net telemetered demand amount (withdrawal positive, injection negative) for that Dispatch Interval, expressed in MW; where such total amount is allocated to specific Demand Response Resources – Type II in any proportion as determined by the Market Participants. If the Dispatch Interval Demand

Forecast is equal to zero or is not submitted to the Transmission Provider, the Calculated DRR-Type II Output shall be equal to zero (0).

viii. Hourly Deficient Energy for Generation Resource, Stored Energy Resource, or External Asynchronous Resource. Hourly Deficient Energy for a Generation Resource, Stored Energy Resource or External Asynchronous Resource is equal to the sum of the Deficient Energy amounts in each Dispatch Interval for that Generation Resource, Stored Energy Resource or External Asynchronous Resource in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. 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 average telemetered output for that Generation Resource expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output for that External Asynchronous Resource, expressed in MW and scaled by Actual Energy Injection, 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 average telemetered output for that Stored Energy Resource, expressed in MW and scaled by Actual Energy Injection, or (b) zero (0) MW.

ix. Hourly Deficient Energy for Demand Response Resource-Type I. Hourly Deficient Energy for one or more Demand Response Resource-Type I is equal to the sum of the Deficient Energy amounts for such one or more Demand Response Resources – Type I in each Dispatch Interval in a specific Hour with Excessive Energy, Deficient Energy or any combination thereof in four (4) or more consecutive Dispatch Intervals. Deficient Energy in a Dispatch Interval for such one or more Demand Response Resources-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 such one or more Demand Response Resources-Type I and the Calculated DRR-Type I Output of such one or more Demand Response Resources -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.

x. Hourly Deficient Energy for Demand Response Resource-Type II. Hourly Deficient Energy for one or more Demand Response Resources-

Type II is equal to the sum of the Deficient Energy amounts for such one or more Demand Response Resources – Type II in each Dispatch Interval in a specific Hour with Excessive Energy, Deficient Energy of any combination thereof in four (4) or more consecutive Dispatch Intervals. Deficient Energy in a Dispatch Interval for such one or more Demand Response Resources-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 one or more Demand Response Resources-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. The Calculated DRR -Type II Output, scaled by Actual Energy Injection, for a Dispatch Interval is equal to the host Load Zone Dispatch Interval Demand Forecast (positive value) in a Dispatch Interval, expressed in MW, minus the host Load Zone average net telemetered demand amount (withdrawal positive, injection negative) for that Dispatch Interval, expressed in MW; where such total amount is allocated to specific Demand Response Resources – Type II in any proportion as determined by the Market Participant. If the Dispatch Interval Demand Forecast is equal to zero or is not submitted to the Transmission Provider, the Calculated DRR-Type II Output shall be equal to zero (0) MW.

xi. Hourly Non-Excessive Energy for Generation Resource, Stored Energy Resource, or External Asynchronous Resource. Hourly Non-Excessive Energy for a Generation Resource, Stored Energy Resource, or

External Asynchronous Resource is equal to the sum of Non-Excessive Energy amounts in each Dispatch Interval for the Generation Resource, Stored Energy Resource, or External Asynchronous Resource in a specific Hour. 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, 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 average telemetered output, scaled by Actual Energy Injection, of the Stored Energy Resource.

xii. Hourly Non-Excessive Energy for Demand Response Resource-Type I. Hourly Non-Excessive Energy for one or more Demand Response Resources-Type I is equal to the sum of Non-Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type I in a specific Hour. 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 such one or more 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 one or more Demand Response Resource-Type I, or such one or more Demand Response Resources'-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 such one or more Demand Response Resources 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 the Measurement and Verification procedures. 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.

xiii. Hourly Non-Excessive Energy for Demand Response Resource-Type II. Hourly Non-Excessive Energy for one or more Demand Response Resource-Type II is equal to the sum of Non-Excessive Energy amounts in each Dispatch Interval for such one or more Demand Response Resources-Type II in a specific Hour. 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 such one or more Demand Response Resources-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 one or more Demand Response Resources-Type II, or such one or more Demand Response Resources-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 such one or more Demand Response Resources-Type II is equal to the product of the Dispatch Interval duration in Hours and the Calculated DRR-Type II Output of such one or more Demand Response Resources-Type II.

For Demand Response Resources - Type II that are Regulation Qualified resources, the Calculated DRR-Type II Output, scaled by Actual Energy Injection, for a Dispatch Interval is equal to the host Load Zone Dispatch Interval Demand Forecast (positive value) in a Dispatch Interval, expressed in MW, minus the host Load Zone average net telemetered demand amount (withdrawal positive, injection negative) for that Dispatch Interval, expressed in MW; where such total amount is allocated to specific Demand Response Resources – Type II in any proportion as determined by the Market Participant. If the Dispatch Interval Demand Forecast is equal to zero or is not submitted to the Transmission Provider, the Calculated DRR-Type II Output shall be equal to zero (0) MW.

For Demand Response Resources - Type II that are not Regulation Qualified, the Calculated DRR-Type II Output is calculated in accordance with the Measurement and Verification procedures.

xiv. 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 and (ii) the Regulating Reserve credits/charges calculated pursuant to Section 40.3.3.b.iii 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 and (ii) the Real-Time Regulating Reserve charges/credits calculated pursuant to Section 40.3.3.b.iii 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.

Not withstanding 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.

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 II, Demand Response Resources-Type II, and Stored Energy Resources 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 or Stored Energy Resource; or

(4) The Hour when a Generation Resource or Stored Energy Resource 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 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 Hourly Real-Time Ex Post LMP of the Resource Commercial Pricing Node for the Hour 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 and for 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. Revenue Distribution from Contingency Reserve Deployment Failure Charge and Excessive/Deficient Energy Deployment Charge. Credits resulting from Contingency 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.

g. 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 ove 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 eith percent (108%) 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) ninety-two percent (92%) 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.

h. 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. As Contingency Reserve Deployment Failure Charge that is equal to the Resource's Shortfall Amount(s) multiplied by the Hourly Ex Post LMP of the Resource Commercial Pricing Node for the Hour 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.

40.3.5.1 Rationale for RTORSGP Version: 2.0.0 Effective: 12/31/9998

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 and hourly net Operating 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 in accordance with the eligibility and other requirements as stated in Section 33.8.

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, Demand Response Resources – Type I committed for the deployment of Spinning Reserve, and External Asynchronous Resources 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. 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.

40.3.6.1 Rationale for DAMAP Version: 1.0.0 Effective: 12/31/9998

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 and/or Day-Ahead Schedule for Supplemental 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 the Midwest ISO, 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 cleared in excess of Day-Ahead Schedules for Operating Reserve. 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 in accordance with the eligibility and other requirements stated in Section 33.8 of this Tariff.

40.4.1 Transmission Usage Charges in the Real-Time EORM Version: 1.0.0 Effective: 12/31/9998

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 Hourly 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 1100 hours EST (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 will be the product of: (i) the amount of Energy scheduled to be withdrawn by the Market Participant in each Hour 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 Hourly Real-Time Ex Post LMP at the Commercial Pricing Node for the relevant Interface in $/MWh.

c. Interchange Schedules that represent Through Transactions are subject to Transmission Usage Charges based on the Hourly Real-Time Ex Post LMP at the Interface where they enter or exit the Transmission Provider Region. The Transmission Usage Charge will be the product of: (i) the amount of Energy scheduled to be withdrawn by that Market Participant in each Hour 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 Hourly Real-Time Ex Post LMP at the Commercial Pricing Node for the Interface relevant to the Interchange Schedule Delivery Point, minus the Hourly Real-Time Ex Post LMP at the Commercial Pricing Node of the Interface relevant to the Interchange Schedule Receipt Point, in $/MWh.

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 Hourly Real-Time Ex Post LMP at the Interface for the Interchange Schedule Delivery Point minus the Marginal Congestion Component of the Hourly 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 Hourly 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 Hourly Real-Time Ex Post LMP at the Interface for the Interchange Schedule Delivery Point minus the Marginal Losses Component of the Hourly 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.

40.4.2 Financial Schedule Settlements Version: 1.0.0 Effective: 12/31/9998

The Transmission Provider shall collect 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.

40.5.1 Hourly Real-Time Marginal Loss Surplus Version: 1.0.0 Effective: 12/31/9998

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.

IV. FINANCIAL TRANSMISSION RIGHTS AND AUCTION REVENUE RIGHTS Version: 1.0.0 Effective: 12/31/9998

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.

42.1 FTR Obligations Version: 1.0.0 Effective: 12/31/9998

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.

42.2 FTR Options Version: 1.0.0 Effective: 12/31/9998

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.

45.2.3 Information to be Made Available to FTR Bidders and Offerors Version: 1.0.0 Effective: 12/31/9998

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.

69.3.5 Demand Resource Eligibility Version: 1.0.0 Effective: 12/31/9998

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can request accreditation for a Demand Resource as an LMR by registering such resource with the Transmission Provider as documented in the BPM for Resource Adequacy and by meeting the following requirements:

i. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources that can reduce Demand may qualify in meeting this standard).

ii. The Demand Resource must be available to be scheduled for a Demand reduction at the targeted Demand reduction level or by moving to a specified firm service level with no more than 12 Hours advance notice from the Transmission Provider.

iii. Once Scheduling Instructions are given by the Transmission Provider that require a Demand reduction, the Demand Resource must be capable of ramping down to meet the targeted Demand reduction level or achieve the firm service level by the Hour designated by the Transmission Provider's Scheduling Instructions.

iv. Once the targeted level of Demand reduction or firm service level is achieved, the Demand Resource must be able to maintain the targeted level of Demand reduction or firm service level for at least four (4) continuous Hours.

v. The Demand Resource must be capable of being interrupted at least five (5) times during the Summer Season (when called upon by the Transmission Provider) during any Planning Year for which the Demand Resource receives credit as a Planning Resource.

vi. Unless the Demand Resource is unavailable as a result of maintenance requirements or for reasons of Force Majeure, when a Demand reduction is requested by the Transmission Provider, the resultant reduction must be a reduction that would not have otherwise occurred within the next twenty four (24) hour period. There shall be no penalties assessed to a Market Participant representing the entity that has designated the PRCs from the LMR if the Demand Resource is unavailable for interruption as a result of maintenance requirements or for reasons of Force Majeure, or in the event the specified Demand reduction had already been accomplished for other reasons (e.g., economic considerations, self-scheduling at or above the credited level of Demand Resource, or local reliability concerns in accordance with instructions from the LBA).

vii. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures will not qualify as an LMR.

viii. The Transmission Provider will use the MECT to ensure that there can be only one LSE using PRCs from a Demand Resource or netting the MW associated with the Demand Resource from its forecasted Demand.

ix. Demand Resources that are offered into the Day-Ahead and/or Real-Time Energy and Operating Reserve Markets as price sensitive Bids are obligated to be interrupted during an Emergency pursuant to the Transmission Provider emergency operating procedures regardless of the projected or actual LMP.

x. A Market Participant must provide written documentation to the Transmission Provider from the state having jurisdiction over the Market Participant, or from customers represented by the LMR MP, with the amount and type of Demand Resource and the procedures for achieving the Demand reduction. For a Market Participant without state accreditation procedures for a Demand Resource, the Market Participant must secure verification from a third party auditor that is unaffiliated with the Market Participant to provide documentation of the Demand Resource's ability to reduce to the targeted Demand reduction level or to a specified firm service level when called upon by the Transmission Provider, or provide past performance data that demonstrates the Demand Resource is able to reduce to the targeted Demand reduction level or to the specified firm service level. If performance data does not exist from the previous Planning Year, at least one mock test must be used to support the validity of the Demand Resource, in accordance with the Business Practices Manual for Resource Adequacy. The mock test should employ all systems necessary to initiate a Demand reduction short of actual Demand reduction. The Transmission Provider will periodically review such procedures with the operator of the Demand Resource to confirm that, among other things, adequate training has occurred to comply with such procedures.

69.3.9 Penalty Provisions for LMRs Version: 1.0.0 Effective: 12/31/9998

Unless an LMR is unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Market Participant representing the entity which has designated the PRCs from the LMR will be subject (except as otherwise provided in Section 69.3.7.b) to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to achieve its Scheduling Instructions. The penalties defined below will only apply to the portion of the Scheduling Instruction that is not achieved during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties.

There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (i.e., for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the LBA) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (i.e., a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

a. The Transmission Provider shall assess the responsible Market Participant in Section 69.3.9 the costs that were otherwise incurred to replace the deficient Resource at the time the LMR is called upon by the Transmission Provider and does not respond in full or in part. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any RSG charges. The

Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand, and may, if deemed appropriate by the Transmission Provider, disqualify the Demand Resource or BTMG from further utilization as an LMR for the remainder of the Planning Year when the LMR was unavailable.

b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69.3.9.a above, and the Demand Resource or BTMG will no longer be eligible for utilization as an LMR by any Market Participant in meeting its PRMR or being used to net against forecasted Demand for the remainder of the current Planning Year and for the next Planning Year.

83.4.2 Version: 1.0.0 Effective: 12/31/9998

For each occasion that the Congestion Management Customer increases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3, and does not simultaneously decrease the output of one or more Congestion Management Customer units on the opposite side of the constraint to match at least the increased output of the incremented units, the Transmission Provider shall arrange, for and on behalf of the Midwest ISO Market Participants, the delivery of a quantity of Energy from the Congestion Management Customer equal to the megawatt hour quantity of the net increase in output for the duration of the net increase in output. The price for such delivery shall be the Day-Ahead Ex Post LMP or the Hourly Real-Time Ex Post LMP at the Congestion Management Customer-Transmission Provider interface node at the time of each occasion. If the Operating Procedure referred to in the preceding Section 83.4.1 is followed for a redispatch request, the Congestion Management Customer shall not be required to pay any Revenue Sufficiency Guarantee charges for quantity deviations from Day-Ahead Schedules as specified in Section 40.3.3.a.ii that would otherwise be associated with purchases under this Section 83.4.2 to comply with that redispatch request.

83.5.2 Version: 1.0.0 Effective: 12/31/9998

For redispatch of generation requiring transfers of Energy in the Real-Time Energy and Operating Reserve Market, the Congestion Management Customer will receive charges or credits associated with such transfers that will be settled at the Hourly Real-Time Ex Post LMP at the Congestion Management Customer-Transmission Provider interface node, including any applicable Revenue Sufficiency Guarantee Charges for quantity deviations from Day-Ahead Schedules as specified in Section 40.3.3.a.ii. Where re-dispatch of generation includes the additional commitment of Midwest ISO Resources, the Congestion Management Customer shall pay, in addition to previously specified charges, an amount equal to the applicable Start-Up costs and the No-Load Production Costs for the Resource.

SCHEDULE 2-A Reactive Supply and Voltage Control From Generation or Other Version: 1.0.0 Effective: 12/31/9998

SCHEDULE 2-A

Reactive Supply And Voltage Control From

Generation or Other Sources Service

(For Zones Electing Schedule 2-A)

I. GENERAL

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, Generation Resources and non-generation resources capable of providing this service need to produce or absorb reactive power. Thus, service under Schedule 2 Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided to support all transactions on the Transmission System. The amount of Reactive Supply Service that must be supplied with respect to a Transmission Customer's transaction will be determined by the Transmission Provider based on the reactive power support necessary to maintain transmission voltages within the voltage range and the resulting reactive power ranges that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided by the Transmission Provider by making arrangements with the Local Balancing Authority (s) who acquire this service for the Transmission Provider's Transmission System, except that, in the case of ITC Reactive Supply and Voltage Control from Generation Sources Service, the service may, at the election of the ITC, be acquired by the ITC in accordance with the ITC Control Area Services and Operations Tariff and the standards for qualification of Generation Resources set out in this Schedule 2-A. The Transmission Customer must purchase this service from the Transmission Provider or from the ITC, as appropriate. The charges for such service by the Transmission Provider or the ITC will be based on the rates set forth below.

The Transmission Owner(s) within each Zone may elect to use this Schedule 2-A in lieu of Schedule 2. Any Zone that does not elect to utilize this Schedule 2-A and all qualified Generation within the Zone shall be governed by Schedule 2 and not by the terms of this Schedule 2-A. Any Zone that elects to use this Schedule 2-A and all Qualified Generation within that Zone shall be governed by the terms of this Schedule 2-A and not by the terms of Schedule 2. The Transmission Owner(s) electing this Schedule 2-A shall provide the Transmission Provider with sixty (60) days notice of such election. Transmission Owner(s) within each Zone also may choose to terminate the participation of a Zone in this Schedule 2-A upon sixty (60) days notice to the Transmission Provider. The Transmission Provider shall post the Zones to which this Schedule 2-A applies. If there are multiple Transmission Owners within a Zone and there is a disagreement between those Transmission Owners regarding any election, such disagreements shall be resolved pursuant to the dispute resolution provisions of the Tariff.

As detailed in Section III, Qualified Generators interconnected with the Transmission System are expected to operate within a range of 0.95 leading to 0.95 lagging power factor (or, the range specified in the interconnection agreement with the Qualified Generator, if different) based on full rated megawatt output at the Point of Interconnection (the “Deadband”) and, therefore, will not receive compensation for providing Reactive Supply and Voltage Control from Generation Sources Service within that range. The Transmission Provider shall establish a Deadband for each Qualified Generator and notify the Qualified Generator of its Deadband. If a Qualified Generator satisfies the requirements of this Schedule 2-A and is directed to provide Reactive Supply and Voltage Control from Generation Sources Service outside of the Deadband, then the Transmission Provider shall compensate the generator as provided in Section III.

II. QUALIFIED GENERATOR

A. General Qualifications: All existing Generation Resources collecting charges for Reactive Supply and Voltage Control from Generation Sources Service under a Commission approved cost-based rate schedule as of December 1, 2007, are deemed to be Qualified Generators. Any other Generation Resource may collect charges associated with Reactive Supply and Voltage Control from Generation Sources Service under this Schedule 2-A, where the Transmission Provider determines that the Generation Resource is a Qualified Generator based on the requirements of this Section II. The Transmission Provider shall have the right to review the Qualified Generator status of any Generation Resource at a subsequent time and revoke the Qualified Generator status of Generation Resources that do not meet the requirements of this Section II.

B. Technical Qualifications: If a Generation Resource meets the qualifications as stated below, it shall be recognized as a Qualified Generator.

1. The Generation Resource (i) operates with its voltage regulators in automatic mode and responds to voltage schedules of the Transmission Provider or Local Balancing Authority for the pricing zone in which the Generation Resource is located; (ii) is able to maintain voltage support within its design limits; and (iii) is capable of a reactive power range of 95% leading to 95% lagging at the Point of Interconnection unless otherwise stated in the Generation Resource's Generator Interconnection and Operating Agreement;

2. The Generation Resource (i) can respond to changes in voltage on the

system and to changes in voltage schedules if the facility is operating; or (ii) will provide voltage control specified by the Transmission Provider or Local Balancing Authority immediately, if intra-day system conditions require additional reactive power supply to maintain reliability, or as instructed by the Transmission Provider prior to the Operating Day based on forecasted system conditions, taking into consideration the unit's operating characteristics, and whether the Generation Resource is expected to be available for operation during the time of the request;

3. The Generation Resource has met the testing requirements for voltage control capability required by the Regional Reliability Council where the Generation Resource is located within the past five years; and

4. The Generation Resource has submitted a request to the Transmission Provider for Qualified Generator status as outlined in Section II.C below.

C. Notification to Transmission Provider of Qualified Generator Status: To be eligible to receive compensation for its voltage control capability, all Generation Resources shall submit a request to the Transmission Provider certifying compliance with this Section II. The Transmission Provider shall notify the Local Balancing Authority upon receiving a certification request from a Generation Resource. Such certification of compliance must include the following information about the Generation Resource:

1. Name and Position/Title of party providing certification;

2. Name of Company;

3. Name of Generation Resource;

4. Full rated megawatt output of Generation Resource at Deadband;
5. Commercial Pricing Nodes by unit;
6. Four Character NERC ID (for settlement purposes);
7. Reactive Minimum and Maximum limits at rated summer maximum power output, including Unit Name, production maximum (summer), MVAR maximum and MVAR minimum; and
8. Signature and date from the party providing certification.

The executed Certification Statement should be returned to:

Midwest ISO

Attn: Manager Interconnection Planning

701 City Center Drive

Carmel, IN 46032

or sent by e-mail to ginterconnection@midwestiso.org.

If after receiving a completed request, the Transmission Provider does not notify the Generation Resource of a deficiency to the certification within fifteen (15) days, Qualified Generator status is effective on the first day of the month immediately following the end of the fifteen-day notice period.

III. RATES, CHARGES, AND REVENUE DISTRIBUTION

A. Within Deadband

The Transmission Provider shall provide no compensation to any Qualified Generator for Reactive Supply and Voltage Control from Generation Sources Service within the Deadband. No Qualified Generator shall maintain a service schedule or tariff provision pertaining to the production of reactive power that imposes or may impose charges associated with the supply of reactive power within the Deadband.

B. Outside of Deadband

Each Qualified Generator shall be compensated for providing Reactive Supply and Voltage Control from Generation Sources Service outside of the Deadband provided that it is supplying such service at the explicit direction of the Local Balancing Authority. A Qualified Generator appropriately following voltages schedules shall not be compensated for service outside the Deadband unless the Local Balancing Authority directed it to do so. The revenues that each such Qualified Generator receives shall be based upon the following:

1. Compensation shall be the higher of lost opportunity costs or cost. Cost shall be $2.20 per MVARhr.

2. Lost opportunity costs shall be the Hourly Real-Time Ex Post LMP less the generator's incremental cost savings of producing less real power and more reactive power times the reduction in MW output requested by the Local Balancing Authority. In order to receive lost opportunity costs, a Qualified Generator must be directed to reduce real power output and must be producing in excess of the calculated MVAR output at .95 power factor (or the power factor specified in the generator interconnection agreement if different) pertaining to full real power output at the interconnection point (less station service use). A Qualified Generator will not be compensated for a reduction in real power output for MW produced above its rated capability. A Qualified Generator must submit its monthly lost opportunity cost calculation to the Transmission Provider no later

than 20 days following the end of a month.

3. The MVARhrs outside the deadband shall be the total MVARhrs provided in an hour less the MVARhrs that would be produced at the full rated MW output at .95 power factor (or the power factor specified in the generator interconnection agreement if different) at the Point of Interconnection (i.e., a 900 MW generator with 50 MW of station service use would produce 850 MW at the Point of Interconnection; and produce 279 MVARs at .95 power factor.).

4. On a monthly basis, the Transmission Provider shall determine the Reactive Supply and Voltage Control from Generation Sources Service that each Qualified Generator produced outside of the Deadband pursuant to directions of the Local Balancing Authority in MVARhr. For each such Qualified Generator, the Transmission Provider shall multiply the MVARhrs by the cost of reactive power set forth in paragraph 1. The Transmission Provider will not include the MVARhrs for any period in which the Qualified Generator has requested lost opportunity costs.

5. The "Reactive Power Cost," which will be set forth on a monthly basis, will be the sum of the lost opportunity costs and the MVARhr costs. The Transmission Provider shall then for each Qualified Generator develop a percentage based on that Qualified Generator's Reactive Power Cost under this paragraph 5 divided by the total Reactive Power Costs under this paragraph ("Zonal Percentage").

C. Development of the Schedule 2 Charge

Beginning on the first day of the third month after ___[the effective date of these

Tariff sheets], there shall be a Schedule 2 charge developed for each Zone to be developed as follows:

1. There will be a two month lag in imposing charges with no true-up. This means that the Reactive Power Costs for January of a particular year, for example, will be used as the basis for charges in March of that same year, and the Reactive Power Costs for February of that year will be used as the basis for charges in April of that same year and so on.

2. For each Zone, the charge shall be calculated based upon the following formula:

    a. The Reactive Power Costs for each Qualified Generator in each Zone shall be added together. The Reactive Power Costs used shall be monthly costs. These Reactive Power Costs for each Zone shall be reduced by the portion of through and out reactive revenue distributed to each Zone for that month. This means that a March reactive power charge will be developed based upon January costs and revenues. This shall be considered the "Monthly Revenue Requirement" for each Zone. If the through and out reactive revenues distributed to a Zone exceed the Reactive Power Costs in any month, the Monthly Revenue Requirement for that Zone shall equal zero.

    b. Dividing the Monthly Revenue Requirement determined in step (a) above by the Attachment O, Page 1, Line 15 rate divisor for each Zone to derive a monthly rate; and deriving from that monthly rate the rates for weekly, daily and hourly service consistent with Attachment O, page 2 of 2. For those Zones not utilizing Attachment O to derive rates for base Transmission Service, the Transmission Provider shall use the same rate divisor used in calculating base transmission rates for Schedule 7, the Midwest ISO Single System-Wide Rates, or use a divisor specified by Commission order as the Schedule 2 rate divisor.

3. Rates for Reactive Supply and Voltage Control from Generation Sources Service for transactions exiting the Transmission System

The rate for Reactive Supply and Voltage Control from Generation Sources Service for Transmission Customers with loads located outside the Transmission Provider's Transmission System shall be calculated using an average rate. The average rate shall be calculated as provided in Section III of Schedule 2 except that the revenue requirements reflected for each Zone which has elected to use this Schedule 2-A shall be the revenue requirements established by this Schedule 2-A.

D. Collection of Charges and Distribution of Revenues

1. For each Zone under this Schedule 2-A, each Transmission Customer taking Transmission Service which sinks in that Zone shall pay the Transmission Provider a charge for Reactive Supply and Voltage Control from Generation Sources Service determined by multiplying the applicable rate as calculated above by the Reserved Capacity for the Transmission Customer taking Point-To-Point Transmission Service or by the Network Load for a Transmission Customer

taking Network Integration Transmission Service. Each Transmission Customer taking Transmission Service which is provided to Points of Delivery of loads sinking in a Zone which is not under this Schedule 2-A shall pay the applicable rate under Schedule 2. For Transmission Service provided to Points of Delivery or loads located outside of the Transmission System, the Transmission Customer shall pay the applicable charge under Schedule 2, subject to using the revenue requirements calculated under this Schedule 2-A for Zones electing to use this Schedule 2-A.

2. Each month for Point-to-Point Transmission Service or Network Integration Transmission Service provided to load within a Zone covered by this Schedule 2-A, the Transmission Provider shall distribute to each Qualified Generator owner a pro rata allocation of the amounts collected under this Schedule 2-A for that Zone based upon the Zonal Percentage calculated in Section III.B.5. The revenue distribution associated with Transmission Service sinking in a Zone which did not elect this Schedule 2-A shall be as provided by the revenue distribution provision in Schedule 2 (which shall only reflect the distribution of revenues to Zones which are not under this Schedule 2-A).

3. Each month for Transmission Service provided to Points of Delivery or loads located outside the Transmission System, the Transmission Provider shall distribute to each Qualified Generation owner a pro rata allocation of the amounts collected as provided in Section III.C.3 of Schedule 2 with the revenue requirement reflected in such revenue distribution for Zones electing this Schedule 2-A calculated pursuant to this Schedule 2-A.

IV. QUALIFIED GENERATOR STATUS

A. Re-Evaluation of Qualified Generator Status

1. If a Qualified Generator fails to comply with the Local Balancing Authority's voltage control requirements three or more times in a calendar month for reasons other than planned or unscheduled outages, the Transmission Provider shall determine whether the Generation Resource should continue to be a Qualified Generator based on the criteria established in Section II.B of this Schedule 2-A.

2. In making a determination of whether a Generation Resource should continue to be a Qualified Generator, the Transmission Provider will evaluate, among other factors, whether the Generation Resource was operated consistently with its design characteristics, and whether system conditions prevented it from responding as required by the Local Balancing Authority.

SCHEDULE 3 Regulating Reserve Version: 2.0.0 Effective: 12/31/9998

SCHEDULE 3

REGULATING RESERVE

I. GENERAL

Regulating Reserve is necessary to i) continuously balance the total output of all Resources within the Midwest ISO Balancing Authority Area with the total demand of all loads (including losses) within the Midwest ISO Balancing Authority Area plus the Net Scheduled Interchange of the Midwest ISO Balancing Authority Area and ii) assist in maintaining the difference between scheduled Interconnection frequency and actual Interconnection frequency within acceptable limits based on Applicable Reliability Standards. Regulation Deployment is accomplished by using automatic control equipment to raise or lower the output of on-line Resources as necessary to follow the moment-by-moment changes in demand and frequency. The obligation to maintain this balance between supply and demand lies with the Midwest ISO Balancing Authority. The Midwest ISO Balancing Authority will procure this service on behalf of the Load Serving Entities from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets, as provided for in Sections 39.2 and 40.2 of this Tariff. A Load Serving Entity must either purchase this service from the Midwest ISO Balancing Authority or make alternative comparable arrangements to satisfy its Regulating Reserve Obligation, where such Obligation is defined below. The Midwest ISO Balancing Authority shall determine whether alternative arrangements proposed by the Load Serving Entity are comparable to the provision of this service by the Midwest ISO Balancing Authority.

II. DESCRIPTION OF SERVICE

Regulating Reserve is unloaded and loaded Resource capacity utilized by the Midwest ISO Balancing Authority to manage the area control error as necessary to comply with Applicable Reliability Standards. Regulating Reserve is cleared and priced every Hour in the Day-Ahead Energy and Operating Reserve Market and every Dispatch Interval in the Real-Time Energy and Operating Reserve Market. Regulating Reserve is settled on an Hourly basis in both the Day-Ahead Energy and Operating Reserve Market and Real-Time Energy and Operating Reserve Markets. Regulating Reserve can only be supplied by Regulation Qualified Resources.

III. PURCHASE OBLIGATIONS WITHIN THE MIDWEST ISO BALANCING AUTHORITY AREA AND RATES

Day-Ahead and Real-Time Regulating Reserve procurement costs are collected from Load Serving Entities on a zonal basis using the following rate methodology:

A. Binding Settlement Zone Regulating Reserve Charges

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals within a Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants ("MP") for Resources providing Regulating Reserve within that Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Regulating Reserve Charge = GFA Regulating Reserve Procurement Rate multiplied by MP Carved-Out GFA Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Regulating Reserve multiplied by the Minimum of [Regulating Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for the Binding Settlement Zone,

Where:

GFA Regulating Reserve Procurement Rate = Regulating Reserve Procurement Cost / Total Actual Energy Withdrawal in the Non-Binding Settlement Zone;

Regulating Reserve Procurement Cost = The sum of all credits calculated under

Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve within the Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Binding Settlement Zone;

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Binding Settlement Zone; and

MP Carved-Out GFA Regulating Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Regulating Reserve schedules within the Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Regulating Reserve Charge non-GFA = Non-GFA Regulating Reserve Procurement

Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Regulating Reserve Procurement Rate = The difference between the Non-GFA Regulating Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Regulating Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Binding Settlement Zone;

Non-GFA Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Regulating Reserve multiplied by the Minimum of [Regulating Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for all GFA billing entities within the Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy

	Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Binding Settlement Zone; and
Total Actual Non-GFA Energy Withdrawals =	The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Binding Settlement Zone.

B. Non-Binding Settlement Zone Regulating Reserve Charge

Market Participants, other than Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals within a Non-Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Regulating Reserve within that Non-Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Regulating Reserve Charge =	GFA Regulating Reserve Procurement Rate multiplied by the MP Carved-Out GFA Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Regulating Reserve multiplied by the Minimum of [Regulating Reserve schedules

associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for the Non-Binding Settlement Zone,

Where:

GFA Regulating Reserve Procurement Rate = Regulating Reserve Procurement Cost / Total Actual Energy Withdraw in the Non-Binding Settlement Zone;

Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing Regulating Reserve within the Non-Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Non-Binding Settlement Zone;

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Non-Binding Settlement Zone; and

MP Carved-Out GFA Regulating Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Regulating Reserve schedules within the Non-Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Regulating Reserve Charge non-GFA = Non-GFA Regulating Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Regulating Reserve Procurement Rate = the difference between the Non-GFA Regulating Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Regulating Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Non-Binding Settlement Zone;

Non-GFA Regulating Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.a plus the sum of all charges/credits calculated under Section 40.3.3.b.iii specific to Resources providing

Regulating Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Regulating Reserve multiplied by the Minimum of [Regulating Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Regulating Reserve Obligation] for all GFA billing entities within the Non-Binding Settlement Zone;

MP Actual Energy Withdrawal =	Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and excluding real-time Export Schedules, within the Non-Binding Settlement Zone; and
Total Actual Non-GFA Energy Withdrawals =	The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and excluding real-time Export Schedules, within the Non-Binding Settlement Zone;

IV. PROVISIONS TO SATISFY REGULATING RESERVE OBLIGATIONS VIA SELF-SCHEDULES

A Market Participant may Self-Schedule from their Regulation Qualified Resources in the Energy and Operating Reserve Markets to meet their hourly Market-Wide Regulating

Reserve Obligation. A Market Participant's hourly Market-Wide Regulating Reserve Obligation shall be equal to the Market-Wide Regulating Reserve Requirement multiplied by the ratio of the Market Participant's Actual Energy Withdrawals, excluding real-time Export Schedules to Midwest ISO Balancing Authority Load, excluding real-time Export Schedules. Such Self-Scheduled Regulating Reserve shall be compensated at the applicable Regulating Reserve Market Clearing Price for that Resource pursuant to Sections 39 and 40 of this Tariff.

SCHEDULE 5 Spinning Reserve Version: 1.0.0 Effective: 12/31/9998

SCHEDULE 5
Spinning Reserve

I. GENERAL

Spinning Reserve is required to immediately offset deficiencies in Energy supply that result from a Resource contingency or other abnormal event. Spinning Reserve may be provided by Resources that are Spin Qualified Resources available to provide Spinning Reserve. The obligation to maintain this immediate response capability to contingency events lies with the Midwest ISO Balancing Authority. The Midwest ISO Balancing Authority will procure Spinning Reserve on behalf of the Load Serving Entities, and Exporting Entities from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets as provided for in Sections 39.2 and 40.2 of this Tariff. Load Serving Entities, and Exporting Entities must either purchase this service from the Midwest ISO Balancing Authority or make alternative comparable arrangements to satisfy its Spinning Reserve Obligation, where such Obligation is defined below. The Midwest ISO Balancing Authority shall determine whether alternative arrangements proposed by Load Serving Entities, and Exporting Entities are comparable to the provision of this service by the Midwest ISO Balancing Authority.

II. DESCRIPTION OF SERVICE

Spinning Reserve is synchronized unloaded resource capacity set aside to be available to immediately offset abnormal supply deficiencies. Spinning Reserve must be immediately available and must be fully deployable within the Contingency Reserve Deployment Period. Spinning Reserve is a specified percentage of the Contingency Reserve requirements of the Midwest ISO Balancing Authority that must be provided by Spin Qualified Resources. Spinning Reserve is cleared and priced every Hour in the Day-Ahead Energy and Operating Reserve Market and every Dispatch Interval in the Real-Time Energy and Operating Reserve Market. Spinning Reserve is settled on an hourly basis in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

III. PURCHASE OBLIGATIONS WITHIN THE MIDWEST ISO BALANCING AUTHORITY AREA AND RATES

Day-Ahead and Real-Time Spinning Reserve procurement costs are collected from Load Serving Entities and Exporting Entities on a zonal basis using the following rate methodology:

A. Binding Settlement Zone Spinning Reserve Charges

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Spinning Reserve within that Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Spinning Reserve Charge = GFA Spinning Reserve Procurement Rate multiplied by the MP Carved-Out GFA

Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Spinning Reserve multiplied by the Minimum of [Spinning Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Spinning Reserve Obligation] for the Binding Settlement Zone,

Where:

GFA Spinning Reserve Procurement Rate = Spinning Reserve Procurement Cost / Total Actual Energy Withdrawal in the Binding Settlement Zone;

Spinning Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve within the Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone; and

MP Carved-Out GFA Spinning Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Spinning Reserve schedules within the Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Spinning Reserve Charge non-GFA = Non-GFA Spinning Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Spinning Reserve Procurement Rate = The difference between the Non-GFA Spinning Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Spinning Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Binding Settlement Zone;

Non-GFA Spinning Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Spinning Reserve multiplied by

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone.

B. Non-Binding Settlement Zone Spinning Reserve Charge

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Non-Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Spinning Reserve within that Non-Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Spinning Reserve Charge = GFA Spinning Reserve Procurement Rate multiplied by the MP Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Spinning Reserve multiplied by the Minimum of [Spinning Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Spinning Reserve Obligation] for the Non-Binding Settlement Zone,

Where:

GFA Spinning Reserve Procurement Rate =	Spinning Reserve Procurement Cost / Total Actual Energy Withdraw in the Non-Binding Settlement Zone;
Spinning Reserve Procurement Cost =	The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve within the Non-Binding Settlement Zone;
MP Actual Energy Withdrawal =	Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within

the Non-Binding Settlement Zone;

Total Actual Energy Withdrawal = The sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

MP Carved-Out GFA Spinning Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Non-Binding Settlement Zone multiplied by the sum of all Spinning Reserve schedules within the Non-Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Spinning Reserve Charge non-GFA = Non-GFA Spinning Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Spinning Reserve Procurement Rate = The difference between the Non-GFA Spinning Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Spinning Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Non-Binding Settlement Zone;

Non-GFA Spinning Reserve Procurement Cost =	The sum of all credits calculated under Section 39.3.2A.b plus the sum of all charges/credits calculated under Section 40.3.3.b.iv specific to Resources providing Spinning Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Spinning Reserve multiplied by the Minimum of [Spinning Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Spinning Reserve Obligation] for all GFA billing entities within the Non-Binding Settlement Zone;
MP Actual Energy Withdrawal =	Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone; and
Total Actual Non-GFA Energy Withdrawals =	The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone.

IV. PROVISIONS TO SATISFY SPINNING RESERVE OBLIGATIONS VIA SELF-

SCHEDULES

A Market Participant may Self-Schedule from their Spin Qualified Resources in the Energy and Operating Reserve Markets to meet their hourly Market-Wide Spinning Reserve Obligation. A Market Participant's hourly Market-Wide Spinning Reserve Obligation shall be equal to the Market-Wide Spinning Reserve Requirement multiplied by the ratio of the Market Participant's Actual Energy Withdrawals, including real-time Export Schedules to Midwest ISO Balancing Authority Load, including real-time Export Schedules. Such Self-Scheduled Spinning Reserve shall be compensated at the applicable Spinning Reserve Market Clearing Price for that Resource pursuant to Sections 39 and 40 of this Tariff.

SCHEDULE 6 Supplemental Reserve Version: 1.0.0 Effective: 12/31/9998

SCHEDULE 6
Supplemental Reserve

I. GENERAL

Supplemental Reserve is required to offset deficiencies in Energy supply that result from a Resource contingency or other abnormal event. Supplemental Reserve may be provided by Resources that are Supplemental Qualified Resources that are available to supply Supplemental Reserve. The obligation to maintain this response capability to contingency events lies with the Midwest ISO Balancing Authority. The Midwest ISO Balancing Authority will procure Supplemental Reserve on behalf of the Load Serving Entities and Exporting Entities from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets as provided for in Sections 39.2 and 40.2 of this Tariff. Load Serving Entities and Exporting Entities must either purchase this service from the Midwest ISO Balancing Authority or make alternative comparable arrangements to satisfy its Supplemental Reserve

Obligation, where such Obligation is defined below. The Midwest ISO Balancing Authority shall determine whether alternative arrangements proposed by the Load Serving Entities and Exporting Entities are comparable to the provision of this service by the Midwest ISO Balancing Authority.

II. DESCRIPTION OF SERVICE

Supplemental Reserve is unloaded resource capacity set aside to be available to offset abnormal supply deficiencies. Supplemental Reserve must be fully deployable within the Contingency Reserve Deployment Period. Supplemental Reserve is a specified percentage of the Contingency Reserve requirement of the Midwest ISO Balancing Authority that is provided by Supplemental Qualified Resources. Supplemental Reserve is cleared and priced every Hour in the Day-Ahead Energy and Operating Reserve Market and every Dispatch Interval in the Real-Time Energy and Operating Reserve Market. Supplemental Reserve is settled on an hourly basis in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

III. PURCHASE OBLIGATIONS WITHIN THE MIDWEST ISO BALANCING AUTHORITY AREA AND RATES

Day-Ahead and Real-Time Supplemental Reserve procurement costs are collected from Load Serving Entities and Exporting Entities on a zonal basis using the following rate methodology:

A. Binding Settlement Zone Supplemental Reserve Charges

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Supplemental Reserve within that Binding Settlement Zone for that Hour as follows:

Cost allocated to Carved-Out GFAs:

Carved-Out GFA Supplemental Reserve Charge = GFA Supplemental Reserve Procurement Rate multiplied by the MP Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Supplemental Reserve multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for the Binding Settlement Zone,

Where:

GFA Supplemental Reserve Procurement Rate = Supplemental Reserve Procurement Cost / Total Actual Energy Withdrawal in the Binding Settlement Zone;

Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve within the Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy

Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Energy Withdrawal = the sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone; and

MP Carved-Out GFA Supplemental Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Binding Settlement Zone multiplied by the sum of all Supplemental Reserve schedules within the Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Supplemental Reserve Charge non-GFA = Non-GFA Supplemental Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Supplemental Reserve Procurement Rate = The difference between the Non-GFA Supplemental Reserve Procurement

Cost and the aggregate sum of all Carved-Out GFA Supplemental Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Binding Settlement Zone;

Non-GFA Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Supplemental Reserve multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for all GFA billing entities within the Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal including real-time Export Schedules, within the Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Binding Settlement Zone.

B. Non-Binding Settlement Zone Supplemental Reserve Charge

Market Participants, and Carved-Out GFA billing entities associated with Carved-Out GFAs, with Actual Energy Withdrawals and real-time Export Schedules within a Non-Binding Settlement Zone shall be charged each Hour, a pro-rata share of the total payments to Market Participants for Resources providing Supplemental Reserve within that Non-Binding Settlement Zone for that Hour as follows:

Costs allocated to Carved-Out GFAs:

Carved-Out GFA Supplemental Reserve Charge = GFA Supplemental Reserve Procurement Rate multiplied by the MP Actual Energy Withdrawal minus the Hourly Real-Time Ex Post MCP for Supplemental Reserve multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for the Non-Binding Settlement Zone,

Where:

GFA Supplemental Reserve Procurement Rate = Supplemental Reserve Procurement Cost / Total Actual Energy Withdraw in the Non-Binding Settlement Zone;

Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve within the Non-Binding Settlement Zone;

MP Carved-Out GFA Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, associated with Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone;

Total Actual Energy Withdrawal = the sum of all Market Participant Actual Energy Withdrawals, including Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

MP Carved-Out GFA Supplemental Reserve Obligation = MP Carved-Out GFA Actual Energy Withdrawal divided by Total Actual Energy Withdrawal within the Non-Binding Settlement Zone multiplied by the sum of all

Supplemental Reserve schedules within the Non-Binding Settlement Zone.

Costs allocated to Non-GFA Withdrawals:

Supplemental Reserve Charge non-GFA = Non-GFA Supplemental Reserve Procurement Rate * MP Actual Energy Withdrawal for the Non-Binding Settlement Zone,

Where:

Non-GFA Supplemental Reserve Procurement Rate = The difference between the Non-GFA Supplemental Reserve Procurement Cost and the aggregate sum of all Carved-Out GFA Supplemental Reserve Charges divided by Total Actual Non-GFA Energy Withdrawals within the Non-Binding Settlement Zone;

Non-GFA Supplemental Reserve Procurement Cost = The sum of all credits calculated under Section 39.3.2A.c plus the sum of all charges/credits calculated under Section 40.3.3.b.v specific to Resources providing Supplemental Reserve minus the aggregate sum of the Hourly Real-Time Ex Post MCP for Supplemental Reserve multiplied by the Minimum of [Supplemental Reserve schedules associated with the Carved-Out GFA, and the MP Carved-Out GFA Supplemental Reserve Obligation] for all GFA billing entities within the Non-Binding Settlement Zone;

MP Actual Energy Withdrawal = Market Participant Actual Energy Withdrawal, excluding Carved-Out GFA Actual Energy Withdrawal and including real-time Export Schedules, within the Non-Binding Settlement Zone; and

Total Actual Non-GFA Energy Withdrawals = The sum of all Market Participant Actual Energy Withdrawals, excluding Carved-Out GFA Actual Energy Withdrawals and including real-time Export Schedules, within the Non-Binding Settlement Zone.

IV. PROVISIONS TO SATISFY SUPPLEMENTAL RESERVE OBLIGATIONS VIA SELF-SCHEDULES

A Market Participant may Self-Schedule from their Supplemental Qualified Resources in the Energy and Operating Reserve Markets to meet their hourly Market-Wide Supplemental Reserve Obligation. A Market Participant's hourly Market-Wide Supplemental Reserve Obligation shall be equal to the Market-Wide Supplemental Reserve Requirement multiplied by the ratio of the Market Participant's Actual Energy Withdrawals, including real-time Export Schedules to Midwest ISO Balancing Authority Load, including real-time Export Schedules.

Such Self-Scheduled Supplemental Reserve shall be compensated at the applicable Supplemental Reserve Market Clearing Price for that Resource pursuant to Sections 39 and 40 of this Tariff.

SCHEDULE 20 Treatment of Station Power Version: 1.0.0 Effective: 12/31/9998

SCHEDULE 20

Treatment of Station Power

I. RECOGNIZED MEANS OF PROVIDING FOR STATION POWER

A Generation Owner may arrange to provide for Station Power of a Facility:

1) Through On-Site Self-Supply, Remote Self-Supply, or Third-Party Supply (pursuant to Section II of this Schedule); or

2) By procuring Transmission Service under Module B of the Tariff (pursuant to Section III of this Schedule) in instances of Remote Self-Supply or Third-Party Supply.

II. ON-SITE SELF-SUPPLY, REMOTE SELF-SUPPLY AND THIRD-PARTY SUPPLY OF STATION POWER

1) A Generation Owner may obtain Station Power for its Facility through any of the following sources: a) from the same Facility (*i.e*., On-Site Self-Supply); b) from a remote Facility owned by the same entity that owns such Facility (*i.e*., Remote Self-Supply); *provided that*, if an entity owns a portion of a jointly-owned Facility, it may remotely self-supply its other Facility up to the amount of Energy from such jointly-owned Facility if: i) the entity has the right to call upon that Energy for its own use; and (ii) such Energy entitlement is not characterized as a sale from the jointly-owned Facility to any of its owners; or c) from a third party pursuant to an

applicable retail rate or tariff (*i.e.*, Third-Party Supply).

2) During any Month when the Net Output of a Facility is positive as a result of either the On-Site Self-Supply or Remote Self-Supply of Station Power, Generation Owner shall be deemed not to have engaged in the retail purchase of electric Energy with respect to Station Power service hereunder.

3) The determination of Net Output under paragraph (2) of this subsection will apply only to determine whether the Facility self-supplied Station Power during the Month and will not affect the price of Energy sold or consumed by the Generation Owner at any Bus during any Hour during the Month. For each Hour when a Facility has positive net output and delivers Energy into the Transmission System, Generation Owner will be paid the Hourly Real-Time Ex Post LMP at its Bus for that Hour for the net Energy delivered (i.e., minus On-Site Self-Supply of Station Power). Conversely, for each Hour when a Facility has negative net output and has received Station Power from the Transmission System, Generation Owner will pay the Hourly Real-Time Ex Post LMP at its Bus for that Hour for all of the Energy consumed.

4) Transmission Provider will determine the extent to which each affected Facility during the Month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the Month. Generation Owner must provide the Transmission Provider with

sufficient information to allow the Transmission Provider to implement Schedule 20. To the extent that a Transmission Owner or the Transmission Provider has primary access to relevant meter data, it must cooperate with Generation Owners regarding metering arrangements and verification of data to implement Schedule 20.

5) A Generation Owner may remotely self-supply Station Power from its generation facilities located outside the Transmission Provider Region during any Month only if such generation facilities in fact run during such Month and Generation Owner separately has reserved transmission service and scheduled delivery of the Energy from such resource in advance into the Transmission Provider Region.

III. TRANSMISSION SERVICE CHARGES FOR STATION POWER SUPPLY

1) General - A Generation Owner that supplies its Facility with Station Power via On-Site Self-Supply will be deemed not to have used, and will not incur any charges for, Transmission Service to provide such Station Power. In the event, and to the extent, that a Generation Owner obtains Station Power for its Facility through Remote Self-Supply or Third-Party Supply during any Month, Generation Owner shall use and pay for hourly Non-Firm Point-To-Point Transmission Service for the transmission of Energy in an amount equal to the Facility's negative Net Output from Generation Owner's Facility(ies) having positive Net Output. Unless the Generation Owner makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under and subject to the charges and other terms and conditions of Non-Firm

Point-To-Point Transmission Service specified in Module B of the Tariff and Part III of this Schedule 20 with an obligation to pay congestion charges and losses; provided, however, that no reservation shall be necessary for such Transmission Service and the terms and charges under Schedules 1 through 6 of this Tariff shall not apply. In the event a Generation Owner has other permissible transmission arrangements that involve a Transmission Owner providing for use of transmission facilities directly by the Generation Owner, the Transmission Owner shall be responsible for taking Transmission Service under the Tariff to satisfy its obligations to provide for delivery of Station Power and shall pay any applicable zonal Transmission Service rate under Schedules 7, 8 or 9 and all other charges applicable to such Transmission Service under this Tariff. In the event the Generation Owner has existing rights to use an ITC's facilities, the Generation Owner shall be responsible for taking Transmission Service under the Tariff but shall not be liable for any applicable zonal Transmission Service rate under Schedules 7, 8 or 9 of the Tariff. Such Generation Owner, with existing rights to use an ITC's facilities, shall be responsible for all other charges under the Tariff applicable to such Transmission Service. The amount of Energy that a Generation Owner transmits in conjunction with the Remote Self-Supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or Energy by or for such Generation Owner under any other provisions of the Tariff.

IV. RETAIL PURCHASE OF STATION POWER

Nothing in this Schedule 20 is intended to: 1) preclude a Generation Owner from purchasing Station Power pursuant to an applicable retail rate or tariff; or 2) supercede otherwise applicable jurisdiction of a state regulatory commission, except in the event of a conflict between Federal and state tariff provisions, in which case the Federal tariff provisions will control.

V. METERING REQUIREMENTS

Generation Owners shall be responsible for making all appropriate metering arrangements for Station Power Transmission Service requirements to enable the Transmission Provider to implement Schedule 20. The Generation Owner shall also be responsible for timely submission of accurate, complete and verified metering information to the Transmission Provider, which shall have the right to audit such submissions. The Transmission Provider shall determine whether a Generation Owner's metering information is sufficiently accurate, complete and verifiable for purposes of implementing Schedule 20. The Transmission Provider shall have the sole responsibility of determining whether a facility self-supplied Station Power during a Month.

SCHEDULE 27 RTORSGP and DAMAP Version: 5.0.0 Effective: 12/31/9998

SCHEDULE 27

Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP) and Day-Ahead Margin Assurance Payment (DAMAP)

The RTORSGP under Section 40.3.5 and the DAMAP under Section 40.3.6 of this Tariff shall be calculated as set forth below.

A. Calculation of RTORSGP for Day-Ahead Committed and Real-Time Must-Run Committed Resources

The RTORSGP for Day-Ahead committed and Real-Time Must-Run committed

Generation Resources and Demand-Response Resources – Type II with Non-Excessive Energy levels greater than their Day-Ahead Schedules for Energy and the RTORSGP for External Asynchronous Resources with Non-Excessive Energy levels greater than their Day-Ahead Schedules for Energy shall be calculated in three steps. The first step shall determine the cost of following dispatch, *i.e.*, the cost to the Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource of following the Transmission Provider's Setpoint Instructions. The second step shall determine the payment for following dispatch, *i.e.*, the value of the payment to the Generation Resources, Demand Response Resources – Type II or External Asynchronous Resources for following the Transmission Provider Setpoint Instructions. The third step shall determine the RTORSGP.

1. Step One: Cost of Following Dispatch

    a. Two intermediate quantities must be derived to properly calculate Incremental Energy Costs associated with following the Transmission Provider Setpoint Instructions for both Day-Ahead committed and Real-Time Must-Run committed Generation Resources and Demand Response Resources – Type II and for External Asynchronous Resources.

        i. Determination of base output:

            1. For Real-Time Must-Run committed Generation Resource and Demand Response Resource – Type II, the base output is equal to the Economic Minimum Dispatch for a given Dispatch Interval ("i"). For External Asynchronous Resource's with Day-Ahead Schedules for Energy that are equal to zero, the base output is equal to zero.

2. For Day-Ahead committed Generation Resources and Demand Response Resources – Type II or External Asynchronous Resources with Day-Ahead Schedules for Energy, the base output MW is equal to the Day-Ahead cleared MW, and will be the same for all intervals in an Hour.

3. The base output shall be calculated for every Dispatch interval ("i") in each eligible Hour as provided for in Section 40.3.5 of this Tariff.

ii. Determination of pay output:

1. The pay output shall be derived in the same way for Generation Resources, Demand Response Resources – Type II and External Asynchronous Resources for each Hour in the contiguous Day-Ahead Commitment Period.

2. The pay output shall be calculated for every eligible Hour and shall be equal to the Generation Resource's, Demand Response Resource's – Type II or External Asynchronous Resource's Non-Excessive Energy.

b. The base output and pay output are inputs into the calculation of the cost of following dispatch.

i. The cost of following dispatch for each eligible Hour is equal to the sum of the hourly integration of incremental Energy costs from base output up to Pay Output (as defined below) in each interval ("i").

1. Cost of following dispatch is performed for every interval ("i") within each eligible Hour, and integrated to an hourly value, as specified below.

$$EnergyCost_h^{RT} = \sum_{\text{Hour}} \int^{\text{POi}} \text{RTOen}_{\text{i}} - \int^{\text{BOi}} \text{RTOen}_{\text{i}} \times \text{S}_{\text{i}} / 3600$$

Where:

$EnergyCost_h^{RT}$ = Additional cost for Non-Excessive Energy produced in real-time above the Base Output within Hour *h* in the contiguous Day-Ahead Commitment Period.

n = Number of intervals in the Hour *h* in the commitment period.

BO_i = Base Output for interval *i* in Hour *h* as defined above.

PO_i = Pay Output for interval *i* in Hour *h* as defined above.

$RTOen_i$ = RT Offer for Energy for interval *i*.

s_i = Number of seconds in interval *i*.

2. Step Two: Payment for Following Dispatch:

a. The Energy related payment (Energy revenues) for following dispatch shall be calculated as follows:

$$LMPRev_h^{RT} = LMP_h^{RT} \times (NXE_h - EI_h^{DA})$$

Where:

$LMPRev_h^{RT}$ = The Energy revenue in an Hour h within the contiguous Day-Ahead Commitment Period.

LMP_h^{RT} = Hourly Real-Time Ex Post LMP for Hour h.

EI_h^{DA} = Day-Ahead Schedule for Energy in Hour h

NXE_h= Non-Excessive Energy for Hour h.

b. The Spinning Reserve related payment (Spinning Reserve net revenues) for following dispatch shall be calculated as:

$$NetSpinRev_h^{RT} = (\text{ Max } ((ClrSpin_h^{RT} - ClrSpin_h^{DA}) \times (SpinMCP_h^{RT} - SpinOffer_h^{RT}) , 0)$$

Where:

$NetSpinRev_h^{RT}$ = Real-Time Spinning Reserve revenue credit for Hour h within the contiguous Day-Ahead Commitment Period.

$ClrSpin_h^{RT}$ = Cleared Real-Time Spinning Reserve for Hour h.

$ClrSpin_h^{DA}$ = Cleared Day-Ahead Spinning Reserve for Hour h.

$SpinMCP_h^{RT}$ = Hourly Real-Time Ex Post MCP for Spinning Reserve for Hour h.

$SpinOffer_h^{RT}$ = Real-Time Offer for Spinning Reserve for Hour h.

c. The Supplemental Reserve related payment (Supplemental Reserve net revenues) supplied from synchronized Resources for following dispatch shall be calculated as follows:

$NetSynSuRev_h^{RT} =$

$MAX\,(\,(\,ClrSynSu_h^{RT} - ClrSynSu_h^{DA}\,) \times (\,SynSuMCP_h^{RT} - SynSuOffer_h^{RT}\,),\,0\,)$

Where:

$NetSynSuRev_h^{RT} =$ Real-Time synchronized Supplemental Reserve revenue credit for Hour h within the contiguous Day-Ahead Commitment Period.

$ClrSynSu_h^{RT} =$ Cleared Real-Time synchronized Supplemental Reserve for Hour h.

$ClrSynSu_h^{DA} =$ Cleared Day-Ahead synchronized Supplemental Reserve for Hour h.

$SynSuMCP_h^{RT} =$ Hourly Real-Time Ex Post MCP for synchronized Supplemental Reserve for Hour h.

$SynSuOffer_h^{RT} =$ Real-Time Offer for synchronized Supplemental Reserve for hour h.

d. The Regulating Reserve related payment (Regulating Reserve net revenues) for following dispatch shall be calculated as follows:

$$NetRegRev_h^{RT} = MAX(\,(\,ClrReg_h^{RT} - ClrReg_h^{DA}\,) \times (\,RegMCP_h^{RT} - RegOffer_h^{RT}\,),\,0\,)$$

Where:

$NetRegRev_h^{RT} =$ Real-Time Regulating Reserve revenue credit for Hour h

within the contiguous Day-Ahead Commitment Period.

$ClrReg_h^{RT}$ = Cleared Real-Time Regulating Reserve for Hour h.

$ClrReg_h^{DA}$ = Cleared Day-Ahead Regulating Reserve for hour h.

$RegMCP_h^{RT}$ = Hourly Real-Time Ex Post MCP for Regulating Reserve for Hour h.

$RegOffer_h^{RT}$ = Real-Time Offer for Regulating Reserve for hour h.

e. The net Operating Reserve related payment (Operating Reserve net revenues) shall be calculated as follows:

$$NetORRev_h^{RT} = NetSpinRev_h^{RT} + NetSynSuRev_h^{RT} + NetRegRev_h^{RT}$$

Where:

$NetORRev_h^{RT}$ = Net Operating Reserve revenue for Hour h within the contiguous Day-Ahead Commitment Period.

f. The total Energy and Operating Reserve related payment (total net revenue) in Hour h for following dispatch shall be calculated as follows:

$$Rev_h^{RT} = LMPRev_h^{RT} + NetORRev_h^{RT} + RDA_h$$

Where:

Rev_h^{RT} = Total Real-Time net revenue in Hour h within the contiguous Day-Ahead Commitment Period.

$RDA_h =$ Regulation Deployment Adjustment in Hour *h* within the contiguous Day-Ahead Commitment Period as calculated pursuant to Section 40.3.3.a.xi of this Tariff.

$$Payment\_for\_Following\_Dispatch_t = Expost\_LMP_t \times (Metered\_MWH_t - Base\_Output_t)$$

3. Step Three: Real-Time Offer Revenue Sufficiency Guarantee Payment:

a. If the eligible Generation Resource's, Demand Response Resource's Type II or External Asynchronous Resource's cost of following dispatch exceeds the value of its payment for following dispatch in an eligible Hour, then the Resource will receive a RTORSGP in that Hour. The RTORSGP shall be calculated at an hourly level as a credit as specified below.

$$RTORSGP_h^{RT} = MAX(EnergyCost_h^{RT} - Rev_h^{RT}, 0)$$

Where:

$RTORSGP_h^{RT} =$ RTORSGP for Hour *h* within the contiguous Day-Ahead Commitment Period.

$EnergyCost_h^{RT} =$ Additional cost for Non-Excessive Energy produced above the Day-Ahead Schedule for Hour *h* within the contiguous Day-Ahead Commitment Period.

$Rev_h^{RT} =$ Total Real-Time net revenue in Hour *h* within the contiguous Day-Ahead Commitment Period.

B. Calculation of DAMAP for Day-Ahead Committed Resources and External Asynchronous Resources

The DAMAP for Generation Resources, Demand Response Resources – Type II, Stored Energy Resources with Day-Ahead Schedules for Regulating Reserve, External Asynchronous Resources with Day-Ahead Schedules for Energy, and Demand Response Resources-Type I with

Day-Ahead Schedules for Contingency Reserve shall be calculated for each Hour in three steps. The first step shall determine adjustments to Day-Ahead Schedules to account for real-time de-rates for Generation Resources and Demand Response Resources – Type II or an adjustment to Day-Ahead Schedules for Regulating Reserve to the Real-Time cleared Regulating Reserve for Stored Energy Resources if the real-time decrease is the result of dispatch limitations due to reduced Energy storage capability for Dispatch Interval *i*. The second step shall determine 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, *i.e.*, the reduction in Day-Ahead Margin to the Generation Resource, Demand Response Resource – Type II, Stored Energy Resource or External Asynchronous Resource for following the Transmission Provider instructions for Dispatch Interval *i,* including any offsetting real-time margins associated with real-time cleared Energy and/or Operating Reserve in excess of Day-Ahead Schedules for Operating Reserve. The third step shall determine the DAMAP for an Hour.

1. Step One: Calculate Day-Ahead Schedule Adjustments

Prior to the determination of eligible amounts of Energy, Regulating Reserve, Spinning Reserve and/or Supplemental Reserve for use in DAMAP calculations, the Day-Ahead Schedules for Energy, Regulating Reserve, Spinning Reserve and/or Supplemental Reserve associated with Resources, are adjusted to account for Midwest ISO approved real-time reductions in Resource capability caused by physical operating restrictions. For Stored Energy Resources, if the real-time reduction is the result of dispatch limitations due to reduced Energy storage capability, the Adjusted Day-Ahead Schedule for Regulating Reserve for the given Dispatch Interval will be set equal to the Real-Time cleared Regulating Reserve. These Day-Ahead Schedule adjustments are calculated as follows for Dispatch Interval *i*.

$$AdjDASen_i = DASen_h - REDen_i$$

$$AdjDASreg_i = DASreg_h - REDreg_i$$

$$AdjDAScr_{ip} = DAScr_{hp} - REDcr_{ip}$$

Where:

$$REDen_i = (POTREDen_i / (POTREDen_i + POTREDreg_i + \sum_p POTREDcr_{ip})) \times REDtot_i$$

$$REDreg_i = (POTREDreg_i / (POTREDen_i + POTREDreg_i + \sum_p POTREDcr_{ip})) \times REDtot_i$$

$$REDcr_{ip} = (POTREDcr_{ip} / (POTREDen_i + POTREDreg_i + \sum_p POTREDcr_{ip})) \times REDtot_i$$

and where:

$$POTREDen_i = MAX (DASen_h - RTSen_i , 0)$$

$$POTREDreg_i = MAX (DASreg_h - RTSreg_i , 0)$$

$$POTREDcr_{ip} = MAX (DAScr_{hp} - RTScr_{ip} , 0)$$

and where:

$$REDtot_i = MAX(DASen_h + DASreg_h + \sum_p DAScr_{hp} - RTEcoMax_i , 0)$$

Where:

$REDtot_i$ = Total MW reduction of Day-Ahead Schedules for interval *i*.

$DASen_h$ = Day-Ahead Schedule for Energy for hour *h* containing interval *i*.

$DASreg_h$ = Day-Ahead Schedule for Regulating Reserve for hour *h* containing interval *i*.

$DAScr_{hp}$ = Day-Ahead Schedule for Contingency Reserve product *p* for hour *h* containing interval *i*.

$RTEcoMax_i$ = Real-Time Economic Maximum Dispatch for interval *i*.

$POTREDen_i$ = Potential reduction in the Day-Ahead Schedule for Energy schedule for interval *i*.

$RTSen_i$ = Average Dispatch Target for Energy for interval *i*.

$POTREDreg_i$ = Potential reduction in the Day-Ahead Schedule for Regulating Reserve or interval *i*.

$RTSreg_i$ = Real-Time cleared Regulating Reserve for interval *i*.

$POTREDcr_{ip}$ = Potential reduction in the Day-Ahead Schedule for Contingency Reserve, product *p*, for interval *i*.

$RTScr_{ip}$ = Real-Time cleared Contingency Reserve, product p, for interval *i*.

$REDen_i$ = Actual reduction in the Day-Ahead Schedule for Energy for interval *i*.

$REDreg_i$= Actual reduction in Day-Ahead Schedule for Regulating Reserve for interval *i*.

$REDcr_{ip}$ = Actual reduction in the Day-Ahead Schedule for Contingency Reserve, product *p*, for interval *i*.

$AdjDASen_i$ = Adjusted Day-Ahead Schedule for Energy for interval *i*.

$AdjDASreg_i$ = Adjusted Day-Ahead Schedule for Regulating Reserve for interval *i*.

$AdjDAScr_{ip}$ = Adjusted Day-Ahead Schedule for Contingency Reserve, product p, for interval i.

2. Step Two: Calculate Energy and Operating Reserve Contributions to DAMAP.

a. The Energy contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource for Dispatch Interval i is then calculated as follows. The Energy contribution to the DAMAP for a Stored Energy Resource is always set equal to zero.

i. If

$$RTSen_i < AdjDASen_h \text{ and } NXE_i < AdjDASen_h$$

Then:

$$CDAMAPen_i = (AdjDASen_h – MAX(Act_i ,DET_i)) \times LMP_h^{RT} – MAX (\int^{AdjDASen} DAOen_h - \int^{MAX (NXE, DE T)} DAOen_h , (\int^{AdjDASen} RTOen_h - \int^{MAX(NXE, DE T)} RTOen_h)$$

ii. If $RTSen_i >= AdjDASen_h$ and $NXE_i >= AdjDASen_h$

$$CDAMAPen_i = MIN((AdjDASen_h – Act_i) \times LMP_h^{RT} + (\int^{NXE} RTOen_h – \int^{AdjDASen} RTOen_h), 0)$$

Where:

$RTSen_i$ = average Dispatch Target for Energy for interval i.

$AdjDASen_i$ = Adjusted Day-Ahead Schedule for Energy for interval i.

$CDAMAPen_i$ = Energy contribution to DAMAP for interval i.

NXE_i = Non-Excessive Energy for interval i.

DET_i = Resource Deficient Energy Threshold for interval i.

LMP_h^{RT} = Hourly Real-Time Ex Post LMP at the Resource bus for hour h containing interval i.

$RTOen_h$ = Real-Time Offer for Energy for hour h containing interval i.

$DAOen_h$ = Day-Ahead Offer for Energy for hour h containing interval i.

b. The Contingency Reserve contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II or External Asynchronous Resource for Dispatch Interval i is calculated as follows. The Contingency Reserve contribution to the DAMAP for a Stored Energy Resource is always set equal to zero.

i. If $RTScr_{ip} < AdjDAScr_{hp}$

Then:

$$CDAMAPcr_{ip} = (AdjDAScr_{hp} - RTScr_{ip}) \times (RTMCPcr_{hp} - DAOcr_{hp})$$

ii. If $RTScr_{ip} >= AdjDAScr_{hp}$

$$CDAMAPcr_{ip} = (AdjDAScr_{hp} - RTScr_{ip}) \times MAX((RTMCPcr_{hp} - RTOcr_{hp}), 0)$$

Where:

$RTScr_{ip}$ = Real-Time cleared Contingency Reserve, product p, for interval *i*.

$AdjDAScr_{hp}$ = Adjusted Day-Ahead Schedule for Contingency Reserve, product *p*, for interval *i*.

$CDAMAPcr_{ip}$ = Contingency Reserve, product *p*, contribution to DAMAP for interval *i*.

$RTMCPcr_{hp}$ = Hourly Real-Time Ex Post MCP for Contingency Reserve, product *p*, for Hour *h* containing interval *i*.

$DAOcr_{hp}$ = Day-Ahead Offer for Contingency Reserve, product *p*, for Hour *h* containing interval *i*.

$RTOcr_{hp}$ = Real-Time Offer for Contingency Reserve, product *p*, for Hour *h* containing interval *i*.

c. The Regulating Reserve contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II, Stored Energy Resources, or External Asynchronous Resource for Dispatch Interval i is calculated as follows.

i. If $RTSreg_i < AdjDASreg_h$

Then:

$$CDAMAPreg_i = (AdjDASreg_h - RTSreg_i) \times (RTMCPreg_i - DAOreg_h)$$

ii. If $RTSreg_i >= AdjDASreg_h$

$$CDAMAPreg_i = (AdjDASreg_h - RTSreg_i) \times MAX((RTMCPreg_i - RTOreg_h), 0)$$

Where:

$RTSreg_i$ = Real-Time cleared Regulating Reserve for interval i.

$AdjDASreg_h$ = Adjusted Day-Ahead Schedule for Regulating Reserve for interval i.

$CDAMAPreg_i$ = Regulating Reserve contribution to DAMAP for interval i.

$RTMCPreg_i$ = Real-Time Ex Post MCP for Regulating Reserve for hour h containing interval i.

$DAOreg_h$ = Day-Ahead Offer for Regulating Reserve for hour h

containing interval i.

$RTOreg_h$ = Real-Time Offer for Regulating Reserve for hour h containing interval i.

d. The total contribution to the DAMAP for a Generation Resource, Demand Response Resource – Type II, Stored Energy Resource, or External Asynchronous Resource for Dispatch Interval i is calculated as follows.

$$CDAMAP_i = (CDAMAPen_i + \sum_p CDAMAPcr_{ip} + CDAMAPreg_i) \times s_i / 3600$$

Where:

$CDAMAP_i$ = Dispatch interval i contribution to DAMAP for hour h.

$CDAMAPen_i$ = Energy contribution to DAMAP for interval i.

$CDAMAPcr_{ip}$ = Contingency Reserve, product p, contribution to DAMAP for interval i.

$CDAMAPreg_i$ = Regulating Reserve contribution to DAMAP for interval i.

s_i = Length of dispatch interval i in seconds.

3. Step Three: Calculation of Hourly DAMAP:

a. If the sum of the eligible Generation Resource's, Demand Response Resource's Type II, Stored Energy Resource's, or External Asynchronous Resource's Dispatch Interval contribution to DAMAP is greater than zero, then the Resource will receive a DAMAP credit for the Hour.

b. The DAMAP shall be calculated at an hourly level as specified below.

$$\mathrm{DAMAP}_h = MAX\left(\sum_{\mathrm{Hour}} \mathrm{CDAMAP}_i , 0 \right)$$

Where:

$DAMAP_h$ = Day-Ahead Margin Assurance Payment to a Resource for hour h.

n = Number of intervals in hour h.

$CDAMAP_i$ = Dispatch interval i contribution to DAMAP for hour h.

SCHEDULE 29A ELMP for Energy and Operating Reserve Market: Exp-Post Prici Version: 0.0.0 Effective: 12/31/9998

SCHEDULE 29A

ELMP for Energy and Operating Reserve Market:

Ex-Post Pricing Formulations

I. INTRODUCTION

The Transmission Provider utilizes an extension of the simultaneously co-optimized Security Constrained Economic Dispatch (SCED) algorithm to calculate prices for Energy and Operating Reserves. The SCED-Pricing algorithm utilizes a linear programming solver to minimize objective costs represented by a linear objective function subject to linear or linearized physical, reliability and Good Utility Practice constraints as in the simultaneously co-optimized SCED algorithm described in Schedule 29. The SCED-Pricing objective function includes total Energy costs, Regulating Reserve costs, Spinning Reserve costs, Supplemental Reserve costs, Market-Wide Operating Reserve value, Market-Wide Regulating Reserve value, Reserve Zone Operating Reserve value and Reserve Zone Regulating Reserve value. The SCED-Pricing algorithm is solved on an Hourly basis for the Day-Ahead Energy and Operating Reserve Market and for each five (5) minute Dispatch Interval for the Real-Time Energy and Operating Reserve Market. The SCED-Pricing algorithm extends the concept of LMP and MCP by allowing the cost of committing Fast Start Resources, the Energy cost of Fast Start Resources dispatched at limits, and Emergency Demand Response Resources to set Energy and reserve prices. This process is known as Extended LMP (ELMP). The SCED-Pricing algorithm in Schedule 29A is the same as the SCED algorithm in Schedule 29 with the exception of its treatment of Fast Start Resources and Emergency Demand Response Resources.

II. DAY-AHEAD PRICING FORMULATIONS

The Day-Ahead Pricing formulation considers the cost of Energy, Regulating Reserves, and Spinning Reserves from Resources committed in the Hour. It also considers the costs of Supplemental Reserves from off-line or uncommitted Resources. In addition, the Day-Ahead Pricing formulation considers the costs of committing and the costs of keeping on-line those Fast-Start Resources that are committed by the Transmission Provider to be on line in the Hour. It also considers the costs of committing and dispatching off-line Fast Start Resources that are available for the Transmission Provider to commit in the Hour under conditions of Energy or Ancillary Service scarcity or that could alleviate transmission constraint violations, except for the Surplus Conditions in the Day-Ahead EORM described in section 39.2.11.c.

If an on-line Resource that is not a Fast Start Resource committed by the Transmission Provider in the Day-Ahead Market processes described in Section 39.2.9, the costs in the objective function for the Resource and the constraints on the Resource's Energy and Ancillary Service Schedules in the SCED-Pricing problem are the same as those for the Resource in the simultaneously co-optimized SCED algorithm described in Schedule 29.

For a Fast Start Resource committed by the Transmission Provider in the Day-Ahead market processes described in Section 39.2.9 to be on-line in the Hour, the SCED-Pricing algorithm considers the cost of committing and dispatching the Resource when setting prices. The SCED-Pricing algorithm considers the Resource eligible to set prices even if the Resource was scheduled to operate at its minimum or maximum limit. It also considers Start-Up Costs and No-Load Costs for the Fast Start Resource when setting prices. To achieve this, the SCED-Pricing algorithm allows fractional commitment of a Fast Start Resource for purposes of setting prices, even though fractional commitment is not a physically achievable outcome. SCED-Pricing represents the fraction of the Fast Start Resource committed in the Hour by a continuous decision variable, on_{hour}. The SCED-Pricing algorithm requires that on_{hour} satisfy

$$0 \leq on_{hour} \leq 1$$

The SCED-Pricing algorithm allocates a share of the Start-Up Cost for the Fast Start Resource to the Hour for which prices are being calculated. In the following N is the Minimum Run Time offered by the Fast Start Resource in hours.

$AllocatedShareStartUpCost_{hour}$ = *StartUpCost / N if hour is within N hours of the time the Resource was committed, or 0 if hour is later than N hours after the Resource was committed.*

The SCED-Pricing algorithm allocates the No-Load Cost for the Hour to the Hour for which prices are being calculated.

If the Fast-Start Resource was not committed to provide Regulation Reserves, the constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing will include the following. Let $DispatchSchedule_{hour}$ be the dispatch scheduled for the Resource in Hour *hour* and $SpinningReservesSchedule_{hour}$ be the Spinning Reserve Schedule for the Resource in Hour *hour* in SCED-Pricing.

$$on_{hour} \times EconMin_{hour} \leq EnergyDispatchSchedule_{hour}$$

$$0 \leq SpinningReservesSchedule_{hour}$$

$$EnergyDispatchSchedule_{hour} + SpinningReservesSchedule_{hour} \leq on_{hour} \times EconMax_{hour}$$

The ramping constraints affecting Energy and Spinning Reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$$on_{hour} \times (AllocatedShareStartUpCost_{hour} + NoLoadCost_{hour})$$

$$+ \int_{0}^{EnergyDispatchSchedule_{hour}} IncrementalEnergyCost_{hour}(x)dx$$

$$+ SpinningOfferCost_{hour} \times SpinningReservesSchedule_{hour}$$

If the Fast-Start Resource was committed to provide Regulating Reserves, the constraints for the Energy, Spinning Reserves, and Regulating Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_{hour}$ be the dispatch scheduled for the Resource in Hour *hour*, $SpinningReservesSchedule_{hour}$ be the Spinning Reserve Schedule for the Resource in Hour *hour,* and $RegulatingReservesSchedule_{hour}$ be the Regulating Reserve Schedule for the Resource in Hour *hour* in SCED-Pricing.

$$on_{hour} \times RegMin_{hour} \leq EnergyDispatchSchedule_{hour}$$

$$0 \leq SpinningReservesSchedule_{hour}$$

$$0 \leq RegulatingReservesSchedule_{hour}$$

$$on_{hour} \times RegMin_{hour} \leq EnergyDispatchSchedule_{hour} - RegulatingReservesSchedule_{hour}$$

$$EnergyDispatchSchedule_{hour} + SpinningReservesSchedule_{hour} + RegulatingReservesSchedule_{hour} \leq on_{hour} \times RegMax_{hour}$$

The ramping constraints affecting Energy and reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$on_{hour} \times (AllocatedShareStartUpCost_{hour} + NoLoadCost_{hour})$

$$+ \int_0^{EnergyDispatchSchedule_{hour}} IncrementalEnergyCost_{hour}(x)dx$$

$$+SpinningOfferCost_{hour} \times SpinningReservesSchedule_{hour}$$

$$+ RegulatingOfferCost_{hour} \times RegulatingReservesSchedule_{hour}$$

Off-line Fast Start Resources that are available to be committed in the Day-Ahead Market by the Transmission Provider participate in SCED-Pricing if either or both of the following conditions hold:

The SCED algorithm finds a solution that does not meet energy and/or reserve requirements in the Hour except for the Surplus Conditions in the Day-Ahead EORM described in section 39.2.11.c; and/or

The SCED algorithm finds a solution that violates a transmission constraint and the Transmission Provider determines that commitment of the Fast Start Resource provides relief to the violation.

In these scenarios, committing and dispatching off-line Fast Start Resource is an action that the Transmission Provider could take to address the shortage or violation. Rather than set price using a shortage cost or a transmission penalty price, the SCED-Pricing algorithm determines prices based on the action that the Transmission Provider could take to address the problem. The constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_{hour}$ be the dispatch scheduled for the

Resource in Hour *hour* and let $OffLineSupplementalReservesSchedule_{hour}$ be the Off Line Supplemental Reserve Schedule for the Resource in Hour *hour* in SCED-Pricing.

$$on_{hour} \times EconMin_{hour} \leq EnergyDispatchSchedule_{hour} \leq on_{hour} \times EconMax_{hour}$$

$$0 \leq OffLineSupplementalReservesSchedule_{hour}$$

$$\leq (1 - on_{hour}) \times min\{EconMax_{hour}, MaxOfflineResponseLimit_{hour}\}$$

The objective function elements for the Fast Start Resource includes:

$$on_{hour} \times (AllocatedShareStartUpCost_{hour} + NoLoadCost_{hour})$$

$$+ \int_{0}^{EnergyDispatchSchedule_{hour}} IncrementalEnergyCost_{hour}(x)dx$$

$$+ OffLineSupplementalOfferCost_{hour} \times OffLineSupplementalReservesSchedule_{hour}$$

The SCED-Pricing algorithm is the same as the SCED algorithm, with the exceptions for treatment of Fast Start Resources described above.

Objective Function:

Minimize {Total Hourly Energy Costs

+ Total Hourly Commitment Costs for Fast Start Resources

+ Total Hourly Regulating Reserve Costs

+ Total Hourly Spinning Reserve Costs

+ Total Hourly Supplemental Reserve Costs

- Total Hourly Market-Wide Operating Reserve Value

- Total Hourly Market-Wide Regulating Reserve Value

- Total Hourly Zonal Operating Reserve Value

- Total Hourly Zonal Regulating Reserve Value}

Where:

Total Hourly Energy Costs

= The sum of the hourly Energy costs that would be incurred by all Resources supplying dispatchable Energy, based on their submitted Energy offer curves, if they were to operate according to the schedule produced by SCED-Pricing for the given Hour.

Total Hourly Commitment Costs for Fast Start Resources

= The sum of the hourly Start-Up Costs and No-Load Costs that would be incurred by all Fast Start Resources available for commitment by the Transmission Provider, based on their submitted Start-Up and No-Load Offer Costs, if they were to operate according to the commitment produced by SCED-Pricing for the given Hour.

Total Hourly Regulating Reserve Costs

= The sum of the hourly Regulating Reserve costs, based on the Regulating Reserve offer prices, that would be incurred by all Resources supplying dispatchable Regulating

Reserve, if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Hour.

Total Hourly Spinning Reserve Costs

= The sum of the hourly Spinning Reserve costs, based on the Spinning Reserve offer prices, that would be incurred by all Resources supplying dispatchable Spinning Reserve, if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Hour.

Total Hourly Supplemental Reserve Availability Costs

= The sum of the hourly Supplemental Reserve availability costs, based on the Supplemental Reserve offer prices, that would be incurred by all Resources supplying dispatchable Supplemental Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Hour.

Total Hourly Market-Wide Operating Reserve Value

= The hourly value of the Market-Wide Operating Reserve cleared by SCED-Pricing to the Load Serving Entities and Market Participant with Exports on whose behalf the Transmission Provider is procuring Operating Reserves based on the Market-Wide Operating Reserve Demand Curve.

Total Hourly Market-Wide Regulating Reserve Value

= The hourly value of the Market-Wide Regulating Reserve cleared by SCED-Pricing to the Load Serving Entities on whose behalf the Transmission Provider is procuring Regulating Reserves based on the Market-Wide Regulating Reserve Demand Curve.

Total Hourly Zonal Operating Reserve Value

= The hourly zonal value of the Operating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities and Market Participants with Exports on whose behalf the Transmission Provider is procuring Operating Reserves based on the Zonal Operating Reserve Demand Curves.

Total Hourly Zonal Regulating Reserve Value

= The hourly zonal value of the Regulating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities on whose behalf the Transmission Provider is procuring Regulating Reserves based on the Zonal Regulating Reserve Demand Curves.

Constraints:

Subject to

Nodal Power Balance Constraint

Market-Wide Operating Reserve Constraint

Market-Wide Regulating and Spinning Reserve Constraint

Market-Wide Regulating Reserve Constraint

Reserve Zone Operating Reserve Constraints

Reserve Zone Regulating and Spinning Reserve Constraints

Reserve Zone Regulating Reserve Constraints

Maximum Stored Energy Resource Regulation Constraints

Market-Wide Non-DRR1 Operating Reserve Constraint

Resource Limit Constraints

Resource Ramping Constraints

Transmission Constraints

Where:

The Nodal Power Balance Constraint ensures that the net Energy injected at an electrical Node to equal the net Energy flowing out of the same electrical Node on connected branches.

The Market-Wide Operating Reserve Constraint ensures the supply of Market-Wide Operating Reserve is greater than or equal to the Market-Wide Operating Reserve cleared by SCED-Pricing.

The Market-Wide Regulating and Spinning Reserve Constraint ensures that the supply of Market-Wide Regulating and Spinning Reserve is greater than or equal to the Market-Wide Regulating and Spinning Reserve requirement.

The Market-Wide Regulating Reserve Constraint ensures the supply of Market-Wide Regulating Reserve is greater than or equal to the Market-Wide Regulating Reserve cleared by SCED-Pricing.

The Reserve Zone Operating Reserve Constraints ensure the supply of Operating Reserve within a specific Reserve Zone is greater than or equal to the Operating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Reserve Zone Regulating and Spinning Reserve Constraints ensure that the supply of Regulating and Spinning Reserve within a specific Reserve Zone is greater than or equal to the Zonal Regulating and Spinning Reserve requirement.

The Reserve Zone Regulating Reserve Constraints ensure~~s~~ the supply of Regulating Reserve within a specific Reserve Zone is greater than or equal to the Regulating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Maximum Stored Energy Resource Regulation Constraints ensure that the supply of Regulating Reserve that is cleared by SCED-Pricing on Stored Energy Resources is less than or equal to the Market-Wide Regulating Reserve Requirement.

The Market-Wide Non-DRR1 Operating Reserve Constraint ensures the percentage of Market-Wide Operating Reserve that is cleared by SCED-Pricing on Generation Resources, Demand Response Resources – Type II, Stored Energy Resources, and/or External Asynchronous Resources complies with Applicable Reliability Standards.

The Resource Limit Constraints ensure that each Resource has the Capacity, based on submitted limits, to simultaneously supply cleared Energy, deploy one hundred percent (100%) of cleared Regulating Reserve in the upward direction, deploy one hundred percent (100%) of cleared Spinning Reserve and deploy one hundred percent (100%) of cleared Supplemental Reserve. In addition, the Resource Limit Constraints ensure that each Resource has the ability to simultaneously supply cleared Energy and deploy one hundred percent (100%) of the cleared Regulating Reserve in the downward direction with no Spinning Reserve or Supplemental Reserve deployment. For Fast Start Resources, the upper limits and lower limits on capacity available to provide energy and reserves are adjusted by the fractional commitment level for the Resource determined by SCED-Pricing.

The Resource Ramping Constraints ensure that each Resource is cleared by SCED-Pricing in a manner to follow load based on cleared Energy levels in adjacent dispatch intervals and deploy Regulating Reserve and Contingency Reserve in a manner that will comply with Applicable Reliability Standards.

The Transmission Constraints ensure that Energy is cleared by SCED-Pricing on Resources and Loads in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility. In addition, beginning November 1, 2011, the Transmission Constraints shall also ensure that Operating Reserves can be deployed in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility.

Under Shortage Condition in the Day-Ahead EORM described in section 39.2.10, Emergency Maximum Limits are used in SCED-Pricing for Resources available to be dispatched up to Emergency Maximum Limits in SCED. Under Surplus Condition in the Day-Ahead EORM described in section 39.2.11, Emergency Minimum Limits are used in SCED-Pricing for Resources available to be dispatched down to Emergency Minimum Limits in SCED. In addition, during a Surplus Condition, the commitment variable for all Fast Start Resource that were physically committed by the Transmission Provider are held at the value 1 in SCED-Pricing.

III. REAL-TIME FORMULATIONS

The Real-Time Pricing formulation considers the cost of Energy, Regulating Reserves, and Spinning Reserves from Resources committed in the Dispatch Interval. It also considers the costs of Supplemental Reserves from off-line or uncommitted Resources. In addition, the Real-

Time Pricing formulation considers the costs of committing and the costs of keeping on-line those Fast-Start Resources that are committed in the RAC processes by the Transmission Provider to be on line in the Dispatch Interval. It also considers the costs of committing and dispatching off-line Fast Start Resources that are available for the Transmission Provider to commit in the Dispatch Interval under conditions of Energy or Ancillary Service scarcity or that could alleviate transmission constraint violations, except for the Capacity Surplus under Minimum Load Conditions in RT EORM described in section 40.2.21.b. If the Transmission Provider called upon Emergency Demand Response, the SCED-Pricing algorithm will also consider the cost of the Emergency Demand Response scheduled by the Transmission Provider.

If an on-line Resource that is not a Fast Start Resource is committed in the RAC processes by the Transmission Provider, the costs in the objective function for the Resource and the constraints on the Resource's Energy and Ancillary Service Schedules in the SCED-Pricing problem are the same as those for the Resource in the simultaneously co-optimized SCED algorithm described in Schedule 29.

For a Fast Start Resource that was committed in the RAC processes by the Transmission Provider to be on-line in the Dispatch Interval, the SCED-Pricing algorithm considers the cost of committing and dispatching the Resource when setting prices. The SCED-Pricing algorithm considers the Resource eligible to set prices even if the Resource was scheduled to operate at its minimum or maximum limit. It also considers Start-Up Costs and No-Load Costs for the Fast Start Resource when setting prices. To achieve this, the SCED-Pricing algorithm allows fractional commitment of a Fast Start Resource for purposes of setting prices, even though this is not a physically achievable outcome. SCED-Pricing represents the fraction of the Fast Start Resource that is committed in the Dispatch Interval, *t*, for which prices are being calculated by the continuous decision variable on_t. The SCED-Pricing algorithm requires that on_t satisfy

$0 \leq on_t \leq 1$

The SCED-Pricing algorithm allocates a share of the Start-Up Cost for the Fast Start Resource to the interval for which prices are being calculated. In the following N is the minimum run time offered by the Fast Start Resource in hours.

$AllocatedShareStartUpCost_t$ = *StartUpCost / (N × Intervals per Hour) if t is within N hours of the time the Resource was committed, or 0 if t is later than N hours after the Resource was committed.*

The SCED-Pricing algorithm allocates the No-Load Cost for the Dispatch Interval to the Dispatch Interval for which prices are being calculated.

If the Fast-Start Resource was not committed to provide Regulation Reserves, the constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing includes the following. Let $DispatchSchedule_t$ be the dispatch scheduled for the Resource in Dispatch Interval *t* and $SpinningReservesSchedule_t$ be the Spinning Reserve Schedule for the Resource in Dispatch Interval *t* in SCED-Pricing.

$on_t \times EconMin_t \leq EnergyDispatchSchedule_t$

$0 \leq SpinningReservesSchedule_t$

$EnergyDispatchSchedule_t + SpinningReservesSchedule_t \leq on_t \times EconMax_t$

The ramping constraints affecting Energy and Spinning Reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$$on_t \times (AllocatedShareStartUpCost_t + ({}^{NoLoadCost}{}_t / _{(Intervals\ per\ Hour)}))$$

$$+ \left(\int_0^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t\,(x)dx\right) / (Intervals\ per\ Hour)$$

$$+ (SpinningOfferCost_t \times SpinningReservesSchedules_t) / (Intervals\ per\ Hour)$$

If the Fast-Start Resource was committed to provide Regulation Reserves, the constraints for the Energy, Spinning Reserves, and Regulating Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_t$ be the dispatch level for the Resource in Dispatch Interval t, $SpinningReservesSchedule_t$ be the Spinning Reserve Schedule for the Resource in Dispatch Interval t, and $RegulatingReservesSchedule_t$ be the Regulating Reserve Schedule for the Resource in Dispatch Interval t in SCED-Pricing.

$on_t \times RegMin_t \leq EnergyDisptachSchedule_t$

$on_t \times RegMin_t \leq EnergyDispatchSchedule_t - RegulatingReservesSchedule_t$

$0 \leq SpinningReservesSchedule_t$

$0 \leq RegulatingReservesSchedule_t$

$Energy_t + SpinningReservesSchedule_t + RegulatingReservesSchedule_t \leq on_t \times RegMax_t$

The ramping constraints affecting Energy and Reserve schedules from the Fast Start Resource in the SCED-Pricing algorithm are the same as those in the SCED algorithm.

The objective function elements for the Fast Start Resource include:

$$on_t \times (AllocatedShareStartUpCost_t + ({}^{NoLoadCost}{}_{t}/_{(Intervals\ per\ Hour)}))$$

$$+ (\int_0^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t(x)dx) / (Intervals\ per\ Hour)$$

$$+ (SpinningOfferCost_t \times SpinningReservesSchedules_t) / (Intervals\ per\ Hour)$$

$$+ (RegulatingOfferCost_t \times RegulatingReservesSchedules_t) / (Intervals\ per\ Hour)$$

Off-line Fast Start Resources that are available to be committed by the Transmission Provider participate in SCED-Pricing if either or both of the following conditions hold:

a) The SCED algorithm finds a solution that does not meet energy and/or reserve requirements in the hour, except for the Capacity Surplus under Minimum Load Conditions in RT EORM described in section 40.2.21.b;

b) The SCED algorithm finds a solution that violates a transmission constraint and the Transmission
Provider determines that commitment of the Fast Start Resource provides relief to the violation.

In these scenarios, committing and dispatching an off-line Fast Start Resource is an action that the Transmission Provider could take to address the shortage or violation. Rather than set price using a shortage cost or a transmission penalty price, the SCED-Pricing algorithm determines prices based on the action that the Transmission Provider could take to address the problem. The constraints for the Energy and Spinning Reserves scheduled for the Fast Start Resource in SCED-Pricing include the following. Let $DispatchSchedule_t$ be the dispatch scheduled for the Resource in Dispatch Interval t and $OffLineSupplementalReservesSchedule_t$ be the Off Line Supplemental Reserve Schedule for the Resource in Dispatch Interval t in SCED-Pricing.

$$on_t \times EconMin_t \leq EnergyDispatchSchedule_t \leq on_t \times EconMax_t$$

$$0 \leq OffLineSupplementalReservesSchedule_t$$

$$\leq (1 - on_t) \times min\{EconMax_t, MaxOfflineResponseLimit_t\}$$

The objective function elements for the Fast Start Resource includes:

$$on_t \times (AllocatedShareStartUpCost_t + (NoLoadCost_t / (Intervals\ per\ Hour)))$$

$$+ \left(\int_0^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t(x)dx\right) / (Intervals\ per\ Hour)$$

$+ (OffLineSupplementalOfferCost_t \times OffLineSupplementalReservesSchedules_t) / (Intervals\ per\ Hour)$

For an Emergency Demand Response Resource that was scheduled by the Transmission Provider to provide Energy by reduction in Load (or increase in behind the meter generation) in the Dispatch Interval, the SCED-Pricing algorithm will consider the cost of committing the Resource to reduce Energy consumption and the incremental cost of Energy reduction from the Resource when setting prices. To achieve this, the SCED-Pricing algorithm allows the reduction of Energy consumption by the Emergency Demand Response Resource to be adjusted for pricing purposes. SCED-Pricing represents the fraction of the Emergency Demand Response Resource that committed by the SCED-Pricing algorithm in the Dispatch Interval *t*by the continuous decision variable on_t. SCED-Pricing algorithm requires that on_t satisfy

$$0 \leq on_t \leq 1$$

The SCED-Pricing algorithm allocates a share of the Shut-Down Cost for the Emergency Demand Response Resource to the interval for which prices are being calculated. In the following, N is the period of time in Hours for which the Transmission Provider scheduled reduction in Energy consumption from the Emergency Demand Resource, $EconMax_t$ is the maximum reduction in power consumption in Dispatch Interval *t* that can be scheduled from the Emergency Demand Response Resource if called upon to reduce consumption in Dispatch Interval t, and $EconMin_t$ is the minimum reduction in power consumption in Dispatch Interval *t* that can be scheduled from the Emergency Demand Response Resource if called upon to provide reduce consumption in Dispatch Interval t. The allocation of Shut-Down Cost is then given by the following:

$$AllocatedShareShutDownCost_t = ShutDownCost/N \times (Intervals\ per\ Hour)$$

The constraints for the scheduled reduction from the Emergency Demand Response Resource in SCED-Pricing include the following:

$$on_t \times EconMin_t \leq EnergyReduction_t \leq on_t \times EconMax_t$$

The objective function elements for the Emergency Demand Response Resource includes:

$$on_t \; x \; AllocatedShareShutDownCost_t$$

$$+ \left(\int_0^{EnergyDispatchSchedule_t} IncrementalEnergyCost_t\,(x)dx\right) / (Intervals\ per\ Hour)$$

The SCED-Pricing algorithm is the same as the SCED algorithm, with the exceptions for treatment of Fast Start Resources and Emergency Demand Response Resources described above.

Objective Function:

Minimize {Total Dispatch Interval Energy Costs

+ Total Dispatch Interval Commitment Costs for Fast Start Resources

+Total Dispatch Interval Commitment Costs and Energy Reduction Costs for Emergency Demand Response Resources

+ Total Dispatch Interval Regulating Reserve Costs

+ Total Dispatch Interval Spinning Reserve Costs

+ Total Dispatch Interval Supplemental Reserve Costs

- Total Dispatch Interval Market-Wide Operating Reserve Value

- Total Dispatch Interval Market-Wide Regulating Reserve Value

- Total Dispatch Interval Zonal Operating Reserve Value

- Total Dispatch Interval Zonal Regulating Reserve Value}

Where

Total Dispatch Interval Energy Costs

= The sum of the Dispatch Interval Energy costs that would be incurred by all Resources supplying dispatchable Energy, based on their submitted Energy offer curves, if they were to operate according to the schedule produced by SCED-Pricing for the given Dispatch Interval.

Total Dispatch Interval Commitment Costs for Fast Start Resources

= The sum of the Dispatch Interval Start-Up Costs and No-Load Costs that would be incurred by all Fast Start Resources available for commitment by the Transmission

Provider, based on their submitted Start-Up and No-Load Offer Costs, if they were to operate according to the commitment produced by SCED-Pricing for the given Dispatch Interval.

Total Dispatch Interval Commitment Costs and Energy Reduction Costs for Emergency Demand Response Resources

= The sum of the Dispatch Interval Shut-Down Costs and Energy Reduction Costs that would be incurred by Emergency Demand Response Resources, based on their submitted Shut-Down and Incremental Energy Reduction Offer Costs, if they were to operate according to the schedule produced by SCED-Pricing for the given Dispatch Interval.

Total Dispatch Interval Regulating Reserve Costs

= The sum of the Dispatch Interval Regulating Reserve costs, based on the Regulating Reserve offer prices, that would be incurred by all Resources supplying dispatchable Regulating Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Dispatch Interval.

Total Dispatch Interval Spinning Reserve Costs

= The sum of the Dispatch Interval Spinning Reserve costs, based on the Spinning Reserve offer prices, that would be incurred by all Resources supplying dispatchable Spinning Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Dispatch Interval.

Total Dispatch Interval Supplemental Reserve Availability Costs

= The sum of the Dispatch Interval Supplemental Reserve availability costs, based on the Supplemental Reserve offer prices, that would be incurred by all Resources supplying dispatchable Supplemental Reserve if they were to operate according to the schedule produced by SCED-Pricing algorithm for the given Dispatch Interval.

Total Dispatch Interval Market-Wide Operating Reserve Value

= The Dispatch Interval value of the Market-Wide Operating Reserve cleared by SCED-Pricing to the Load Serving Entities and Market Participant with Exports on whose behalf the Transmission Provider is procuring Operating Reserves based on the Market-Wide Operating Reserve Demand Curve.

Total Dispatch Interval Market-Wide Regulating Reserve Value

= The Dispatch Interval value of the Market-Wide Regulating Reserve cleared by SCED-Pricing to the Load Serving Entities on whose behalf the Transmission Provider is procuring Regulating Reserve based on the Market-Wide

Regulating Reserve Demand Curve.

Total Dispatch Interval Zonal Operating Reserve Value

= The Dispatch Interval zonal value of the Operating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities and Market Participants with Exports on whose behalf the Transmission Provider is procuring Operating Reserve based on the Zonal Operating Reserve Demand Curves.

Total Dispatch Interval Zonal Regulating Reserve Value

= The Dispatch Interval zonal value of the Regulating Reserve cleared by SCED-Pricing in each Reserve Zone to the Load Serving Entities on whose behalf the Transmission Provider is procuring Operating Reserve based on the Zonal Regulating Reserve Demand Curves.

Constraints:

Subject to

Global Power Balance Constraint

Market-Wide Operating Reserve Constraint

Market-Wide Regulating and Spinning Reserve Constraint

Market-Wide Regulating Reserve Constraint

Reserve Zone Operating Reserve Constraints

Reserve Zone Regulating and Spinning Reserve Constraints

Reserve Zone Regulating Reserve Constraints

Maximum Stored Energy Resource Regulation Constraints

Market-Wide Non-DRR1 Operating Reserve Constraint

Resource Limit Constraints

Resource Ramping Constraints

Transmission Constraints

Where

The Global Power Balance Constraint ensures that the net Energy injected into the Eastern Interconnection model equals the net Energy withdrawn from the Eastern Interconnection model plus losses.

The Market-Wide Operating Reserve Constraint ensures the supply of Market-Wide Operating Reserve is greater than or equal to the Market-Wide Operating Reserve cleared by SCED-Pricing.

The Market-Wide Regulating and Spinning Reserve Constraint ensures that the supply of Market-Wide Regulating and Spinning Reserve is greater than or equal to the Market-Wide Regulating and Spinning Reserve requirement.

The Market-Wide Regulating Reserve Constraint ensures the supply of Market-Wide Regulating Reserve is greater than or equal to the Market-Wide Regulating Reserve cleared by SCED-Pricing.

The Reserve Zone Operating Reserve Constraints ensure the supply of Operating Reserve within a specific Reserve Zone is greater than or equal to the Operating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Reserve Zone Regulating and Spinning Reserve Constraint ensures that the supply of Regulating and Spinning Reserve within a specific Reserve Zone is greater than or equal to the Zonal Regulating and Spinning Reserve requirement.

The Reserve Zone Regulating Reserve Constraint ensures the supply of Regulating Reserve within a specific Reserve Zone is greater than or equal to the Regulating Reserve cleared by SCED-Pricing within the Reserve Zone.

The Maximum Stored Energy Resource Regulation Constraints ensure that the supply of Regulating Reserve that is cleared by SCED-Pricing on Stored Energy Resources is less than or equal to the Market-Wide Regulating Reserve Requirement

The Market-Wide Non-DDR1 Operating Reserve Constraint ensures the percentage of Market-Wide Operating Reserve that is cleared by SCED-Pricing on Generation Resources, Demand Response Resources – Type II, Stored Energy Resources, and/or External Asynchronous Resources complies with Applicable Reliability Standards.

The Resource Limit Constraints ensure that each Resource has the Capacity, based on submitted limits, to simultaneously supply cleared Energy, deploy one hundred percent (100%) of cleared Regulating Reserve in the upward direction, deploy one hundred percent (100%) of cleared Spinning Reserve and deploy one hundred percent (100%) of cleared Supplemental Reserve. In addition, the Resource Limit Constraints ensure that each Resource has the ability to simultaneously supply cleared Energy and deploy one hundred percent (100%) of the cleared Regulating Reserve in the downward direction with no Spinning Reserve or Supplemental Reserve deployment. For Fast Start Resources, the upper limits and lower limits on capacity available to provide energy and reserves are adjusted by the partial commitment level for the Resource determined by SCED-Pricing. For Emergency Demand Resources, the upper and lower limits on energy reduction are adjusted by the partial commitment level for the Resource as determined by SCED-Pricing.

The Resource Ramping Constraints ensure that each Resource is cleared in a manner to follow load based on cleared Energy levels in adjacent Dispatch Intervals and deploy Regulating Reserve and Contingency Reserve in a manner that will comply with Applicable Reliability Standards.

The Transmission Constraints ensure that Energy is cleared by SCED-Pricing on Resources and Loads in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility. In addition, beginning November 1, 2011, the Transmission Constraints shall also ensure that Operating Reserves can be deployed in such a way as to prevent flows on transmission flowgates and branches from exceeding normal operating limits under basecase conditions or Emergency operating limits under a first contingency loss of a Resource or transmission facility.

Under Capacity Shortage Conditions in the Real-Time EORM described in section 40.2.20.b, Emergency Maximum Limits are used in SCED-Pricing for Resources available to be dispatched up to Emergency Maximum Limits in SCED. Under Capacity Surplus Condition under Minimum Load Conditions in RT EORM described in section 40.2.21.b, Emergency Minimum Limits are used in SCED-Pricing for Resources available to be dispatched down to Emergency Minimum Limits in SCED. In addition, during a Capacity Surplus Condition , the commitment variable for all Fast Start Resource that were physically committed by the Transmission Provider are held at the value 1 in SCED-Pricing.

SCHEDULE 30 Emergency Demand Response Initiative Version: 1.0.0 Effective: 12/31/9998

SCHEDULE 30

EMERGENCY DEMAND RESPONSE INITIATIVE

I. GENERAL

Schedule 30 provides for the commitment and dispatch of interruptible demand, behind-the-meter generation and other demand resources that are capable of helping meet the energy balance during NERC Energy Emergency Alert 2 (“EEA2”) or Alert 3 (“EEA3”) events. Schedule 30 provides procedures for the Transmission Provider to be able to dispatch such resources (“Emergency Demand Response” or “EDR”) only during EEA2 or EEA3 events. Such procedures provide for reductions in Load and/or increased behind-the-meter generation (*i.e.*, “demand reduction”) to be compensated under the conditions specified below (*i.e.*, “EDR Initiative”). Schedule 30 does not pertain to demand reductions during non-EEA2 or EEA3 events. These EDR procedures: (i) enhance the Transmission Provider’s ability to utilize demand response during EEA2 or EEA3 events; (ii) enable the Transmission Provider to establish curtailment priorities; (iii) reflect varying costs of EDR options; and (iv) allow the Transmission Provider to evaluate and dispatch EDR Offers in merit order by location and by priority status.

II. EMERGENCY DEMAND RESPONSE PARTICIPATION

A Market Participant within the Transmission Provider Region may become an EDR Participant by complying with these Schedule 30 requirements if it: (i) has the ability to cause a reduction in demand in response to receiving an EDR Dispatch Instruction from the Transmission Provider either because the Market Participant is the operator of a facility capable of reducing demand, or the Market Participant is a Load Serving Entity (“LSE”) or ARC with a contract that entitles the Market Participant to reduce Load at such facility; or (ii) has the ability to cause an increase in output from a Behind the Meter generation resource to enable a net demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission

Provider. Only a Market Participant is allowed to register to become an EDR Participant on behalf of an asset owner and be an eligible EDR Participant by submitting EDR Offers to the Transmission Provider to reduce demand during an EEA2 or EEA3 event.

Prior to participating in the EDR Initiative, a Market Participant must complete the EDR registration form posted on the Transmission Provider's website and submit it to the Transmission Provider. An EDR Participant and its associated load asset or Behind the Meter Generation asset must be defined in the EDR registration form.

The Transmission Provider shall notify the Market Participant when it has met all required qualifications to become an eligible EDR Participant and that the Market Participant is eligible to submit EDR Offers.

EDR Participants must be able to receive an EDR Dispatch Instruction from the Transmission Provider via XML. EDR Participants must utilize metering equipment that meets the requirements, including, but not limited to, the ability to provide integrated hourly kWh values on a Commercial Price Node ("CPNode") basis. EDR Participants may provide hourly kWh values for non-interval metered demand reductions (*e.g.*, direct Load control) using the alternative Measurements and Verification Procedures provided in Sections 6 through 8 of this Schedule 30. Measurement of demand reductions shall be made on an aggregated applicable CPNode basis to enable the EDR Participant's demand reduction to be identified with an LMP; EDR Offers can set the Real-Time Ex Post LMP.

An EDR Participant that intends to use a Behind the Meter Generation Resource for the purpose of reducing demand during an EEA2 or EEA3 event shall confirm to the Transmission Provider in writing that: (1) it holds all necessary permits (including, but not limited to, environmental permits) applicable to the operation of the Generation Resource; (2) it possesses rights to operate the Generation Resource that are equivalent to ownership of such unit; and (3) the Generation Resource is not a designated Network Resource. Unless notified otherwise, the Transmission Provider shall deem such representation applies each time the Generation Resource is used to reduce demand during an EEA2 or EEA3 event and that the generation resource is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits. The EDR Participant shall be solely liable for identification of and compliance with all such applicable permits.

If the Generation Resource designated by an EDR Participant historically is operated during non-Emergency conditions, the Energy that can be offered under the EDR Initiative is the increase in output from a Behind the Meter generation resource to enable a net Demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Determination of such output shall be based on the EDR Offer and the amount of load reduction provided, which is more fully described in the Business Practices Manuals. If a Demand reduction is subject to a contractual agreement with an LSE, then the operator of the facility will be entitled to submit an EDR Offer for the specified Demand reduction to the Transmission Provider only if, and to the extent that, an EDR Offer is consistent with the terms and conditions of the contract with such LSE and the operator of the facility is a Market Participant.

EDR Participants shall be required to identify if the Demand reduction can be variable or alternatively provide a specific level of Demand reduction. Upon receipt of an EDR Dispatch Instruction, an EDR Participant shall either: 1) curtail to the firm service level specified in their EDR Offer; or 2) provide a specific level of Demand reduction as specified in their EDR Offer. EDR Participants electing the first option shall be required to identify an expected peak Load in their EDR Offer.

An EDR Participant shall verify in writing to the Transmission Provider that it has received any required approvals from all applicable state regulatory agencies to enable the entity to participate in the EDR Initiative.

EDR Participants are responsible for maintaining Demand reduction information, including the amount in MWh of reduced Demand during EEA2 or EEA3 events whenever the EDR Participant responds to an EDR Dispatch Instruction from the Transmission Provider. The EDR Participant shall provide this information to the Transmission Provider in accordance with the procedures specified in the appropriate Business Practices Manuals.

III. EDR OFFER

An EDR Participant seeking to reduce Demand during an EEA2 or EEA3 event and receive compensation under this Schedule 30 must submit an EDR Offer to reduce Load to the Transmission Provider no later than 1100 EST on the day prior to the next Operating Day and will be in effect for the next Operating Day. If an EDR Participant is unable to reduce Demand in accordance with an EDR Offer due to exigent circumstances, then the EDR Participant shall promptly notify the Transmission Provider in accordance with the procedures in the Business Practices Manuals. Such notification must be made prior to the issuance of EDR Dispatch Instructions.

The EDR Offer shall specify: (i) the minimum and maximum amount of the offered Demand reduction (in minimum increments of 0.1 MWh) or; specify the firm service level to which the EDR Participant will curtail Demand and specify the EDR Participant's peak Load; (ii) the applicable minimum and maximum number of contiguous Hours for which the Demand reduction must be committed for such curtailments; (iii) shutdown costs associated with a demand reduction, including direct labor and equipment costs and/or opportunity costs; (iv) the number of Hours of advance notice from the Transmission Provider that the EDR Participant requires to reduce Demand; (v) the daily availability of the Demand reduction; (vi) an hourly curtailment offer for such Demand reduction specified in dollars per MWh, not to exceed $3,500/MWh.

The hourly curtailment Offer is a single dollar per MWh value that is applicable to every Hour of the day. Any EDR Offer shall remain valid until it is modified or revoked by the EDR Participant. EDR Offers must be made for a minimum period of one (1) Operating Day and may not be modified after 1100 EST on the day prior to the next Operating Day. EDR Offers must be consistent with any applicable contractual agreements with an LSE.

At the time of EDR registration, an EDR Participant shall provide complete details regarding any limitations on the EDR Participant's ability to reduce Demand, including, but not limited to: (i) information regarding the total number of times that the EDR Participant is able to reduce Demand during the year; (ii) the number of times that the EDR Participant has already reduced Demand during the current year; and (iii) any and all restrictions (including, but not limited to, contractual restrictions) that may preclude the EDR Participant from reducing Demand in the future. These limitations provided at the time of registration but not included in the EDR Offer will have no impact on the Transmission Provider's decision to commit the EDR. It is the responsibility of the EDR Participant to ensure the limitations that exist outside of the parameters outlined in the EDR Offer are not violated.

IV. ISSUANCE OF EMERGENCY DEMAND RESPONSE DISPATCH INSTRUCTIONS

The Transmission Provider may issue EDR Dispatch Instructions to EDR Participants, in accordance with the Business Practices Manuals, based upon factors, including, but not limited to, consideration of: (i) terms and conditions of the EDR Offer; (ii) anticipated need for Demand reduction during the EEA2 or EEA3 event; (iii) availability of other EDR Demand reductions; (iv) the location of the Demand reduction; and (v) anticipated future Emergency conditions. EDR Dispatch Instructions shall detail: (i) the commencement of such Demand reductions; (ii) the amount of Demand reduction that the EDR Participant shall reduce, including a schedule for modified Demand reductions, if appropriate; and (iii) the duration for such Demand reductions. The Transmission Provider may also issue updates to EDR Dispatch Instructions if changing system conditions warrant such action. Any updates to EDR Dispatch Instructions will be consistent with the EDR Offer. The Transmission Provider's Emergency operating procedures documentation shall provide further detailed information on EDR Dispatch Instructions during EEA2 or EEA3 events.

EDR Participants shall be entitled to receive compensation for reducing Demand only to the extent that the EDR Participants comply with the Transmission Provider's EDR Dispatch Instructions. EDR Participants shall not be entitled to compensation for Demand reductions in excess of the EDR Dispatch Instruction amounts (*i.e.*, if Demand was reduced by more than that requested by the Transmission Provider in an EDR Dispatch Instruction), provided that EDR Participants shall be entitled to proportionate compensation if they reduced Demand by a fraction of the EDR Dispatch Instruction. If an EDR Participant reduces Demand by more than the EDR Dispatch Instruction during an EEA2 or EEA3 event, the EDR Participant will not be allocated Real-Time Revenue Sufficiency Guarantee Charges for deviations in Load, pursuant to Section 40.3.3.a.iv. To the extent that an EDR Demand reduction would have occurred during the EDR

Dispatch Instruction time period absent the Transmission Provider issuing an EDR Dispatch Instruction to the EDR Participant, then the EDR Participant will not be entitled to compensation for such Demand reduction.

V. COMPENSATION

EDR Participants that reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider shall receive the higher of the applicable Hourly Real-Time Ex Post LMP revenue for the associated CPNode of the EDR Participant or the EDR Production Costs during the period of actual Demand reductions. For EDR Participants that are ARCs, the provisions of Section 38.6, part 2(a), (b), or (c) will apply, for purpose of billing and settlement with adjustment for the applicable MFRR. EDR Production Costs are the sum of (i) the shutdown cost and (ii) the lesser of (a) the amount of hourly verifiable Demand reduction or (b) the hourly Dispatch Instruction for each hour multiplied by the EDR Offer during the period of actual Demand reductions.

EDR Participants must submit documentation of Demand reductions made in response to EDR Dispatch Instructions to enable the EDR Participant to verify in writing under oath to the Transmission Provider that the Demand reductions actually occurred during an EEA2 or EEA3 event. EDR Participants must verify in writing to the Transmission Provider that the amount of Demand reductions were made in direct response to the Transmission Provider's EDR Dispatch Instruction and that the Demand reductions otherwise would not have been made.

EDR Participants that receive EDR Dispatch Instructions in response to submitted EDR Offers but do not reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider to the levels specified in the EDR Dispatch Instruction, and adjusted for the Demand Reduction Tolerance, shall not be guaranteed cost recovery for such failure to make

Demand reductions. The Demand Reduction Tolerance is equal to (i) the EDR Dispatch Instruction MWhs multiplied by ninety-five percent (95%). EDR Participants that reduce Demand in response to an EDR Dispatch Instruction between the levels specified in the EDR Dispatch Instruction and the Demand Reduction Tolerance will be guaranteed cost recovery for provision of Demand reductions. In addition, such EDR Participants failing to reduce Demand shall be charged an amount equal to the Demand Reduction Shortfall multiplied by the Hourly Real-Time Ex Post LMP of the host load zone. The Demand Reduction Shortfall is calculated as: (i) the Demand Reduction Tolerance minus the actual Demand reduction; or (ii) zero (0), whichever is greater.

Any reductions in Demand by an EDR Participant shall be subject to verification and potential investigation by the Transmission Provider and the Federal Energy Regulatory Commission to confirm the validity of all EDR Participant assertions.

VI. PAYMENTS

The sum of the EDR Initiative payments made in an Hour in excess of market revenues shall be funded through an assessment of debits on Market Participants on a *pro rata* basis, based on the metered Load Ratio Share in the local Balancing Authority Area(s) where the EEA2 or EEA3 events occurred that served Load during the EDR Dispatch Instruction period in that same Hour. For the purposes of this calculation, the Load Ratio Share shall be the factor calculated as the withdrawal reported at a given CPNode divided by the sum of all the withdrawals at all CPNodes in the local Balancing Authority Area(s) where the EEA2 or EEA3 conditions occurred that served Load during the EDR Dispatch Instruction period. Any credits that result from EDR Participant(s) failure to reduce Demand as described in Section V shall be allocated in the same *pro rata* basis as costs are allocated in Section VI.

VII. METER DATA

Unless an alternate approach is agreed upon by the Transmission Provider and an EDR Participant and such alternate approach is documented in the Business Practices Manuals, measurement and verification for hourly interval metered EDR Participants will be based upon actual hourly usage in the Hour immediately preceding notification to the EDR Participant of the EDR Dispatch Instruction by the Transmission Provider. If EEA2 or EEA3 events occur during sequential days, the relevant data will be based upon the actual hourly usage prior to the first of the sequential EEA2 or EEA3 event days.

Except as may otherwise be agreed to, EDR Participants must provide the Transmission Provider with meter information for the Hour prior to notification of the EDR Dispatch Instruction, as well as every Hour during the Demand reduction, except under the following circumstances. When on-site generation is deployed exclusively to support the Demand reduction, the EDR Participant may provide qualified meter data from the on-site generation for each Hour of the EEA2 or EEA3 event day. Provision of hourly meter data from the on-site generation will be deemed a certification by the EDR Participant that the on-site generation was not used for any purpose other than to support the Demand reduction during the EEA2 or EEA3 event day.

VIII. MEASUREMENT AND VERIFICATION PROCEDURES

An EDR Participant that achieves Demand reduction through the use of direct load control procedures must provide the Transmission Provider with proposed Measurement and Verification Procedures. Proposed Measurement and Verification Procedures must include: (1) a description of the direct Load control system, including communication technology, type of Load(s) which are controlled, proposed control scheme (*e.g.* cycling or complete Load shed), number of participants, geographic location of participants and other relevant information; (2) a description of Load research data that is used in the analysis; (3) a description of the formulae used to produce the estimate, including all assumptions; and (4) a description of all source information for variables used in the analysis, such as a schedule of Demand reductions according to the time of day and weather conditions (*e.g*., temperature and humidity index). The Transmission Provider may request additional information from such EDR Participant and/or request appropriate revisions to the proposed Measurement and Verification Procedures.

For all Demand reductions that are not metered directly by the Transmission Provider, EDR Participants must forward the meter data and/or the results of the direct Load control Measurement and Verification Procedures, as specified in the Business Practices Manuals, to the Transmission Provider within fifty-three (53) calendar days after the Demand reduction, in order to be eligible to receive compensation.

ATTACHMENT AA Compensation and Cost Recovery for Actions During Emergency Version: 1.0.0 Effective: 12/31/9998

ATTACHMENT AA

COMPENSATION AND COST RECOVERY

FOR ACTIONS DURING EMERGENCY CONDITION

A. GENERAL

Pursuant to Sections 3.4 and 3.6 of the Operating Protocol for Existing Generators, Article 7 of the IOA, Article 13 of the LGIA, and pursuant to Article III, Section I and Appendix E of the ISO Agreement, the Transmission Provider has the authority to direct Generation Resources to provide any of the following services during an Emergency or Emergency System Conditions including: (1) shut down, start up, and increase or decrease real or reactive power output of the Generation Resource; (2) implement a reduction or disconnection pursuant to Articles 7.7 and 7.8 of the IOA and Article 13.5.2 of the LGIA; (3) assist with black start (if available) or restoration efforts; and/or (4) defer a scheduled outage. In addition, during an Emergency or Emergency System Condition, the Transmission Provider has the authority to address shortage conditions in the Real-Time Energy Markets and during a Maximum Generation Emergency under Sections 40.2.15, 40.2.17, and 48 of the Tariff, as may be further set forth in the Business Practices Manuals.

B. COMPENSATION FOR EMERGENCY CONDITION SERVICES

If the Transmission Provider requests or directs the Generation Resource, either directly or through a Local Balancing Authority, to provide such services during an Emergency or Emergency System Conditions, the Market Participant owning the Generation Resource shall be compensated in accordance with the provisions of Sections 40.2.15, 40.2.17 or 48 of this Tariff.

Where a Generation Resource has cleared the Day-Ahead Energy Market, is directed by the Transmission Provider to reduce production below the Day-Ahead cleared level, and is required to settle the associated negative Day-Ahead imbalance at a higher Hourly Real-Time Ex Post LMP, the Generation Resource shall be reimbursed for such cost based on the difference in Real-Time output from that cleared Day-Ahead multiplied by the difference between Hourly Real-Time Ex Post LMP and Day-Ahead Ex Post LMP. Costs associated with such reimbursements will be allocated to all Load on a Load Ratio Share basis.

C. EMERGENCY REDISPATCH COST RECOVERY

The Transmission Provider reserves the right to assign all costs of Emergency or Emergency System Conditions to an individual Transmission Customer(s), or a Market Participant(s) owning a Resource(s) where circumstances conclusively demonstrate that the actions or inactions of one or more such Transmission Customer(s) or Market Participant(s), which were in violation of a Transmission Provider directive and Good Utility Practices, proximately caused the Emergency or Emergency System Conditions to arise, provided that, prior to any such direct assignment of costs, the Transmission Provider must receive approval from the Commission pursuant to a filing under Section 205 of the Federal Power Act. To the extent that any costs are directly assigned hereunder, the cost allocation set forth in Section 40.2.17(e) would not then apply

D. BILLING

The Transmission Provider shall submit invoices to the Market Participant or Transmission Customer for the charges incurred under this Attachment AA pursuant to Section 7.6 of this Tariff.

E. INFORMATION

1. Information in Support of Emergency Condition Services

Generation Resource will provide the Transmission Provider with information sufficient to permit the Transmission Provider to verify Generation Resource's invoice for service under this Attachment AA. Unless otherwise mutually agreed, Generation Resource will provide such information within 15 days of Generation Resource's provision of Emergency Condition Services. Upon written request of Generation Resource, the Transmission Provider will provide Generation Resource with information sufficient to permit Generation Resource to verify that the Transmission Provider's request for services under this Attachment AA was consistent with the purposes for which such services may be requested, as set forth herein. Unless otherwise mutually agreed, such information will be provided within 15 days by the Transmission Provider.

2. Verification of Emergency Condition

Upon written request of Generation Resource, the Transmission Provider will provide within 15 days of such written request, all documentation supporting the existence of an Emergency Condition. Disputes about the existence of an Emergency Condition shall be submitted for resolution in accordance with the dispute resolution procedures of the Tariff. If the Transmission Provider orders the provision of Emergency Condition Services through a Balancing Authority, the Transmission Provider will direct the Balancing Authority to advise the Generation Resource that the redispatch is at the direction of the Transmission Provider and shall provide confirmation of such direction within seventy-two (72) hours of issuance of the redispatch order.

3. Confidential Information

Generation Resource will indicate and mark any such Confidential Information that is provided to the Transmission Provider that is not publicly available or of a proprietary nature. The Transmission Provider will keep such information confidential in accordance with the Standards of Conduct, Appendix A of the ISO Agreement, on file with the Commission, and the relevant provisions of the Tariff.

ATTACHMENT DD Day-Ahead Locational Marginal Prices Version: 1.0.0 Effective: 12/31/9998

ATTACHMENT DD

Day-Ahead Locational Marginal Prices

The following procedures apply to both Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs.

The Transmission Provider calculates the price of Energy at the Load buses and Resource buses in the Transmission Provider's Market Footprint and at the External Interfaces between the

Transmission Provider's Market Footprint and adjacent BAs on the basis of LMPs. LMPs can be set by Offers to sell or Bids to purchase Energy, including Physical Bilateral Transactions. The Transmission Provider establishes Hubs and Load Zones based on a pre-defined set of buses. The LMPs, Hub prices, External Interface prices, and Load Zone prices include separate components for the marginal costs of energy, congestion, and losses. Day-Ahead Market LMPs are calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Energy Market at 1600 hours EST, or such later time as may be required from time to time due to unanticipated events.

A. LMP Components

In each hour of the Day-Ahead Energy Market, the Transmission Provider calculates the LMP for each CPNode, which is equal to the marginal cost of Energy available at the CPNode in the hour, based on the Offers of sellers and Bids of buyers selected in the Day-Ahead Energy Market. The Transmission Provider designates a Reference Bus, *r*, for all other buses in the power system. The Marginal Energy Component (MEC_r) is the marginal cost of energy available to the Reference Bus, based on Offers and Bids selected in the Day-Ahead Energy Market. For each bus other than the Reference Bus, the Transmission Provider determines separate components of the LMP for the marginal costs of energy, congestion, and losses relative to the Reference Bus, consistent with the following equation:

$$LMP_i = MEC_r + MCC_i + MLC_i$$

$$LMP_r = MEC_r$$

where:

- MEC_r is the LMP component representing the marginal cost of Energy (also referred to as λ) at the Reference Bus, *r*.

- MCC_i is the LMP component representing the marginal cost of congestion (also referred to as ρ) at bus *i* relative to the Reference Bus.

- MLC_i is the LMP component representing the marginal cost of losses (also referred to as γ) at bus *i* relative to the Reference Bus.

B. Marginal Congestion Component Calculation

The Transmission Provider calculates the marginal costs of congestion at each bus as a component of the bus-level LMP. The Marginal Congestion Component (MCC_i) of the LMP at bus *i* is calculated using the equation:

$$MCC_i = -\left(\sum_{k=1}^{k} GSF_{ik} * FSP_k\right)$$

where:

- K is the number of thermal or interface transmission constraints (also called Flowgate).

- GSF_{ik} is the Generation Shift Factor for the generator at bus i on Flowgate k which limits flows across that constraint when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The industry convention is to ignore the effect of losses in the determination of GSFs.

- FSP_k is the Flowgate Shadow Price on Flowgate k and is equivalent to the reduction in system cost expressed in $/MWh that results from an increase of 1MW of the capacity on Flowgate k.

C. Marginal Losses Component Calculation

The Transmission Provider calculates the Marginal Losses Component (MLCi) at each bus i. The MLC of the LMP at any bus i within the Transmission Provider's Market Footprint is calculated using the equation:

$$MLC_i = (DF_i - 1) * MEC_r$$

where:

- DF_i is the Delivery Factor for bus i to the system Reference Bus.

- DF_i is equal to $(1 - \partial L/\partial G_i)$, where: L is system losses, G_i is "generation injection" at bus *i*, $\partial L/\partial G_i$ is the partial derivative of system losses with respect to generation injection at bus *i*, that is, the incremental change in system losses associated with an incremental change in the generation injections at bus *i* holding constant other injection and withdrawals at all buses other than the Reference Bus and bus *i*.

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

D. Hub Price Calculation

The Transmission Provider calculates a hub price based on the LMPs for a set of buses that comprise the hub. These hub prices are the weighted average of the LMPs at the buses that comprise the hub. The weights are pre-determined by the Transmission Provider and remain fixed.

The price for Hub *j* is:

$$\text{Hub Price}_j = \sum_{i=1}^{NH} (W_{Hi} * LMP_i)$$

where:

- NH is the number of buses in Hub j.

- W_{Hi} is the weighting factor for bus i in Hub j. The sum of the weighting factors must add up to 1.

E. Load Zone Price Calculation

The Transmission Provider calculates a Load Zone price based on the LMPs for a set of buses that comprise the Load Zone. These Load Zone prices are the weighted average of the LMPs at the set of buses that comprise the Load Zone. The Load Zone bus weight is equal to the fractional share of each Load bus in the total Load in the Load Zone in the hour.

The price for Load Zone j is:

$$\text{Load Zone Price}_j = \sum_{i=1}^{NZ} (W_{Zi} * \text{LMP}_i)$$

where:

- NZ is the number of Load buses in Load Zone j.

- W_{Zi} is the load-weighting factor for bus i in Load Zone j. The sum of the weighting factors must add up to 1. These weights are based on State Estimator results from the 24-hour period, seven days prior to the Operating Day.

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

- Each Load Zone includes only the buses of Asset Owners who are in the zone and who have Load that is represented by that zone's definition. Asset Owners that have metered Load must either be settled at a zone defined by their Load points (zonal settlement) or must have a separate Load Zone created for each Load point (nodal settlement). Asset owners in retail choice areas where profiling, rather than metering is used, can be settled at an aggregate of all Load buses in the BA area.

- MPs who want to be billed at a zonal price must include in their zone all of the buses where energy deliveries are billed at the zonal price.

- **Multi-Element Flowgate Shadow Price Calculation**

The Transmission Provider, in addition to the calculation of the LMPs, calculates Flowgate Shadow Prices (FSPs) on sets of transmission constraints. The Transmission Provider calculates the FSP on the set of transmission elements designated as a Flowgate, based on a weighted average of the transmission FSPs that comprise the Flowgate:

$$\text{Flowgate Shadow Price}\, f = \sum_{k=1}^{M} (W_k * FSP_k)$$

where:

f is the index of Flowgates.

- *k* is a transmission element in the Flowgate *f*.

- *M* is the set of the transmission elements that comprise Flowgate *f*.

- W_k is the weights attached to each of the *M* transmission elements that comprise Flowgate *f*. The sum of the weighting factors adds up to 1. For Flowgates comprised of one transmission element, the W_k for that element is equal to 1. The Transmission Provider determines the W_k for transmission elements defined as Flowgates.

- FSP_k is the Flowgate Shadow Price on transmission element *k* and is equivalent to the reduction in system cost expressed in $/MWh that results from an increase of 1MW of the capacity on transmission element *k*.

F. External Interface Price Calculation

The Transmission Provider calculates an External Interface price for all non-Transmission Provider Balancing Authorities. These prices are based on the LMPs for a set of generator buses that exist in external Balancing Authorities. Generally speaking, the set of buses used for an External Interface price is the set of generators in the external Balancing Authority for which the calculation is being done. If the external Balancing Authority is not in the Transmission Provider Network model, then an electrically equivalent Balancing Authority will be assigned for the Balancing Authority and the interface price for that non-modeled Balancing Authority will use the same interface price as is used for the electrical equivalent. The Transmission Provider may need to change, which EPNodes are used in the External Interface price calculations as operational experience dictates.

The price for an External Interface *j* is:

$$\text{External Interface Price} = \left[\sum_{j=1}^{NE} \text{LMP}_i \right] / \textit{NE average of LMPs}$$

where:

- *NE* is the number of buses in External Interface *j*

ATTACHMENT RR Real-Time Reserve Service Available to Balancing Authorities Version: 1.0.0 Effective: 12/31/9998

ATTACHMENT RR

Real-Time Reserve Services Available to Balancing Authorities During Phased Integration

A. <u>Availability</u>

If a Transmission Owner has signed the Transmission Owners Agreement, but will not integrate its transmission facilities with the Transmission System until a later date, a Balancing Authority whose loads and resources are connected to the Transmission Owner's facilities will be eligible to obtain Spinning Reserve Service and Supplemental Reserve Service from the Energy and Operating Reserves Market during the phased integration on the following terms and conditions. The Transmission Provider will assume responsibility for the valid single contingencies of the eligible Balancing Authority, and the Transmission Provider will set its Contingency Reserve Requirement to comply with NERC Standard, inclusive of these contingencies.

B. Eligibility

To be eligible to obtain Spinning Reserve Service and Supplemental Reserve Service under this Attachment RR:

1. The Transmission Owner that provides transmission service for the loads and resources of the Balancing Authority must have executed the signature page of the Transmission Owners Agreement, and the application for membership must have been accepted by the Transmission Provider's Board of Directors.

2. The Transmission Owner has committed in writing to integrate its transmission facilities into the Transmission System not later than nine (9) months from the date that Real-Time Reserve Service first begins pursuant to an executed service agreement as shown in Attachment RR-1.

3. The Balancing Authority has executed the Balancing Authority Agreement and will become, upon final integration, a Local Balancing Authority as defined in that agreement.

4. The Balancing Authority or the Transmission Owner has executed a service agreement as shown in Attachment KK-1 to obtain Reliability Coordination Service from the Transmission Provider during the phased integration period; provided however, that the effective date of the Service Agreement may be extended by mutual agreement as necessary to accommodate the installation of communication systems and the completion of necessary training.

5. The Balancing Authority is a registered Market Participant, or is represented by an agent that is a registered Market Participant.

6. The Balancing Authority requesting service under this Attachment RR will not be a member of a contingency reserves sharing group during the phased integration period.

7. The Balancing Authority has executed a service agreement as shown in Attachment RR-1 to obtain Reserve Services from the Transmission Provider during the phased integration period.

C. Rate for Spinning Reserve Service and Supplemental Reserve Service

1. Notwithstanding any other provision of the Transmission Provider's Tariff, a Balancing Authority eligible for service under this Attachment RR will pay for obtained Spinning Reserve Service at the rate set forth in Schedule 5 of the Tariff, as set forth in Section C.3 of this Attachment RR.

2. Notwithstanding any other provision of the Transmission Provider's Tariff, a Balancing Authority eligible for service under this Attachment RR will pay for

obtained Supplemental Reserve Service at the rate set forth in Schedule 6 of the Tariff as set forth in Section C.3 of this Attachment RR.

3. For the sole purposes of calculating the charges to be paid under Schedule 5 and Schedule 6 of the Tariff, the hourly load of the eligible Balancing Authority shall be reported to the Transmission Provider. The eligible Balancing Authority and the Transmission Provider shall mutually agree upon a representative Reserve Zone to be designated in the applicable service agreement as shown in Attachment RR-1 for the purpose of determining the Regulation and Spinning Reserves Distribution Rate used to calculate charges under this Section C.3.

4. The rate to be charged for energy delivered to the eligible Balancing Authority pursuant to this Attachment RR shall be the Hourly Real-Time Ex Post LMP at the point of delivery to the eligible Balancing Authority, all applicable charges under the Tariff, including Revenue Sufficiency Guarantee charges, and charges pursuant to Schedules 1, 2, 10, and 17.

5. The terms and conditions of the Energy and Operating Reserves Market Tariff, including the settlement and payment terms of the Tariff, apply to all transactions under this Attachment RR.

D. <u>Procedure to Supply Reserve Services</u>

During the phased integration, the Transmission Provider will meet its Balancing Authority obligations to supply reserves by using its Energy and Operating Reserves Market. The Transmission Provider will assume responsibility for the valid NERC criteria single contingencies of the eligible Balancing Authority, and the Transmission Provider will set its Contingency Reserve Requirement to comply with NERC Standard, inclusive of these contingencies. The eligible Balancing Authority will not be obligated to supply reserves to the Transmission Provider. The following procedures shall be used by the eligible Balancing Authority to obtain Reserves pursuant to this Attachment RR.

1. When reserves are required by the eligible Balancing Authority to maintain compliance with applicable reliability standards, the eligible Balancing Authority will enter a zero-minute ramp schedule between the Transmission Provider and the eligible Balancing Authority that will be implemented immediately by the Transmission Provider.

2. The resulting emergency energy flow to serve the eligible Balancing Authority's load will be used by the eligible Balancing Authority to offset the Real Time demand on its generation resources, in response to Disturbances, and in a fashion consistent with BAL-002-0. The eligible Balancing Authority will satisfy its requirements to carry Contingency Reserves, and comply with the NERC Disturbance Control standard by having access to the Contingency Reserves of the Transmission Provider.

2.1 When the eligible Balancing Authority requests Contingency Reserves assistance from the Transmission Provider, compliance to the NERC Disturbance Control standard BAL-002-0 shall be calculated using the combined ACE of the eligible Balancing Authority and the Midwest ISO

Balancing Authority and DCS Compliance shall be reported against the Transmission Provider Reportable Disturbance level.

2.2 If the Transmission Provider is contractually obligated to share reserves, the Midwest ISO Balancing Authority ACE for purposes of compliance to NERC Disturbance Control standard BAL-002-0 under that agreement shall be calculated as the sum of the Midwest ISO Balancing Authority ACE plus the ACE of each eligible Balancing Authority under this Attachment RR involved in a coincident contingency reserve event.

2.3 If the eligible Balancing Authority does not request Contingency Reserve activation from the Transmission Provider, the eligible Balancing Authority shall report NERC Disturbance Control Compliance as a stand alone Balancing Authority against its own DCS Compliance reporting threshold.

2.4 Combined ACE shall be calculated by aligning frequency deviation of time stamped ACE and frequency deviation data from all participating parties to ensure accuracy of aligned ACE data.

3. The Transmission Service Reservation for this transfer will indicate a “Normal” Point-to-Point export transaction from the Transmission Provider as “Source” to the eligible Balancing Authority as “Sink”.

4. The eligible Balancing Authority, as the Receiving Balancing Authority, shall ensure that a request for an Arranged Interchange is submitted by creating an

Electronic Tag (e-Tag) designating the Transmission Provider, (the Delivery Balancing Authority) as “Source” with a start time no more than 60 minutes beyond the resource loss or initiation of the event. The following requirements will apply to the e-Tag:

4.1 Transaction type of “Normal”.

4.2 Transmission allocation designation of “Non-Firm” or NN-6 for every listed transmission provider.

4.3 Transmission Reservations shall be done after the fact for point to point deliveries from the Transmission Provider.

4.4 Receiving Balancing Authority, the Scheduler, and any intermediate transmission providers shall approve the e-Tag.

4.5 The appropriate Transmission Provider Control Center staff shall communicate and coordinate necessary operations with the Transmission Provider’s Local Balancing Authorities and any affected Balancing Authorities.

4.6 This process will be performed for every event, regardless of duration.

E. <u>Termination</u>

The availability of Reserve Services pursuant to this Attachment RR terminates automatically upon the earliest of:

1. Full integration of the Transmission Owner's facilities into the Transmission System, and the integration of the eligible Balancing Authority into the Midwest ISO Balancing Authority;

2. The failure by the Transmission Owner to achieve final integration on the date established in the phased integration plan approved by FERC;

3. Receipt by the Transmission Provider of written notice, provided by the Transmission Owner prior to the final integration date approved by FERC, that the Transmission Owner intends to withdraw from the Midwest ISO; or

4. A determination by the Transmission Provider that the Balancing Authority has initiated a transaction under this Attachment RR for a purpose other than the ability to meet its reserves obligations as set forth in the applicable NERC and regional reliability standards.

ATTACHMENT RR-1

Form of Service Agreement for Real-Time Reserve Services During Phased Integration

1.0 This Service Agreement, dated as of the ___day of _________, _____ is entered into, by and between the Midwest ISO ("Transmission Provider") and ____________________________________ ("Reserve Services Customer"), (also hereafter referred to as Party or Parties as the context requires).

2.0 The Reserve Services Customer has been determined by the Transmission Provider to be eligible for Reserve Services as set forth in Attachment RR of the Tariff, and the Transmission Provider agrees to provide service upon the request of an authorized representative of the Reserve Services Customer.

3.0 The Reserve Services Customer: (i) agrees to supply information as set forth in Attachment RR of this Tariff , and such other information, data, and specifications reasonably necessary, in accordance with Good Utility Practice, to permit the Transmission Provider to provide the requested service; (ii) agrees to perform the obligations required of Reserve Services Customers set forth in the Tariff; and, (iii) agrees to take and pay for the requested service in accordance with the provisions of the Tariff and this Service Agreement.

4.0 Service under this Service Agreement shall commence on the later of: (1) the requested service commencement date, (2) the date on which all required technical data has been received and entered into the Transmission Provider models, or (3) a date that may be established by the Commission. Service under this Service Agreement shall terminate as required by Attachment RR of the Tariff, or as otherwise required by Commission orders or regulations.

5.0 Any notice required or authorized by Attachment RR or this Service Agreement ("Notice") or a request made by a Party regarding this Service Agreement shall be in writing. Notice shall be personally delivered, transmitted by facsimile (with receipt verbally or electronically confirmed), emailed, delivered by overnight courier or mailed, postage prepaid, to the other Party at the address designated below. A Party may change its designated address upon Notice to the other Party.

	Transmission Provider	Reserve Services Customer
Name	Stephen G. Kozey	____________________
Title:	General Counsel	____________________
Address:	PO Box 4202	____________________
	Carmel, IN 46082-4202	____________________
	Fax: 317-249-5912	____________________
Email@	skozey@midwestiso.org	____________________

5.0 The Tariff is incorporated herein and made a part hereof.

6.0 Description of Reserve Services Customer points of interconnection, via the Transmission Owner's facilities, with the Transmission System:

[Attach a separate sheet if necessary, listing points of interconnection]

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7.0 Upon meeting all other conditions required by Attachment RR and the Tariff, the Reserve Services Customer and Transmission Provider agree to commence service at midnight, on the _________day of _____________ 20__. Service under this Service Agreement shall terminate automatically upon the earlier of: (i) failure by the Transmission Owner to achieve final integration on the date established in the phased integration plan approved by FERC; (ii) the integration of the Reserve Services Customer's Balancing Authority into the Midwest ISO Balancing Authority Area; (iii) receipt by the Transmission Provider of written notice, provided by the Transmission Owner prior to the final integration date approved by FERC, that the Transmission Owner intends to withdraw from the Midwest ISO; or (iv) determination by the Transmission Provider that the Balancing Authority has initiated a transaction under this Attachment RR for a purpose other than the ability to meet its reserves obligations as set forth in the applicable NERC and regional reliability standards.

8.0 The Parties mutually agree to use ________________________________ as a representative Reserve Zone for the purpose of determining the Regulation and Spinning

Reserves Distribution rate to be used in the calculation of charges under Section C.3 of Attachment RR. This representative Reserve Zone may be changed only by mutual consent of the Parties, and will remain in effect until termination of this Service Agreement.

9.0 Representations and Warranties. Each Party represents and warrants to the other that, as of the date it executes this Service Agreement:

9.1 The Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

9.2 The execution and delivery by the Party of this Service Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict, based on present knowledge and information, with any applicable law or with any other agreement binding upon the Party; this Service Agreement has been duly executed and delivered by the Party, and, upon receipt of any necessary regulatory approvals, this Service Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity;

9.3 There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder; and

9.4 It is in compliance with all NERC and Regional Entity standards applicable to its operations and facilities.

10. Assignment. Neither Party may assign this Service Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld, except in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. Notwithstanding anything to the contrary herein, the following conditions shall apply to assignment of this Service Agreement by the Reserve Services Customer: (1) assignment may be made to only another eligible Reserve Services Customer; (2) if any change is requested by the assignee, it may be approved by the Transmission Provider only if such change does not impair reliability; and (3) the assignee must agree to be subject to and bound by all applicable terms and conditions of the Service Agreement and the Tariff. .

11. Third Party Beneficiaries. There are no intended third-party beneficiaries of this Service Agreement. Nothing in this Service Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any person not a Party to this Service Agreement.

12. Entire Agreement. This Service Agreement, which incorporates the Tariff, constitutes the entire understanding and agreement of the Parties, and supersedes any and all previous communications, representations, understandings, and agreements (oral or written) between the Parties with respect to the subject matter hereof. The headings used in this Service Agreement are for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

13. No Joint Venture. Nothing contained in this Service Agreement shall be construed to imply the existence of a joint venture, principal and agent relationship, or employment relationship between the Parties, and no Party shall have any right, power or authority to create any obligation, express or implied, on behalf of the other Party without the express written consent of the other.

14. Governing Law. This Service Agreement, to the extent not subject to the jurisdiction of the FERC, shall be governed by and construed in accordance with applicable State laws.

15. Additional Terms. If the Reserve Services Customer is the United States of America or an agency thereof, the terms and conditions found in Section 12B of the Tariff applicable to participation by the United State of America shall be incorporated in this Service Agreement and shall become a part hereof by this reference. If the Reserve Services Customer is a public-power entity, the terms and conditions found in Section 12E of the Tariff applicable to participation by public power entities shall be incorporated in this

Service Agreement and shall become a part hereof by this reference.

16. <u>No Waiver of Jurisdictional Immunity</u>. If the Reserve Services Customer is not subject to the jurisdiction of the FERC as a "public utility" under the Federal Power Act, the Reserve Services Customer shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over the Reserve Services Customer. Nothing in this Service Agreement waives any objection to, or otherwise constitutes consent to, the jurisdiction by FERC over the Reserve Services Customer or its transmission service, facilities and rates.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

<u>Transmission Provider</u>		<u>Reserve Services Customer</u>	
By:	______________________	By:	___________________________
Name:	______________________	Name:	___________________________
Title:	______________________	Title:	___________________________
Date:	______________________	Date:	___________________________

TAB C

Tab C

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	))	Docket No. ER12 -___ -000

DIRECT TESTIMONY OF DR. PAUL R. GRIBIK

FILED ON BEHALF OF THE

MIDWEST INDEPENDENT TRANSMISSION

SYSTEM OPERATOR, INC.

I. QUALIFICATIONS AND PURPOSE

Q. PLEASE STATE YOUR NAME, POSITION, THE NAME OF YOUR EMPLOYER ON WHOSE BEHALF YOU ARE SUBMITTING THIS TESTIMONY, AND YOUR BUSINESS ADDRESS.

A. My name is Paul R. Gribik. I am employed by the Midwest Independent Transmission System Operator, Inc. ("MISO") as Consulting Advisor, Market Development. My business address is 720 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR BACKGROUND.

A. I graduated from Carnegie-Mellon University where I earned a Bachelors of Science degree in Electrical Engineering in 1971, a Masters of Science degree in Industrial

Administration in 1973 and a PhD in Industrial Administration (Operations Research) in 1976. I was employed by Pacific Gas and Electric Company from 1979 to 1989, where I worked on issues related to transmission, generation and fuels planning. From 1989 to 2003, I was employed by several consulting and systems development firms (Arthur D. Little, Inc., Mykytyn Consulting Group Inc., Perot Systems Corporation and, PA Consulting Group). I was engaged in consulting assignments involving the application of operations management techniques, economic analysis, and engineering analysis to evaluate the market potential of new business areas, to improve operations, and to meet new regulatory requirements for a variety of firms involved in the energy industry. During this time, I was engaged in assignments for the California Independent System Operator, The California Power Exchange, and ISO-New England.

Q. WHAT ARE YOUR RESPONSIBILITIES AT MISO?

A. As Consulting Advisor, Market Development for MISO, I currently am responsible for providing advice to MISO Management regarding the operation and performance of MISO markets, including, but not limited to market improvement initiatives, such as the subject Extended Locational Marginal Pricing ("ELMP") initiative.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this Testimony is to: (1) summarize MISO reasons for making a Section 205 filing to further enhance the provisions of MISO's Tariff by implementing Extended Locational Marginal Pricing ("ELMP"); (2) discuss the extensive stakeholder process that MISO conducted to refine and improve the filing; and (3) describe the key elements of the ELMP filing (with the exception of how MISO will conduct Settlements[1], which will be addressed in Mr. Kevin A. Vannoy's filed Testimony).

II. USING EXTENDED LOCATIONAL MARGINAL PRICING

Q. WHAT ARE MARKET CLEARING PRICES?

A. In a competitive market, producers and consumers react to prices by adjusting output and consumption. In wholesale energy markets, the market clearing prices for Energy and Ancillary Services would be the prices at which benefit maximizing consumers would want to purchase from the market the same quantities of Energy and Operating Reserves that profit maximizing suppliers would wish to supply to the market.

Q. HOW ARE RESOURCES COMMITTED AND DISPATCHED?

A. Most wholesale energy markets run by Regional Transmission Organizations ("RTOs") in the United States use bid-based Security-Constrained Unit Commitment ("SCUC") to commit resources and Security-Constrained Economic Dispatch ("SCED") to schedule or dispatch committed resources. These processes are used in both the Day-Ahead Market ("DAM") as well as the Real-Time Market ("RTM"). SCUC models the commitment of resources and models some aspects of the dispatch of the committed resources. SCED incorporates a more detailed model of the dispatch of the resources committed by SCUC as well as a more detailed model of the transmission system.

[1] Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the Tariff or the proposed Tariff provisions.

Q. HOW ARE PRICES DEFINED BY MISO TODAY AND ARE THEY TRUE MARKET CLEARING PRICES?

A. The Locational Marginal Price ("LMP") at a node on the transmission system is the cost of serving an infinitesimal increment (or decrement) of Energy requirement at the location given system congestion in the respective market. Similarly, what is termed the Market Clearing Price ("MCP") for a Operating Reserve is the cost of serving an infinitesimal increment (or decrement) of the requirement for the Operating Reserve. System congestion costs cause location-based differences in prices. In many instances, calculated LMPs and MCPs may not completely cover a resource's operating costs at the dispatch point. As such, the LMPs and MCPs may not be true market clearing prices in that some profit maximizing suppliers would not be willing to supply Energy and Operating Reserves at a level sufficient to meet demand for those services at the given prices. As a result, MISO's Tariff authorizes it to use uplift payments to cover the offered operating costs of resources that are not entirely compensated by Energy LMPs and MCPs for Operating Reserves and to encourage Market Participants to follow MISO dispatch instructions. It is also possible that profit maximizing suppliers would want to supply more Energy and Operating Reserves than consumers would want to purchase at the given prices. That is, they would want to over supply Energy and Operating Reserves. If so, suppliers would experience opportunity costs by following the MISO dispatch instructions. Again, LMPs and MCPs would not be true market clearing prices because they would give an incentive to produce more than consumers would wish to purchase.

Q. **HOW ARE THESE PRICES CALCULATED TODAY?**

A. Prices (Energy LMPs and MCPs for Operating Reserves) in MISO's DAM and RTM are currently calculated through the SCED algorithm, which also determines Energy and Ancillary Service schedules for both MISO's DAM and RTM. A key drawback of the SCED pricing algorithm is that it often does not allow certain Fast Start Resources to set prices, even though such Resources may have the highest Offer costs of the Resources that MISO must deploy to meet demand for Energy or Operating Reserves at a location. The SCED prices also may not reflect the Start-Up Costs and the No-Load Offer costs of Generation Resources or Demand Response Type II Resources. Similarly, SCED prices may not reflect the Shut Down Offer Costs and Hourly Curtailment Offer Costs of Demand Response Type I Resources. The SCED prices, thus, do not always cover a Market Participant's Offer costs. In that event, MISO must make Revenue Sufficiency Guarantee ("RSG") or make whole payments to compensate the Market Participant for its Offer costs. Enabling such costs to more fully participate in setting prices can result in prices that come closer to clearing the market.

Also, SCED does not allow off-line Resources (in particular Fast Start Resources) to participate in setting prices. Allowing such resources to participate in setting prices when their commitment and dispatch could address certain system conditions may reduce the opportunity costs when today's prices would give suppliers an incentive to produce more than is required. Again, allowing such resources to participate in setting prices can result in prices that come closer to clearing the market.

Q. WHY IS THERE A NEED TO CHANGE THE CALCULATION OF ENERGY AND OPERATING RESERVE PRICES?

A. Under the current market rules, Energy LMPs and MCPs for Operating Reserves may not reflect the cost of expensive actions that were taken in order to meet requirements. In certain circumstances, the last action that MISO takes to meet requirements at a location is to schedule a combustion turbine Generation Resource for which the offered economic minimum operating limit ("EconMin") is equal to the offered economic maximum operating limit ("EconMax") (*i.e*. block loaded), or is dispatched at its EconMin. While energy is needed from the combustion turbine in order to meet demand, the entire quantity of energy from zero to EconMin might not be needed, requiring the system operator to reduce the output on other, less expensive Resources. To rephrase, because the combustion turbine is block loaded or running at EconMin, the grid operator must "back down" a less expensive Generation Resource in order to make room for the combustion turbine. Under the current SCED algorithm, LMP would reflect the Incremental Energy costs of the less expensive resource that was backed down, rather than the costs of the combustion turbine that was committed and dispatched at a limit to meet demand. In this case, LMP would not reflect the cost of the last action needed to meet demand. Similar behavior can be experienced when a combustion turbine must be deployed to meet Operating Reserve requirements.

When SCED dispatch results in a shortage of Operating Reserves, MISO sets prices based on demand curve shortage prices even if there are Fast Start Resources that MISO could commit to address the shortage at a lower cost than the shortage cost. That is, while SCED may be short of resources, MISO may not actually be short of resources that it could use to meet system requirements. Similarly, the SCED dispatch may result in violation of a transmission constraint leading to the Shadow Price of the constraint being set at the marginal value limit or penalty price. Again, there may be Fast Start Resources that MISO could commit to alleviate the violation at lower cost. In these cases, LMPs and MCPs at some locations may reflect shortage or penalty costs rather than the true costs of actions that MISO could take to alleviate the problem.

Q. HOW DID MISO RESPOND TO THE PROBLEM?

A. MISO investigated ways to reflect the cost of actual commitment decisions in the prices and developed the subject approximate ELMP methodology to improve MISO pricing signals. The subject proposal is the development of a SCED-Pricing algorithm, separate from the SCED algorithm used for dispatch, that will be used to calculate ELMPs.

Q. WILL ELMP BE A SOLUTION TO THE PROBLEM OF SOME RESOURCES NOT BEING ABLE TO SET PRICES IN THE MARKET?

A. By adopting ELMP, the costs of Fast Start Resources as well as Emergency Demand Response ("EDR") resources operating at either their EconMax or EconMin will be considered, and these Resources will be eligible to set prices in the pricing algorithm. For Fast Start Resources, the offered Start-Up Cost, No-Load Cost, as well as Incremental Energy Cost and Offer Costs for Operating Reserves will be considered in the pricing algorithm. For EDRs, the pricing algorithm will consider Shut Down Cost and Energy Reduction costs. ELMPs will be calculated using a separate algorithm which allows for the consideration of "partially committing" Fast-Start Resources and EDR Resources. That is, instead of the actual nature of each commitment decision, "yes" and "no", the algorithm will be allowed to commit any percentage of Fast-Start Resources, between 0 and 100%.

In addition, off-line Fast Start Resources can set prices during periods with shortages or transmission constraint violations if committing such Resources could alleviate the problem.

MISO will continue to operate and dispatch the system by only dispatching committed Resources and by honoring both the EconMin and EconMax Offers submitted by Generation Resources. MISO's dispatch algorithm (*i.e*, SCED) will not change.

Q. WHAT IS THE FOUNDATION FOR THE ELMP PROPOSAL?

A. The ELMP proposal began as a more complicated and rigorous attempt to completely reflect the costs of operation in pricing. In electricity markets, market clearing prices usually do not exist due to the complexities arising from the commitment process. That is, prices alone would not give the required incentives for suppliers to commit resources and produce Energy and Operating Reserves at a level equal to that at which consumers would want to purchase them. MISO undertook an investigation to develop a pricing approach that would calculate prices that came closer to clearing the market than the prices produced by SCED. The SCUC model includes a detailed model of commitment decisions and related costs and so it considers the costs of committing and dispatching

Resources, including Resources dispatched at their limits. We started by enhancing the current SCUC model to incorporate a dispatch and transmission model equivalent to those in SCED. Prices were defined using the total cost as a function of the constraint limits in the enhanced SCUC model using a mathematical concept called convex hull. In discussions with stakeholders, MISO termed this approach full ELMP. MISO found that prices produced by full ELMP came as close as possible to being market clearing prices and efficient prices in that they minimized the side payments to Market Participants that would be necessary to give Market Participants incentives to follow the least cost commitment and schedules produced by SCUC and SCED. The side payments (or uplift) that full ELMP minimizes include: (1) costs to Market Participants for following schedules that would incur losses at the market prices, and (2) foregone increased profits or opportunity costs experienced by Market Participants for following schedules produced by SCUC and SCED that are profitable but not the most profitable possible at the given prices.

Q. WHY IS MISO NOT IMPLEMENTING FULL ELMP?

A. After working on the full ELMP approach, and after discussions with stakeholders, MISO concluded that the complex modifications that would be required to the SCUC commitment engine, as well as complexities, costs, and risks associated with developing software to completely solve the convex hull pricing problem were not warranted at this time. MISO determined that developing methods that approximate full ELMP could efficiently capture many of the benefits of full ELMP by including the costs of committing and dispatching Fast Start Resources and EDR resources. Using an approximation method based upon an extension of SCED allows the development of a robust pricing engine to consistently produce reliable and accurate results.

Q. WHAT ARE THE BENEFITS OF USING APPROXIMATE ELMP?

A. The current ELMP proposal uses an approximation of the convex hull in order to efficiently capture many of the benefits of full ELMP while simultaneously minimizing the costs and complexities. The ELMP process will calculate prices based on changes in operating costs that result from changes in dispatch of all resources and as well as commitment of Fast Start and EDR resources. As discussed above, the commitment related costs of Fast Start Resources as well as EDR resources are captured by extending SCED to consider the fractional commitment of these resources.

Q. WHAT ELSE DOES MISO EXPECT TO ACHIEVE BY IMPLEMENTING APPROXIMATE ELMP?

A. Approximate ELMP is expected to reduce uplift charges by incorporating more Offer costs into the market prices of Energy and Operating Reserves. ELMP provides an analytically grounded methodology for achieving multiple energy market objectives to: (1) reduce uplift costs; (2) allow gas turbines and other Fast Start Resources that are operating at their EconMin or EconMax to affect the prices when appropriate; (3) allow Emergency Demand Response ("EDR") resources to affect prices when appropriate; and (4) relieve price spikes that can result from shortages or transmission constraint violations due to forecasting errors.

Q. HOW DOES ELMP ACHIEVE THOSE GOALS?

A. The ELMP approach that MISO has developed with interested stakeholders achieves these goals, because it: (1) allows Fast Start Resources which are dispatched at limits to set prices for Energy and Operating Reserves when appropriate; (2) meets MISO Independent Market Monitor ("IMM") recommendations; (3) allows Start-Up and No-Load costs for Fast Start Resources committed by MISO to be included in prices; (4) during periods with scarcity and transmission constraint violations, allows offline Fast Start Resources that are available for commitment by MISO and that can alleviate the scarcity or violation to set prices; and (5) allows EDR resources to set prices in the RTM if such resources are dispatched.

III. EXTENSIVE STAKEHOLDER INVOLVEMENT IN ELMP

Q. HOW HAS MISO WORKED WITH STAKEHOLDERS TO DEVELOP THE CURRENT ELMP PROPOSAL?

A. For several years, the IMM has recommended that MISO incorporate changes to allow gas turbines that are dispatched at limits and interruptible load and demand response resources to set energy prices in the RTM.[2] MISO commenced work after the IMM's recommendations. MISO also commenced discussions with stakeholders through its existing stakeholder committees, a series of workshops in 2009 and 2010, and a new ELMP Task Team ("ELMPTT").

[2] *E.g.*, *2007 State of the Market Report for the Midwest ISO*, p. vii (available at: http://www.potomaceconomics.com/uploads/midwest_reports/2007_State_of_the_Market_Report-Full_Text_07-08.pdf).

MISO and stakeholders have been discussing the need for ELMP and reviewing a variety of approaches that could be adopted. In responding to stakeholder questions during this period, MISO has developed many examples of how both full ELMP and approximate ELMP will influence Energy and Operating Reserve pricing. MISO has discussed the status of its work with stakeholders in several different types of stakeholder meetings, particularly through an extensive series of ELMPTT meetings.[3] MISO has also used these meetings to collect comments and suggestions from affected parties regarding ELMP. Rather than recount all of the extensive stakeholder history surrounding ELMP[4], recent ELMP stakeholder developments are discussed below.

Beginning early in 2011, MISO presented to the ELMPTT the initial results based on both hypothetical examples and case studies of ELMP, using both a full ELMP method based on a convex hull of the SCUC problem and an ELMP approximation method based extending SCED to allow partial commitment of some resources. MISO initially analyzed a full ELMP methodology[5] which would more precisely calculate Energy and

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[3] Minutes and meeting materials documenting the work at the numerous ELMPTT meetings can be found on the MISO website: https://www.midwestiso.org/Library/MeetingMaterials/Pages/ELMPTT.aspx.

[4] Since July of 2008, MISO has submitted quarterly status reports in Docket No. ER08-404 to the Commission to document its efforts to enable EDR resources to set Energy prices, which is a fundamental feature of ELMP. These quarterly reports of the more than two dozen stakeholder meetings addressing this topic during the last 3 years also document the extensive stakeholder involvement in the development of ELMP.

[5] A few of the benefits of full ELMP that are not achieved by the approximate ELMP include: (1) approximate ELMP only treats a single dispatch interval at a time, so costs incurred in one period cannot contribute to setting prices in another period (full ELMP would allow such inter-temporal effects to be considered in setting prices); (2) in approximate ELMP implementation, the opportunity costs for some commitment-related actions, such as

Ancillary Services prices. As discussed herein, MISO has decided to implement an approximate ELMP methodology to permit enhancing existing SCED software to calculate prices rather than developing new algorithms and production-grade software to calculate prices based on the convex hull of SCUC, thereby reducing implementation costs, development time, and risks while improving the pricing signals.

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS TO DEVELOP ELMP?

A. MISO held four workshops with stakeholders in 2009 and 2010. The ELMPTT was formed in 2010 and met on August 24, 2010, October 5, 2010, and November 1, 2010. During 2011, MISO held multiple stakeholder meetings on the following dates: January 7, February 4, March 4, April 8, April 29, May 23, June 14, September 9, September 23, October 21, November 4, November 18, December 2, and December 16.

Q. WHAT TOPICS WERE DISCUSSED WITH THE STAKEHOLDERS?

A. At the March 4, 2011 meeting, for example, MISO presented some of the results of its studies and described methods by which Start-Up Offer costs could potentially be allocated to periods (hours or dispatch intervals) to incorporate in approximate ELMP. MISO tested the various methods on several MISO-sized test problems and reported that these results indicated that the approximation ELMP methods may be applied in a fashion

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reducing the maximum dispatch limit for a resource when the resource is committed to provide regulation from that when it is not committed to provide Regulation, are not considered when setting approximate ELMPs; however, opportunity costs for dispatch related actions such as reducing the dispatch of one product to enable increased dispatch of another product are captured in the prices; and (3) approximate ELMP implementation allows a limited set of commitment related costs to participate in setting prices, including start-up and no-load costs from Fast Start Resources and the Incremental Energy and Operating Reserve offer costs of those resources when dispatched at limits.

that can deliver results close to the full ELMP calculations. MISO reported that the ELMP approximation methodology would allow MISO to implement software to calculate ELMPs in a shorter time and at a lower cost than implementing a full ELMP methodology.

Q. HOW HAS MISO RESPONDED TO STAKEHOLDER INPUT?

A. At the April 29, 2011 ELMPTT meeting, MISO presented a revised decision tree of potential approaches for developing ELMP for the RTM and the DAM, based upon stakeholder feedback from an April 8, 2011 ELMPTT meeting. MISO presented its proposed recommendations for calculation of ELMP in the RTM with the following elements: (1) use of approximation ELMP, rather than full ELMP; (2) use of a multi-period look forward only; (3) allowing committed and uncommitted Fast Start Resources to participate in price setting; (4) incorporating the Start-up, No-Load, Incremental Energy and Operating Reserve Offer Costs for Fast Start Resources committed by MISO in the Reliability Commitment Processes or off-line and available for commitment by MISO in setting prices; (5) only allowing committed slow start resources to participate in price setting; and (6) only considering Incremental Energy Cost and Operating Reserve Offer costs for committed slow start resources or Fast Start Resources committed in Day-Ahead or self-committed by Market Participants in setting prices. In subsequent ELMPTT meetings, MISO and stakeholders decided to implement a single period ELMP approach since that was consistent with MISO's current dispatch approach. The multi-period look forward would be postponed until such time as MISO may implement a Look Ahead Dispatch capability.

MISO also presented proposed recommendations for calculation of ELMP in the DAM with the following elements: (1) use of approximation ELMP, rather than full ELMP; (2) use of a 24-hour pricing window; (3) allowing committed and uncommitted Fast Start Resources to participate in price setting; (4) incorporating the Start-up, No-Load, Incremental Energy and Operating Reserve Offer Costs for Fast Start Resources committed by MISO in the Day-Ahead Market processes or off-line and available for commitment by MISO in setting prices; (5) only allowing committed slow start resources to participate in price setting; and (6) only considering Incremental Energy Costs and Operating Reserve Offer costs for committed slow start resources or Fast Start Resources self-committed by Market Participants in setting prices. In subsequent ELMPTT meetings, MISO and stakeholders decided to implement a single period ELMP approach in DAM since that was consistent with MISO's current scheduling process in DAM.

In addition, MISO presented a comparison between MISO's recommendations and the pricing approaches currently used by other Regional Transmission Organizations (including ISO-New England, PJM Interconnection, L.L.C. ("PJM"), and New York ISO). MISO sought stakeholder feedback by May 13, 2011 through an electronic ballot on a revised decision tree that documented the various ELMP approaches that MISO could follow.

Q. WHAT WAS THE FEEDBACK FROM STAKEHOLDERS?

A. At the May 23, 2011 ELMPTT meeting, MISO reviewed the results of the ELMP ballots that stakeholders had cast; these results had previously been posted on MISO's website and also had been sent to the MISO Market Subcommittee ("MSC") exploder list. MISO sought additional stakeholder feedback and discussed how the results of the feedback related to MISO's proposal. MISO also discussed stakeholder comments on DAM ELMP method and answered clarifying questions from stakeholders. Stakeholders expressed support for a staged implementation proposal. MISO then discussed a proposed MSC motion to support continued development of ELMP.

Q. DID THE STAKEHOLDERS PROVIDE MISO WITH A RECOMMENDATION TO PROCEED WITH ELMP?

A. At the June 14, 2011 ELMPTT meeting, MISO reviewed a proposed staged implementation approach for ELMP. This approach would be developed by enhancing existing software to the extent possible to minimize implementation costs, development time and risks. MISO then outlined the Resources and Offer costs that would participate in setting ELMPs in the RTM. MISO explained that Start-Up Offer costs, No-Load Offer costs and Incremental Energy Costs as well as offer costs for Operating Reserves of On-Line Fast Start Resources committed by MISO in the RAC processes would participate in setting Energy and Operating Reserve prices. Shut-Down Offer costs and energy reduction costs of Committed EDR resources would participate in setting ELMPs in the RTM. Start-Up Costs, No-Load Costs and Incremental Energy Costs as well as Operating Reserve offer costs of Off-Line Fast Start Resources would be able to participate in setting Energy and Operating Reserve prices. Only Incremental Energy Costs and Operating Reserve Offer costs of On-Line slow start resources, Fast Start Resources committed in Day-Ahead Market or self-committed by Market Participants would participate in setting prices under the approximate ELMP methodology.

MISO also explained that in the DAM, On-Line and Off-Line Fast Start Resources and their Start-Up, No-Load and Incremental Energy Costs as well as Operating Reserve offer costs would participate in setting Energy and Operating Reserve prices. Only the Incremental Energy costs as well as Operating Reserve Offer costs of On-Line slow start resources and Fast Start Resources self-committed by Market Participants would participate in setting Energy prices.

MISO also discussed potentially restricting the use of Off-Line Fast Start Resources in DAM and RTM in setting ELMP Energy prices to intervals in which shortages exist or transmission constraint violation(s) occur and committing the Off-Line Fast Start Resource would alleviate the shortage. MISO proposed that further changes could be evaluated over time, and adjustments could be made as necessary to improve confidence before considering whether to move toward implementing full ELMP at a later time.

In addition, MISO discussed mathematical approaches to implement the proposed treatment of Fast Start Resources and EDR resources in the approximate ELMP method with the ELMPTT. The ELMP methodology develops a local convex approximation to the total cost curve from SCUC over the range in which the Fast Start resources (or EDR resources) are committed, for use in calculating the approximate ELMP Energy prices by allowing the partial commitment of such resources in an enhanced version of SCED. MISO summarized that the proposed staged implementation would improve pricing signals, but that multiple-interval dispatch related costs would not be reflected because the implementation at this stage would be built upon existing single period dispatch software. In addition, MISO again discussed the language of a proposed MSC motion to support moving forward with ELMP work. The ELMPTT supported the proposed motion[6] by a vote of 13 in favor, 1 against, and 13 abstentions.

Q. DID MISO DISCUSS ELMPTT RECOMMENDATION WITH THE MSC?

A. At the June 28, 2011 MSC meeting, MISO reviewed the proposed ELMP staged approach which had been endorsed by the ELMPTT. MISO explained that additional details would be vetted over the coming months. Some stakeholders wanted to see draft Tariff language regarding the ELMP modifications. The MSC then approved the ELMP motion by a roll call vote of 41 in favor, 2 opposed, and 20 abstentions.

Q. DID MISO CONTINUE TO MEET WITH THE ELMPTT?

A. Yes. On September 9, 2011 and September 23, 2011, MISO conducted ELMPTT meetings to review a detailed ELMP process outline with the stakeholders describing the procedures that MISO proposed to implement for ELMP, including a description of

6 "The Extended LMP Task Team (ELMPTT) recommends that the Market Subcommittee (MSC) support the following proposal to MISO: (1) to move forward with development of a revised pricing approach based on a staged implementation as outlined with the June 14, 2011 ELMPTT and June 28, 2011 MSC meeting materials; and (2) to develop cost estimates before proceeding with developing systems to implement the pricing approach".

planned tasks and a proposed timeline. MISO presented simplified examples of how ELMP pricing would differ from existing LMP pricing, including a discussion of whether it was appropriate to conduct a two-pass or a single-pass approach for ELMP pricing. The presentations concluded that a two-pass approach was not required. MISO also presented an Issues List describing some of the on-going matters that MISO was investigating.

On October 21, 2011, MISO conducted an ELMPTT meeting to discuss: (1) a review of current work with vendors that were assisting MISO; (2) initial cost estimates to implement ELMP; (3) proposed next steps; and (4) additional examples of how ELMP would operate. MISO also discussed the relative merits of defining a Fast Start Resource as one that could respond to notification and be on-line in 30 minutes versus one that could respond more quickly in 10 minutes. MISO concluded that to be more conservative, it proposed to use the 10-minute response-time definition, although it would continue to study the matter and it might subsequently seek FERC approval for a different time period.

On November 4, 2011, MISO discussed proposed redlined and clean Tariff language to implement ELMP which MISO had posted on its website on October 28, 2011. The ELMPTT asked a variety of questions regarding the proposed Tariff language, including a discussion of the need for clarifying in the Tariff the terminology regarding the different types of LMP and MCP prices that were used in the DAM and RTM.

During the November 18, 2011 meeting, MISO recapped comments from stakeholders and presented a frequently asked questions ("FAQ") document responding to stakeholders' queries. MISO presented examples on how ELMP might effect RSG payments in the DAM. MISO then proceeded to discuss the next steps with the ELMPTT, including a review of revised Tariff edits and a motion supporting the ELMP approach, to be voted upon at the December 2, 2011 meeting.

Q. DID THE ELMPTT APPROVE A MOTION TO FILE THE ELMP TARIFF LANGUAGE?

A. The ELMPTT supported an amended proposed motion at the December 2, 2011 ELMPTT meeting. The motion passed the ELMPTT by a vote of 10 in favor, 3 against, and 16 abstentions

Q. **DID THE MSC APPROVE A MOTION TO FILE THE ELMP TARIFF LANGUAGE?**

A. Yes. The MSC again reviewed the conceptual design of ELMP at its December 6, 2011 meeting and approved MISO making an ELMP filing. The MSC approved an amended MISO motion[7] to make an ELMP filing by a vote of 26 in favor, 2 opposed, and 21 abstentions.

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[7] "The Market Subcommittee (MSC) supports MISO filing Tariff language with FERC in 2011 that is substantially similar to Tariff language that was posted with the December 2, 2011 ELMPTT meeting materials, in order for MISO to implement a revised pricing approach that will be consistent with the pricing approach approved at the June 14, 2011 ELMPTT meeting. Such support is contingent on MISO including in the transmittal letter, a commitment to providing two settlement statements during parallel operations, one under LMP pricing and a shadow settlement statement under ELMP pricing."

Q. DID MISO CONTINUE DISCUSSIONS WITH THE ELMPTT?

A. During the December 16, 2011 ELMPTT meeting, MISO reviewed the final proposed changes with stakeholders and worked to incorporate additional stakeholder suggestions into the filing.

IV. <u>DESCRIPTION OF EXTENDED LOCATIONAL MARGINAL PRICING</u>

Q. HOW WILL ELMP IMPROVE UPON THE REFLECTION OF ACTUAL COST STRUCTURE IN ENERGY AND ANCILLARY SERVICES PRICING?

A. ELMP will be an important step forward in enhancing energy and ancillary services pricing to reflect the physical reality of how costs are incurred in generating electricity. Electricity markets will function most efficiently, and with the least *ad hoc* intervention, when they are structured to provide prices that are consistent with the underlying cost structure. In these markets, LMP originated in order to reflect the physical reality that congestion costs cause locational differences in prices. ELMP is a logical extension of LMP. Another way to think of ELMP is to recognize that LMP attempts to incorporate the cost of dispatch in prices, and as an evolutionary step, ELMP incorporates the costs of commitment as well as dispatch into prices.

ELMP is a new computational method for calculating the LMPs and MCPs for MISO's Energy and Ancillary Services Market. The key improvement of ELMP over MISO's current price calculation method is that ELMP will allow Fast Start Resources that are scheduled at limits to set prices. ELMP will take into account the Start-up Cost and No-

Load Cost of Fast Start Resources committed by MISO in the respective market processes. It will also allow off-line Fast Start Resources to set prices during periods of scarcity or with transmission violations when committing the resource could alleviate the problem. As such, the prices will reflect the cost of the action that MISO could logically take to address the problem rather than show scarcity prices or transmission penalty prices when MISO is not short resources to address the problem. In addition, ELMP will allow EDR resources to set prices in the Real-Time Energy and Operating Reserve Market.

Q. HOW WILL ELMP PRICING BE CALCULATED?

A. ELMP pricing will be calculated using a modified version of the current SCED software in use today. MISO refers to this new process as SCED-Pricing, the SCED-Pricing algorithm, or the SCED-Pricing engine. SCED-Pricing will be defined in a new Schedule 29A in the Tariff. The mathematical algorithms being applied within the ELMP process will send more accurate price signals to Market Participants. Importantly, ELMP will change pricing by properly reflecting more of the costs included in the offers of Fast Start Resources and EDR Resources, but will not change the physical dispatch of the resources. MISO’s operations and its dispatch of resources will not be affected by the implementation of ELMP because ELMP will only modify the calculation of Energy and Ancillary Service prices.

Q. WILL THE TERMS LMP AND MCP REMAIN IN THE TARIFF?

A. The terms "LMP" and "MCP" often will be referenced in conjunction with prefixes "Ex Ante" and "Ex Post" in the Tariff. These prefixes will help to clarify the process in which the energy LMPs and Operating Reserve MCPs are calculated. In defining ELMP, references were made to the general definitions of LMP and MCP, because these two terms are incorporated into the overall ELMP process. The general terms LMP and MCP are used to refer to all prices, including Ex Ante LMP and Ex Post LMP, as well as Ex Ante MCP and Ex Post MCP. Ex Post LMPs and Ex Post MCPs are prices calculated using ELMP, or the SCED-Pricing algorithm, while Ex Ante LMPs and Ex Ante MCPs are prices calculated using the dispatch engine, or SCED algorithm.

Q. WILL ELMP IMPACT BOTH THE DAM AND THE RTM?

A. ELMP will modify both DAM and RTM pricing. Prior to the implementation of ELMP, the SCED algorithm solves for both schedules and prices for Settlement. After ELMP is implemented, the SCED algorithm will produce the schedule and the SCED-Pricing algorithm will calculate ELMP prices to be used for Settlement. Both the DAM and RTMs will be executing SCED-Pricing (*i.e.*, the ELMP software engine) after SCED has been run to produce the schedules in DAM or RTM. SCED will still produce prices; the SCED prices will be called Ex Ante prices, and they will be used for information only. The SCED-Pricing prices will be called Ex Post prices, and they will be used for settlement.

MARKET PARTICIPATION BY FAST START RESOURCES

Q. WHAT ROLE WILL FAST START RESOURCES PLAY UNDER ELMP?

A. MISO is proposing a new classification of Resources: Fast Start Resources which are able to respond in ten (10) minutes or less to a commitment and dispatch decision. MISO proposes defining Fast Start Resources as separate and distinct from Quick Start Resources to provide flexibility under ELMP and to avoid confusing their separate operations. A Fast Start Resource will be defined in the Tariff as a Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that will participate in setting prices. MISO has discussed with stakeholders the potential for modifying the definition of Fast Start Resources in the future to allow a notification time of thirty (30) minutes instead of the currently proposed ten (10) minutes. Currently, MISO proposes to use 10 minutes in the Fast Start Resource definition, for several reasons. First, decisions can be made to commit and dispatch 10 minute Fast Start Resources in the RTM close to the time in which MISO makes decisions to dispatch committed resources. Second, in current Real-Time dispatch, MISO looks 10 minutes ahead; if an off-line resource cannot be operationally available within the 10-minute window, then it will not considered an available resource for setting price. Third, 10-minute Fast Start Resources will provide a better transition for MISO. Fourth, defining Fast Start Resources as those that are able to respond within 10 minutes will also provide a more conservative starting point for the transition to ELMP implementation.

Q. HOW MAY THE DEFINITION OF FAST START RESOURCES CHANGE IN THE FUTURE?

A. Because the Look Ahead Commitment ("LAC") may or may not result in the need for a longer period for the definition of Fast Start Resources, MISO proposes to keep the interval at ten (10) minutes for this initial filing. By having the flexibility of a tailored definition, MISO and Stakeholders may be able to revisit the appropriate time interval based upon Operator and Stakeholder experiences with LAC. MISO will work with its stakeholders to consider extending the Fast Start Resource definition to 30 minutes in the future.

Q. WHEN CAN OFF-LINE FAST START RESOURCES PARTICIPATE IN SETTING PRICES?

A. Off-line Fast Start Resources can participate in setting prices when the SCED dispatch experiences Operating Reserve deficits, or when transmission constraint violation conditions occur and when the Off-Line Fast Start Resources could mitigate the conditions. During Real-Time operation, these conditions may or may not result in the actual commitment of the Fast Start Resources by MISO depending on the transient nature of the conditions. Persisting Operating Reserve deficits or transmission constraint violations will lead to commitment of the Fast Start Resources for mitigation. Although ELMP will be calculated based upon the assumption that a Fast Start Resource is allowed to be partially committed, MISO will continue to operate and dispatch the system by honoring both the EconMin and EconMax limits submitted by resources.

Q. ARE THERE SITUATIONS IN WHICH PARTIAL COMMITMENT OF FAST START RESOURCES WILL NOT BE PERMITTED WHEN CALCULATING ELMPS?

A. There is one exception to the conditions under which SCED-Pricing will allow partial commitment of on-line Fast Start Resources for purposes of calculating prices. That exception is when the DAM or RTM experiences surplus conditions.[8] For Ex Post pricing during a minimum-generation event, neither partial commitment of On-Line Fast Start Resources nor off line Fast Start Resources will be allowed in the SCED-Pricing algorithm. This is done to avoid eliminating the surplus condition through partial commitment of such resources. As a result, Ex Ante prices and Ex Post prices will remain the same during surplus conditions.

ELMP IN THE REAL-TIME MARKET

Q. WILL FRACTIONAL COMMITMENT OF RESOURCES BE ALLOWED? IF SO, HOW WILL THEIR COSTS BE ALLOCATED?

A. Fractional or partial commitment of Fast Start Resources committed by MISO in a Reliability Assessment Commitment process will be allowed in SCED-Pricing. The Start-Up costs for Fast Start Resources committed by MISO in a Reliability Assessment Commitment process will be allocated over the resource's minimum run time. No-Load Costs for these Fast Start Resource will stay in the hour in which they occur. Partial commitment of the Fast Start Resource in SCED-Pricing will allow a share of Start-Up

[8] Under Surplus Condition in the Day-Ahead EORM described in Section 39.2.11, on-line Fast Start Resources will be considered fully committed in SCED-Pricing. Under Capacity Surplus Condition under Minimum Load Conditions in RT EORM described in section 40.2.21.b, on-line Fast Start Resources will be considered fully committed in SCED-Pricing.

costs and No-Load costs to be included when setting price if a partial resource commitment is marginal. In addition, partial commitment of the Fast Start Resource can relax the limits on the resource so that a Fast Start Resource that is scheduled at a limit by SCED can still be marginal in SCED-Pricing and so be eligible to set prices.

During periods with transmission constraint violations or with energy or Operating Reserve scarcity in SCED dispatch, available off-line Fast Start Resources can be partially committed to set prices. The Start-Up costs for off-line Fast Start Resources available for commitment are allocated over their offered minimum run time while their No-Load costs remain in the hour in which they are offered. Partial commitment of these resources allows prices to reflect cost of actions that MISO could take to address violations or scarcity.

Q. WHAT TREATMENT DOES MISO PROPOSE FOR EDR RESOURCES?

A. EDR resources are available in the RTM only. EDR resources are scheduled before SCED is run. Consequently, EDR schedules are fixed in SCED. When MISO schedules energy reduction from an EDR resource in Real-Time, the EDR resource will be able to participate in setting prices through SCED-Pricing. The fractional commitment of scheduled EDR resources will be allowed in SCED-Pricing so that the EDR schedule can be adjusted in SCED-Pricing and can participate in setting prices. The shut-down costs for EDR resources scheduled will be allocated over the hours the resource is scheduled; and this will allow a share of shut-down costs allocated to each hour to be included when setting price if the partial commitment of EDR is marginal.

Q. ARE THERE CHANGES TO THE MODELING OF OTHER RESOURCES?

A. All other resources and constraints will be modeled in the same fashion as the Real-Time SCED algorithm.

Q. ON WHAT INTERVALS WILL PRICES BE CALCULATED?

A. The SCED-Pricing algorithm will calculate Ex Post LMP for each Real-Time dispatch interval. The resultant Energy LMPs and Operating Reserve MCPs from the SCED-Pricing solution are Real-Time Ex Post LMP and Real-Time Ex Post MCPs, and are calculated every 5 minutes. Hourly Real-Time Ex Post LMP is the time-weighted average of Real-Time Ex Post LMP over all dispatch intervals during a market hour. Hourly Real-Time Ex Post MCPs are the quantity-weighted average of the Real-Time Ex-Post MCPs over the dispatch intervals during a market hour. The RTM will be settled on Hourly Real-Time Ex Post LMPs and Hourly Real-Time Ex Post MCPs. However, Market Participants will be notified of the Real-Time Ex Post LMPs and MCPs as they are being calculated. This process is consistent with the other real-time prices that are similarly defined in the Tariff.

<u>ELMP IN THE DAY-AHEAD MARKET</u>

Q. HOW WILL ELMP IMPACT THE DAM?

A. In the DAM, the Security Constrained Unit Commitment ("SCUC"), that is used to commit resources, will remain unchanged under ELMP. Submitted offers and bids are input into the SCED algorithm and the algorithm supplies Energy and Operating Reserve schedules, as well as Ex Ante LMPs for Energy and Ex Ante MCPs for Operating Reserves. The submitted offers and bids will be input into the SCED-Pricing algorithm that allows Fast Start Resources that are scheduled at limits and offline Fast Start Resources, to participate in setting prices. The SCED-Pricing algorithm will provide Ex Post LMPs for Energy and Ex Post MCPs for Operating Reserves.

Q. HOW WILL FAST START RESOURCES BE TREATED IN THE DAM?

A. Fractional or partial commitment of Fast Start Resources committed by MISO in the DAM process will be allowed in SCED-Pricing. The Start-Up costs for Fast Start Resources committed by MISO will be allocated over the resource's minimum run time. No-Load Costs for the Fast Start Resource will stay in the hour in which they occur. During periods with transmission constraint violations or with energy or Operating Reserve scarcity in SCED dispatch, available off-line Fast Start Resources can be partially committed to set prices. The Start-Up costs for off-line Fast Start Resources available for commitment will be allocated over their offered minimum run time while their No-Load costs will remain in the hour in which they are offered. Partial commitment of these resources will allow prices to reflect cost of actions that MISO could take to address violations or scarcity.

V. CONCLUSION

Q. HOW DOES APPROXIMATE ELMP IMPROVE THE MISO ENERGY AND ANCILLARY SERVICES MARKET?

A. Approximate ELMP allows the Start-Up and No-Load offer costs of Fast Start Resources committed by MISO in DAM or RTM processes to be considered when setting prices in the respective market. It also allows the Incremental Energy and Operating Reserve Offer costs of such Fast Start Resources to participate in setting prices when the Fast Start Resource is dispatched at a limit in the respective market. The resulting prices take into account more of the costs that MISO incurs to meet requirements in the DAM and RTM. Approximate ELMP can improve price signals during periods of scarcity or when there are transmission constraint violations. ELMP can set prices based on committing off-Line Fast Start Resources if MISO could alleviate the shortage or transmission violations by committing the resources at lower cost than the respective shortage cost or transmission violation penalty cost. Finally, approximate ELMP will allow MISO to set prices based on its use of EDRs.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes. This completes my testimony in the subject proceeding.

Dated this 22nd day of December, 2011.

AFFIDAVIT

County of Hamilton

State of Indiana

PAUL R. GRIBIK, being duly sworn, deposes and states: that he prepared the Testimony of Paul R Gribik and the statements contained therein are true and correct to the best of his knowledge and belief.

Paul R. Gribik

SUBSCRIBED AND SWORN BEFORE ME, this 21st day of December, 2011.

Christi I. Larson

Notary Public, Marion County

State of Indiana

My Commission Expires: August 15, 2013

STATE OF INDIANA NOTARY SEAL

CHRISTI I. LARSON
Notary Public, State of Indiana
Marion County
Commission # 542850
My Commission Expires
August 15, 2013

TAB D

Tab D

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	))	Docket No. ER12 -___ -000

DIRECT TESTIMONY OF KEVIN A. VANNOY

FILED ON BEHALF OF THE

MIDWEST INDEPENDENT TRANSMISSION

SYSTEM OPERATOR, INC.

I. QUALIFICATIONS AND PURPOSE

Q. PLEASE STATE YOUR NAME, ON WHOSE BEHALF YOU ARE SUBMITTING THIS TESTIMONY, AND YOUR BUSINESS ADDRESS.

A. My name is Kevin A. Vannoy. I am employed by the Midwest Independent Transmission System Operator, Inc. ("MISO"), which is located at 701 and 720 City Center Drive, Carmel, Indiana, 46032. This testimony is on behalf of MISO.

Q. WHAT POSITIONS AND RESPONSIBILITIES HAVE YOU HELD WITH MISO?

A. I joined MISO in May of 2005 as the Senior Manager of Market Quality. From July of 2007 to October 2010, I was MISO's Director of Market Services. As the Director of Market Services, I was responsible for MISO's Market Settlements, Market Quality, and Transmission Settlements functions. These functions oversee the development, maintenance and operation of Market and Transmission Settlements Systems which are governed by Modules B and C of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "ASM Tariff"). These responsibilities primarily involve the maintenance and execution of Settlements Systems, producing Settlement Statements, resolving disputes, as well as, developing and implementing Transmission and Market rates and charges, including implementing Tariff modifications and creating and updating Business Practices Manuals for Market Settlements.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND

A. I hold a Bachelor of Science Degree in Civil Engineering from the University of Florida. Prior to joining the MISO, I was employed as a Consultant with the Structure Consulting Group LLC in their Regional Transmission Organization ("RTO") Consulting Practice from 2003 to 2005, and Accenture (formerly Andersen Consulting) in their Utilities Industry Practice from 1995 to 2003. Prior to joining Andersen Consulting, I served as a Commissioned Officer in the United States Navy from 1988 until 1994 in the Submarine Force, attaining the rank of Lieutenant.

Q. WHAT IS YOUR CURRENT ROLE WITH MISO?

A. My current role is the Director of Market Administration, responsible for administering the Day-Ahead and Financial Transmission Rights Markets, Resource Adequacy, Forecast Engineering, as well as the Reliability Assessment Commitment and Market Administration Engineering functions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Testimony is to discuss how the proposed Extended Locational Marginal Pricing ("ELMP") Tariff changes will impact Settlements[1], and, in particular explain how the proposed ELMP Tariff changes may impact Make Whole Payments ("MWP") and/or Revenue Sufficiency Guarantee ("RSG") payments that are currently included in the Tariff.

II. <u>ELMP AND SETTLEMENTS</u>

Q. WHAT IS ELMP AND HOW IS IT CALCULATED?

A. ELMP refers to MISO's new process for calculating market settlement prices, including both energy Locational Marginal Prices ("LMPs") and Operating Reserve Marginal Clearing Prices ("MCPs"). After implementing ELMP, the terms LMPs and MCPs often will be referenced in conjunction with prefixes "Ex Ante" and "Ex Post" in the proposed ELMP Tariff provisions. These prefixes will help to clarify the process in which the energy LMPs and Operating Reserve MCPs are calculated. Ex Post LMPs and Ex Post

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[1] Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the Tariff or the proposed Tariff provisions.

MCPs will refer to the prices calculated using the ELMP process. All Settlement sections of the Tariff have been updated to use either Day-Ahead Ex Post LMP or MCP, Hourly Real-Time Ex Post LMP, or Hourly Real-Time Ex Post MCP terminology.

Q. CURRENTLY, HOW ARE ENERGY AND ANCILLARY SERVICES PRICES CALCULATED?

A. Energy and Ancillary Services prices are currently being calculated through the Security Constrained Economic Dispatch ("SCED") algorithm. SCED is MISO's primary algorithm for determining the Energy and Operating Reserve product clearing schedules for committed resources in both its Real Time and Day-Ahead markets. SCED also generates prices for the cleared products that reflect the system marginal costs. A key drawback of the SCED pricing algorithm is that it often does not allow certain Fast Start Resources to set price, even though such Resources often have the highest Offer cost of the resources that MISO must deploy to meet requirements at a location. The SCED prices also may not reflect the Start-Up/Shut-Down Offer costs and the No-Load Offer costs of resources. The SCED prices, thus, do not always cover a Market Participant's Offer costs. In that event, MISO must make RSG payments to compensate the Market Participant for its Offer costs.

Q. HOW WILL ELMP ALTER THE SCHEDULES AND PRICES FOR SETTLEMENT?

A. SCED currently produces both schedules and prices for market Settlement. After ELMP, the SCED schedules and ELMP prices will be used in Settlement. The processes used by MISO to commit resources and to produce schedules for committed resources will not change in the Day-Ahead and Real-Time Markets. Both the Day-Ahead and Real-Time Markets will be executing SCED-Pricing (*i.e.*, the ELMP software engine) after SCED has been executed. The SCED prices will be called Ex Ante prices, and they will be used for information only. The SCED-Pricing prices will be called Ex Post prices, and they will be used for Settlement. All charges and credits associated with the Settlement of the Day-Ahead and Real-Time Energy and Operating Reserve Markets and FTR Markets will use Ex Post pricing based on the SCED-Pricing Algorithm that is described in the new Schedule 29A.

III. IMPACT OF ELMP ON RSG PAYMENTS

Q. WHAT CAUSES THE NEED FOR THE PROPOSED CHANGES TO THE DAY-AHEAD RSG?

A. Under the proposed ELMP methodology, certain Market Transactions may not be kept whole to their Offer costs due to differences between the SCED process which generates cleared schedules, and the SCED-Pricing process which defines the prices. Currently, MISO's Day-Ahead RSG provisions keep Resources whole for MISO economic commitments for transactions settled in the Day Ahead Market. Other price sensitive Day-Ahead Market Transactions include: (1) Must-Run Resources; (2) Price Sensitive Demand Bids; (3) Virtual Transactions; and (4) Dispatchable and Up-to-Transmission Usage Charge ("TUC") Interchange Schedules. The current Tariff contains no provisions for keeping these Day Ahead Transactions whole as the Day Ahead SCED clearing is consistent with the Day Ahead SCED pricing, respecting Offer and Bid prices and quantities.

Virtual Supply Offers, dispatchable Import Schedules, and Must Run Generation may require MWPs when an Ex Ante to Ex Post decrease in price results in insufficient revenue to cover their offered costs. Virtual Demand Bids, Price Sensitive Demand Bids, and Price Sensitive Exports may require MWPs when an Ex Ante to Ex Post increase in price results in a charge that is greater than their willingness to pay. In addition, Up-to-TUC Interchange Transactions may require MWPs when the TUC Offer that cleared based on the Ex Ante LMP price spread between two Commercial Pricing Nodes is no longer satisfied based on the updated Ex Post prices.

Q. WHAT ARE THE PROPOSED CHANGES TO DAY-AHEAD RSG?

A. The existing Tariff contains RSG provisions to keep parties whole under certain circumstances. The proposed ELMP Tariff provisions will also update the Day-Ahead Revenue Sufficiency Guarantee MWP to include provisions specific to differences in Day-Ahead Ex Ante and Ex Post pricing in order to ensure economically cleared transactions receive adequate market compensation. The Day-Ahead RSG will be similar to the current process. The difference will be that price sensitive demand, Must-Run resources, Virtual supply, demand bid, and dispatchable transactions will also be eligible for Day-Ahead RSG payment in order to ensure economically cleared transactions receive adequate market compensation.

When considering price sensitive demand bids, virtual bids and Export, MISO will calculate Day-Ahead charges based on the Day Ahead Ex Post LMP. MISO will then calculate the Day-Ahead willingness-to-pay based on the applicable bid. MISO will calculate the difference between the Day-Ahead charges and Day-Ahead willingness-to-pay in an hour, and if the difference is negative, then the price sensitive demand, virtual bid, or Export will be eligible for the RSG payment for the hour.

When considering Must-Run Generation, Virtual Supply Offers and dispatchable exports, MISO will calculate Day-Ahead revenue based on Day Ahead Ex Post LMPs and MCPs. MISO will then calculate the Day-Ahead production cost based on the applicable Offer. MISO will calculate the difference between the Day Ahead production cost and Day-Ahead revenue in an hour, and if the difference is positive, then the Must-Run Generation, Virtual Supply Offer, or dispatchable export is eligible for the RSG payment for the hour.

Q. HOW WILL DAY-AHEAD RSG BE CALCULATED FOR MUST RUN RESOURCES?

A. A Must-Run Resource will be eligible for Day-Ahead RSG payment only when it is cleared above its achievable minimum for Energy and/or its Self-Scheduled quantities for Operating Reserves. The achievable minimum is the maximum of: (1) its Hourly Economic Minimum Limit (or Hourly Regulation Minimum Limit if scheduled to provide Regulation Reserves), (2) its Self Scheduled quantity for Energy, and (3) the energy scheduled in the last hour minus the resource’s offered ramp rate times 60 minutes. When a Must-Run resource is cleared above its achievable minimum for Energy and/or Self Scheduled amounts for Operating Reserves in Day Ahead SCED, MISO will calculate the incremental cost and revenue for the MW above its achievable minimum for Energy and/or Self Schedule amounts for Reserves. MISO will then compare the revenue with the incremental cost for an hour, and if the revenue is less that the incremental cost, then the Must-Run Resource will receive a MWP in the hour.

Q. WHY ARE THERE NO PROPOSED CHANGES TO THE REAL-TIME MWPs?

A. Under Real Time RSG, the only price sensitive transactions are for Resources that provide an Offer Curve used as part of the SCED and SCED-Pricing Algorithms. The current Tariff keeps such Resources whole for transactions settled in the Real Time Market via three types of MWP mechanisms: (1) RSG; (2) Day-Ahead Margin Assurance; and (3) Real-Time Offer RSG payments. As a result, no additional MWP are required.

Q. WILL THE PROPOSED APPROXIMATE ELMP METHODOLOGY ALLOW THE RECOVERY OF OPPORTUNITY COSTS?

A. No. After careful consideration, MISO believes that the recovery of certain opportunity costs is inappropriate under the current circumstances. Such opportunity costs are those that may arise when a Generation Resource follows MISO's schedule and therefore does not receive the potential additional profits that the resource could have earned by committing and dispatching itself in response to the Ex Post prices. The potential recovery of such opportunity costs, however, is a topic that is currently being explored in

MISO's RSG Task Force meetings, so future Tariff modifications might be made to allow recovery of such opportunity costs. Opportunity costs arising from dispatch decisions that trade one product for another will continue to be reflected in prices as in the current Tariff.

Q. CAN MISO PREDICT WITH SPECIFICITY THE RSG CHANGES FROM APPROXIMATE ELMP?

A. No. Many stakeholders have questioned whether implementation of ELMP will result in increased or decreased MWP and associated RSG allocations. Under certain circumstances, MISO must commit a more expensive resource that will be scheduled at EconMin to provide needed Energy or Operating Reserves which cannot set LMPs under the current Tariff. To make room for the energy provided at EconMin, MISO may have to dispatch down a cheaper Resource which may set LMPs under the current Tariff. This potentially results in increased RSG or MWPs. A benefit to adoption of the proposed ELMP will be that the resource dispatched at EconMin could set ELMPs, thereby reducing some RSG uplift costs. As a result, the proposed ELMP, in some instances, may reduce RSG payments to Resources by providing a more accurate pricing signal that is based upon the assumption that Resources can be dispatched anywhere along an Energy Offer curve, including at an operating limit, and still have such Resources be able to set prices.

It is not possible for MISO to estimate in the abstract the impact on RSG payments if ELMP was implemented. MISO is also not able to calculate, for example, whether or not the reduced RSG costs are outweighed or not by changes to LMPs and MCPs as a result of implementing ELMP. Such a calculation would depend, for example, upon many variables (*e.g.*, Market Participant potential changed bidding behaviors) that MISO cannot accurately estimate.

Q. HOW IS MISO RESPONDING TO STAKEHOLDER REQUESTS FOR PARALLEL SETTLEMENT STATEMENTS?

A. MISO has received requests, at various times during the stakeholder process, to run two settlement statements during the parallel operations phase of testing for ELMP. MISO seriously considered this option and to the extent reasonably feasible, MISO will be providing stakeholders with parallel settlement data. MISO will conduct parallel testing of ELMP before there is a "cut-over" from LMP pricing to ELMP pricing. MISO currently plans to conduct such parallel testing for a period of about three (3) months prior to implementation of ELMP pricing. During this period, MISO will be posting indicative ELMP prices and indicative Settlement statements, including RSG billing determinants, which will not be binding. Posting these prices and Settlement statements will assist stakeholders in being able to compare the *status quo* pricing to ELMP pricing. However, Market Participant bidding behaviors may be different during parallel testing, as opposed to after ELMP pricing is implemented. Once ELMP has been implemented, MISO will provide an estimate of RSG payments based upon *status quo* LMPs.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. This completes my Testimony in the subject proceeding.

Dated this 22nd day of December, 2011.

AFFIDAVIT

County of Hamilton

State of Indiana

KEVIN A. VANNOY, being duly sworn, deposes and states: that he prepared the Testimony of Kevin A. Vannoy and the statements contained therein are true and correct to the best of his knowledge and belief.

Kevin A. Vannoy

SUBSCRIBED AND SWORN BEFORE ME, this 21st day of December, 2011.

Christi Larson

Christi I. Larson

Notary Public, Marion County

State of Indiana

My Commission Expires: August 15, 2013

CHRISTI I. LARSON
Notary Public, State of Indiana
Marion County
Commission # 542850
My Commission Expires
August 15, 2013

STATE OF INDIANA NOTARY SEAL