

ORIGINAL

RE FILED

JUL 20 2018

PUBLIC SERVICE
COMMISSION



Your Touchstone Energy® Cooperative 

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION**

)
)
)

**Case No.
2017-00384**

**Responses to Commission Staff's
First Request for Information
dated
June 22, 2018**

**Volume 2 of 4
Item Nos. 21 through 35**

FILED: July 20, 2018

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
First Request for Information
dated June 22, 2018**

July 20, 2018

1 **Item 21) *Refer to the IRP, Chapter 6, Section 6.6.4, page 101 , regarding***
2 ***the Burns and McDonnell final Green Station Coal Combustion***
3 ***Residuals/Effluent Limitations Guidelines Compliance report. Provide a***
4 ***copy of the report.***

5

6 **Response) Please see the CONFIDENTIAL Burns and McDonnell Green Station**
7 **Coal Combustion Residuals/Effluent Limitations Guidelines Compliance report dated**
8 **July 2017 provided with these responses.**

9

10

11 **Witness) Dr. Thomas L. Shaw**

12

In the Matter of:

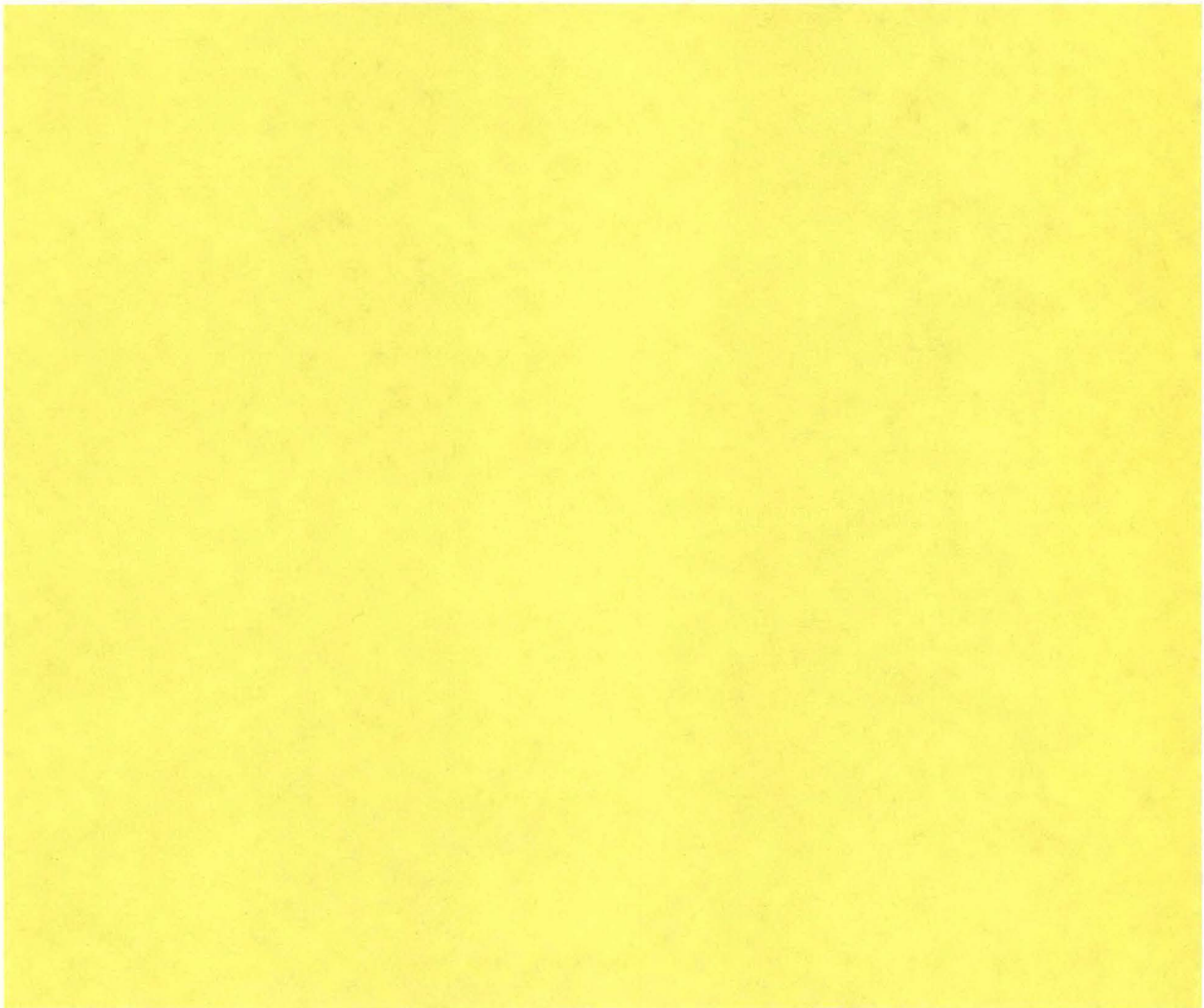
2017 INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION) Case No. 2017-00384

CONFIDENTIAL RESPONSE

to Item 21 of the Commission Staff's
First Request for Information
dated June 22, 2018
FILED: July 20, 2018

Burns and McDonnell Green Station –
CCR / ELG Compliance Project Definition Report

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL
TREATMENT



BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
First Request for Information
dated June 22, 2018**

July 20, 2018

1 Item 22) *Refer to the IRP, Chapter 6, Section 6.6.6, page 104, where it states*
2 *that "Big Rivers has suspended further development of any specific strategy*
3 *to comply with the CPP."*

4 a. *Identify the strategies that have been suspended as a result of the*
5 *actions on the CPP to date.*

6 b. *Identify the environmental compliance programs that are still in*
7 *effect at this time.*

8

9 **Response)**

10 a. The investigation to identify possible compliance options was not developed
11 to a point that a specific strategy was identified; therefore, there are no
12 specific suspended strategies to list.

13 b. The environmental compliance programs that are still in effect at this time
14 are as follows:

- 15 1. Cross State Air Pollution Rule,
- 16 2. Coal Combustion Residuals Rule,
- 17 3. Mercury Air Toxics Rule,
- 18 4. Acid Rain,
- 19 5. Effluent Limit Guidelines, and
- 20 6. Clean Water Act § 316b.

21

22

23 **Witness) Dr. Thomas L. Shaw**

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
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dated June 22, 2018**

July 20, 2018

1 **Item 23)** *Refer to the IRP, Chapter 7, Section 7.1, The Plexos Model - An*
2 *Overview, page 106.*

3 *a. When Plexos adds the program costs of DSM alternatives, confirm*
4 *that they are added based on marginal cost pricing and when added*
5 *have the least marginal cost.*

6 *b. Explain what encompasses the program costs of DSM alternatives*
7 *and provide an example.*

8 *c. Explain if the DSM alternatives are forecasted DSM additions or*
9 *existing DSM programs.*

10

11 **Response)**

12 *a. PLEXOS® utilized the inputs provided by GDS for an additional DSM*
13 *spend (from \$1 million to \$2 million) and evaluated the additional DSM*
14 *spend energy efficiency savings (peak and energy) as a generation resource.*

15 *b. Program costs of DSM alternatives consist of incentives to customers to*
16 *adopt DSM measures and administrative costs, e.g., promotion, to run the*
17 *programs which provide the DSM measures.*

18 *c. The evaluation of the additional \$1.0 million in DSM spend was based on*
19 *the same program measures as the initial \$1.0 million analysis.*

20

21

22 **Witnesses)** *Duane E. Braunecker (a. only) and*

23 *Russell L. Pogue (b. and c. only)*

Case No. 2017-00384

Response to PSC 1-23

Witnesses: Duane E. Braunecker (a. only) and

Russell L. Pogue (b. and c. only)

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**2017 INTEGRATED RESOURCE PLAN OF
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CASE NO. 2017-00384**

**Response to Commission Staff's
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dated June 22, 2018**

July 20, 2018

1 **Item 24) Refer to the IRP, Chapter 7, Section 7.1.2, page 110, regarding the**
2 **scenario with the option to exit the HMP&L contract in 2018 and to Case No.**
3 **2018-00146.¹**

4 **a. Identify and explain the impact that Case No. 2018-00146, if**
5 **approved by the Commission, will have on the assumptions and**
6 **conclusions in Big Rivers' 2017 IRP**

7 **b. Explain the impacts that Case No. 2018-00146, if approved by the**
8 **Commission, will have on Big Rivers' currently idled Coleman**
9 **Station and Reid Station Unit 1.**

10 **c. Identify and explain the impacts that Case No. 2018-00146, if**
11 **approved by the Commission, will have on Big Rivers'**
12 **environmental analysis and associated capital and operating and**
13 **maintenance expenses associated with its environmental**
14 **compliance planning contained in its IRP.**

15

16 **Response)**

17 **a. Approval of Case No. 2018-00146 by the Commission would be consistent**
18 **with the assumptions and conclusions in the Big Rivers' 2017 IRP. The**
19 **2017 IRP concluded that Big Rivers should exit the Station Two contracts**
20 **which is the subject of Case No. 2018-00146.**

¹ Case No. 2018-00146, *Notice of Termination of Contracts and Application of Big Rivers Electric Corporation for a Declaratory Order and for Authority to Establish a Regulatory Asset* (filed May 1, 2018).

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOUC E PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
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dated June 22, 2018**

July 20, 2018

- 1 b. Since the generation is not needed to serve the Big Rivers' native load and
2 contractual commitments, there will be no impacts.
- 3 c. Approval of Case No. 2018-00146 by the Commission would be consistent
4 with the assumptions and conclusions in the Big Rivers' 2017 IRP. Big
5 Rivers would not need to fund the project to convert the Station Two units
6 from a wet bottom ash system.

7
8
9 Witnesses) Michael T. Pullen (*a. and b. only*) and
10 Dr. Thomas L. Shaw (*c. only*)

11

BIG RIVERS ELECTRIC CORPORATION
2017 INTEGRATED RESOURCE PLAN OF
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CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1 **Item 25) *Refer to the IRP, Chapter 7, Section 7.1.2, page 111 , regarding***
2 ***the Burns and McDonnell decommissioning study for the Coleman Station.***
3 ***Provide a copy of the referenced study.***

4
5 **Response) A CONFIDENTIAL copy of the Burns and McDonnell Decommissioning**
6 **Cost Estimate Study dated March 3, 2016, is provided as an attachment to this**
7 **response.**

8
9
10 **Witness) Michael T. Pullen**

11

In the Matter of:

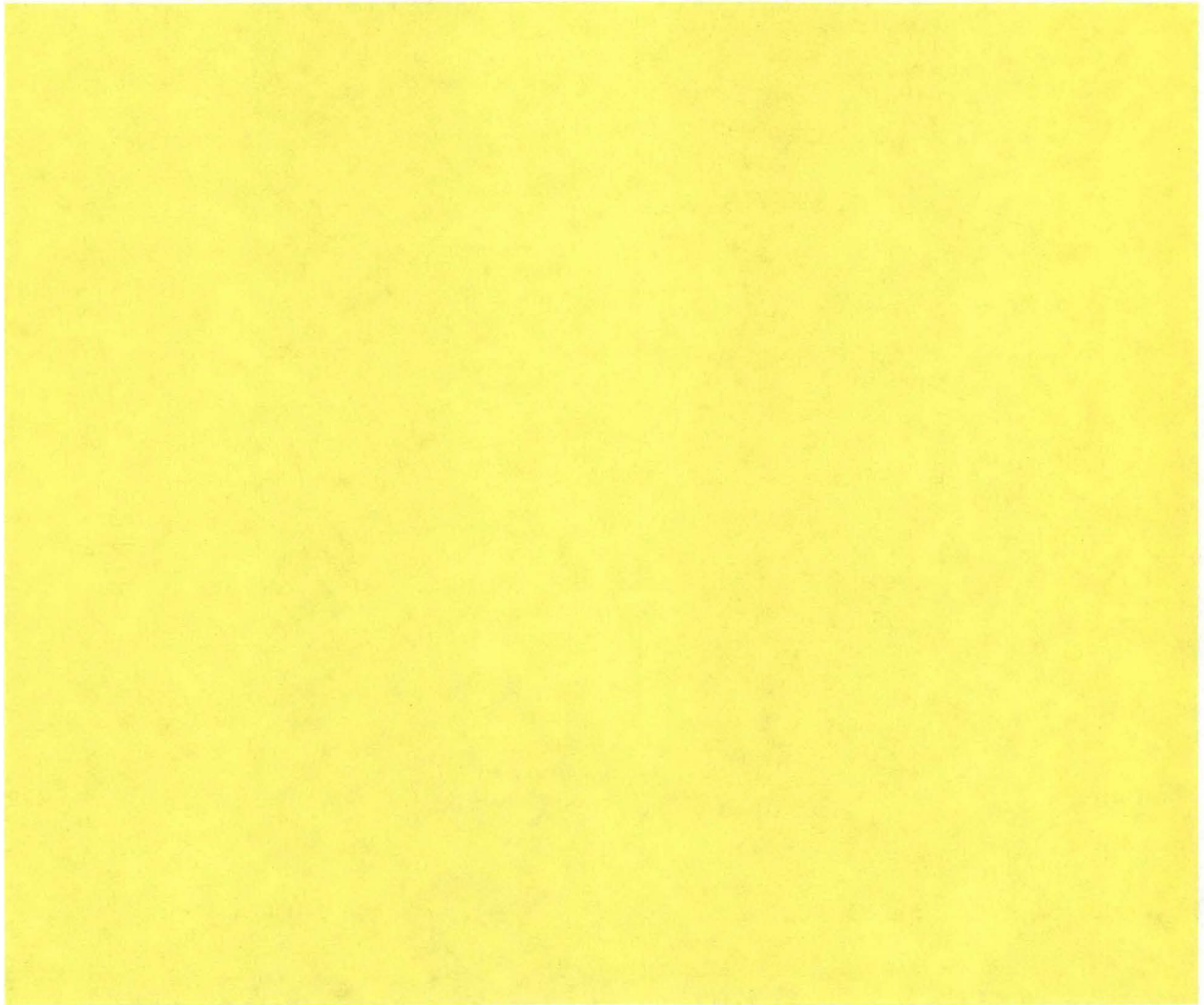
2017 INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION) Case No. 2017-00384

CONFIDENTIAL RESPONSE

to Item 25 of the Commission Staff's
First Request for Information
dated June 22, 2018
FILED: July 20, 2018

Burns and McDonnell Decommissioning Cost Estimate Study –
March 3, 2016

**INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL
TREATMENT**



BIG RIVERS ELECTRIC CORPORATION
2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
Initial Request for Information
dated June 22, 2018

July 20, 2018

1 **Item 26)** *Refer to the IRP, Chapter 7, Section 7.1.2, page 113, Table 7.3.*
2 *Explain the variances in the historical cost per megawatt hour for the SEPA*
3 *energy.*

4
5 **Response)** Historical cost per megawatt hour for the Southeastern Power
6 Administration ("SEPA") energy for years 2013 through 2016 are the effective
7 \$/MWH based on actual invoiced amounts at the demand, energy, and TVA rates in
8 effect at the time, less capacity interruption credits. For 2013 through June 2014,
9 only energy and transmission charges were applicable under Interim Operation for
10 the marketing and delivery of Cumberland System power due to dangerous seepage
11 problems at the Wolf Creek Dam and Center Hill Dam. Beginning July 1, 2014, the
12 Revised Interim Operating Procedures established by SEPA reduced the dependable
13 capacity and energy and established a capacity and energy rate for all energy. For
14 2017, the cost per megawatt hour is the forecasted amount for demand, energy, and
15 TVA transmission.

16
17
18 **Witness)** Marlene S. Parsley
19

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
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CASE NO. 2017-00384**

**Response to Commission Staff's
First Request for Information
dated June 22, 2018**

July 20, 2018

1 **Item 27)** *Refer to the IRP, Chapter 7, Section 7.1.2, page 114, regarding*
2 *onshore wind energy. Explain if there are any other options for onshore wind*
3 *energy considered other than the referenced northwestern Kentucky option.*

4

5 **Response)** There were no other sources for onshore wind energy considered beyond
6 the northwestern Kentucky option.

7

8

9 **Witnesses)** Russell L. Pogue and

10 Duane E. Braunecker

11

BIG RIVERS ELECTRIC CORPORATION
2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

- 1 **Item 28)** *Refer to the IRP, Chapter 7, Section 7.2.1, page 119, Table 7.6.*
2 *a. Explain the variances in the historical MISO Capacity Auction*
3 *prices per \$/Megawatt-Day.*
4 *b. Identify and explain any legal matters related to the MISO Capacity*
5 *Auctions and other market operations since Big Rivers' 2014 IRP.*
6 *Provide copies of all litigation information with respect to any*
7 *issues.*
8 *c. Provide the results of all MISO Capacity Auctions and other interim*
9 *capacity and energy auctions/market indicators since Big Rivers'*
10 *2014 IRP.*
11 *d. Provide all information that MISO has provided Big Rivers with*
12 *respect to capacity auction prices and hedged capacity prices since*
13 *its 2014 IRP.*

14
15 **Response)**

- 16 *a. Cost recovery for generating resources is a component of regulated retail*
17 *rates in most states in the MISO region. As such, the MISO capacity*
18 *market functions as a residual market. In addition, due to ample*
19 *transmission transfer capability between MISO zones, and modest local*
20 *clearing requirements in each zone, auction clearing prices across in the*
21 *MISO north region (including Big Rivers' Zone 6) are typically the same in*
22 *each zone. Consistent with this structure, as illustrated in Table 7.6, over*
23 *the 2014/2015 Planning Year ("PY"), the 2015/2016 PY and the 2017/2018*

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July 20, 2018

1 PY, MISO Capacity Auction Prices for Zone 6 ranged between \$1.50 MW-
2 day to \$16.75 MW-day. It is thought that the \$72 MW-day auction price in
3 the 2016/2017 PY is the result of bidding behavior by generating resources
4 and revisions to local clearing requirement parameters in MISO north
5 region.

- 6 b. The MISO Legal Department does not internally maintain an ongoing list
7 of all MISO docket numbers for proceedings at the Federal Energy
8 Regulatory Commission ("FERC") and at the state level. MISO does,
9 however, daily list all of its FERC and state-level filings. MISO provides
10 the following links from the MISO website:

11 FERC filings:

12 <https://www.misoenergy.org/legal/ferc-filings/#t=10&p=0&s=&sd=>

13 State Filings:

14 <https://www.misoenergy.org/legal/state-filings/#t=10&p=0&s=state&sd=asc>

15
16 Since the filing of its 2014 IRP, Big Rivers filed a motion to intervene
17 and limited protest in FERC Docket No. ER18-1173-000, MISO's filing to
18 enhance the Locational aspect of its resource adequacy construct to create
19 External Resource Zones ("ERZs"). In its protest, Big Rivers requested
20 FERC direct MISO to include Big Rivers' allocation of SEPA capacity and
21 energy in Border External Resources and thus be exempted from External
22 Resource Zone treatment and potential Planning Resource Auction price
23 separation. Attached hereto is MISO's filing in Docket No. ER18-1173-000.

BIG RIVERS ELECTRIC CORPORATION
2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
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July 20, 2018

1 Also attached hereto is Big Rivers' motion to intervene and limited protest
2 in ER18-1173-000. As of the filing of this response, FERC has not ruled in
3 this Docket. For more information see Docket ER18-1173 at the FERC
4 website: https://elibrary.ferc.gov/idmws/docket_sheet.asp.

5 c. For results of all MISO Capacity Auctions since Big Rivers' 2014 IRP,
6 please see the MISO presentations on Planning Resource Auction Results
7 for Planning Years 2014/15 through Planning Year 2018/19, which are
8 attached hereto.

9 d. Since the filing of Big Rivers' 2014 IRP, MISO has provided Big Rivers no
10 information with respect to capacity auction prices and hedged capacity
11 prices other than what is publicly available on the MISO website
12 <https://www.misoenergy.org/planning/resource-adequacy/#nt=>.

13
14
15 Witness) Marlene S. Parsley

16

Case No. 2017-00384

**PSC 1-28b (MSP)(Att1) - MISO FERC filing in
Docket No ER18-1173-000**



Jacob T. Krouse
Managing Sr. Corporate Counsel
Direct Dial: 317-249-5715
E-mail: jkrouse@misoenergy.org

March 26, 2018

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

**Re: Midcontinent Independent System Operator, Inc.
Filing to Enhance Locational Aspect of Resource Adequacy Construct
Docket No. ER18-____-000**

Dear Secretary Bose:

The Midcontinent Independent System Operator, Inc. ("MISO"), through this filing,¹ proposes to revise certain locational aspects of its resource adequacy construct of its Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"). This proposal, created through an extensive stakeholder process over the past few years, aligns auction inputs and pricing for internal and External Resources while recognizing the unforeseeable risks capacity market changes may impose on pre-existing, long-term capacity arrangements. More specifically, these revisions create External Resource Zones ("ERZs"), allocate excess auction revenues to Load Serving Entities impacted by changes to MISO's resource adequacy construct through Historic Unit Considerations ("HUCs"), and align parameters used to calculate auction inputs such as Capacity Import Limits ("CIL"), Capacity Export Limits ("CEL"), and Local Clearing Requirements ("LCR") with the use of these limits in the Planning Resource Auction ("PRA"). MISO requests an effective date for this filing of May 30, 2018 to allow for the inclusion of these provisions in the 2019/2020 Planning Year.

¹ MISO makes this filing pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1, *et seq.* All capitalized terms in this filing that are not otherwise defined have the same meaning as they have under the current MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

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March 26, 2018
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I. BACKGROUND

Since the implementation of MISO's wholesale electricity markets in 2005, MISO's approach to resource adequacy, as currently documented in Module E-1, has been developed in collaboration with its members, Market Participants and regulators. The goal of this construct is to establish mechanisms to encourage the proper mixture of Planning Resources (*e.g.*, Capacity Resources, Demand Resources, Behind the Meter Generation, Energy Efficiency Resources) to be available in the right locations in the MISO Region to maintain MISO's targeted level of loss of load expectation. As MISO has reviewed this construct with stakeholders in 2015, five guiding principles were developed to shape MISO's role in supporting resource adequacy. One of these principles is to provide appropriate regional and zonal resource adequacy transparency and awareness. Given the current treatment of External Resources in MISO's resource adequacy construct, and the potential for significant volumes of existing resources on neighboring systems to offer into the Planning Resource Auction as early as the 2019-2020 Planning Year as new External Resources, MISO may not be able to continue to meet this principle. This concern has prompted MISO to develop the instant proposal, which creates a balanced package of revisions to refine the modeling and treatment of External Resources to allay possible transparency and awareness concerns.

II. OVERVIEW OF MISO'S LOCATIONAL ENHANCEMENT PROPOSAL

As noted above, the revisions in MISO's proposal center in three areas: (1) the creation of External Resource Zones; (2) proposed changes to the allocation of excess PRA revenues through the provision of Historic Unit Considerations; and (3) the alignment of Loss of Load Expectation ("LOLE") outputs such as Capacity Import Limit, Capacity Export Limit, and Local Clearing Requirement parameters with the treatment of those limits in the PRA. These revisions were created as a complete and balanced package based on discussions and adjustments made during the stakeholder process. As such, they are intended to be an integrated set of elements to improve MISO's existing resource adequacy construct and should not be viewed in isolation.

A. External Resource Zones

MISO's resource adequacy processes serve to support Load Serving Entities and applicable regulatory agencies in maintaining resource adequacy in the MISO Region. As such, MISO establishes Local Clearing Requirements for each Local Resource Zone ("LRZ" or "Zone") that represent the minimum capacity needed within that Zone to support local load. Under MISO's current processes, resources within MISO are given credit and cleared in the LRZ in which they are physically located. However, an External Resource participating in MISO's PRA is currently given capacity credit in the Zone in which its firm transmission service crosses the MISO border, creating potential reliability concerns and pricing inequity. More specifically, the current treatment of External Resources could cause reliability concerns in an instance where External Resources displace sufficient local resources to cause the cleared resources physically within the Zone to be less than that Zone's LCR because some of the "local" resources required for reliability would actually be located external to both the LRZ and to the MISO footprint. Further, these "local" resources would be granted the Auction Clearing Price ("ACP") based on a

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Zone remote from their physical location, creating pricing inequity when compared to both their reliability benefit provided to that Zone and to internal resources located in other Zones throughout MISO.

1. Creation of External Resource Zones

To prevent inequity and address potential reliability concerns,² MISO is proposing to modify its treatment of External Resources to model and price them in External Resource Zones.³ Unless it meets one of the exceptions discussed below, each External Resource will be placed into an External Resource Zone that aligns with the external Balancing Authority in which it is physically located. External Resources in ERZs are able to participate in the Planning Resource Auction and offset MISO's regional Planning Reserve Margin Requirement ("PRMR"), but will not be able to offset Local Clearing Requirements for any given MISO LRZ.

2. Pricing of External Resource Zones

The PRA will continue to clear resources to minimize the total system cost while managing resource and transmission constraints such as LCR, CIL, CEL, and Sub-Regional Import or Export Constraints ("SRIC" or "SREC"). As such, ERZs will be priced based upon their support of the regional resource requirements, subject to the CEL from each ERZ and sub-regional constraints (SRIC and SREC). As further described in the Testimony of Laura Rauch, Director of Resource Adequacy, in the Affidavit of David B. Patton, Ph.D., and shown in the graphic below,⁴ MISO proposes to generally price ERZs in three ways,⁵ depending on their connection to the MISO region.⁶

² See Rauch Testimony at 4-5 and 9-10.

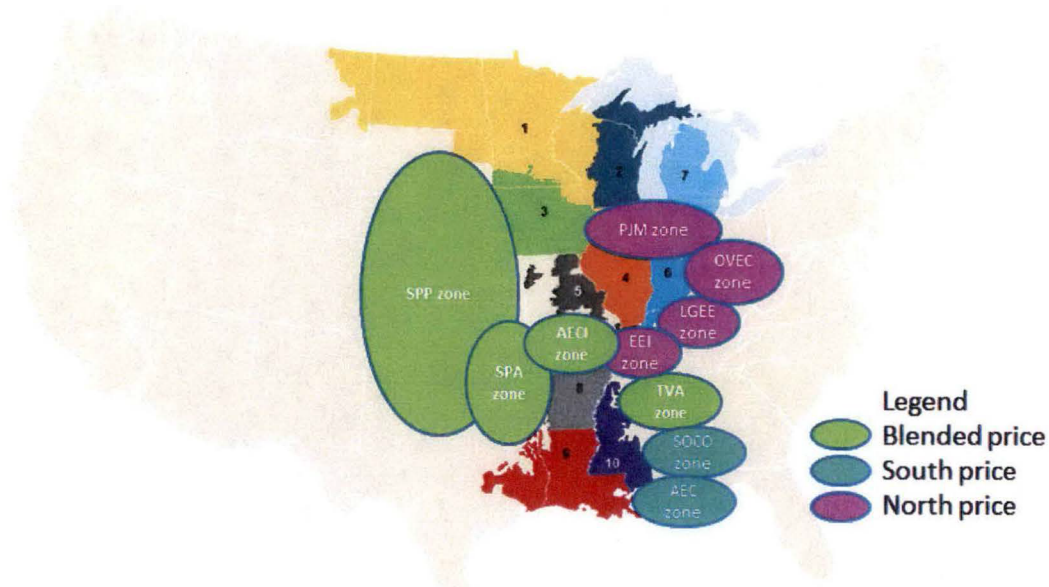
³ See revised Tariff Sections 1.A, 1.C, 1.E, 1.P, 1.Z, 68A, 68A.3, 68A.4, 68A.5, 69A, 69A.3.1.h, 69A.7, 69A.7.1, 69A.7.6, 69A.7.7(a), 69A.7.7(b), 69A.7.8, 69A.7.9, and 69A.9.

⁴ This graphic is an indicative example based on historic participation and balancing authority boundaries existing at the time of the External Resource participation.

⁵ See Rauch Testimony at 14-16. See also Patton Affidavit at P 14-16.

⁶ See revised Tariff Section 69A.7.1.

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External balancing authorities with ties solely to the northern part of the MISO footprint – such as EEI, LGEE, OVEC, or PJM – would receive the unconstrained price of MISO North. Those balancing authorities with ties solely to the southern part of the MISO footprint, like SOCO or AEC, would receive the unconstrained price of MISO South. External balancing authorities that tie to both MISO North and MISO South, or any future ERZs with no direct interfaces to the footprint, will receive a blended price based upon the shift factors calculated based on real time energy flows, such as those in the MISO-SPP Settlement Agreement.⁷ Additionally, the price for a given ERZ may vary if exports from that ERZ are constrained in the Simultaneous Feasibility Test.⁸

3. Local qualification criteria for External Resources

Local Clearing Requirements (“LCR”) are intended to ensure that sufficient capacity is located within each Zone to support local resource needs during emergency conditions. In general, External Resources are not able to offset a Zone’s local resource needs, as represented by its LCR, due to their physical separation from the MISO footprint. Additionally, all resources that obtain local credit, or otherwise reduce the number of local resources that clear the PRA (as discussed further in II.C), must be available for MISO’s use during Emergency Operating Procedures. However, some External Resources—Border External Resources and Coordinating Owner resources—meet both the physical and operational criteria to obtain local credit in certain Zones.⁹ These resource types are discussed further in Ms. Rauch’s testimony.¹⁰

⁷ See Appendix D of the Offer of Settlement filed in Docket Nos. EL14-21, *et al.*

⁸ See revised Tariff Section 69A.7.1.

⁹ **Physical criteria (location):** resources should be given credit where the resource is located, similar to the treatment of resources internal to MISO. **Operational characteristics:** MISO should be able to rely on units during capacity emergencies with unit specific dispatch to ensure local support.

¹⁰ See Rauch Testimony at 11-14.

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i. Border External Resources

MISO proposes to create a subcategory of External Resources called Border External Resources.¹¹ These resources have a point of interconnection in a substation that contains the terminal of a transmission line under MISO's functional control. To qualify as a Border External Resource, the resource must also respond to recall requirements designated in Module E-1 and MISO's Emergency Operating Procedures in a unit-specific manner from this substation (as opposed to a slice-of-system method).¹² Such electrical proximity and emergency operation provisions allow Border External Resources to meet the physical location and operational requirements noted above and therefore, Border External Resources should qualify for local treatment within the bordering MISO LRZ.¹³

ii. Coordinating Owner Resources

MISO also proposes to allow the existing subcategory of External Resources, the resources of Coordinating Owners, to continue to qualify for local treatment.¹⁴ These resources are physically located in an external region in which MISO is the Reliability Coordinator, and they are supported by Seams Operating Agreements¹⁵ that state what coordination will occur during both normal and emergency operations, meeting MISO's operational criteria. Additionally, the Coordinating Owner area has strong, direct ties to MISO without an intervening system, adding certainty as to the ability of capacity to be delivered to the MISO footprint and meeting locational requirements.

B. Historic Unit Considerations

Given the proposed change in the treatment of External Resources, MISO believes it is necessary and equitable to pair the creation of ERZs with a new methodology to allocate excess auction revenue. This treatment helps avoid imposing unforeseeable costs on entities that formed contracts that relied on MISO's existing pricing treatment of External Resources. As described further in Ms. Rauch's testimony, MISO's proposed HUC concept replaces the existing

¹¹ See revised Tariff Section 1.B. See also revised Tariff Sections 68A.3 and 69A.7.1.

¹² See Rauch Testimony at 12.

¹³ Should a Border External Resource border more than one MISO LRZ, MISO has revised Tariff Section 69A.7.1 to allow "the Market Participant may elect the LRZ in which the Border External Resource is granted ZRCs through notice submitted no later than two (2) years prior to February 1 preceding the applicable Planning Year. Such representation will not be modified more frequently than every other year."

¹⁴ See Rauch Testimony at 12-13. See also revised Tariff Sections 68A.3 and 69A.7.1.

¹⁵ See Seams Operating Agreement between MISO and Manitoba Hydro (Rate Schedule 8) and Coordination Agreement Between MISO and Manitoba Hydro (Rate Schedule 2).

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Grandmother Agreement provisions¹⁶ and modifies the allocation of excess auction revenue to first recognize historic capacity transactions.¹⁷ If prices in the PRA separate, Load Serving Entities with historic arrangements that could not have foreseen MISO's zonal construct or changes (such as Grandfather Agreements, pre-zonal capacity contracts, or pre-ERZ contracts with External Resources) would be eligible to receive excess auction revenue.¹⁸ If there is any excess auction revenue remaining after this allocation, it will be allocated by the existing Zonal Deliverability Benefit mechanism.¹⁹ However, if the excess revenue does not fully offset all eligible HUCs, all HUCs will receive a MW-weighted portion of excess revenue.²⁰

When evaluating HUCs with stakeholders, MISO reviewed past auctions and determined that there is minimal risk of there being insufficient revenue for all HUCs.²¹ In fact, the revenue needed for HUCs represented a small amount of the excess revenue currently allocated via Zonal Deliverability Benefit.²²

C. Capacity Import Limit and Capacity Export Limit changes

MISO proposes to further align LOLE outputs, such as CIL, CEL, and LCR, with Planning Resource Auction assumptions and visibility. As described further in the Ms. Rauch's testimony, to start, the output from all resources in LOLE studies will be aligned with the LRZ or ERZ in which they are accredited in the auction, creating a base interchange and list of resources studied in each Zone that matches PRA assumptions.²³ Further, MISO proposes to adjust CIL and CEL to reflect the transfer capacity used by resources that cannot clear in the PRA, such as exports to non-MISO load.

The proposal creates two new terms—Zonal Import Ability and Zonal Export Ability—to aid in the determination of CIL, CEL, and LCR.²⁴ Zonal Import Ability represents the

¹⁶ Currently, Tariff Section 69A.7.7(a) provides for certain agreements to be deemed Grandmother Agreements. Such status exempts the associated Planning Resources from the Zonal Deliverability Charge for a two year transitional period. MISO's proposed HUC construct will allow arrangements that qualified for Grandmother Agreements to be eligible for HUCs and therefore MISO is replacing Grandmother Agreements.

¹⁷ See Rauch Testimony at 19-25.

¹⁸ See revised Tariff Sections 69A.7.7, 69A.7.7(a), 69A.7.7(b), and 69A.11.11.

¹⁹ See revised Tariff Sections 69A.7.7(c) and 69A.11.12.

²⁰ See revised Tariff Section 69A.7.7.

²¹ See Resource Adequacy Subcommittee, 20170712 RASC Item 03b Locational Update (July 12, 2017 meeting) at pp 15-16, available at <https://cdn.misoenergy.org/20170712%20RASC%20Item%2003b%20Locational%20Update87556.pdf>.

²² See Rauch Testimony at 24-25.

²³ See Rauch Testimony at 25-30.

²⁴ See revised Tariff Section 1.Z.

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summation of the initial base interchange for each Zone and any incremental transfers. Zonal Export Ability represents summation of the base interchanges for each Zone and any incremental transfers. MISO will then calculate CIL by taking Zonal Import Ability and adding the counterflow of exports to external areas, such as SPP or PJM.²⁵ Likewise, CEL will be calculated by taking Zonal Export Ability and subtracting the exports of internal resources.²⁶ MISO will continue to update these values annually in March to reflect updated exports to non-MISO load.

MISO also proposes to change the calculation of Local Clearing Requirement to be calculated as the difference of the Local Reliability Requirement, the Zonal Import Ability, and controllable exports.²⁷ More specifically, current references to CIL in the LCR formulation would be replaced with Zonal Import Ability; this represents the system's total ability to import capacity, as opposed to using the CIL, which will be focus on the transmission constrained import limit in the PRA.²⁸ Additionally, MISO's current LCR calculation specifically refers to non-pseudo-tied exports. MISO proposes to replace the reference to "non-pseudo-tied" exports to instead reference "controllable" exports.²⁹ If MISO is able to obtain sufficient emergency control over pseudo-tied exporting resources, those controllable resources would be automatically included in the calculation of LCR without further Tariff changes.

III. STAKEHOLDER PROCESS

MISO worked extensively with stakeholders to create a balanced proposal with multiple viewpoints represented. This work began in 2014, with the introduction of concerns surrounding External Resources in stakeholder forums such as the Loss of Load Expectation Working Group ("LOLEWG") and the Supply Adequacy Working Group ("SAWG"). In 2015, MISO led stakeholders through discussions on the overall priorities of Resource Adequacy through artifacts such as a Resource Adequacy Issues Statement, Resource Adequacy Workshops, and a locational straw proposal. MISO continued to engage through the end of 2015 to 2018 in such forums as the LOLEWG, the SAWG and the Resource Adequacy Subcommittee ("RASC"), which succeeded the SAWG in 2016. Given the length of this stakeholder process, a list of stakeholder meetings and presentations on MISO's proposed locational enhancement filing is attached as Tab E to this filing.

Through these discussions MISO clarified and refined the proposals, incorporating stakeholder feedback as appropriate. For example, the inclusion of Border External Resources into the proposal was championed by a stakeholder based on the electrical and locational similarity of External Resources on the border of MISO with internal resources. Historic Unit

²⁵ See revised Tariff Sections 1.C, 1.Z, 68A, 68A.4, 68A.6, 69A, and 69A.7.1.

²⁶ *Id.*

²⁷ See Rauch Testimony at 28-29.

²⁸ See revised Tariff Section 68A.6.

²⁹ *Id.*

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Considerations were also included to recognize and address concerns by stakeholders on the impacts of zonal changes to historic, and non-negotiable, contracts. As such, the filing represents a complete package based on input received and adjustments made during the stakeholder process.

IV. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, this submission includes:³⁰

- Tab A – Clean Tariff Sheets effective 5/30/2018³¹
- Tab B – Redline Tariff Sheets effective 5/30/2018^{32 33}
- Tab C – Testimony of Laura Rauch
- Tab D – Affidavit of David B. Patton, Ph.D.
- Tab E – Table of Stakeholder Meetings and Presentations

V. PROPOSED EFFECTIVE DATE

MISO requests an effective date for this filing of May 30, 2018 for this filing, which is not less than sixty (60) days but not more than one hundred twenty (120) days after the filing date.

³⁰ 18 C.F.R. § 35.13(b)(1) (2017).

³¹ MISO has revised metadata of sections 68A.3, 69A.7.7, and 69A.7.7(a) to change the Tariff Record Titles. MISO's eTariff software does not redline changes to the metadata associated with its Tariff Records, thus no redlines will be shown in the Tariff Record Title.

³² Language currently pending before the Commission in the following, unrelated dockets is highlighted in yellow: ER18-1152-000. MISO requests that the Commission treat such highlighted language as subject to the outcomes of those pending proceedings. MISO commits to file any revisions to this highlighted language as necessary to comply with any Commission orders in those proceedings.

³³ MISO has removed language that has a future effective date of 7/1/2018 and is accepted in Docket No. ER18-314-000. MISO commits to make a subsequent filing with the Commission to update the Tariff records to reflect the most up-to-date versions of the then-current Tariff provisions prior to the effective date.

MISO has also removed language that has a future effective date of 7/1/2018 and 11/1/2018, and is pending in Docket Nos. ER18-906-000 and ER18-622-001. MISO commits to file any revisions to this pending language as necessary to comply with any Commission orders in those proceedings.

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VI. COMMUNICATIONS

MISO respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3) (2017), to the extent necessary to permit the designation of more than two persons for service on behalf of MISO in this proceeding and requests all communications related to this filing be directed to:

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VII. NOTICE AND SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the region. The filing has been posted electronically on MISO's website at <https://www.misoenergy.org/legal/ferc-filings/> for other parties interested in this matter.

VIII. CONCLUSION

For all of the foregoing reasons, MISO respectfully requests that the Commission accept this locational filing as a complete package based on compromises achieved during the stakeholder process, effective May 30, 2018, and grant waiver of any Commission regulations not addressed herein that the Commission may deem applicable to this filing.

Respectfully submitted,

/s/ Jacob T. Krouse

Jacob T. Krouse
Midcontinent Independent System Operator,
Inc.

*Attorney for the Midcontinent Independent
System Operator, Inc.*

Attachments

Tab A

Active Transmission Constraint: Any transmission constraint for which a Resource is committed to avoid exceeding, or to relieve, the constraint limit.

Actual Energy Injections: For a Generation Resource a net Metered volume measured in MWh that flows into the Transmission System during the Operating Day at a specified location that is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day or, for a Stored Energy Resource or External Asynchronous Resource or Stored Energy Resource – Type II, a net Metered volume measured in MWh that flows into or out of (withdrawal positive, injection negative) the Transmission System during the Operating Day at a specified location that is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day. For a Demand Response Resource-Type I, or for a Demand Response Resource-Type II, or an EDR resource, a calculated volume in MWh that is equal to the amount as calculated or Metered according to the specifications and protocols in the Measurement and Verification Procedures. The Actual Energy Injection of the Demand Response Resource is calculated by the Transmission Provider based on the meter data submitted by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day that is used for Settlement purposes. Given the appropriate qualification, Demand Response Resources-Type I Resources can provide the following products: Energy, Contingency Reserve, and capacity under Module E.

Actual Energy Withdrawal: For a Load Zone where one or more Demand Response Resources Type I are committed for Energy and/or are offered for Contingency Reserve, where one

or more Demand Response Resource Type II are committed during a specific Hour, or where an EDR resource has reduced load, a calculated volume in MWh that flows out of the Transmission System during the Operating Day at a specified location that is equal to the time-weighted average of the Metered volume of the Load Zone for that Hour plus Actual Energy Injects within the Load Zone for the Demand Response Resources and EDR resources. For all other Load Zones, a Metered volume measured in MWh that flows out of the Transmission System during the Operating Day at a specified location. The Load Zone Metered volume in MWh that flows out of the Transmission System during the Operating Day, used for the calculation of the Actual Energy Withdrawal, is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day that is used for Settlement purposes. For an Hour where the Hourly Ex Post LMP is less than the Net Benefits Price Threshold, the amount of Actual Energy Injections for all DRRs associated with a given Load Zone are added to the Metered volume at the specified Load Zone.

Actual Resource Response: The actual movement, in MWs, relative to Setpoint Instructions for a Resource within a Dispatch Interval.

Additional Regulating Mileage: Any Regulating Mileage Target for a Resource in a Dispatch Interval beyond the amount considered for the Dispatch Interval during the market clearing.

Adjusted Financial Transmission Rights Capability: The expected available transmission capacity in the FTR Auction, respecting the Simultaneous Feasibility Test, over the Transmission Provider Region during: (1) a given Month, less FTRs held by existing

FTR Holders; or (2) a Season, less FTRs held by existing FTR Holders and baseloading assumptions.

Affected Participant: A Market Participant, a person that engages in Market Activities or a person that takes any other service under the Tariff that has provided to the Transmission Provider, Confidential Information that is requested by, or is disclosed to, an Authorized Requestor under a Non-Disclosure Agreement.

Affiliate: With respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity.

Agency Agreement: The agreement that is Appendix G of the ISO Agreement.

Aggregate Annual Transmission Revenue Requirement (Aggregate ATRR): The annual transmission revenue requirement calculated by combining the annual transmission revenue requirements of each individual RFP Respondent and each individual Proposal Participant identified in a Proposal, all as provided in Section VIII.D.4.3 of Attachment FF of the Tariff.

Aggregate Power Supply Curve: The combined Energy Offer curves for all Resources, excluding DRRs, which is the capacity from all such resources at each price offered.

Aggregate Price Node (APNode): An aggregation of Elemental Pricing Nodes whose LMP is calculated as the sum of the products of the LMP at each Elemental Pricing Node defined in the Aggregate Price Node and the associated pre-established normalized weighting factors for the Elemental Pricing Node.

Aggregator of Retail Customers (ARC): A Market Participant that represents demand response on behalf of one or more eligible retail customers, for which the participant is not such customers' LSE, and intends to offer demand response directly into the Transmission Provider's Energy and Operating Reserve Markets, as a Planning Resource or as an EDR resource.

Allowance Level: A description of the mitigation measure described in Module D which allows a Market Participant that is an LSE or represents an LSE, to purchase or schedule a specified portion of its Energy, Operating Reserve, Up Ramp Capability, and Down Ramp Capability requirements in the Real Time Energy and Operating Reserve Market.

Alternate Selected Developer(s): Shall be the RFP Respondent(s) whose Proposal is selected to be the alternate Proposal by the Competitive Transmission Executive Committee, pursuant to Attachment FF of the Tariff, for implementation if the Selected Developer fails to execute or request an unexecuted filing of the Selected Developer Agreement and provide the required Project Financial Security within the timeframe provided in Attachment FF Section VIII.H.

Ancillary Services: Those services that are necessary to support Capacity and the transmission of Energy from Resources to Loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

Annual ARR Allocation: The procedure used by the Transmission Provider annually to allocate ARRs and MVP ARRs.

Annual ARR Registration: The annual process for registering ARR Entitlements and MVP ARR Entitlements.

Applicable Laws and Regulations: All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the Parties, their respective facilities and/or the respective services they provide.

Applicable Reliability Standards: Reliability Standards approved by the Federal Energy Regulatory Commission (FERC) under Section 215 of the Federal Power Act relating to operation of the Transmission Provider in carrying out its Reliability Coordinator, Balancing Authority, Market Operator, Transmission Service Provider, and Planning Coordinator functions. In addition to FERC approved standards, any regional reliability criteria and/or standards relating to operation of the Transmission Provider in carrying out the functions listed above.

Applicant: An entity desiring to hold FTRs, take Transmission Service, engage in Market Activities or take any other service under this Tariff, or become a Market Participant, Transmission Customer or Coordination Customer under this Tariff.

Application: A request by an Eligible Customer for Transmission Service pursuant to the provisions of this Tariff.

ARR Delivery Point: The ARR Zone or Interface specified in an ARR where Transmission Service terminates.

ARR Entitlement(s): Right to nominate and be allocated ARRs based on transmission usage, upgrades or other basis.

ARR Holder(s): The Market Participant that receives ARRs, or the Transmission Provider to the

extent it receives ARR, through the Annual ARR Allocation.

ARR Obligation: The financial credit or obligation resulting from the difference between the clearing prices from the annual FTR Auction at the ARR Delivery Point and the clearing prices at the ARR Receipt Point.

ARR Receipt Point: The transaction receipt point specified in an ARR.

ARR Settled Exposure: The potential exposure to non-payment associated with ARRs that have been settled.

ARR Stage Factors: The factors that determine the nomination caps in Stage 1A and Stage 1B of the ARR allocation procedure.

ARR Term: The term specified in the ARR.

ARR Transactions Not Yet Settled: The value of the ARRs based on the clearing price(s) established as a result of the most recent annual FTR Auction which have not been settled.

ARR Zone(s): Geographic areas defined for the purpose of allocating ARRs based upon locations where a Market Participant serves Load.

Area Control Error (ACE): The instantaneous difference between Net Actual Interchange and Net Scheduled Interchange, taking into account the effects of frequency bias, including a correction for meter error, expressed in MW.

Asset Owner: An entity identified by a Market Participant through the Transmission Provider registration process that is eligible to be represented by the Market Participant in Market Activities.

Auction Clearing Price (ACP): The price, expressed in \$/MW-day, associated with the MW

quantity that clears in the Planning Resource Auction for a given LRZ or ERZ for the applicable Planning Year.

Auction Revenue Rights (ARR): Entitlements to a share of the revenues generated in the annual FTR Auction.

Authorized Agency: (i) a State public utility commission within the geographic limits of the Transmission Provider Region that regulates the distribution or supply of electricity to retail customers or is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State; (ii) the Organization of MISO States or any successor organization, formed to act as a regional state committee within the Transmission Provider Region; or (iii) a state agency that has both access to documents in the possession of a state public utility commission pursuant to state statute and the ability to protect those documents in accordance with the Non Disclosure Agreement.

Authorized Requestor: A person who has executed a Non Disclosure Agreement, and is authorized by an Authorized Agency to receive and discuss Confidential Information. Authorized Requestors may include State public utility commissioners, State commission staff, attorneys representing an Authorized Agency, and employees, consultants and/or contractors directly employed by an Authorized Agency, provided, however, that consultants or contractors may not initiate requests for Confidential Information from the Transmission Provider or the IMM.

Available Non-FTR Financial Security: For Credit purposes, any Financial Security held in excess of alternative capitalization requirements and Total FTR Obligations and available

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FERC Electric Tariff
MODULES

1.A
Definitions - A
50.0.0

for securing Non-FTR Potential Exposure.

Available Transfer Capability: The maximum amount of additional Energy that may be carried by the Transmission System or by the transmission systems of Coordination Customers under current or projected operating conditions.

Balancing Authority: The responsible entity that integrates Resource plans ahead of time, maintains Load-generation balance within a Balancing Authority Area and supports the Eastern Interconnection frequency in real time.

Balancing Authority Agreement: The “Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of the TEMT” which was filed October 5, 2004 in Docket Nos. ER04-691-002 and EL02-104-002, as may be amended from time to time, and is designated as FERC Electric Tariff, Rate Schedule No. 3.

Balancing Authority Area: An electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied within the Balancing Authority in order to: (i) match the power output of the Generation Resources within the electric power system(s) and Energy delivered from or to entities outside the electric power system(s), with the demand (including losses) within the electric power system(s); (ii) maintain scheduled Interchange with other Balancing Authority Areas, within the limits of Good Utility Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and Applicable Reliability Standards.

Base Penalty Charge: A base sanction that is assessed by the Independent Market Monitor against a Market Participant that is found to have engaged in conduct that is not permitted under the Tariff.

Baseline Reliability Projects: Network Upgrades identified in the MTEP as required to ensure the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Entities

and applicable to the Transmission Provider's Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria. Baseline Reliability Projects include projects of 100kV voltage class or above needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers.

Baseline Reliability Study: A study performed by the Transmission Provider as part of the MTEP development to determine whether the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Entities and applicable to the Transmission Provider's or Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria, the result of which is the identification of Baseline Reliability Projects.

Baseload Reserved Source Point (RSP): The Baseload Reserved Source Point for use in the ARR allocation process.

Baseload Reserved Source Set (BRSS): The Baseload Supply Resources that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone.

Baseload Supply Resource(s): Generation Resource associated with serving a Market Participant's Baseload Usage and that is used for Baseload Reserved Source Point calculations.

Baseload Usage: Transmission usage that is fifty percent (50%) of Peak Usage of Network Load. For Market Participants utilizing Point-To-Point Transmission Service, fifty

percent (50%) of the Point-To-Point Transmission Service MW amount will be assumed to be Baseload Usage. However, this assumption will not require an LSE to pay multiple Transmission Service charges for Loads included in the LSE's Baseload Usage.

Behind the Meter Generation (BTMG): Generation resources used to serve wholesale or retail load located behind a CPNode that are not included in the Transmission Provider's Setpoint Instructions and in some cases can also be deliverable to Load located within the Transmission Provider Region using either Network Integration, Point-To-Point Transmission Service or transmission service pursuant to a Grandfathered Agreement. These resources have an obligation to be made available during Emergencies.

Bid: A request to purchase Energy in the Day Ahead Energy and Operating Reserve Market, including Demand Bids, Price Sensitive Demand Bids, and Fixed Interchange Schedule Export Schedules, Dispatchable Interchange Schedule Export Schedules, and Virtual Bids, at a specified location, quantity, and time period, that is duly submitted to the Transmission Provider pursuant to this Tariff and the Business Practices Manuals.

Bi-Directional Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments at which a Generation Resource or Demand Response Resource - Type II can respond to either increasing or decreasing Setpoint Instructions.

Bilateral Transaction Schedule: A schedule associated with a Bilateral Transaction.

Bilateral Transactions: Interchange Schedules, Dynamic Interchange Schedules, Financial Schedules and GFA Schedules.

Billing Agent: An entity designated by a Market Participant as the entity to receive from, or forward payment to, the Transmission Provider on the Market Participant's Settlement

Statements. The Market Participant shall remain liable for all obligations issued to it in the Settlement Statements.

Binding Reserve Zone Constraint: A constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to meet the Reserve Zone's minimum Operating Reserve requirements.

Binding Settlement Zone: Any Reserve Zone with a Market Clearing Price for Regulating Reserve, Spinning Reserve or Supplemental Reserve, as applicable, derived in the Day-Ahead Energy and Operating Reserve Market or in the Real-Time Energy and Operating Reserve Market that has any non-zero Market Clearing Price Zonal Terms for Operating Reserves.

Binding Transmission Constraints: A transmission constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to avoid exceeding, or to relieve, the constraint limit.

Blackstart Equipment: The equipment that is necessary to make a generation unit a Blackstart Unit capable of reliably providing Blackstart Service.

Blackstart Service: The process used by the Transmission Operator, Load Serving Entities, and Generator operators to reenergize to a fully operational state the entire transmission network and the remainder of the delivery system to normal operation. This process includes systematic start up of Blackstart Units via Blackstart Equipment, energizing transmission to critical facilities such as larger generating units, energizing to the largest generators to facilitate the restoration of system loads.

Blackstart System Restoration Plan: The plan developed by the Transmission Provider acting

in its capacity as the Reliability Coordinator, to coordinate the system restoration plans developed by the individual Transmission Operators to re-energize the Transmission System following a system-wide blackout.

Blackstart Unit: A generation unit that has Blackstart Equipment attached to it, which allows the unit to be started without assistance from any other resource.

Blackstart Unit Owner: An entity that either: (1) owns and controls the output of, or operates a Blackstart Unit; or (2) has contractual rights to direct the operation of a Blackstart Unit and to receive the compensation provided for under Schedule 33 of the Tariff.

Border External Resource: An External Resource that: (i) has interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; and (ii) which will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to such substation.

Branch Facility: A facility located within a pricing Zone having a defined Line Outage Distribution Factor.

Broad Constrained Area: An electrical area in which sufficient competition usually exists even with one or more Binding Transmission Constraints or Binding Reserve Zone Constraints, or into which the transmission constraints or reserve constraints bind infrequently, but within which a Binding Transmission Constraint or Binding Reserve Zone Constraint can result in substantial locational market power under certain market or operating conditions.

Bulk Electric System: The electrical Generation Resources, transmission lines, interconnections

with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher as further defined by the applicable Regional Entity.

Bundled Load: The aggregate usage by customers who purchase electric services as a single service or customers who purchase electric services under a retail tariff rate schedule that includes Energy and delivery components, as distinguished from customers who purchase Transmission Service as a separate service.

Bus: A specific electrical location within the Transmission System and/or within other transmission systems within the Eastern Interconnection modeled in the Network Model.

Business Day: A day in which the Federal Reserve System is open for business.

Business Practices Manuals: The instructions, rules, policies, procedures and guidelines established by the Transmission Provider for the operation, planning, accounting and settlement requirements of the Transmission Provider Region.

Calculated Demand Response Resource-Type I Output: The hourly average Actual Energy Injection for each associated Demand Response Resource – Type I for the Hour for the purposes of assessing Excessive/Deficient Energy Deployment Charges.

Calculated Demand Response Resource-Type II Output: For a Demand Response Resource-Type II, the hourly average Actual Energy Injection for the Hour for the purposes of assessing Excessive/Deficient Energy Deployment Charges.

Calendar Day: Any day of the week, including Saturday, Sunday or a Federal holiday.

Candidate ARR (CARR): ARR nominations submitted by Market Participants to be considered throughout the Annual ARR Allocation process.

Candidate Baseload ARR: Candidate ARR rights equal to each Market Participant's Baseload Usage in an ARR Zone.

Candidate Peak ARR: Candidate ARR rights equal to each Market Participant's Peak Usage in an ARR Zone.

Candidate MVP ARR: MPV ARR nominations submitted by the Transmission Provider to be considered during the Annual ARR Allocation process.

Capacity: The instantaneous rate at which Energy can be delivered, received or transferred, including Energy associated with Operating Reserve, Up Ramp Capability, and Down Ramp Capability, measured in MW.

Capacity Deficiency Charge: A charge that is assessed to an LSE that has not demonstrated to the Transmission Provider that it has sufficient Planning Resources to meet its PRMR.

Capacity Export Limit (CEL): The amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or

ERZ.

Capacity Import Limit (CIL): The amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ.

Capacity Resources: The Generation Resources, Demand Response Resource- Type I, Demand Response Resource-Type II, Dispatchable Intermittent Resources, External Resources, Intermittent Generation, or Stored Energy Resources – Type II that are available to meet Demand.

Carved Out GFA(s): Any Grandfathered Agreement(s) that the Commission has identified as “carved out” pursuant to Appendix B of the Commission’s September 16, 2004 order, Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,236 (2004) or that meet the criteria in Section 38.8.3(A).b, and set forth in Attachment P to this Tariff, as that Attachment may be amended from time to time.

Cash Collateral Agreement: A Credit Support Document taking the form found in Exhibit III of Attachment L of this Tariff.

Cash Deposit: Cash collateral provided to Transmission Provider to secure Applicant’s and/or Tariff Customer’s performance under the terms and conditions of Transmission Provider’s Tariff, and/or other agreements.

Category A Tariff Customer: A Tariff Customer who grants a continuing first-priority security interest to the Transmission Provider in all right, title and interest in any and all accounts receivable and other rights of payment of the Tariff Customer for goods and services provided under, or otherwise arising under, pursuant to or in connection with, the Tariff and/or any of the Agreements.

Category B Tariff Customer: Any Tariff Customer who does not grant a Receivable Security Interest to the Transmission Provider.

Change in Total System Cost: The net change in variable operational costs, which include fuel, variable O&M, variable environmental costs, and other variable costs as mutually agreed upon by the Transmission Provider and the Market Participant, measured in dollars as a result of changing the output of one or more units in response to a redispatch request from the Transmission Provider.

Charge: The withdrawal of energy from the Transmission System by a Stored Energy Resource for the purpose of storing the energy for injection back into the Transmission System at a later time.

Coincident Peak Demand: The Demand in MWs, for an LSE and/or EDC, that occurs coincident to the annual peak Demand in the Transmission Provider Region, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

Combined Reliability Systems: The Reliability Coordination Customer Transmission Facilities and all other transmission facilities for which the Transmission Provider performs Reliability Coordination Services under Part I of Module F.

Commercial Model: A presentation of the relationships between Market Participants and their Resources, Commercial Pricing Nodes and the Network Model in the Energy and Operating Reserve Markets.

Commercial Operation Date: Shall have the meaning set forth in Attachment X of this Tariff.

Commercial Pricing Node (CPNode): An Elemental Pricing Node or an Aggregate Price Node

in the Commercial Model used to schedule and settle Market Activities. Commercial Pricing Nodes include Resources, Hubs, Load Zones and/or Interfaces.

Commercially Significant Voltage and Local Reliability Issue: Transmission System voltage or other local reliability concerns that result in Voltage and Local Reliability Commitments. These issues are designated for reasons including, but not limited to, occurrence frequency, monetary impact, or other criteria as defined in Schedule 44. A Local Balancing Authority or an interested Market Participant may request that the Transmission Provider evaluate a Voltage and Local Reliability Issue for designation as commercially significant.

Commission: The Federal Energy Regulatory Commission, also known as FERC, or its successor.

Common Bus: A single Bus to which two or more Resources are connected in an electrically equivalent manner where such Resources are treated as a single Resource for compliance monitoring purposes.

Common Information Model (CIM): The format adopted by the NERC Data Exchange Working Group that will be used by the Congestion Management Customer and the Transmission Provider to exchange Energy Management System models once a year.

Comparable FTRs: FTRs that are identical in all material respects except for the quantity of MW specified.

Competitive Developer Qualification Process: The process utilized to certify Qualified Transmission Developers pursuant to Section VIII.B of Attachment FF of the Tariff.

Competitive Developer Selection Process: The process utilized to solicit Proposals, evaluate Proposals, and designating a Selected Proposal and Selected Developer(s) pursuant to Section VIII of Attachment FF of the Tariff.

Competitive Substation Facility: A transmission substation facility contained within an Eligible Project that is subject to the Competitive Developer Selection Process in accordance with Section VIII.A of Attachment FF of the Tariff.

Competitive Transmission Executive Committee: A committee consisting of three (3) or more executive staff of the Transmission Provider, including at least one (1) officer, that is charged with overseeing all Transmission Provider staff and consultants involved in evaluating Transmission Developer Applications and Proposals in response to a posted Request for Proposal. The Competitive Transmission Executive Committee will have exclusive and final decision-making authority over: (i) the certification and termination of Qualified Transmission Developers; and (ii) the evaluation and selection of Proposals, resulting in designating Selected Developers. The Competitive Transmission Executive Committee shall possess the specific technical, financial, and regulatory expertise necessary for evaluation of Transmission Developer Applications and Proposals.

Competitive Transmission Facility: A Competitive Substation Facility or Competitive Transmission Line Facility.

Competitive Transmission Line Facility: A transmission line facility contained within an Eligible Project that is subject to the Competitive Developer Selection Process in accordance with Section VIII.A of Attachment FF of the Tariff.

Competitive Transmission Process: The process utilized to certify Qualified Transmission Developers, identify Competitive Transmission Projects, solicit Proposals, evaluate Proposals, and designating a Selected Proposal and Selected Developer(s) pursuant to Section VIII of Attachment FF of the Tariff. The Competitive Transmission Process includes the Competitive Developer Qualification Process and Competitive Developer Selection Process.

Competitive Transmission Project: The Competitive Transmission Facilities contained within an Eligible Project.

Competitively Sensitive Information: Information that is not public and the unauthorized disclosure of which could have anti-competitive effects, provide a competitor with an unfair or improper competitive advantage, or unfairly or improperly result in competitive harm, detriment, prejudice, disadvantage or injury to the legitimate proprietary rights, business or commercial interests, market position, or ability to bargain freely, of the lawful owners, possessors or users of such information.

Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Composite Credit Score: A composite numerical score scaled from 1.00 to 6.99, representing the sum of the Qualitative and Quantitative score as calculated by the Transmission Provider's credit scoring model in Attachment L of this Tariff.

Confidential Information: Any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or

planned business of a Transmission Customer, Market Participant, or other user, which is designated as confidential by the entity supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by the Transmission Provider and is not disclosed except under the terms of a Confidential Information policy.

Congestion Management Customer: Any entity taking Interconnected Operations and Congestion Management Service under Part II of Module F.

Congestion Management Process (CMP): The process described in Attachment LL of the Tariff.

Constraint Contribution Factor: Factor that represents the impact that an incremental Actual Energy Injection or Actual Energy Withdrawal of one MW has on a given Active Transmission Constraint.

Constraint Generation Shift Factor Cutoff: A Generation Shift Factor level defined for each transmission constraint that determines the generating units to be included in a Broad Constrained Area associated with the constraint. Generation Resources with a Generation Shift Factor whose absolute value is greater than the Constraint Generation Shift Factor Cutoff are included in the Broad Constrained Area.

Constraint Management Charge Allocation Factor: A factor that is used to apportion Real-Time Revenue Sufficiency Guarantee Credits in an Hour between (i) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge and (ii) the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and the Real-Time Revenue Sufficiency Guarantee Headroom Charge.

Contingency Reserve: Spinning Reserve and Supplemental Reserve provided by Resources available to the Transmission Provider to use in the event of a system contingency as specified in Schedule 5-Spinning Reserve and Schedule 6– Supplemental Reserve of this Tariff.

Contingency Reserve Deployment Failure Charge: A charge assessed to any Resource that fails to achieve in a Contingency Reserve Deployment Period at least one hundred percent (100%) of the Contingency Reserve Deployment Instruction target.

Contingency Reserve Deployment Instruction: An instruction issued by the Transmission Provider to Resources with cleared Contingency Reserve to deploy a specific MW quantity of cleared Contingency Reserve as communicated via Setpoint Instructions or other electronic means.

Contingency Reserve Deployment Period: The period of time the Resource has to deploy Contingency Reserve following the issuance of a Contingency Reserve Deployment Instruction that is equal to ten minutes.

Contingency Reserve Offer Price Cap: The maximum price permitted for a Spinning Reserve Offer, an On-Line Supplemental Reserve Offer, an Off-Line Supplemental Reserve Offer or a Supplemental Reserve Offer in the Energy and Operating Reserve Markets.

Control: The possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent (10%) or more shall create a rebuttable presumption of Control.

Controllable Devices: Devices that may include phase shifters, DC lines, and back-to-back AC/DC converters.

Coordinated Flowgate: A Flowgate that is subject to the Transmission Provider's or Coordination Customer's operational control and through which flows are affected by transmission over transmission facilities within its operational control, or with respect to which Transmission Provider serves as a Reliability Authority.

Coordinated Transaction Schedule: An Interchange Schedule to purchase Energy in the Real-Time Energy and Operating Reserve Market from a Source Point in either the MISO Balancing Authority Area or PJM Balancing Authority Area and sell it at a Sink Point in the other balancing authority area that is cleared if the forecasted LMP at the Sink Point minus the forecasted LMP at the Source Point is greater than or equal to the dollar value specified in the bid associated with the Interchange Schedule.

Coordinating Owner: Any entity that is not subject to the jurisdiction of the Commission but participating in the ISO through the execution of a coordination agreement which includes provisions for the elimination of rate pancaking. The terms and provisions of a Coordinating Owner's coordination agreement shall supersede the similar terms and provisions of this Tariff where applicable.

Coordination Customer: Any customer taking Coordination Services from the Transmission Provider pursuant to Module F of the Tariff. The term Coordination Customer includes: Reliability Coordination Customer, and Congestion Management Customer.

Coordination Services: The services provided by the Transmission Provider pursuant to Module F of the Tariff. Coordination Services include Reliability Coordination Service and Interconnected Operations and Congestion Management Service.

Corporate Guaranty: A legal document taking the form found in Exhibit I of Attachment L of

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this Tariff used by an Affiliate of an Applicant and/or Tariff Customer that guarantees the obligations of such Applicant or Tariff Customer.

Cost Allocation Zone: The zones identified in Attachment WW of this Tariff used for allocating the costs of Market Efficiency Projects.

Cost of Congestion: The Marginal Congestion Component of LMP at the sink minus the Marginal Congestion Component of LMP at the source.

Cost of Losses: Marginal Losses Component of LMP at the sink minus the Marginal Losses Component of LMP at the source.

Cost of New Entry (CONE): The capital, operating, financial and other costs of acquiring a new Generation Resource within the Transmission Provider Region for any designated LRZ.

Counterflow ARR: ARR allocated during the LTTR Restoration and Termination Stage of an Annual ARR Allocation based on a Counterflow ARR Entitlement.

Counterflow ARR Entitlement: Any Stage 1A eligible ARR Entitlement's portion that was not nominated in Stage 1A of a Market Participant's year 1 Annual ARR Allocation but that the Transmission Provider deems to provide counterflow necessary to enable curtailed Stage 1A CARRs to be restored (fully or partly) during the LTTR Restoration and Termination Stage of an Annual ARR Allocation.

Credit and Security Agreement: A Credit Support Document taking the form found in Exhibit V of Attachment L of this Tariff.

Credit Policy: The Transmission Provider's creditworthiness requirements and credit evaluation procedures as contained in Attachment L of this Tariff.

Credit Support Documents: Any agreement or instrument in any way guaranteeing or securing

any or all of a Tariff Customer's obligations under this Tariff (including, without limitation, the Credit Policy), any agreement entered into under, pursuant to, or in connection with this Tariff or any agreement entered into under, pursuant to, or in connection with this Tariff or the Credit Policy, and/or any other agreement to which the Transmission Provider and the Tariff Customer are parties, including, without limitation, any Corporate Guaranty, Cash Collateral Agreement, Letter of Credit, Credit and Security Agreement or agreement granting a security interest.

Critical Energy Infrastructure Information (CEII): Confidential information described in 18 C.F.R § 388.113(c)(1), as may be amended from time to time.

Curtailement: A reduction in firm or non-firm Transmission Service in response to a transfer capability shortage as a result of system reliability conditions pursuant to Section 14.7 or Section 27A of this Tariff.

Customer Load Aggregation: A Load Zone approved by the Transmission Provider for the purposes of submitting Bids to or scheduling into the Energy and Operating Reserve Markets and for settlement of Market Activities.

Eastern Interconnection: The ERO certified Balancing Authorities operating in the eastern part of North America.

Eastern Prevailing Time (EPT): Eastern Daylight Time during periods when the eastern time zone is observing daylight saving time, Eastern Standard Time during periods when the eastern time zone is observing standard time.

Economic Maximum Dispatch: The maximum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Maximum Dispatch will equal the Actual Energy Injections.

Economic Minimum Dispatch: The minimum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Minimum Dispatch will equal the Actual Energy Injections.

Effective Import Tie Capability (EITC): The maximum aggregate level of power in MW that can be reasonably expected to flow on the transmission tie lines into a specified Zone of the Transmission System, while maintaining reliable operation.

Effective Export Tie Capability (EETC): The maximum aggregate level of power in MW that can be reasonably expected to flow outward on the transmission tie lines of a specified Zone of the Transmission System, while maintaining reliable operation.

Electric Distribution Company (EDC): A company that distributes electricity to retail customers through distribution substations and/or lines owned by the company.

Electric Facility: Equipment used for the generation, transmission, storage, or control of the transmission of electricity and that is connected to or part of the Transmission System operated by the Transmission Provider.

Electric Generation and Transmission Cooperative (Coop): An electric Generation and Transmission cooperative is a not for profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners.

Electric Reliability Organization (ERO): The organization certified by the Commission to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

Elemental Pricing Node (EPNode): A single Bus where LMP is calculated.

Eligible Confirmed Transmission Service Reservation: Any reservation for Transmission Service that has been confirmed and has a start date later than the date a Default first occurs. Any reservation for Transmission Service that has been confirmed remains a conditionally approved request at all times prior to such reservation's start date and may be cancelled if a Default occurs prior to such start date.

Eligible Customer: (i) Any electric utility (including the Transmission Owner(s), ITC Participants(s), and any power marketer), Market Participant, Federal Power Marketing Agency, or any person generating electric Energy for sale or for resale is an Eligible Customer under this Tariff. Electric Energy sold or produced by such entity may be electric Energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by § 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a

state requirement that a Transmission Owner or ITC Participant offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant; or (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that a Transmission Owner or ITC Participant offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant, that is an Eligible Customer under this Tariff. Unbundled retail customers that seek to take local distribution service cannot be Eligible Customers under this Tariff with respect to that service.

Eligible Projects: Shall mean any Market Efficiency Projects (“MEP”) and Multi-Value Projects (“MVP”) approved by the Transmission Provider’s Board after December 1, 2015 regardless of whether such project is subject to the Transmission Provider’s Competitive Developer Selection Process.

Emergency: (i) An abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of Emergency procedures as defined in this Tariff.

Emergency Demand Response (EDR): The commitment and dispatch of Load reductions, Behind the Meter Generation Resources and other Demand Resources during an Emergency, in accordance with Schedule 30.

EDR Dispatch Instruction: Directives issued by the Transmission Provider to EDR Participants indicating MW quantities to be reduced during Emergencies.

EDR Initiative: Procedures for EDR Participants to respond to an Emergency through a defined reduction in Load or increase in output from Behind the Meter Generation Resources, as described in Schedule 30 of this Tariff.

EDR Offer: An offer made by an EDR Participant to reduce demand in response to an Emergency event which will not be considered in the clearing of the Day-Ahead Energy and Operating Reserve Market or Real-Time Energy and Operating Reserve Markets.

EDR Participant: A Market Participant capable of reducing demand in response to directives received from the Transmission Provider during an Emergency event.

Emergency Energy: Purchases of Energy coordinated by the Transmission Provider following the issuance of an Energy Emergency Alert in accordance with the procedure set forth in Section 40.2.22 of this Tariff.

Emergency System Conditions: Are (i) situations in which a systemic equipment malfunction, including telecommunications, hardware, or software failures, prevents the Transmission Provider from operating the Energy and Operating Reserve Markets in accordance with the Market Rules; or (ii) widespread electric transmission or generation equipment outages that prevent the Transmission Provider from dispatching the system in accordance with the Market Rules.

Emergency Tier I Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation

emergency warning as specified in the Transmission Provider's Emergency operating procedures.

Emergency Tier II Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency event, step 2 as specified in the Transmission Provider's Emergency operating procedures.

Energy: An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold or transmitted over a period of time and measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Market(s): The Day Ahead and/or Real Time Energy and Operating Reserve Markets operated by the Transmission Provider.

Energy Consumer: Any end-use customer, including but not limited to commercial retail consumers of electricity, located within the Transmission Provider Region.

Energy Deficient Region: An area in which one or more LSEs within the MISO Balancing Authority Area are experiencing or are expected to experience an Emergency under the procedures specified under Section 40.2.20 of this Tariff.

Energy Efficiency Resource (EE Resource): A Planning Resource consisting of installed measures on retail customer facilities that achieves a permanent reduction in electric energy usage while maintaining a comparable quality of service.

Energy Emergency: A condition when a balancing authority can no longer meet the energy requirements of the firm end-use load within its balancing authority area and has initiated its Energy Emergency procedures.

Energy Emergency Alert: An alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area.

Energy Emergency Area: The area within a balancing authority area that is experiencing an Energy Emergency.

Energy Emergency Alert Level 2 (EEA2): Energy Emergency Alert Level 2 as defined by NERC.

Energy Management System (EMS): The software system used by the Transmission Provider and Transmission Operators for acquisition and processing of operational data.

Energy Market Counterparty: The Transmission Provider as the contracting counterparty to Market Participants for all Market Activities contemplated by this Tariff, solely in the Transmission Provider's capacity as a principal and not as an agent for any other party, consistent with the provisions of Section 6A.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource.

Energy Offer Price Cap: The maximum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Offer Price Floor: The minimum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Resource Interconnection Service: The interconnection of a Generation Resource to the Transmission System or distribution system, as applicable, to be eligible to deliver the Generation Resource's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis.

EPT: Eastern Prevailing Time.

Equity: For credit scoring purposes, the ownership interest in a firm, including the residual dollar value of a futures trading account, assuming its liquidation is at the going trade price of Applicant or Market Participant.

Equivalent Forced Outage Rate Demand (EFORD): The Equivalent Forced Outage Rate Demand, as defined by NERC.

EST: Eastern Standard Time.

Ex Ante MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, and Down Ramp Capability MCP calculated at the beginning of the Dispatch Interval, used for informational purposes in the Real-Time Energy and Operating Reserve Market.

Ex Post MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, and Down Ramp Capability MCP calculated for each Dispatch Interval.

Excess Congestion Charge Fund: A fund established by the Transmission Provider representing, in aggregate, the difference between the total of all Transmission Congestion Payments for a given Hour and the hourly transmission congestion charges.

Excessive/Deficient Charge Rate: The rate used to determine a Resource's Excessive/Deficient Energy Deployment Charge as calculated pursuant to Section 40.3.4.b.

Excessive/Deficient Energy Deployment Charge: A charge assessed to any Resource in an Hour with Excessive Energy and/or Deficient Energy in four (4) or more consecutive Dispatch Intervals within the Hour.

Excessive Energy: The amount of a Generation Resource's, Stored Energy Resource's or External Asynchronous Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold or, the amount of a Demand Response Resource's Type I Calculated DRR Type I Output, as adjusted for Actual Energy Injection or Demand Response Resource's Type II Calculated DRR Type II Output, as adjusted for Actual Energy Injection at a Commercial Pricing Node in the Real Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold.

Excessive Energy Price: The price used to calculate a Market Participant's credit for Excessive Energy that is equal to the Energy Offer price associated with a Generation Resource's, Demand Response Resource's – Type I, Demand Response Resource's – Type II or External Asynchronous Resource's Excessive Energy.

Excessive Energy Threshold: The maximum value of a Resource's Tolerance Band.

Export Schedule: An Interchange Schedule in which the Interchange Schedule Receipt Point lies within the MISO Balancing Authority Area and the Interchange Schedule Delivery Point lies outside the MISO Balancing Authority Area.

Exporting Entity: A Market Participant that is not a Load Serving Entity with a cleared Export Schedule in the Day-Ahead Energy and Operating Reserve Market or an Export Schedule in the Real-Time Energy and Operating Reserve Market.

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 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.

Extended Transmission Outage: A Planned Transmission Outage that exceeds the original outage schedule previously provided by the Transmission Owner to the Transmission Provider.

External Asynchronous Resource: A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

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External Resource: A generator located outside of the metered boundaries of the MISO
Balancing Authority Area.

External Resource Zone (ERZ): A grouping of one or more External Resources in the same
external balancing authority for purposes of the Planning Resource Auction.

GAAP: Generally Accepted Accounting Principles.

Generation Interconnection Projects: New Transmission Access Projects associated with the interconnection of or increase in generating Capacity of Generation Resources pursuant to Attachment R and Attachment X of this Tariff.

Generation Offer: An Energy Offer, Start-Up Offer, No-Load Offer, Regulating Capacity Offer and Regulating Mileage Offer (if a Regulation Qualified Resource), Spinning Reserve Offer (if a Spin Qualified Resource), On Line Supplemental Reserve Offer (if not a Spin Qualified Resource), Off Line Supplemental Reserve Offer (if a Quick Start Resource), and Up and Down Ramp Capability dispatch status submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Generation Resource to supply Energy, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability to the Energy and Operating Reserve Market.

Generation Owner: An entity that owns, leases with rights equivalent to ownership in, and controls the output of or operates Generation Resources.

Generation Outage: A forced or planned outage of Generation Resources.

Generation Resource: A Generation Resource is a Generator within the MISO Balancing Authority Area or an External Resource that is Pseudo-tied into the MISO Balancing Authority Area and that (i) is registered to participate in the Energy and Operating Reserve Markets, (ii) is capable of supplying Energy, Capacity, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability, (iii) is capable of complying with the Transmission Provider's Setpoint Instructions and (iv) has the appropriate metering equipment installed.

Generation Shift Factors: Ratios equal to the incremental increase or decrease in flow on a flowgate divided by an incremental increase or decrease in a Generation Resource's output.

Generation Verification Test Capacity (GVTC): The maximum output (MW) that a Generation Resource, External Resource or BTMG can sustain over the specified period of time, if there are no equipment, operating, or regulatory restrictions, minus any Capacity utilized for On-Site Self-Supply, as detailed in the Business Practices Manual for Resource Adequacy.

Generator: Any generating facility subject to the Transmission Provider's direction hereunder pursuant to either the Operating Protocol for Existing Generators, an IOA or an LGIA.

Generator Forced Outage: An immediate reduction in output, Capacity or removal from service, in whole or in part, of a Generation Resource by reason of an Emergency or threatened Emergency, unanticipated failure, inability to return on schedule from a Planned Transmission Outage, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the Business Practices Manuals. A reduction in output or removal from service of a Generation Resource in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Interconnection Agreement (GIA): The form of interconnection agreement provided in Appendix 6 of Attachment X to the Tariff.

Generator Planned Outage: The scheduled removal from service, in whole or in part, of a Generation Resource for inspection, maintenance or repair with the approval of the Transmission Provider in accordance with the Business Practices Manuals.

Generator Self Supply: For any given period of time, the total Energy taken out of the Transmission System by the Loads designated as Self-Supply by a Market Participant which is a Generation Owner up to an amount equal to the total Energy placed into the Transmission System by the Generators designated as Self-Supply by the same Market Participant and owned by it.

GFA Schedule Delivery Point: The location where a GFA Schedule sinks.

GFA Schedule Receipt Point: The location where a GFA Schedule sources.

Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governmental Authority: Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the

Transmission Provider.

Grandfathered Agreement(s) (GFA): An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies.

These agreements are set forth in Attachment P to this Tariff.

Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under this Tariff.

Grandfathered Agreement (GFA) Schedule: A Schedule associated with a Grandfathered Agreement.

Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling Transmission Service or Energy transactions related to Grandfathered Agreements under this Tariff.

Guarantor: A guarantor under a Corporate Guaranty.

Headroom: For all Resources committed by the Transmission Provider in any real-time RAC processes or the LAC process conducted for the Operating Day, the difference between (i) the real-time Economic Maximum Dispatch and (ii) the sum of the Real-Time (a) Dispatch Target for Energy, (b) Dispatch Target for Regulating Reserve, (c) Dispatch Target for Spinning Reserve, and (d) Dispatch Target for Supplemental Reserve.

High Utilization Factor Unit (HUFU) Reserved Source Point (RSP): An RSP that does not qualify for inclusion in the BRSS per section 43.2.4.a.i.(b) but has a RSP Utilization Factor of seventy percent (70%) or greater.

Historic Unit Consideration: A right to receive excess Planning Resource Auction revenue based on qualification described in Section 69A.7.7(a).

Hour: A sixty (60) minute clock hour interval commencing the first second of each clock hour.

Hot-to-Cold Time: The number of hours that must elapse between the time a Generation Resource or Demand Response Resource – Type II is desynchronized and the time at which a cold Start-Up Offer would apply.

Hot-to-Intermediate Time: The number of hours that must elapse between the time a Generation Resource or Demand Response Resource – Type II is desynchronized and the time at which an intermediate Start-Up Offer would apply.

Hourly Bi-Directional Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource, Demand Response Resource - Type II, or Stored Energy Resource can respond to either increasing or decreasing Setpoint Instructions that may be submitted to override the default value submitted during the asset registration process.

Hourly Curtailment Offer: The compensation request, in dollars per Hour, in a Demand Response Resource-Type I Offer by a Market Participant representing the fees required for operating a Demand Response Resource Type I in an interrupted state.

Hourly Economic Maximum Limit: The maximum MW level at which a Generation Resource, Demand Response Resource Type II or External Asynchronous Resource may operate under normal system conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Economic Minimum Limit: The minimum MW level at which a Generation Resource or Demand Response Resource Type II or External Asynchronous Resource may operate under normal system conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Emergency Maximum Limit: The maximum MW level at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource Type II may operate under Emergency conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Emergency Minimum Limit: The minimum MW level at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource Type II may operate under Emergency conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Energy Storage Loss Rate: The rate at which energy is consumed over a one-minute time period to maintain a Stored Energy Resource at its maximum energy storage level assuming no Regulating Reserve deployments, expressed in MWh/min.

Hourly Excessive Energy Price: The weighted average of the Dispatch Interval Energy Offer Price where the weighting factors are determined by normalizing the Excessive Energy in each Dispatch Interval in the Hour. The Dispatch Interval Energy Offer Price is the Energy Offer price at the Dispatch Target for Energy.

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

Hourly Full Charge Energy Withdrawal Rate: The rate at which additional energy can be consumed by a Stored Energy Resource over a one minute time period while at its Maximum Energy Storage Level, expressed in MWh/min.

Hourly Integrated Forecast Maximum Limit: The hourly integration of the Forecast Maximum Limits of a Dispatchable Intermittent Resource as used by the SCED algorithm in the Real-Time Energy and Operating Reserve Market for a given Hour.

Hourly Maximum Energy Charge Rate: The maximum rate at which a Stored Energy Resource may be Charged, expressed in MWh per Minute, that may be submitted to override the default value submitted during the asset registration process.

Hourly Maximum Energy Discharge Rate: The maximum rate at which a Stored Energy Resource may be Discharged, expressed in MWh per Minute, that may be submitted to override the default value submitted during the asset registration process.

Hourly Maximum Energy Storage Level: The maximum amount of Energy that may be stored by a Stored Energy Resource on a sustained basis, expressed in MWh, that may be submitted to override the default value submitted during the asset registration process.

Hourly Ramp Rate: The MW/minute response rate for a Generation Resource, External Asynchronous Resource, Demand Response Resource Type-II, or Stored Energy Resource that is utilized in the clearing of the Day-Ahead Energy and Operating Reserve Market and all Reliability Assessment Commitment processes that may be submitted to override the default value submitted during the asset registration process.

Hourly Real-Time Ex Post LMP: 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.

Hourly Real-Time Ex Post MCP: The average MCPs for Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, and Down Ramp Capability 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, Up Ramp Capability, and Down Ramp Capability in the Real-Time Energy and Operating Reserve Market.

Hourly Regulation Maximum Limit: The maximum MW output at which a Generation Resource, Demand Response Resource – Type II, External Asynchronous Resource, or Stored Energy Resource can respond to automatic control signals that may be submitted to override the default value submitted during the asset registration process.

Hourly Regulation Minimum Limit: The minimum MW output at which a Generation Resource, Demand Response Resource–Type II, External Asynchronous Resource, or Stored Energy Resource can respond to automatic control signals that may be submitted to override the default value submitted during the asset registration process.

Hourly Single-Directional-Down Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the downward direction only that may be submitted to override the default value submitted during the asset registration process.

Hourly Single-Directional-Up Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the upward direction only that may be submitted to override the default value submitted during the asset registration process.

Hourly Transmission Congestion Charges Collection: The aggregate amount of Transmission Usage Charge collected in a given Hour.

Hub: A Commercial Pricing Node developed for financial and trading purposes.

HUFU ARR: An ARR allocated during the LTTR Restoration and Termination Stage of an Annual ARR Allocation from a HUFU ARR Entitlement.

HUFU ARR Entitlement: An ARR Entitlement defined from a HUFU RSP to the applicable ARR Zone. The MW amount of a HUFU ARR Entitlement is calculated, and corresponds to, the RSP MW at a fifty percent (50%) implied capacity factor. A HUFU ARR Entitlement is calculated as follows:

HUFU MW Level = (total net generation MWh in the test period) / (50% x Total Hours in the test period).

Hub LMP: The weighted-averaged LMP for an invariant set of Elemental Pricing Nodes that comprise the Hub. The weights are static over time, except for those of Elemental Pricing Nodes constituting ARR Zones administered as Hub Commercial Pricing Nodes. The weights, or weighting factors, for determining ARR Zone LMPs are updated daily based on State Estimator information.

High-Voltage Direct Current Facilities: The high voltage direct current transmission facilities, including associated alternating current facilities, if any, that are subject to Section 27A of this Tariff and that are specifically identified in: (i) any Agency Agreement pertaining to such facilities between the Transmission Provider and the Transmission Owner that owns or operates such facilities, or (ii) in any other contractual arrangement that permits the Transmission Provider to provide HVDC Service over such facilities, as set forth in Section 27A of this Tariff.

High-Voltage Direct Current Facility Upgrades: All or portion of the modifications or additions to any HVDC Facilities for the general benefit of all Users of such HVDC Facilities.

High-Voltage Direct Current Service: Firm and Non-Firm Point-to-Point Transmission Service provided by the Transmission Provider on HVDC Facilities pursuant to Section 27A of this Tariff.

High-Voltage Direct Current Service Agreement: Any executed or unexecuted agreement for HVDC Service, as reflected in Attachment A-3, A-4, and B-1 of this Tariff.

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High-Voltage Direct Current Service Charge(s): The charge(s) for HVDC Service, as stated in
the relevant HVDC Service Agreement.

Partial-Year FTR Allocation: The procedure used by the Transmission Provider to allocate FTRs to Market Participants in the new ARR Zones added as a result of Transmission Provider Region expansion that becomes effective after the start of the Annual ARR Allocation period. The Partial-Year FTR Allocation will cover the partial year period when the new ARR Zone(s) become effective to the start of the next Annual ARR Allocation. For the partial year period, the Market Participants in the new ARR Zone(s) may request an allocation of FTRs, which will be in lieu of an allocation of ARRs.

Party(ies): The Transmission Provider, ITC where appropriate, Market Participants, Transmission Customers, or any combination of the above.

Past Due Amount: Any amount invoiced by the Transmission Provider that is not paid when due.

Peak Reserved Source Set: Set of Resources including those constituting the Baseload Reserved Source Point that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone.

Peak Usage: A Market Participant's Total Forecasted Peak Load in a given ARR Zone for the upcoming Annual ARR Allocation period calculated using the immediate prior three year actual peak Loads. The Total Forecast Peak Load is the sum of the forecast Network Integration Transmission Service peak Load for the upcoming allocation period plus peak Load served by Option A – Grandfathered Agreements plus peak Load served by Option B – Grandfathered Agreements.

Penalty Level: A component of a mitigation measure described in Module D that represents the amount of Energy purchased by a Market Participant that is an LSE or represents an LSE

in the Real Time Energy Market in excess of the Allowance Level the entity is subject to.

Physical Withholding Threshold Quantity: Threshold employed by the IMM to identify physical withholding by a supplier of Planning Resources for the Planning Resource Auction, expressed in MW.

Plan: The Transmission Provider's Market Monitoring Plan set forth in Module D of this Tariff.

Planned Transmission Outage: Any transmission outage scheduled for the performance of maintenance or repairs or the implementation of a system enhancement which is planned in advance for pre-determined duration and which meets the notification requirements for such outages as specified by the Transmission Provider.

Planning Advisory Committee: A committee of stakeholders established under the ISO Agreement for the purpose of providing input to the planning staff on the development of the MTEP.

Planning Area(s): A collective or alternative reference to the First Planning Area and/or the Second Planning Area.

Planning Coordinator: The entity responsible for the longer term reliability of its planning coordinator area.

Planning Reserve Margin (PRM): The percentage above forecasted Coincident Peak Demand of Planning Resources for the Transmission Provider Region in order to meet the LOLE. This percentage will include a quantity sufficient to cover transmission losses.

Planning Reserve Margin Requirement (PRMR): The amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements.

Planning Resource: A Capacity Resource, Energy Efficiency Resource, or Load Modifying Resource that can be used to satisfy PRMR.

Planning Resource Auction (PRA): An annual auction that is conducted by the Transmission Provider to determine the ACP and the cleared ZRC Offers for each LRZ and ERZ for the applicable Planning Year.

Planning Year: The period of time from June 1st of one year to May 31st of the following year that is used for developing Resource Plans. The first Planning Year shall commence on June 1, 2009.

PMAX: The maximum Generator real power output reported in MWs on a seasonal basis.

PMIN: The minimum Generator real power output reported in MWs on a seasonal basis.

Point(s) of Delivery: Point(s) on the Transmission System where Capacity and Energy transmitted by the Transmission Provider will be made available to the Receiving Party under Module B and Module C of this Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long Term Firm Point To Point Transmission Service or the HVDC Service Agreement.

Point(s) of Receipt: Point(s) of interconnection on the Transmission System where Capacity and Energy will be made available to the Transmission Provider by the Delivering Party under Module B and Module C of this Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long Term Firm Point To Point Transmission Service or the HVDC Service Agreement.

Point-To-Point Transmission Service: The reservation of Capacity and of Energy on either a firm or non firm basis from the Point(s) of Receipt to the Point(s) of Delivery under

Module B of this Tariff.

Portfolio: For Multi-Value Project purposes, means two or more Multi-Value Projects proposed to be located in one or more Transmission Pricing Zones that, when evaluated together, are expected to result in regional benefits.

Power Purchaser: The entity that is purchasing the Capacity and reserved Energy to be transmitted under this Tariff.

PPA Schedule: Schedule associated with a PPA that is executed after April 3, 2014.

Pre-Confirmed Application: An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Price Sensitive Demand Bids: Demand Bids in which the Market Participant specifies a maximum price (dollars per MWh) at which the Market Participant desires to purchase the designated MWh of Energy.

Price Taker: A Market Participant with an Energy and/or Operating Reserve Offer not capable of setting LMPs or MCPs.

Production Costs: The Energy output cost of a Generation Resource or a Demand Response Resource-Type II based upon Start Up, No Load and Energy Offer cost components set forth in an Offer or the Energy reduction cost of a Demand Response Resource-Type I based upon Shut Down Offer, Hourly Curtailment Offer and Energy Offer cost components set forth in an Offer.

Project Cost: All costs for Network Upgrades, as determined by the Transmission Provider to be a single transmission expansion project, including those costs associated with seeking and obtaining all necessary approvals for the design, engineering, construction, and testing of

the Network Upgrades. These Network Upgrades will include costs classified by the Transmission Owners and Independent Transmission Companies as transmission plant using the Uniform System of Accounts 350 through 359 or equivalent set of accounts for any Coordinating Owner.

Project Financial Security: The Cash Deposit or Irrevocable Letter of Credit described in Appendix 1 to Attachment FF of the Tariff that a Selected Developer is required to provide.

Proposal: A proposal to construct, implement, own, operate, maintain, repair, and restore all Competitive Transmission Facilities associated with a Competitive Transmission Project, in response to a Request for Proposal. Proposals may be submitted in one of two different forms: (i) a Single-Developer Proposal; or (ii) a Joint-Developer Proposal. The term “Proposal” shall include “Single-Developer Proposal” and “Joint-Developer Proposal”.

Proposal Cure Period: A period of time, equal to ten (10) Business Days, allowed for a RFP Respondent to correct deficiencies identified by the Transmission Provider in a previously submitted Proposal. The Cure Period commences upon notification by the Transmission Provider of deficiencies in the Proposal.

Proposal Participant(s): Any entity or entities involved in a Proposal, excluding the RFP Respondent(s), that will co-own the Competitive Transmission Project and rely on the RFP Respondent(s) to be the Selected Developer(s) responsible for constructing and implementing the Competitive Transmission Facilities associated with the Competitive Transmission Project. Proposal Participants may be identified in a Proposal as responsible for one or more aspects of operations, maintenance, repair, or restoration, on

terms comparable to those that would apply if the RFP Respondent(s) intended to rely on a third-party contractor.

Proposal Submission Deadline: The date and time Proposals must be submitted to the Transmission Provider by in order to be considered and evaluated by the Transmission Provider. The Submission Deadline shall be no later than 5:00 PM EPT on the date specified in the RFP, which shall not exceed one hundred and eighty (180) Calendar Days from the date the RFP was issued by the Transmission Provider, unless such date falls on a Saturday, Sunday, or MISO observed holiday in which case the Proposal Submission Deadline shall be the next Business Day that is not a MISO observed holiday.

Proposed Generator Planned Outage: The planned removal from service, in whole or in part, of a Generation Resource for inspection, maintenance or repair for which the Generation Owner has sought or will seek approval from the Transmission Provider for such planned removal in accordance with the Business Practices Manuals.

Protected Information: Privileged and non public information to be maintained by the Transmission Provider.

Proxy Offers: The Offers created for resources that are deployed during Emergency operating procedures by the Transmission Provider as specified in Schedule 29A.

Pseudo tie: A telemetered reading or value that is updated in real time and used as a tie line flow in the Area Control Error equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes. Pseudo tied status of Resources and Loads may only be changed during Network Model updates and the timing of such updates shall be as defined in the Business Practices Manuals.

Public Power: For credit scoring purposes, an Applicant or Market Participant that is a not for profit municipality, cooperative, Joint Action Agency, or agent representing one or more Public Power entities and whose credit quality is directly derived from the credit quality of the Public Power entities represented through the agency relationship.

Public Power Composite Score: For credit scoring purposes, the weighted average value of the Public Power Qualitative Score and the Public Power Quantitative Score. The relative weights are sixty percent (60%) and forty percent (40%).

Public Power Qualitative Score: A component of a Public Power Composite Score which has, for credit scoring purposes, a value ranging from 1 to 6.99, with 1 being the best and 6.99 being the worst. The value is based on a review by the Transmission Provider of qualitative factors relative to an Applicant's business, including but not limited to: i) regulatory; ii) legal; iii) demographic; and iv) energy supply/price factors as provided in Attachment L to this Tariff.

Public Power Quantitative Score: A component of a Public Power Composite Score which has, for credit scoring purposes, a value ranging from 1 to 6.99, with 1 being the best and 6.99 being the worst. The value is based on a review by the Transmission Provider of various financial metrics as detailed in the Transmission Provider's credit scoring model in Attachment L.

Zonal Deliverability Charge (ZDC): A positive charge per ZRC associated with ZRCs in a FRAP that may be assessed to an LSE based upon the congestion contribution to the constraints between LRZs or ERZs of any ZRCs that are located outside of the LRZ where the LSE has Load.

ZDC Hedge: The mechanism that permits an LSE to avoid Zonal Deliverability Charge assessments through the investment in new or upgraded Transmission System facilities which are a result of approved firm transmission service requests where the LSE's Planning Resource and the LSE's Demand are in separate LRZs or the Planning Resource is located in an ERZ.

Zonal Contingency Reserve Requirement: The minimum amount of Contingency Reserve the Transmission Provider shall procure within a Reserve Zone as determined based upon Reserve Zone Studies.

Zonal Export Ability: The ability of an LRZ to export capacity to areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to export generation.

Zonal Import Ability: The ability of an LRZ to import capacity from areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to import generation.

Zonal Operating Reserve: Operating Reserve that is available on a Reserve Zone basis.

Zonal Operating Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is used to calculate the Shadow Price of a particular Operating Reserve requirement constraint when there is a shortage of Operating Reserve cleared on a

Reserve Zone basis.

Zonal Operating Reserve Requirement: The sum of the Zonal Contingency Reserve Requirement and Zonal Regulating Reserve Requirement.

Zonal Regulating Reserve: Regulating Reserve that is available on a Reserve Zone basis.

Zonal Regulating and Spinning Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is utilized to calculate the Zonal Regulating and Spinning Reserve constraint Shadow Price when there is a shortage of the Zonal Regulating and Spinning Reserve cleared.

Zonal Regulating Reserve and Spinning Reserve Requirement: The amount of Zonal Regulating and Spinning Reserve the Transmission Provider is required to procure on a Transmission Provider Region-wide basis in accordance with Applicable Reliability Standards.

Zonal Regulating Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is utilized to calculate the Shadow Price of the Regulating Reserve requirement constraint when there is a shortage of Regulating Reserve cleared on a Reserve Zone basis.

Zonal Regulating Reserve Requirement: The minimum amount of Regulating Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based upon Reserve Zone Studies.

Zonal Resource Credit (ZRC): A MW unit of Planning Resource which has been converted from a MW of Unforced Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and/or to be submitted

through a Fixed Resource Adequacy Plan.

ZRC Offer: An offer into the PRA of ZRCs by a Market Participant.

Zonal Spinning Reserve Requirement: The minimum amount of Spinning Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based on a percentage of the Zonal Contingency Reserve Requirements where such a percentage adheres to Applicable Reliability Standards.

Zonal Supplemental Reserve Requirement: The minimum amount of Supplemental Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based upon Zonal Contingency Reserve Requirement and Zonal Spinning Reserve Requirement from Reserve Zone Studies.

Zone: A set of Buses in a geographic area as determined by the Transmission Provider.

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing External Resource Zones and associated limits (*i.e.*, Capacity Export Limits (CEL)); determining the annual Planning Reserve Margin; annual Coincident Peak Demand forecasting; annual Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources

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in the Planning Resource Auction process; settlement provisions; and Planning Resource performance requirements.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those with only Coordinating Owner and/or Border External Resources.

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed such that the LRZ would achieve an LOLE of 0.1 day per year, without consideration of the benefit of the LRZ's CIL. The LRR will be determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak Demand as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

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Establishment of Local Clearing Requirement

The Transmission Provider will establish the Local Clearing Requirement for each LRZ as

$LCR = LRR - \text{Zonal Import Ability} - \text{controllable exports}$, where controllable exports are: (i)

from MISO resources that have firm capacity commitments to non-MISO load; and (ii) may be committed and dispatched by the Transmission Provider during a declared Energy Emergency.

The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, an annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data to be used by the Transmission Provider as described herein. The Transmission Provider will then calculate each LSE's PRMR. LSEs will meet their PRMR by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; and/or (iv) paying the Capacity Deficiency Charge. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in a submitted Fixed Resource Adequacy Plan) must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Retirement, Suspension and Replacement of Planning Resources

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. As used in this section, “cleared ZRCs” include ZRCs that cleared in the PRA or TPRA, were used in a FRAP, or were used to replace ZRCs in accordance with this section. As used in this section, “uncleared ZRCs” include ZRCs that did not clear in the PRA or TPRA, were not used in a FRAP, or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs is Retired or Suspended prior to the end of the Planning Year, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.9 and 69A.5 any time during the Planning Year, such Market Participant may replace the cleared ZRCs with uncleared ZRCs to relieve the performance requirements applicable to the Planning Resource. A Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5 for the balance of the Planning Year. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA/TPRA clearing

results, so that such replacement: (1) does not violate any CIL used in the PRA/TPRA; (2) does not violate any CEL used in the PRA/TPRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

- i. ZRC replacement shall be processed on a first come, first served basis.
- ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, TPRA and FRAPs.

Planning Resource Auction

Within ten (10) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA, in accordance with the following provisions:

PRA Procedures

a. **Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Unforced Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not opted out of the PRA by submitting a FRAP, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in either the PRA or a TPRA. The PRA offer window shall begin at 12:01 am EST three (3) Business Days before the last Business Day in March and shall end at 11:59 pm EST on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or reopening's

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circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the CONE value for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs

Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Unforced Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner will be granted ZRCs in the LRZ where their firm Transmission Service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities. Generation Resources, Intermittent Generation and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g.

To the extent a Border External Resource is located on the border of two or more LRZs (e.g. has transmission lines from two or more LRZs terminating at the substation containing the Border External Resource's interconnection facilities), the Market Participant may elect the LRZ in which the Border External Resource is granted ZRCs through notice submitted no later than two (2) years prior to February 1 preceding the applicable Planning Year. Such representation will not be modified more frequently than every other year.

b. Participating Demand: All LSEs will be required to meet their PRMR through the PRA process, unless they have opted out of the PRA pursuant to Section 69A.9 and/or have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a fixed reliability target for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to one hundred percent of the PRMR for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization

methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to clear ZRC Offers and satisfy the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) Objective Function: The objective of the multi-zone optimization methodology shall be to minimize the as-offered overall costs of capacity procurement over the time horizon, subject to network constraints and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of three (3)

successive iterations to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over the next Planning Year for the Transmission Provider Region. Coincident Peak Demand is used to establish LSE's PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to minimize the cost of serving Demand to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the Peak Hour of the

Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP for an LRZ will be based on the total PRMR for the LRZ minus any deficiency volumes of PRMR for an LSE that voluntarily chooses to not participate in the Planning Resource

Auction. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ(s) with which the ERZ interconnects. For ERZs which connect with more than one SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Unforced Capacity

from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(x) **ACP for Shortage Conditions:** The ACP will be set at CONE when there is an insufficient volume of valid ZRC Offers to cover LCR or the total PRMR for the LRZ minus the amount of PRMR associated with the Capacity Deficiency Charge for an LRZ.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the tenth Business Day following the last Business Day in March.

PRA Settlement

- a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9. The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region divided by the total number of days in the Planning Year.
- b. An LSE that submits a FRAP with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:

The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or

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- (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP.
- c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

Distribution of Excess Auction Revenue

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

- (i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then
- (ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a *pro rata* basis to all HUCs and ZDC Hedges.

Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, including a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or arrangements that predate March 26, 2018, and pertain to External Resource represented in External Resource Zones in which:

- i. The LSE has PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;
- ii. The Planning Resource designated in the arrangement and PRMR obligation span multiple LRZs and/or ERZs;
- iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated PRMR obligation; and
- iv. LSEs must note qualification for HUCs for as part of the annual PRA registration process.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of PRMR that are associated with the qualified arrangement. A qualified arrangement shall remain eligible to

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receive excess PRA revenue for the length of the executed contract (including any evergreen contract extensions), until the owned resource status is changed to retired or until the transmission service is not maintained.

ZDC Hedges

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent (100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Zonal Deliverability Benefit

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

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Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZ k by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZ k . This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

The Transmission Provider will also receive FRAP related revenues derived from FRAP ZRCs that would have received payments greater than the charges to the associated FRAP PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

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Self-Scheduling Option:
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Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Installed Capacity (ICAP) Deferral Requirements and Charges

- a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of May prior to the Planning Year.

- b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within ten (10) Business

Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

- i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of May prior to the Planning Year, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on June 1st of the Planning Year and continue until ICAP is submitted and verified by the Transmission Provider, or replacement ZRCs are registered per the BPM for Resource Adequacy, or the ICAP value is forfeited, or the end of the Planning Year, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9 and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

- ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs .
- iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to LSEs that have met their PRMR during the Planning Year on a *pro rata* basis, based upon the LSE's share of total PRMR for the Transmission Provider Region.

Opting Out of the Planning Resource Auction

An LSE electing to opt out of the PRA can continue to use its existing resource planning processes to meet their PRMR by providing the Transmission Provider with a Fixed Resource Adequacy Plan (FRAP), as described below:

- a. An LSE electing to opt out of the PRA must submit a Fixed Resource Adequacy Plan (FRAP) for each LRZ to the Transmission Provider by the 7th business day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or a portion of the LSE's PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year. Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two business days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for a Planning Year and also identify

- the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its total PRMR and also its load ratio share of the LCR for each LRZ. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the LSE's PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that an LSE's PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP.
- b. An LSE that submits a FRAP for an LRZ will be able to opt out of the PRA for such Planning Year for such LRZ, to the extent that the LSE's ZRCs satisfy the LSE's PRMR. To the extent that an LSE that has opted out of the PRA: (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Planning Year; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- c. Any portion of an LSE's PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA. An LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10.

- d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- e. Any ZRCs included in the FRAP from new resources needed to meet an LSE's PRMR will be exempt from application of the minimum offer price provisions.
- f. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.
- g. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

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ZDC Charges and ZDC Hedges
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A New LSE will be subject to the Zonal Deliverability Charge consistent with Section 69A.7.6(b) if the New LSE submits a Fixed Resource Adequacy Plan to meet all or a portion of its Planning Reserve Margin Requirements. A New LSE will be able to receive excess TPRA revenue if a New LSE qualifies for a ZDC Hedge, consistent with Section 69A.7.7(b). A New LSE will be entitled to a Zonal Deliverability Benefit in accordance with Section 69A.7.7(c). A New LSE will be allocated, as appropriate Local Clearing Requirement Charges in accordance with Section 69A.7.7(d). The Tariff provisions in Module E-1 apply to existing LSEs. New LSEs are only subject to the provisions of Module E-2, except to the extent that Module E-2 Tariff provisions incorporate Module E-1 requirements by reference.

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69A.11.12
Distribution of Excess Auction Revenue
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The Transmission Provider will distribute any excess TPRA revenues: first, to Historic Unit Considerations as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7(b). Any remaining amounts will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a *pro rata* basis to all HUCs and ZDC Hedges.

Tab B

Active Transmission Constraint: Any transmission constraint for which a Resource is committed to avoid exceeding, or to relieve, the constraint limit.

Actual Energy Injections: For a Generation Resource a net Metered volume measured in MWh that flows into the Transmission System during the Operating Day at a specified location that is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day or, for a Stored Energy Resource or External Asynchronous Resource or Stored Energy Resource – Type II, a net Metered volume measured in MWh that flows into or out of (withdrawal positive, injection negative) the Transmission System during the Operating Day at a specified location that is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day. For a Demand Response Resource-Type I, or for a Demand Response Resource-Type II, or an EDR resource, a calculated volume in MWh that is equal to the amount as calculated or Metered according to the specifications and protocols in the Measurement and Verification Procedures. The Actual Energy Injection of the Demand Response Resource is calculated by the Transmission Provider based on the meter data submitted by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day that is used for Settlement purposes. Given the appropriate qualification, Demand Response Resources-Type I Resources can provide the following products: Energy, Contingency Reserve, and capacity under Module E.

Actual Energy Withdrawal: For a Load Zone where one or more Demand Response Resources Type I are committed for Energy and/or are offered for Contingency Reserve, where one

or more Demand Response Resource Type II are committed during a specific Hour, or where an EDR resource has reduced load, a calculated volume in MWh that flows out of the Transmission System during the Operating Day at a specified location that is equal to the time-weighted average of the Metered volume of the Load Zone for that Hour plus Actual Energy Injects within the Load Zone for the Demand Response Resources and EDR resources. For all other Load Zones, a Metered volume measured in MWh that flows out of the Transmission System during the Operating Day at a specified location. The Load Zone Metered volume in MWh that flows out of the Transmission System during the Operating Day, used for the calculation of the Actual Energy Withdrawal, is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day that is used for Settlement purposes. For an Hour where the Hourly Ex Post LMP is less than the Net Benefits Price Threshold, the amount of Actual Energy Injections for all DRRs associated with a given Load Zone are added to the Metered volume at the specified Load Zone.

Actual Resource Response: The actual movement, in MWs, relative to Setpoint Instructions for a Resource within a Dispatch Interval.

Additional Regulating Mileage: Any Regulating Mileage Target for a Resource in a Dispatch Interval beyond the amount considered for the Dispatch Interval during the market clearing.

Adjusted Financial Transmission Rights Capability: The expected available transmission capacity in the FTR Auction, respecting the Simultaneous Feasibility Test, over the Transmission Provider Region during: (1) a given Month, less FTRs held by existing

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FTR Holders; or (2) a Season, less FTRs held by existing FTR Holders and baseloading assumptions.

Affected Participant: A Market Participant, a person that engages in Market Activities or a person that takes any other service under the Tariff that has provided to the Transmission Provider, Confidential Information that is requested by, or is disclosed to, an Authorized Requestor under a Non-Disclosure Agreement.

Affiliate: With respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity.

Agency Agreement: The agreement that is Appendix G of the ISO Agreement.

Aggregate Annual Transmission Revenue Requirement (Aggregate ATRR): The annual transmission revenue requirement calculated by combining the annual transmission revenue requirements of each individual RFP Respondent and each individual Proposal Participant identified in a Proposal, all as provided in Section VIII.D.4.3 of Attachment FF of the Tariff.

Aggregate Power Supply Curve: The combined Energy Offer curves for all Resources, excluding DRRs, which is the capacity from all such resources at each price offered.

Aggregate Price Node (APNode): An aggregation of Elemental Pricing Nodes whose LMP is calculated as the sum of the products of the LMP at each Elemental Pricing Node defined in the Aggregate Price Node and the associated pre-established normalized weighting factors for the Elemental Pricing Node.

Aggregator of Retail Customers (ARC): A Market Participant that represents demand response on behalf of one or more eligible retail customers, for which the participant is not such customers' LSE, and intends to offer demand response directly into the Transmission Provider's Energy and Operating Reserve Markets, as a Planning Resource or as an EDR resource.

Allowance Level: A description of the mitigation measure described in Module D which allows a Market Participant that is an LSE or represents an LSE, to purchase or schedule a specified portion of its Energy, Operating Reserve, Up Ramp Capability, and Down Ramp Capability requirements in the Real Time Energy and Operating Reserve Market.

Alternate Selected Developer(s): Shall be the RFP Respondent(s) whose Proposal is selected to be the alternate Proposal by the Competitive Transmission Executive Committee, pursuant to Attachment FF of the Tariff, for implementation if the Selected Developer fails to execute or request an unexecuted filing of the Selected Developer Agreement and provide the required Project Financial Security within the timeframe provided in Attachment FF Section VIII.H.

Ancillary Services: Those services that are necessary to support Capacity and the transmission of Energy from Resources to Loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

Annual ARR Allocation: The procedure used by the Transmission Provider annually to allocate ARRs and MVP ARRs.

Annual ARR Registration: The annual process for registering ARR Entitlements and MVP ARR Entitlements.

Applicable Laws and Regulations: All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the Parties, their respective facilities and/or the respective services they provide.

Applicable Reliability Standards: Reliability Standards approved by the Federal Energy Regulatory Commission (FERC) under Section 215 of the Federal Power Act relating to operation of the Transmission Provider in carrying out its Reliability Coordinator, Balancing Authority, Market Operator, Transmission Service Provider, and Planning Coordinator functions. In addition to FERC approved standards, any regional reliability criteria and/or standards relating to operation of the Transmission Provider in carrying out the functions listed above.

Applicant: An entity desiring to hold FTRs, take Transmission Service, engage in Market Activities or take any other service under this Tariff, or become a Market Participant, Transmission Customer or Coordination Customer under this Tariff.

Application: A request by an Eligible Customer for Transmission Service pursuant to the provisions of this Tariff.

ARR Delivery Point: The ARR Zone or Interface specified in an ARR where Transmission Service terminates.

ARR Entitlement(s): Right to nominate and be allocated ARRs based on transmission usage, upgrades or other basis.

ARR Holder(s): The Market Participant that receives ARRs, or the Transmission Provider to the

extent it receives ARR, through the Annual ARR Allocation.

ARR Obligation: The financial credit or obligation resulting from the difference between the clearing prices from the annual FTR Auction at the ARR Delivery Point and the clearing prices at the ARR Receipt Point.

ARR Receipt Point: The transaction receipt point specified in an ARR.

ARR Settled Exposure: The potential exposure to non-payment associated with ARRs that have been settled.

ARR Stage Factors: The factors that determine the nomination caps in Stage 1A and Stage 1B of the ARR allocation procedure.

ARR Term: The term specified in the ARR.

ARR Transactions Not Yet Settled: The value of the ARRs based on the clearing price(s) established as a result of the most recent annual FTR Auction which have not been settled.

ARR Zone(s): Geographic areas defined for the purpose of allocating ARRs based upon locations where a Market Participant serves Load.

Area Control Error (ACE): The instantaneous difference between Net Actual Interchange and Net Scheduled Interchange, taking into account the effects of frequency bias, including a correction for meter error, expressed in MW.

Asset Owner: An entity identified by a Market Participant through the Transmission Provider registration process that is eligible to be represented by the Market Participant in Market Activities.

Auction Clearing Price (ACP): The price, expressed in \$/MW-day, associated with the MW

quantity that clears in the Planning Resource Auction for a given LRZ or ERZ for the applicable Planning Year.

Auction Revenue Rights (ARR): Entitlements to a share of the revenues generated in the annual FTR Auction.

Authorized Agency: (i) a State public utility commission within the geographic limits of the Transmission Provider Region that regulates the distribution or supply of electricity to retail customers or is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State; (ii) the Organization of MISO States or any successor organization, formed to act as a regional state committee within the Transmission Provider Region; or (iii) a state agency that has both access to documents in the possession of a state public utility commission pursuant to state statute and the ability to protect those documents in accordance with the Non Disclosure Agreement.

Authorized Requestor: A person who has executed a Non Disclosure Agreement, and is authorized by an Authorized Agency to receive and discuss Confidential Information. Authorized Requestors may include State public utility commissioners, State commission staff, attorneys representing an Authorized Agency, and employees, consultants and/or contractors directly employed by an Authorized Agency, provided, however, that consultants or contractors may not initiate requests for Confidential Information from the Transmission Provider or the IMM.

Available Non-FTR Financial Security: For Credit purposes, any Financial Security held in excess of alternative capitalization requirements and Total FTR Obligations and available

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for securing Non-FTR Potential Exposure.

Available Transfer Capability: The maximum amount of additional Energy that may be carried by the Transmission System or by the transmission systems of Coordination Customers under current or projected operating conditions.

Balancing Authority: The responsible entity that integrates Resource plans ahead of time, maintains Load-generation balance within a Balancing Authority Area and supports the Eastern Interconnection frequency in real time.

Balancing Authority Agreement: The “Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of the TEMT” which was filed October 5, 2004 in Docket Nos. ER04-691-002 and EL02-104-002, as may be amended from time to time, and is designated as FERC Electric Tariff, Rate Schedule No. 3.

Balancing Authority Area: An electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied within the Balancing Authority in order to: (i) match the power output of the Generation Resources within the electric power system(s) and Energy delivered from or to entities outside the electric power system(s), with the demand (including losses) within the electric power system(s); (ii) maintain scheduled Interchange with other Balancing Authority Areas, within the limits of Good Utility Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and Applicable Reliability Standards.

Base Penalty Charge: A base sanction that is assessed by the Independent Market Monitor against a Market Participant that is found to have engaged in conduct that is not permitted under the Tariff.

Baseline Reliability Projects: Network Upgrades identified in the MTEP as required to ensure the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Entities

and applicable to the Transmission Provider's Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria. Baseline Reliability Projects include projects of 100kV voltage class or above needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers.

Baseline Reliability Study: A study performed by the Transmission Provider as part of the MTEP development to determine whether the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Entities and applicable to the Transmission Provider's or Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria, the result of which is the identification of Baseline Reliability Projects.

Baseload Reserved Source Point (RSP): The Baseload Reserved Source Point for use in the ARR allocation process.

Baseload Reserved Source Set (BRSS): The Baseload Supply Resources that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone.

Baseload Supply Resource(s): Generation Resource associated with serving a Market Participant's Baseload Usage and that is used for Baseload Reserved Source Point calculations.

Baseload Usage: Transmission usage that is fifty percent (50%) of Peak Usage of Network Load. For Market Participants utilizing Point-To-Point Transmission Service, fifty

percent (50%) of the Point-To-Point Transmission Service MW amount will be assumed to be Baseload Usage. However, this assumption will not require an LSE to pay multiple Transmission Service charges for Loads included in the LSE's Baseload Usage.

Behind the Meter Generation (BTMG): Generation resources used to serve wholesale or retail load located behind a CPNode that are not included in the Transmission Provider's Setpoint Instructions and in some cases can also be deliverable to Load located within the Transmission Provider Region using either Network Integration, Point-To-Point Transmission Service or transmission service pursuant to a Grandfathered Agreement. These resources have an obligation to be made available during Emergencies.

Bid: A request to purchase Energy in the Day Ahead Energy and Operating Reserve Market, including Demand Bids, Price Sensitive Demand Bids, and Fixed Interchange Schedule Export Schedules, Dispatchable Interchange Schedule Export Schedules, and Virtual Bids, at a specified location, quantity, and time period, that is duly submitted to the Transmission Provider pursuant to this Tariff and the Business Practices Manuals.

Bi-Directional Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments at which a Generation Resource or Demand Response Resource - Type II can respond to either increasing or decreasing Setpoint Instructions.

Bilateral Transaction Schedule: A schedule associated with a Bilateral Transaction.

Bilateral Transactions: Interchange Schedules, Dynamic Interchange Schedules, Financial Schedules and GFA Schedules.

Billing Agent: An entity designated by a Market Participant as the entity to receive from, or forward payment to, the Transmission Provider on the Market Participant's Settlement

Statements. The Market Participant shall remain liable for all obligations issued to it in the Settlement Statements.

Binding Reserve Zone Constraint: A constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to meet the Reserve Zone's minimum Operating Reserve requirements.

Binding Settlement Zone: Any Reserve Zone with a Market Clearing Price for Regulating Reserve, Spinning Reserve or Supplemental Reserve, as applicable, derived in the Day-Ahead Energy and Operating Reserve Market or in the Real-Time Energy and Operating Reserve Market that has any non-zero Market Clearing Price Zonal Terms for Operating Reserves.

Binding Transmission Constraints: A transmission constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to avoid exceeding, or to relieve, the constraint limit.

Blackstart Equipment: The equipment that is necessary to make a generation unit a Blackstart Unit capable of reliably providing Blackstart Service.

Blackstart Service: The process used by the Transmission Operator, Load Serving Entities, and Generator operators to reenergize to a fully operational state the entire transmission network and the remainder of the delivery system to normal operation. This process includes systematic start up of Blackstart Units via Blackstart Equipment, energizing transmission to critical facilities such as larger generating units, energizing to the largest generators to facilitate the restoration of system loads.

Blackstart System Restoration Plan: The plan developed by the Transmission Provider acting

in its capacity as the Reliability Coordinator, to coordinate the system restoration plans developed by the individual Transmission Operators to re-energize the Transmission System following a system-wide blackout.

Blackstart Unit: A generation unit that has Blackstart Equipment attached to it, which allows the unit to be started without assistance from any other resource.

Blackstart Unit Owner: An entity that either: (1) owns and controls the output of, or operates a Blackstart Unit; or (2) has contractual rights to direct the operation of a Blackstart Unit and to receive the compensation provided for under Schedule 33 of the Tariff.

Border External Resource: An External Resource that: (i) has interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; and (ii) which will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to such substation.

Branch Facility: A facility located within a pricing Zone having a defined Line Outage Distribution Factor.

Broad Constrained Area: An electrical area in which sufficient competition usually exists even with one or more Binding Transmission Constraints or Binding Reserve Zone Constraints, or into which the transmission constraints or reserve constraints bind infrequently, but within which a Binding Transmission Constraint or Binding Reserve Zone Constraint can result in substantial locational market power under certain market or operating conditions.

Bulk Electric System: The electrical Generation Resources, transmission lines, interconnections

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with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher as further defined by the applicable Regional Entity.

Bundled Load: The aggregate usage by customers who purchase electric services as a single service or customers who purchase electric services under a retail tariff rate schedule that includes Energy and delivery components, as distinguished from customers who purchase Transmission Service as a separate service.

Bus: A specific electrical location within the Transmission System and/or within other transmission systems within the Eastern Interconnection modeled in the Network Model.

Business Day: A day in which the Federal Reserve System is open for business.

Business Practices Manuals: The instructions, rules, policies, procedures and guidelines established by the Transmission Provider for the operation, planning, accounting and settlement requirements of the Transmission Provider Region.

Calculated Demand Response Resource-Type I Output: The hourly average Actual Energy Injection for each associated Demand Response Resource – Type I for the Hour for the purposes of assessing Excessive/Deficient Energy Deployment Charges.

Calculated Demand Response Resource-Type II Output: For a Demand Response Resource-Type II, the hourly average Actual Energy Injection for the Hour for the purposes of assessing Excessive/Deficient Energy Deployment Charges.

Calendar Day: Any day of the week, including Saturday, Sunday or a Federal holiday.

Candidate ARR (CARR): ARR nominations submitted by Market Participants to be considered throughout the Annual ARR Allocation process.

Candidate Baseload ARR: Candidate ARR rights equal to each Market Participant's Baseload Usage in an ARR Zone.

Candidate Peak ARR: Candidate ARR rights equal to each Market Participant's Peak Usage in an ARR Zone.

Candidate MVP ARR: MPV ARR nominations submitted by the Transmission Provider to be considered during the Annual ARR Allocation process.

Capacity: The instantaneous rate at which Energy can be delivered, received or transferred, including Energy associated with Operating Reserve, Up Ramp Capability, and Down Ramp Capability, measured in MW.

Capacity Deficiency Charge: A charge that is assessed to an LSE that has not demonstrated to the Transmission Provider that it has sufficient Planning Resources to meet its PRMR.

Capacity Export Limit (CEL): The amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or

ERZ.

Capacity Import Limit (CIL): The amount of Planning Resources in MWs for an LRZ

determined by the Transmission Provider that can be reliably imported into that LRZ.

Capacity Resources: The Generation Resources, Demand Response Resource- Type I, Demand Response Resource-Type II, Dispatchable Intermittent Resources, External Resources, Intermittent Generation, or Stored Energy Resources – Type II that are available to meet Demand.

Carved Out GFA(s): Any Grandfathered Agreement(s) that the Commission has identified as “carved out” pursuant to Appendix B of the Commission’s September 16, 2004 order, Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,236 (2004) or that meet the criteria in Section 38.8.3(A).b, and set forth in Attachment P to this Tariff, as that Attachment may be amended from time to time.

Cash Collateral Agreement: A Credit Support Document taking the form found in Exhibit III of Attachment L of this Tariff.

Cash Deposit: Cash collateral provided to Transmission Provider to secure Applicant’s and/or Tariff Customer’s performance under the terms and conditions of Transmission Provider’s Tariff, and/or other agreements.

Category A Tariff Customer: A Tariff Customer who grants a continuing first-priority security interest to the Transmission Provider in all right, title and interest in any and all accounts receivable and other rights of payment of the Tariff Customer for goods and services provided under, or otherwise arising under, pursuant to or in connection with, the Tariff and/or any of the Agreements.

Category B Tariff Customer: Any Tariff Customer who does not grant a Receivable Security Interest to the Transmission Provider.

Change in Total System Cost: The net change in variable operational costs, which include fuel, variable O&M, variable environmental costs, and other variable costs as mutually agreed upon by the Transmission Provider and the Market Participant, measured in dollars as a result of changing the output of one or more units in response to a redispatch request from the Transmission Provider.

Charge: The withdrawal of energy from the Transmission System by a Stored Energy Resource for the purpose of storing the energy for injection back into the Transmission System at a later time.

Coincident Peak Demand: The Demand in MWs, for an LSE and/or EDC, that occurs coincident to the annual peak Demand in the Transmission Provider Region, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

Combined Reliability Systems: The Reliability Coordination Customer Transmission Facilities and all other transmission facilities for which the Transmission Provider performs Reliability Coordination Services under Part I of Module F.

Commercial Model: A presentation of the relationships between Market Participants and their Resources, Commercial Pricing Nodes and the Network Model in the Energy and Operating Reserve Markets.

Commercial Operation Date: Shall have the meaning set forth in Attachment X of this Tariff.

Commercial Pricing Node (CPNode): An Elemental Pricing Node or an Aggregate Price Node

in the Commercial Model used to schedule and settle Market Activities. Commercial Pricing Nodes include Resources, Hubs, Load Zones and/or Interfaces.

Commercially Significant Voltage and Local Reliability Issue: Transmission System voltage or other local reliability concerns that result in Voltage and Local Reliability Commitments. These issues are designated for reasons including, but not limited to, occurrence frequency, monetary impact, or other criteria as defined in Schedule 44. A Local Balancing Authority or an interested Market Participant may request that the Transmission Provider evaluate a Voltage and Local Reliability Issue for designation as commercially significant.

Commission: The Federal Energy Regulatory Commission, also known as FERC, or its successor.

Common Bus: A single Bus to which two or more Resources are connected in an electrically equivalent manner where such Resources are treated as a single Resource for compliance monitoring purposes.

Common Information Model (CIM): The format adopted by the NERC Data Exchange Working Group that will be used by the Congestion Management Customer and the Transmission Provider to exchange Energy Management System models once a year.

Comparable FTRs: FTRs that are identical in all material respects except for the quantity of MW specified.

Competitive Developer Qualification Process: The process utilized to certify Qualified Transmission Developers pursuant to Section VIII.B of Attachment FF of the Tariff.

Competitive Developer Selection Process: The process utilized to solicit Proposals, evaluate Proposals, and designating a Selected Proposal and Selected Developer(s) pursuant to Section VIII of Attachment FF of the Tariff.

Competitive Substation Facility: A transmission substation facility contained within an Eligible Project that is subject to the Competitive Developer Selection Process in accordance with Section VIII.A of Attachment FF of the Tariff.

Competitive Transmission Executive Committee: A committee consisting of three (3) or more executive staff of the Transmission Provider, including at least one (1) officer, that is charged with overseeing all Transmission Provider staff and consultants involved in evaluating Transmission Developer Applications and Proposals in response to a posted Request for Proposal. The Competitive Transmission Executive Committee will have exclusive and final decision-making authority over: (i) the certification and termination of Qualified Transmission Developers; and (ii) the evaluation and selection of Proposals, resulting in designating Selected Developers. The Competitive Transmission Executive Committee shall possess the specific technical, financial, and regulatory expertise necessary for evaluation of Transmission Developer Applications and Proposals.

Competitive Transmission Facility: A Competitive Substation Facility or Competitive Transmission Line Facility.

Competitive Transmission Line Facility: A transmission line facility contained within an Eligible Project that is subject to the Competitive Developer Selection Process in accordance with Section VIII.A of Attachment FF of the Tariff.

Competitive Transmission Process: The process utilized to certify Qualified Transmission Developers, identify Competitive Transmission Projects, solicit Proposals, evaluate Proposals, and designating a Selected Proposal and Selected Developer(s) pursuant to Section VIII of Attachment FF of the Tariff. The Competitive Transmission Process includes the Competitive Developer Qualification Process and Competitive Developer Selection Process.

Competitive Transmission Project: The Competitive Transmission Facilities contained within an Eligible Project.

Competitively Sensitive Information: Information that is not public and the unauthorized disclosure of which could have anti-competitive effects, provide a competitor with an unfair or improper competitive advantage, or unfairly or improperly result in competitive harm, detriment, prejudice, disadvantage or injury to the legitimate proprietary rights, business or commercial interests, market position, or ability to bargain freely, of the lawful owners, possessors or users of such information.

Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Composite Credit Score: A composite numerical score scaled from 1.00 to 6.99, representing the sum of the Qualitative and Quantitative score as calculated by the Transmission Provider's credit scoring model in Attachment L of this Tariff.

Confidential Information: Any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or

planned business of a Transmission Customer, Market Participant, or other user, which is designated as confidential by the entity supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by the Transmission Provider and is not disclosed except under the terms of a Confidential Information policy.

Congestion Management Customer: Any entity taking Interconnected Operations and Congestion Management Service under Part II of Module F.

Congestion Management Process (CMP): The process described in Attachment LL of the Tariff.

Constraint Contribution Factor: Factor that represents the impact that an incremental Actual Energy Injection or Actual Energy Withdrawal of one MW has on a given Active Transmission Constraint.

Constraint Generation Shift Factor Cutoff: A Generation Shift Factor level defined for each transmission constraint that determines the generating units to be included in a Broad Constrained Area associated with the constraint. Generation Resources with a Generation Shift Factor whose absolute value is greater than the Constraint Generation Shift Factor Cutoff are included in the Broad Constrained Area.

Constraint Management Charge Allocation Factor: A factor that is used to apportion Real-Time Revenue Sufficiency Guarantee Credits in an Hour between (i) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge and (ii) the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and the Real-Time Revenue Sufficiency Guarantee Headroom Charge.

Contingency Reserve: Spinning Reserve and Supplemental Reserve provided by Resources available to the Transmission Provider to use in the event of a system contingency as specified in Schedule 5-Spinning Reserve and Schedule 6– Supplemental Reserve of this Tariff.

Contingency Reserve Deployment Failure Charge: A charge assessed to any Resource that fails to achieve in a Contingency Reserve Deployment Period at least one hundred percent (100%) of the Contingency Reserve Deployment Instruction target.

Contingency Reserve Deployment Instruction: An instruction issued by the Transmission Provider to Resources with cleared Contingency Reserve to deploy a specific MW quantity of cleared Contingency Reserve as communicated via Setpoint Instructions or other electronic means.

Contingency Reserve Deployment Period: The period of time the Resource has to deploy Contingency Reserve following the issuance of a Contingency Reserve Deployment Instruction that is equal to ten minutes.

Contingency Reserve Offer Price Cap: The maximum price permitted for a Spinning Reserve Offer, an On-Line Supplemental Reserve Offer, an Off-Line Supplemental Reserve Offer or a Supplemental Reserve Offer in the Energy and Operating Reserve Markets.

Control: The possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent (10%) or more shall create a rebuttable presumption of Control.

Controllable Devices: Devices that may include phase shifters, DC lines, and back-to-back AC/DC converters.

Coordinated Flowgate: A Flowgate that is subject to the Transmission Provider's or Coordination Customer's operational control and through which flows are affected by transmission over transmission facilities within its operational control, or with respect to which Transmission Provider serves as a Reliability Authority.

Coordinated Transaction Schedule: An Interchange Schedule to purchase Energy in the Real-Time Energy and Operating Reserve Market from a Source Point in either the MISO Balancing Authority Area or PJM Balancing Authority Area and sell it at a Sink Point in the other balancing authority area that is cleared if the forecasted LMP at the Sink Point minus the forecasted LMP at the Source Point is greater than or equal to the dollar value specified in the bid associated with the Interchange Schedule.

Coordinating Owner: Any entity that is not subject to the jurisdiction of the Commission but participating in the ISO through the execution of a coordination agreement which includes provisions for the elimination of rate pancaking. The terms and provisions of a Coordinating Owner's coordination agreement shall supersede the similar terms and provisions of this Tariff where applicable.

Coordination Customer: Any customer taking Coordination Services from the Transmission Provider pursuant to Module F of the Tariff. The term Coordination Customer includes: Reliability Coordination Customer, and Congestion Management Customer.

Coordination Services: The services provided by the Transmission Provider pursuant to Module F of the Tariff. Coordination Services include Reliability Coordination Service and Interconnected Operations and Congestion Management Service.

Corporate Guaranty: A legal document taking the form found in Exhibit I of Attachment L of

this Tariff used by an Affiliate of an Applicant and/or Tariff Customer that guarantees the obligations of such Applicant or Tariff Customer.

Cost Allocation Zone: The zones identified in Attachment WW of this Tariff used for allocating the costs of Market Efficiency Projects.

Cost of Congestion: The Marginal Congestion Component of LMP at the sink minus the Marginal Congestion Component of LMP at the source.

Cost of Losses: Marginal Losses Component of LMP at the sink minus the Marginal Losses Component of LMP at the source.

Cost of New Entry (CONE): The capital, operating, financial and other costs of acquiring a new Generation Resource within the Transmission Provider Region for any designated LRZ.

Counterflow ARR: ARR allocated during the LTTR Restoration and Termination Stage of an Annual ARR Allocation based on a Counterflow ARR Entitlement.

Counterflow ARR Entitlement: Any Stage 1A eligible ARR Entitlement's portion that was not nominated in Stage 1A of a Market Participant's year 1 Annual ARR Allocation but that the Transmission Provider deems to provide counterflow necessary to enable curtailed Stage 1A CARRs to be restored (fully or partly) during the LTTR Restoration and Termination Stage of an Annual ARR Allocation.

Credit and Security Agreement: A Credit Support Document taking the form found in Exhibit V of Attachment L of this Tariff.

Credit Policy: The Transmission Provider's creditworthiness requirements and credit evaluation procedures as contained in Attachment L of this Tariff.

Credit Support Documents: Any agreement or instrument in any way guaranteeing or securing

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any or all of a Tariff Customer's obligations under this Tariff (including, without limitation, the Credit Policy), any agreement entered into under, pursuant to, or in connection with this Tariff or any agreement entered into under, pursuant to, or in connection with this Tariff or the Credit Policy, and/or any other agreement to which the Transmission Provider and the Tariff Customer are parties, including, without limitation, any Corporate Guaranty, Cash Collateral Agreement, Letter of Credit, Credit and Security Agreement or agreement granting a security interest.

Critical Energy Infrastructure Information (CEII): Confidential information described in 18 C.F.R § 388.113(c)(1), as may be amended from time to time.

Curtailement: A reduction in firm or non-firm Transmission Service in response to a transfer capability shortage as a result of system reliability conditions pursuant to Section 14.7 or Section 27A of this Tariff.

Customer Load Aggregation: A Load Zone approved by the Transmission Provider for the purposes of submitting Bids to or scheduling into the Energy and Operating Reserve Markets and for settlement of Market Activities.

Eastern Interconnection: The ERO certified Balancing Authorities operating in the eastern part of North America.

Eastern Prevailing Time (EPT): Eastern Daylight Time during periods when the eastern time zone is observing daylight saving time, Eastern Standard Time during periods when the eastern time zone is observing standard time.

Economic Maximum Dispatch: The maximum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Maximum Dispatch will equal the Actual Energy Injections.

Economic Minimum Dispatch: The minimum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Minimum Dispatch will equal the Actual Energy Injections.

Effective Import Tie Capability (EITC): The maximum aggregate level of power in MW that can be reasonably expected to flow on the transmission tie lines into a specified Zone of the Transmission System, while maintaining reliable operation.

Effective Export Tie Capability (EETC): The maximum aggregate level of power in MW that can be reasonably expected to flow outward on the transmission tie lines of a specified Zone of the Transmission System, while maintaining reliable operation.

Electric Distribution Company (EDC): A company that distributes electricity to retail customers through distribution substations and/or lines owned by the company.

Electric Facility: Equipment used for the generation, transmission, storage, or control of the transmission of electricity and that is connected to or part of the Transmission System operated by the Transmission Provider.

Electric Generation and Transmission Cooperative (Coop): An electric Generation and Transmission cooperative is a not for profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners.

Electric Reliability Organization (ERO): The organization certified by the Commission to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

Elemental Pricing Node (EPNode): A single Bus where LMP is calculated.

Eligible Confirmed Transmission Service Reservation: Any reservation for Transmission Service that has been confirmed and has a start date later than the date a Default first occurs. Any reservation for Transmission Service that has been confirmed remains a conditionally approved request at all times prior to such reservation's start date and may be cancelled if a Default occurs prior to such start date.

Eligible Customer: (i) Any electric utility (including the Transmission Owner(s), ITC Participants(s), and any power marketer), Market Participant, Federal Power Marketing Agency, or any person generating electric Energy for sale or for resale is an Eligible Customer under this Tariff. Electric Energy sold or produced by such entity may be electric Energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by § 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a

state requirement that a Transmission Owner or ITC Participant offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant; or (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that a Transmission Owner or ITC Participant offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant, that is an Eligible Customer under this Tariff. Unbundled retail customers that seek to take local distribution service cannot be Eligible Customers under this Tariff with respect to that service.

Eligible Projects: Shall mean any Market Efficiency Projects (“MEP”) and Multi-Value Projects (“MVP”) approved by the Transmission Provider’s Board after December 1, 2015 regardless of whether such project is subject to the Transmission Provider’s Competitive Developer Selection Process.

Emergency: (i) An abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of Emergency procedures as defined in this Tariff.

Emergency Demand Response (EDR): The commitment and dispatch of Load reductions, Behind the Meter Generation Resources and other Demand Resources during an Emergency, in accordance with Schedule 30.

EDR Dispatch Instruction: Directives issued by the Transmission Provider to EDR Participants indicating MW quantities to be reduced during Emergencies.

EDR Initiative: Procedures for EDR Participants to respond to an Emergency through a defined reduction in Load or increase in output from Behind the Meter Generation Resources, as described in Schedule 30 of this Tariff.

EDR Offer: An offer made by an EDR Participant to reduce demand in response to an Emergency event which will not be considered in the clearing of the Day-Ahead Energy and Operating Reserve Market or Real-Time Energy and Operating Reserve Markets.

EDR Participant: A Market Participant capable of reducing demand in response to directives received from the Transmission Provider during an Emergency event.

Emergency Energy: Purchases of Energy coordinated by the Transmission Provider following the issuance of an Energy Emergency Alert in accordance with the procedure set forth in Section 40.2.22 of this Tariff.

Emergency System Conditions: Are (i) situations in which a systemic equipment malfunction, including telecommunications, hardware, or software failures, prevents the Transmission Provider from operating the Energy and Operating Reserve Markets in accordance with the Market Rules; or (ii) widespread electric transmission or generation equipment outages that prevent the Transmission Provider from dispatching the system in accordance with the Market Rules.

Emergency Tier I Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation

emergency warning as specified in the Transmission Provider's Emergency operating procedures.

Emergency Tier II Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency event, step 2 as specified in the Transmission Provider's Emergency operating procedures.

Energy: An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold or transmitted over a period of time and measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Market(s): The Day Ahead and/or Real Time Energy and Operating Reserve Markets operated by the Transmission Provider.

Energy Consumer: Any end-use customer, including but not limited to commercial retail consumers of electricity, located within the Transmission Provider Region.

Energy Deficient Region: An area in which one or more LSEs within the MISO Balancing Authority Area are experiencing or are expected to experience an Emergency under the procedures specified under Section 40.2.20 of this Tariff.

Energy Efficiency Resource (EE Resource): A Planning Resource consisting of installed measures on retail customer facilities that achieves a permanent reduction in electric energy usage while maintaining a comparable quality of service.

Energy Emergency: A condition when a balancing authority can no longer meet the energy requirements of the firm end-use load within its balancing authority area and has initiated its Energy Emergency procedures.

Energy Emergency Alert: An alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area.

Energy Emergency Area: The area within a balancing authority area that is experiencing an Energy Emergency.

Energy Emergency Alert Level 2 (EEA2): Energy Emergency Alert Level 2 as defined by NERC.

Energy Management System (EMS): The software system used by the Transmission Provider and Transmission Operators for acquisition and processing of operational data.

Energy Market Counterparty: The Transmission Provider as the contracting counterparty to Market Participants for all Market Activities contemplated by this Tariff, solely in the Transmission Provider's capacity as a principal and not as an agent for any other party, consistent with the provisions of Section 6A.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource.

Energy Offer Price Cap: The maximum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Offer Price Floor: The minimum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Resource Interconnection Service: The interconnection of a Generation Resource to the Transmission System or distribution system, as applicable, to be eligible to deliver the Generation Resource's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis.

EPT: Eastern Prevailing Time.

Equity: For credit scoring purposes, the ownership interest in a firm, including the residual dollar value of a futures trading account, assuming its liquidation is at the going trade price of Applicant or Market Participant.

Equivalent Forced Outage Rate Demand (EFORD): The Equivalent Forced Outage Rate Demand, as defined by NERC.

EST: Eastern Standard Time.

Ex Ante MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, and Down Ramp Capability MCP calculated at the beginning of the Dispatch Interval, used for informational purposes in the Real-Time Energy and Operating Reserve Market.

Ex Post MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, and Down Ramp Capability MCP calculated for each Dispatch Interval.

Excess Congestion Charge Fund: A fund established by the Transmission Provider representing, in aggregate, the difference between the total of all Transmission Congestion Payments for a given Hour and the hourly transmission congestion charges.

Excessive/Deficient Charge Rate: The rate used to determine a Resource's Excessive/Deficient Energy Deployment Charge as calculated pursuant to Section 40.3.4.b.

Excessive/Deficient Energy Deployment Charge: A charge assessed to any Resource in an Hour with Excessive Energy and/or Deficient Energy in four (4) or more consecutive Dispatch Intervals within the Hour.

Excessive Energy: The amount of a Generation Resource's, Stored Energy Resource's or External Asynchronous Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold or, the amount of a Demand Response Resource's Type I Calculated DRR Type I Output, as adjusted for Actual Energy Injection or Demand Response Resource's Type II Calculated DRR Type II Output, as adjusted for Actual Energy Injection at a Commercial Pricing Node in the Real Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold.

Excessive Energy Price: The price used to calculate a Market Participant's credit for Excessive Energy that is equal to the Energy Offer price associated with a Generation Resource's, Demand Response Resource's – Type I, Demand Response Resource's – Type II or External Asynchronous Resource's Excessive Energy.

Excessive Energy Threshold: The maximum value of a Resource's Tolerance Band.

Export Schedule: An Interchange Schedule in which the Interchange Schedule Receipt Point lies within the MISO Balancing Authority Area and the Interchange Schedule Delivery Point lies outside the MISO Balancing Authority Area.

Exporting Entity: A Market Participant that is not a Load Serving Entity with a cleared Export Schedule in the Day-Ahead Energy and Operating Reserve Market or an Export Schedule in the Real-Time Energy and Operating Reserve Market.

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 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.

Extended Transmission Outage: A Planned Transmission Outage that exceeds the original outage schedule previously provided by the Transmission Owner to the Transmission Provider.

External Asynchronous Resource: A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

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External Resource: A generator located outside of the metered boundaries of the MISO

Balancing Authority Area.

External Resource Zone (ERZ): A grouping of one or more External Resources in the same
external balancing authority for purposes of the Planning Resource Auction.

GAAP: Generally Accepted Accounting Principles.

Generation Interconnection Projects: New Transmission Access Projects associated with the interconnection of or increase in generating Capacity of Generation Resources pursuant to Attachment R and Attachment X of this Tariff.

Generation Offer: An Energy Offer, Start-Up Offer, No-Load Offer, Regulating Capacity Offer and Regulating Mileage Offer (if a Regulation Qualified Resource), Spinning Reserve Offer (if a Spin Qualified Resource), On Line Supplemental Reserve Offer (if not a Spin Qualified Resource), Off Line Supplemental Reserve Offer (if a Quick Start Resource), and Up and Down Ramp Capability dispatch status submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Generation Resource to supply Energy, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability to the Energy and Operating Reserve Market.

Generation Owner: An entity that owns, leases with rights equivalent to ownership in, and controls the output of or operates Generation Resources.

Generation Outage: A forced or planned outage of Generation Resources.

Generation Resource: A Generation Resource is a Generator within the MISO Balancing Authority Area or an External Resource that is Pseudo-tied into the MISO Balancing Authority Area and that (i) is registered to participate in the Energy and Operating Reserve Markets, (ii) is capable of supplying Energy, Capacity, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability, (iii) is capable of complying with the Transmission Provider's Setpoint Instructions and (iv) has the appropriate metering equipment installed.

Generation Shift Factors: Ratios equal to the incremental increase or decrease in flow on a flowgate divided by an incremental increase or decrease in a Generation Resource's output.

Generation Verification Test Capacity (GVTC): The maximum output (MW) that a Generation Resource, External Resource or BTMG can sustain over the specified period of time, if there are no equipment, operating, or regulatory restrictions, minus any Capacity utilized for On-Site Self-Supply, as detailed in the Business Practices Manual for Resource Adequacy.

Generator: Any generating facility subject to the Transmission Provider's direction hereunder pursuant to either the Operating Protocol for Existing Generators, an IOA or an LGIA.

Generator Forced Outage: An immediate reduction in output, Capacity or removal from service, in whole or in part, of a Generation Resource by reason of an Emergency or threatened Emergency, unanticipated failure, inability to return on schedule from a Planned Transmission Outage, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the Business Practices Manuals. A reduction in output or removal from service of a Generation Resource in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Interconnection Agreement (GIA): The form of interconnection agreement provided in Appendix 6 of Attachment X to the Tariff.

Generator Planned Outage: The scheduled removal from service, in whole or in part, of a Generation Resource for inspection, maintenance or repair with the approval of the Transmission Provider in accordance with the Business Practices Manuals.

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Generator Self Supply: For any given period of time, the total Energy taken out of the Transmission System by the Loads designated as Self-Supply by a Market Participant which is a Generation Owner up to an amount equal to the total Energy placed into the Transmission System by the Generators designated as Self-Supply by the same Market Participant and owned by it.

GFA Schedule Delivery Point: The location where a GFA Schedule sinks.

GFA Schedule Receipt Point: The location where a GFA Schedule sources.

Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governmental Authority: Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the

Transmission Provider.

Grandfathered Agreement(s) (GFA): An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies.

These agreements are set forth in Attachment P to this Tariff.

Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under this Tariff.

Grandfathered Agreement (GFA) Schedule: A Schedule associated with a Grandfathered Agreement.

Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling Transmission Service or Energy transactions related to Grandfathered Agreements under this Tariff.

~~***Grandmother Agreement (GMA):*** Ownership of, or executed contractual rights to Planning Resources (including generating facilities under construction prior to July 20, 2011 that subsequently become Planning Resources) that are in place prior to July 20, 2011 and maintain annual firm transmission service from such Resources to load in a different LRZ which will provide an LSE with an exemption from the Zonal Deliverability Charge for the volume of such Planning Resources.~~

Guarantor: A guarantor under a Corporate Guaranty.

Headroom: For all Resources committed by the Transmission Provider in any real-time RAC processes or the LAC process conducted for the Operating Day, the difference between (i) the real-time Economic Maximum Dispatch and (ii) the sum of the Real-Time (a) Dispatch Target for Energy, (b) Dispatch Target for Regulating Reserve, (c) Dispatch Target for Spinning Reserve, and (d) Dispatch Target for Supplemental Reserve.

High Utilization Factor Unit (HUFU) Reserved Source Point (RSP): An RSP that does not qualify for inclusion in the BRSS per section 43.2.4.a.i.(b) but has a RSP Utilization Factor of seventy percent (70%) or greater.

Historic Unit Consideration: A right to receive excess Planning Resource Auction revenue based on qualification described in Section 69A.7.7(a).

Hour: A sixty (60) minute clock hour interval commencing the first second of each clock hour.

Hot-to-Cold Time: The number of hours that must elapse between the time a Generation Resource or Demand Response Resource – Type II is desynchronized and the time at which a cold Start-Up Offer would apply.

Hot-to-Intermediate Time: The number of hours that must elapse between the time a Generation Resource or Demand Response Resource – Type II is desynchronized and the time at which an intermediate Start-Up Offer would apply.

Hourly Bi-Directional Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource, Demand Response Resource - Type II, or Stored Energy Resource can respond to either increasing or decreasing Setpoint Instructions that may be submitted to override the default value submitted during the asset registration process.

Hourly Curtailment Offer: The compensation request, in dollars per Hour, in a Demand Response Resource-Type I Offer by a Market Participant representing the fees required for operating a Demand Response Resource Type I in an interrupted state.

Hourly Economic Maximum Limit: The maximum MW level at which a Generation Resource, Demand Response Resource Type II or External Asynchronous Resource may operate under normal system conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Economic Minimum Limit: The minimum MW level at which a Generation Resource or Demand Response Resource Type II or External Asynchronous Resource may operate under normal system conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Emergency Maximum Limit: The maximum MW level at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource Type II may operate under Emergency conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Emergency Minimum Limit: The minimum MW level at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource Type II may operate under Emergency conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Energy Storage Loss Rate: The rate at which energy is consumed over a one-minute time period to maintain a Stored Energy Resource at its maximum energy storage level assuming no Regulating Reserve deployments, expressed in MWh/min.

Hourly Excessive Energy Price: The weighted average of the Dispatch Interval Energy Offer Price where the weighting factors are determined by normalizing the Excessive Energy in each Dispatch Interval in the Hour. The Dispatch Interval Energy Offer Price is the Energy Offer price at the Dispatch Target for Energy.

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

Hourly Full Charge Energy Withdrawal Rate: The rate at which additional energy can be consumed by a Stored Energy Resource over a one minute time period while at its Maximum Energy Storage Level, expressed in MWh/min.

Hourly Integrated Forecast Maximum Limit: The hourly integration of the Forecast Maximum Limits of a Dispatchable Intermittent Resource as used by the SCED algorithm in the Real-Time Energy and Operating Reserve Market for a given Hour.

Hourly Maximum Energy Charge Rate: The maximum rate at which a Stored Energy Resource may be Charged, expressed in MWh per Minute, that may be submitted to override the default value submitted during the asset registration process.

Hourly Maximum Energy Discharge Rate: The maximum rate at which a Stored Energy Resource may be Discharged, expressed in MWh per Minute, that may be submitted to override the default value submitted during the asset registration process.

Hourly Maximum Energy Storage Level: The maximum amount of Energy that may be stored by a Stored Energy Resource on a sustained basis, expressed in MWh, that may be submitted to override the default value submitted during the asset registration process.

Hourly Ramp Rate: The MW/minute response rate for a Generation Resource, External Asynchronous Resource, Demand Response Resource Type-II, or Stored Energy Resource that is utilized in the clearing of the Day-Ahead Energy and Operating Reserve Market and all Reliability Assessment Commitment processes that may be submitted to override the default value submitted during the asset registration process.

Hourly Real-Time Ex Post LMP: 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.

Hourly Real-Time Ex Post MCP: The average MCPs for Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, and Down Ramp Capability 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, Up Ramp Capability, and Down Ramp Capability in the Real-Time Energy and Operating Reserve Market.

Hourly Regulation Maximum Limit: The maximum MW output at which a Generation Resource, Demand Response Resource – Type II, External Asynchronous Resource, or Stored Energy Resource can respond to automatic control signals that may be submitted to override the default value submitted during the asset registration process.

Hourly Regulation Minimum Limit: The minimum MW output at which a Generation Resource, Demand Response Resource–Type II, External Asynchronous Resource, or Stored Energy Resource can respond to automatic control signals that may be submitted to override the default value submitted during the asset registration process.

Hourly Single-Directional-Down Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the downward direction only that may be submitted to override the default value submitted during the asset registration process.

Hourly Single-Directional-Up Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the upward direction only that may be submitted to override the default value submitted during the asset registration process.

Hourly Transmission Congestion Charges Collection: The aggregate amount of Transmission Usage Charge collected in a given Hour.

Hub: A Commercial Pricing Node developed for financial and trading purposes.

HUFU ARR: An ARR allocated during the LTTR Restoration and Termination Stage of an Annual ARR Allocation from a HUFU ARR Entitlement.

HUFU ARR Entitlement: An ARR Entitlement defined from a HUFU RSP to the applicable ARR Zone. The MW amount of a HUFU ARR Entitlement is calculated, and corresponds to, the RSP MW at a fifty percent (50%) implied capacity factor. A HUFU ARR Entitlement is calculated as follows:

HUFU MW Level = (total net generation MWh in the test period) / (50% x Total Hours in the test period).

Hub LMP: The weighted-averaged LMP for an invariant set of Elemental Pricing Nodes that comprise the Hub. The weights are static over time, except for those of Elemental Pricing Nodes constituting ARR Zones administered as Hub Commercial Pricing Nodes. The weights, or weighting factors, for determining ARR Zone LMPs are updated daily based on State Estimator information.

High-Voltage Direct Current Facilities: The high voltage direct current transmission facilities, including associated alternating current facilities, if any, that are subject to Section 27A of this Tariff and that are specifically identified in: (i) any Agency Agreement pertaining to such facilities between the Transmission Provider and the Transmission Owner that owns or operates such facilities, or (ii) in any other contractual arrangement that permits the Transmission Provider to provide HVDC Service over such facilities, as set forth in Section 27A of this Tariff.

High-Voltage Direct Current Facility Upgrades: All or portion of the modifications or additions to any HVDC Facilities for the general benefit of all Users of such HVDC Facilities.

High-Voltage Direct Current Service: Firm and Non-Firm Point-to-Point Transmission Service provided by the Transmission Provider on HVDC Facilities pursuant to Section 27A of this Tariff.

High-Voltage Direct Current Service Agreement: Any executed or unexecuted agreement for HVDC Service, as reflected in Attachment A-3, A-4, and B-1 of this Tariff.

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High-Voltage Direct Current Service Charge(s): The charge(s) for HVDC Service, as stated in
the relevant HVDC Service Agreement.

Partial-Year FTR Allocation: The procedure used by the Transmission Provider to allocate FTRs to Market Participants in the new ARR Zones added as a result of Transmission Provider Region expansion that becomes effective after the start of the Annual ARR Allocation period. The Partial-Year FTR Allocation will cover the partial year period when the new ARR Zone(s) become effective to the start of the next Annual ARR Allocation. For the partial year period, the Market Participants in the new ARR Zone(s) may request an allocation of FTRs, which will be in lieu of an allocation of ARRs.

Party(ies): The Transmission Provider, ITC where appropriate, Market Participants, Transmission Customers, or any combination of the above.

Past Due Amount: Any amount invoiced by the Transmission Provider that is not paid when due.

Peak Reserved Source Set: Set of Resources including those constituting the Baseload Reserved Source Point that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone.

Peak Usage: A Market Participant's Total Forecasted Peak Load in a given ARR Zone for the upcoming Annual ARR Allocation period calculated using the immediate prior three year actual peak Loads. The Total Forecast Peak Load is the sum of the forecast Network Integration Transmission Service peak Load for the upcoming allocation period plus peak Load served by Option A – Grandfathered Agreements plus peak Load served by Option B – Grandfathered Agreements.

Penalty Level: A component of a mitigation measure described in Module D that represents the amount of Energy purchased by a Market Participant that is an LSE or represents an LSE

in the Real Time Energy Market in excess of the Allowance Level the entity is subject to.

Physical Withholding Threshold Quantity: Threshold employed by the IMM to identify physical withholding by a supplier of Planning Resources for the Planning Resource Auction, expressed in MW.

Plan: The Transmission Provider's Market Monitoring Plan set forth in Module D of this Tariff.

Planned Transmission Outage: Any transmission outage scheduled for the performance of maintenance or repairs or the implementation of a system enhancement which is planned in advance for pre-determined duration and which meets the notification requirements for such outages as specified by the Transmission Provider.

Planning Advisory Committee: A committee of stakeholders established under the ISO Agreement for the purpose of providing input to the planning staff on the development of the MTEP.

Planning Area(s): A collective or alternative reference to the First Planning Area and/or the Second Planning Area.

Planning Coordinator: The entity responsible for the longer term reliability of its planning coordinator area.

Planning Reserve Margin (PRM): The percentage above forecasted Coincident Peak Demand of Planning Resources for the Transmission Provider Region in order to meet the LOLE. This percentage will include a quantity sufficient to cover transmission losses.

Planning Reserve Margin Requirement (PRMR): The amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements.

Planning Resource: A Capacity Resource, Energy Efficiency Resource, or Load Modifying Resource that can be used to satisfy PRMR.

Planning Resource Auction (PRA): An annual auction that is conducted by the Transmission Provider to determine the ACP and the cleared ZRC Offers for each LRZ and ERZ for the applicable Planning Year.

Planning Year: The period of time from June 1st of one year to May 31st of the following year that is used for developing Resource Plans. The first Planning Year shall commence on June 1, 2009.

PMAX: The maximum Generator real power output reported in MWs on a seasonal basis.

PMIN: The minimum Generator real power output reported in MWs on a seasonal basis.

Point(s) of Delivery: Point(s) on the Transmission System where Capacity and Energy transmitted by the Transmission Provider will be made available to the Receiving Party under Module B and Module C of this Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long Term Firm Point To Point Transmission Service or the HVDC Service Agreement.

Point(s) of Receipt: Point(s) of interconnection on the Transmission System where Capacity and Energy will be made available to the Transmission Provider by the Delivering Party under Module B and Module C of this Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long Term Firm Point To Point Transmission Service or the HVDC Service Agreement.

Point-To-Point Transmission Service: The reservation of Capacity and of Energy on either a firm or non firm basis from the Point(s) of Receipt to the Point(s) of Delivery under

Module B of this Tariff.

Portfolio: For Multi-Value Project purposes, means two or more Multi-Value Projects proposed to be located in one or more Transmission Pricing Zones that, when evaluated together, are expected to result in regional benefits.

Power Purchaser: The entity that is purchasing the Capacity and reserved Energy to be transmitted under this Tariff.

PPA Schedule: Schedule associated with a PPA that is executed after April 3, 2014.

Pre-Confirmed Application: An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Price Sensitive Demand Bids: Demand Bids in which the Market Participant specifies a maximum price (dollars per MWh) at which the Market Participant desires to purchase the designated MWh of Energy.

Price Taker: A Market Participant with an Energy and/or Operating Reserve Offer not capable of setting LMPs or MCPs.

Production Costs: The Energy output cost of a Generation Resource or a Demand Response Resource-Type II based upon Start Up, No Load and Energy Offer cost components set forth in an Offer or the Energy reduction cost of a Demand Response Resource-Type I based upon Shut Down Offer, Hourly Curtailment Offer and Energy Offer cost components set forth in an Offer.

Project Cost: All costs for Network Upgrades, as determined by the Transmission Provider to be a single transmission expansion project, including those costs associated with seeking and obtaining all necessary approvals for the design, engineering, construction, and testing of

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the Network Upgrades. These Network Upgrades will include costs classified by the Transmission Owners and Independent Transmission Companies as transmission plant using the Uniform System of Accounts 350 through 359 or equivalent set of accounts for any Coordinating Owner.

Project Financial Security: The Cash Deposit or Irrevocable Letter of Credit described in Appendix 1 to Attachment FF of the Tariff that a Selected Developer is required to provide.

Proposal: A proposal to construct, implement, own, operate, maintain, repair, and restore all Competitive Transmission Facilities associated with a Competitive Transmission Project, in response to a Request for Proposal. Proposals may be submitted in one of two different forms: (i) a Single-Developer Proposal; or (ii) a Joint-Developer Proposal. The term “Proposal” shall include “Single-Developer Proposal” and “Joint-Developer Proposal”.

Proposal Cure Period: A period of time, equal to ten (10) Business Days, allowed for a RFP Respondent to correct deficiencies identified by the Transmission Provider in a previously submitted Proposal. The Cure Period commences upon notification by the Transmission Provider of deficiencies in the Proposal.

Proposal Participant(s): Any entity or entities involved in a Proposal, excluding the RFP Respondent(s), that will co-own the Competitive Transmission Project and rely on the RFP Respondent(s) to be the Selected Developer(s) responsible for constructing and implementing the Competitive Transmission Facilities associated with the Competitive Transmission Project. Proposal Participants may be identified in a Proposal as responsible for one or more aspects of operations, maintenance, repair, or restoration, on

terms comparable to those that would apply if the RFP Respondent(s) intended to rely on a third-party contractor.

Proposal Submission Deadline: The date and time Proposals must be submitted to the Transmission Provider by in order to be considered and evaluated by the Transmission Provider. The Submission Deadline shall be no later than 5:00 PM EPT on the date specified in the RFP, which shall not exceed one hundred and eighty (180) Calendar Days from the date the RFP was issued by the Transmission Provider, unless such date falls on a Saturday, Sunday, or MISO observed holiday in which case the Proposal Submission Deadline shall be the next Business Day that is not a MISO observed holiday.

Proposed Generator Planned Outage: The planned removal from service, in whole or in part, of a Generation Resource for inspection, maintenance or repair for which the Generation Owner has sought or will seek approval from the Transmission Provider for such planned removal in accordance with the Business Practices Manuals.

Protected Information: Privileged and non public information to be maintained by the Transmission Provider.

Proxy Offers: The Offers created for resources that are deployed during Emergency operating procedures by the Transmission Provider as specified in Schedule 29A.

Pseudo tie: A telemetered reading or value that is updated in real time and used as a tie line flow in the Area Control Error equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes. Pseudo tied status of Resources and Loads may only be changed during Network Model updates and the timing of such updates shall be as defined in the Business Practices Manuals.

Public Power: For credit scoring purposes, an Applicant or Market Participant that is a not for profit municipality, cooperative, Joint Action Agency, or agent representing one or more Public Power entities and whose credit quality is directly derived from the credit quality of the Public Power entities represented through the agency relationship.

Public Power Composite Score: For credit scoring purposes, the weighted average value of the Public Power Qualitative Score and the Public Power Quantitative Score. The relative weights are sixty percent (60%) and forty percent (40%).

Public Power Qualitative Score: A component of a Public Power Composite Score which has, for credit scoring purposes, a value ranging from 1 to 6.99, with 1 being the best and 6.99 being the worst. The value is based on a review by the Transmission Provider of qualitative factors relative to an Applicant's business, including but not limited to: i) regulatory; ii) legal; iii) demographic; and iv) energy supply/price factors as provided in Attachment L to this Tariff.

Public Power Quantitative Score: A component of a Public Power Composite Score which has, for credit scoring purposes, a value ranging from 1 to 6.99, with 1 being the best and 6.99 being the worst. The value is based on a review by the Transmission Provider of various financial metrics as detailed in the Transmission Provider's credit scoring model in Attachment L.

Zonal Deliverability Charge (ZDC): A positive charge per ZRC associated with ZRCs in a FRAP that may be assessed to an LSE based upon the congestion contribution to the constraints between LRZs or ERZs of any ZRCs that are located outside of the LRZ where the LSE has Load.

ZDC Hedge: The mechanism that permits an LSE to avoid Zonal Deliverability Charge assessments through the investment in new or upgraded Transmission System facilities which are a result of approved firm transmission service requests where the LSE's Planning Resource and the LSE's Demand are in separate LRZs or the Planning Resource is located in an ERZ.

Zonal Contingency Reserve Requirement: The minimum amount of Contingency Reserve the Transmission Provider shall procure within a Reserve Zone as determined based upon Reserve Zone Studies.

Zonal Export Ability: The ability of an LRZ to export capacity to areas outside of that LRZ.
Equal to an LRZ's base interchange plus the LRZ's incremental ability to export generation.

Zonal Import Ability: The ability of an LRZ to import capacity from areas outside of that LRZ.
Equal to an LRZ's base interchange plus the LRZ's incremental ability to import generation.

Zonal Operating Reserve: Operating Reserve that is available on a Reserve Zone basis.

Zonal Operating Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is used to calculate the Shadow Price of a particular Operating Reserve requirement constraint when there is a shortage of Operating Reserve cleared on a

Reserve Zone basis.

Zonal Operating Reserve Requirement: The sum of the Zonal Contingency Reserve Requirement and Zonal Regulating Reserve Requirement.

Zonal Regulating Reserve: Regulating Reserve that is available on a Reserve Zone basis.

Zonal Regulating and Spinning Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is utilized to calculate the Zonal Regulating and Spinning Reserve constraint Shadow Price when there is a shortage of the Zonal Regulating and Spinning Reserve cleared.

Zonal Regulating Reserve and Spinning Reserve Requirement: The amount of Zonal Regulating and Spinning Reserve the Transmission Provider is required to procure on a Transmission Provider Region-wide basis in accordance with Applicable Reliability Standards.

Zonal Regulating Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is utilized to calculate the Shadow Price of the Regulating Reserve requirement constraint when there is a shortage of Regulating Reserve cleared on a Reserve Zone basis.

Zonal Regulating Reserve Requirement: The minimum amount of Regulating Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based upon Reserve Zone Studies.

Zonal Resource Credit (ZRC): A MW unit of Planning Resource which has been converted from a MW of Unforced Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and/or to be submitted

through a Fixed Resource Adequacy Plan.

ZRC Offer: An offer into the PRA of ZRCs by a Market Participant.

Zonal Spinning Reserve Requirement: The minimum amount of Spinning Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based on a percentage of the Zonal Contingency Reserve Requirements where such a percentage adheres to Applicable Reliability Standards.

Zonal Supplemental Reserve Requirement: The minimum amount of Supplemental Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based upon Zonal Contingency Reserve Requirement and Zonal Spinning Reserve Requirement from Reserve Zone Studies.

Zone: A set of Buses in a geographic area as determined by the Transmission Provider.

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing External Resource Zones and associated limits (*i.e.*, Capacity Export Limits (CEL)); determining the annual Planning Reserve Margin; annual Coincident Peak Demand forecasting; annual Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources

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in ~~a~~the Planning Resource Auction process; settlement provisions; and Planning Resource performance requirements.

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No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those with only Coordinating Owner and/or Border External Resources.

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, The the Transmission Provider will use models which contain the physical location of Load and Planning Resources to determine the CIL and CEL for each LRZ. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources.

Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load. ~~The CIL values will be a total transfer capacity value that is neutral to exports from MISO capacity to non-MISO load; that is, CIL will be equal to the base interchange plus the incremental transfer capacity in a model where the exporting units are not dispatched to non-MISO load. These values~~

The CIL and CEL values for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

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Establishment of CIL and CEL Limits
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MISO will determine the CEL for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed such that the LRZ would achieve an LOLE of 0.1 day per year, without consideration of the benefit of the LRZ's CIL. The LRR will be determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

The Transmission Provider will model the ~~physical~~ location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak Demand as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

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 Establishment of Local Clearing Requirement
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Establishment of Local Clearing Requirement

The Transmission Provider will establish the Local Clearing Requirement for each LRZ ~~by subtracting the LRZ's CHL from the LRZ's LRR. (e.g., as~~ $LCR_{zt} = LRR_{zt} - \text{Capacity-Zonal}$ Import ~~Limit_{zt}-Ability – non-pseudo-tied~~ controllable exports), where ~~non-pseudo~~ tied controllable exports are: (i) from MISO resources that have firm capacity commitments to ~~neighboring regions~~ non-MISO load; and (ii) may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes ~~to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction and/or changes in the~~ controllable exporting units expected to pseudo-tied from the MISO footprint.

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, an annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data to be used by the Transmission Provider as described herein. The Transmission Provider will then calculate each LSE's PRMR. LSEs will meet their PRMR by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; and/or (iv) paying the Capacity Deficiency Charge. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in a submitted Fixed Resource Adequacy Plan) must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Retirement, Suspension and Replacement of Planning Resources

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. As used in this section, “cleared ZRCs” include ZRCs that cleared in the PRA or TPRA, were used in a FRAP, or were used to replace ZRCs in accordance with this section. As used in this section, “uncleared ZRCs” include ZRCs that did not clear in the PRA or TPRA, were not used in a FRAP, or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs is Retired or Suspended prior to the end of the Planning Year, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.9 and 69A.5 any time during the Planning Year, such Market Participant may replace the cleared ZRCs with uncleared ZRCs to relieve the performance requirements applicable to the Planning Resource. A Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5 for the balance of the Planning Year. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA/TPRA clearing

results, so that such replacement: (1) does not violate any CIL used in the PRA/TPRA; (2) does not violate any CEL used in the PRA/TPRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

- i. ZRC replacement shall be processed on a first come, first served basis.
- ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, TPRA and FRAPs.

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69A.7
Planning Resource Auction
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Planning Resource Auction

Within ten (10) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL, and CIL are respected for each LRZ, the CEL is respected for each ERZ, ~~as well as~~ and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA, in accordance with the following provisions:

PRA Procedures

a. **Participating ZRCs in ~~an LRZ~~ the PRA:** All Market Participants that own or have ~~operational control of~~ contractual rights to the Planning Resources that are ~~located~~ represented within an LRZ or ERZ and have converted Unforced Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not opted out of the PRA by submitting a FRAP, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in either the PRA or a TPRA. The PRA offer window shall begin at 12:01 am EST three (3) Business Days before the last Business Day in March and shall end at 11:59 pm EST on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice

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shall state the extension or reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the CONE value for the LRZ where the ZRC is ~~sourced~~ represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs

Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Unforced Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D.

External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources ~~treated for PRA purposes as if they~~ are located within a Coordinating Owner will be granted ZRCs in the LRZ where their firm Transmission Service crosses ~~transmission sinks at~~ the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g.

To the extent a Border External Resource is located on the border of two or more LRZs (e.g. has transmission lines from two or more LRZs terminating at the substation containing the Border External Resource's interconnection facilities), the Market Participant may elect the LRZ in which the Border External Resource is granted ZRCs through notice submitted no later than two (2) years prior to February 1 preceding the applicable Planning Year. Such representation will not be modified more frequently than every other year.

b. Participating Demand: All LSEs will be required to meet their PRMR through the PRA process, unless they have opted out of the PRA pursuant to Section 69A.9 and/or have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a fixed reliability target for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to one hundred percent of the PRMR for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization

methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to clear ZRC Offers and satisfy the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; ~~and~~ (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to minimize the as-offered overall costs of capacity procurement over the time horizon, subject to network constraints and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs ~~to~~ of each LRZ are simultaneous to the extent that ~~the imports into the LRZ~~ is are concurrently simulated ~~from all other LRZs and the system external to the Transmission Provider Region~~; and CELs of each LRZ and ERZ are simultaneous to the extent that ~~the exports out of the relevant LRZ or ERZ~~ are is concurrently simulated from each LRZ to all other LRZs and the system external to the Transmission Provider Region. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction

results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of three (3) successive iterations to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over the next Planning Year for the Transmission Provider Region. Coincident Peak Demand is used to establish LSE's PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to minimize the cost of serving Demand to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to

reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the Peak Hour of the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially

binding SRECs and SRICs for SRRZs, if applicable. The ACP for an LRZ will be based on the total PRMR for the LRZ minus any deficiency volumes of PRMR for an LSE that voluntarily chooses to not participate in the Planning Resource Auction. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ(s) with which the ERZ interconnects. For ERZs which connect with more than one SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the total PRMR for the Transmission Provider Region minus the amount of PRMR

associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Unforced Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(~~viii~~ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(ix) **ACP for Shortage Conditions:** The ACP will be set at CONE when there is an insufficient volume of valid ZRC Offers to cover LCR or the total PRMR for the LRZ minus the amount of PRMR associated with the Capacity Deficiency Charge for an LRZ.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the tenth Business Day following the last Business Day in March.

PRA Settlement

- a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is ~~located~~ represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9. The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region divided by the total number of days in the Planning Year.
- b. An LSE that submits a FRAP with ~~ZRCs and~~ PRMR in ~~different an~~ LRZs and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:
- (+) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand that is not met by ZRCs from Planning Resources that are ~~physically~~ ~~located~~ represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's

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ZRCs are ~~located~~represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP.

~~(ii) Any MWs of ZRCs in a FRAP that are qualified under a Grandmother Agreement pursuant to Section 69A.7.7(a) will not be subject to a Zonal Deliverability Charge assessment.~~

- c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

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Distribution of Excess Auction Revenue
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Financial Hedges Distribution of Excess Auction Revenue

The following provisions address situations where ~~Market Participants~~ LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System.

These benefits will provide ~~Market Participants~~ LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

- (i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then
- (ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a *pro rata* basis to all HUCs and ZDC Hedges.

~~Grandmother Agreements~~ Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, including a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or arrangements that predate March 26, 2018, and pertain to External Resource represented in External Resource Zones in which:

- i. The LSE has PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;
- ii. The Planning Resource designated in the arrangement and PRMR obligation span multiple LRZs and/or ERZs;
- iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated PRMR obligation; and
- iv. LSEs must note qualification for HUCs for as part of the annual PRA registration process.

~~LSEs who on or before July 20, 2011 own Planning Resource or have executed contracts for Planning Resources will qualify for a Grandmother Agreement for Planning Years June 2013 through May 2014 and June 2014 through May 2015 if: (i) the Planning Resource and the LSE's Demand are in different LRZs or if external firm transmission service associated with an External Planning Resource sinks in a different LRZ where the LSE's Demand is located; and~~

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 Historic Unit Considerations
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~~(ii) the ACP paid by the LSE is higher than the ACP received for such Planning Resources; (iii) the capacity contract duration covers the entire Planning Year; and (iv) there is or will be annual firm transmission service from such Planning Resource to the LSE's Demand in the higher priced LRZ covered by the contract for the entire Planning Year.~~ A combination of ~~capacity agreements~~ arrangements that require the delivery of capacity throughout the Planning Year will qualify ~~for treatment as Grandmother Agreements~~ to receive excess PRA revenue through a HUC, provided that the ~~agreements otherwise~~ arrangements satisfy the criteria herein. The volume of ~~the Grandmother Agreement hedge~~ MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from ~~such the~~ Planning Resource(s) or the amount of PRMR that are associated with the ~~Grandmother Agreement~~ qualified arrangement. A qualified ~~Grandmother Agreement~~ arrangement shall remain ~~effective~~ eligible to receive excess PRA revenue for the length of the executed contract (including any evergreen contract extensions), ~~or~~ until the owned resource status is changed to retired or ~~the annual transmission service is not maintained.~~ ~~Intrazonal capacity transactions that become interzonal capacity transactions as a result of future revision to the LRZ boundaries during the two-year transition period will be eligible for the Grandmother Agreement hedge.~~ A Market Participant with a valid Grandmother Agreement shall be financially made whole for any ACP differences between the ACP in the LRZ where the Demand is located, and the ACP in the LRZ where the Planning Resource specified in the Grandmother Agreement is located, by using excess PRA payments collected by the Transmission Provider, as described in the BPM for Resource Adequacy. ~~The Transmission Provider will ensure no under funding of Grandmother Agreements by relaxing CIL, CEL or~~

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Historic Unit Considerations
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~~LRR, as appropriate. The effectiveness of all Grandmother Agreements shall terminate at the conclusion of the 2014/2015 Planning Year~~until the transmission service is not maintained.

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69A.7.7(b)
ZDC Hedges
~~31.0.0~~, 32.0.0

ZDC Hedges

An LSE will also be able to ~~reduce payment of the Zonal Deliverability Charge assessment~~ receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm ~~transmission~~ Transmission service ~~Service request~~ Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent (100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm ~~transmission~~ Transmission service ~~Service request~~ Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Zonal Deliverability Benefit

~~Whenever price separation occurs between LRZs, ZRCs will receive the ACP based upon the LRZ where the Planning Resource underlying the ZRC is physically located. The Transmission Provider may collect~~ If there are any remaining excess PRA revenues ~~from the PRA if it collects more debits from LSEs than it credits the owners of ZRCs that cleared in a PRA. The, the~~ Transmission Provider will distribute ~~any such excess revenues: (i) first to fund all Grandmother Agreements in such LRZ pursuant to Section 69A.7.7(a); (ii) second to fund any ZDC Hedges in such LRZ pursuant to Section 69A.7.7(b); and (iii) then any~~ the remaining amounts ~~shall be distributed~~ to Deliverability Benefit Zones ~~as described below.~~

First, the Transmission Provider will subtract PRMR and ZRCs associated with ~~GMA~~ HUCs ~~or~~ and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC).

Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

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 Zonal Deliverability Benefit
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$$\textit{Weighted Average Export ACP} = \frac{\sum(\textit{Net Export}_j \times \textit{ACP}_j)}{\sum \textit{Net Export}_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\textit{ZDB Credit}_k = \textit{Net Import}_k \times (\textit{ACP}_k - \textit{Weighted Average Export ACP})$$

Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

The Transmission Provider will also receive FRAP related revenues derived from FRAP ZRCs that would have received payments greater than the charges to the associated FRAP PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP is ~~physically located~~represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

~~After the two year transition period for Grandmother Agreements concludes, the Zonal Deliverability Benefit shall be distributed by the Transmission Provider such that ZDC Hedges~~

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69A.7.7(c)
Zonal Deliverability Benefit
~~33.0.0~~, 34.0.0

~~are funded first, and then any excess credits are distributed in accordance with the provisions~~
~~herein.~~

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FERC Electric Tariff
MODULES

69A.7.8
Self-Scheduling Option:
~~31.0.0~~, 32.0.0

Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning

Resources associated with ZRCs ~~located~~ represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Installed Capacity (ICAP) Deferral Requirements and Charges

- a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is ~~located~~represented, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of May prior to the Planning Year.
- b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is ~~located~~represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within ten (10) Business

Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

- i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of May prior to the Planning Year, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on June 1st of the Planning Year and continue until ICAP is submitted and verified by the Transmission Provider, or replacement ZRCs are registered per the BPM for Resource Adequacy, or the ICAP value is forfeited, or the end of the Planning Year, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9 and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

- ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is ~~located~~ represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.
- iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to LSEs that have met their PRMR during the Planning Year on a *pro rata* basis, based upon the LSE's share of total PRMR for the Transmission Provider Region.

Opting Out of the Planning Resource Auction

An LSE electing to opt out of the PRA can continue to use its existing resource planning processes to meet their PRMR by providing the Transmission Provider with a Fixed Resource Adequacy Plan (FRAP), as described below:

- a. An LSE electing to opt out of the PRA must submit a Fixed Resource Adequacy Plan (FRAP) for each LRZ to the Transmission Provider by the 7th business day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or a portion of the LSE's PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year. Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two business days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for a Planning Year and also identify

the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its total PRMR and also its load ratio share of the LCR for each LRZ. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the LSE's PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that an LSE's PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP.

- b. An LSE that submits a FRAP for an LRZ will be able to opt out of the PRA for such Planning Year for such LRZ, to the extent that the LSE's ZRCs satisfy the LSE's PRMR. To the extent that an LSE that has opted out of the PRA: (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Planning Year; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- c. Any portion of an LSE's PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA. An LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10.

- d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- e. Any ZRCs included in the FRAP from new resources needed to meet an LSE's PRMR will be exempt from application of the minimum offer price provisions.
- f. To the extent that an LSE designates ZRCs in a FRAP that are ~~physically located~~represented in the same LRZ as the LSE's Demand to meet the LSE's PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.
- g. An LSE that contains ZRCs from Planning Resources that are not ~~physically located~~represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

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MODULES69A.11.11
ZDC Charges and ZDC Hedges
~~31.0.0~~, 32.0.0

A New LSE will be subject to the Zonal Deliverability Charge consistent with Section 69A.7.6(b) if the New LSE submits a Fixed Resource Adequacy Plan to meet all or a portion of its Planning Reserve Margin Requirements. A New LSE will be able to ~~reduce the Zonal Deliverability Charge assessment~~ receive excess TPRA revenue if a New LSE qualifies for a ZDC Hedge, consistent with Section 69A.7.7(b). A New LSE will be entitled to a Zonal Deliverability Benefit in accordance with Section 69A.7.7(c). A New LSE will be allocated, as appropriate Local Clearing Requirement Charges in accordance with Section 69A.7.7(d). The Tariff provisions in Module E-1 apply to existing LSEs. New LSEs are only subject to the provisions of Module E-2, except to the extent that Module E-2 Tariff provisions incorporate Module E-1 requirements by reference.

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MODULES

69A.11.12
Distribution of Excess Auction Revenue
~~30.0.0~~, 31.0.0

The Transmission Provider will distribute any excess TPRA revenues: first, to Historic Unit Considerations as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7(b). Any remaining amounts will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a *pro rata* basis to all HUCs and ZDC Hedges.~~New LSEs who on or before July 20, 2011 own Planning Resource or have executed contracts for Planning Resources that will qualify for a Grandmother Agreement will be able to use such Grandmother Agreements, consistent with the Grandmother Agreement terms and conditions in Section 69A.7.7 for the transitional Planning Year when the New LSE integrates into the Transmission Provider's Balancing Authority Area, and for the next two full Planning Years.~~

Tab C

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**PREPARED DIRECT TESTIMONY OF
LAURA RAUCH**

1 **I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS**

2 **Q. Please state your name, current position, and business address.**

3 A. My name is Laura Rauch and my business address is 720 City Center Drive, Carmel,
4 Indiana 46032. I am the Director of Resource Adequacy Coordination for the
5 Midcontinent Independent System Operator, Inc. (“MISO”) in Carmel, Indiana.

6 **Q. Please describe your educational background and professional experience.**

7 A. I graduated from Michigan Technology University with a Bachelor of Science Degree in
8 Electrical Engineering, and I also received a Master of Business Administration from
9 Indiana University. I am a registered professional engineer in the State of Indiana.

10 I have been employed by MISO since June 2005, when I became a transmission
11 planning engineer in MISO's Transmission Asset Management (“TAM”) Division. In
12 this role, I evaluated long term Transmission Service Requests¹ and Generator
13 Interconnection requests. In August 2008, I transitioned to a strategic role in TAM in
14 which I conducted more complex engineering studies, economic analyses, and policy
15 initiatives. In January 2013, I became the Manager of Expansion Planning at MISO. In
16 that capacity, my duties involved guiding and managing the long-term reliability
17 assessment studies that ultimately recommend transmission projects for approval by
18 MISO's Board of Directors.

¹ All capitalized terms in this filing not otherwise defined have the same meaning as they have under the current MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

1 In September 2014, I transitioned to be the Manager of Resource Adequacy
2 Coordination. In this role I was responsible for managing analyses to support resource
3 adequacy for MISO operations, state regulatory agencies, and load serving entities in the
4 MISO footprint.

5 I am currently the Director of Resource Adequacy Coordination. My current
6 duties include leading long-term resource adequacy efforts throughout the MISO
7 footprint via comprehensive resource assessments and collaboration with all MISO
8 sectors.

9 **Q. Please describe your job responsibilities as they relate to this filing.**

10 **A.** As noted in my experience above, I am responsible for directing long-term resource
11 adequacy analyses at MISO. My team performs both capacity-focused analyses such as
12 the Loss of Load Expectation (“LOLE”) analysis and the OMS-MISO survey, and
13 conducts transmission-focused resource adequacy assessments, such as the Capacity
14 Import Limit (“CIL”) and Capacity Export Limit (“CEL”) analyses.

15

16 **II. INTRODUCTION AND PURPOSE OF TESTIMONY**

17 **Q. What is the purpose of your testimony?**

18 **A.** My testimony supports the Tariff revisions MISO is proposing in this docket to revise the
19 Resource Adequacy Requirements found in Module E-1 and Module E-2 of the MISO
20 Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”), as
21 well as corresponding revisions in other parts of the Tariff, such as Module A (“Resource
22 Adequacy Construct”). If accepted by the Federal Energy Regulatory Commission
23 (“FERC” or “Commission”), the proposal will create zones for external Capacity

1 Resources (also known as “External Resources”), provide an improved methodology to
2 allocate excess auction revenues in MISO’s Resource Adequacy Construct, and adjust
3 Capacity Import Limits, Capacity Export Limits, and Local Clearing Requirements to
4 better reflect capacity that may clear in the MISO Planning Resource Auction (“PRA” or
5 “Auction”). My testimony discusses the adjustments to aspects of the MISO proposal
6 and explains the need for this filing. I describe the principal Tariff revisions included in
7 the MISO filing and explain how they will accomplish the desired reform objectives.

8 **Q. What is MISO’s current Resource Adequacy Construct?**

9 **A.** MISO’s role in Resource Adequacy is to support and facilitate resource adequacy goals
10 shared with the states and Load Serving Entities (“LSEs”) through MISO processes.
11 Module E-1 and related provisions establish MISO’s Resource Adequacy Construct
12 under which Load Serving Entities (“LSEs”) procure or prove sufficient resources to
13 meet their coincident peak load forecast, plus a reserve margin, for the coming Planning
14 Year. MISO works with Market Participants to establish requirements that demonstrate
15 the level of resources required by each LSE to reliably serve anticipated coincident MISO
16 peak demand and thereby ensure resource adequacy, based upon a Loss of Load
17 Expectation of no more than 1 day for every 10 years (“1-in-10 LOLE”). MISO’s
18 Planning Reserve Margin—which defined the percentage volume of resources needed
19 above peak load to reliably meet demand—is then used to determine how much capacity
20 (in megawatts) each LSE is required to procure to meet its regional needs. This is equal
21 to each LSE’s Planning Reserve Margin Requirement (“PRMR”). By procuring
22 resources to meet this margin above peak load expectations, MISO and LSEs ensure the
23 footprint is resource adequate.

1 MISO also establishes both capacity requirements for each Local Resource Zone
2 (“LRZ” or “Zone”) to demonstrate where this capacity must be located due to local
3 resource needs and transmission limitations (Local Clearing Requirement or “LCR).

4 PRMR for each Zone may be served with resources located within or outside of
5 the LRZ in which load is located. However, LCR must be met by resources that are
6 physically located within the LRZ to maintain local reliability, given local risk factors
7 and transmission limitations. As such, the Planning Resource Auction clears resources to
8 meet both the regional and local requirements while respecting other PRA inputs such as
9 Capacity Import Limits and Capacity Export Limits to ensure the capacity can be reliably
10 delivered across the MISO Region. The resulting Auction Clearing Prices (“ACP”)
11 reflect constraints on the use of resources through higher or lower clearing prices.

12 **Q. Why is MISO revising the treatment of External Resources in its Resource**
13 **Adequacy Construct?**

14 **A.** The current treatment of External Resources in MISO’s Resource Adequacy Construct
15 could present reliability and equity concerns if the potential for greater participation of
16 External Resources is realized, as further discussed below.

17 First, the current modeling of External Resources may lead to long-term reliability
18 concerns. Currently, External Resources are modeled in the PRA in the Zone in which
19 their transmission service crosses into MISO and receive credit towards local
20 requirements. Given this modeling treatment, External Resources are not recognized as
21 imports. This could lead to insufficient resources being cleared in a Zone to meet Local
22 Clearing Requirements, or for imports into a zone to exceed the Capacity Import Limit
23 for a Zone.

1 Second, the existing PRA processes create an inherent preference for clearing
2 External Resources for needs of a particular Zone over an internal resource in a different
3 Local Resource Zone, causing equity concerns. Current PRA rules model External
4 Resources in the Zone in which the Transmission Service crosses the MISO border and
5 therefore, these External Resources are inappropriately priced as if they can contribute
6 toward the Zone's Local Clearing Requirement even though they are not physically
7 located in the Zone. However, resources located inside MISO are not priced as if they
8 contribute to another LRZ's LCR, as is appropriate.

9 The goal of MISO's External Resource Zone ("ERZ") proposal is to adjust the
10 physical modeling of electrically distant External Resources. This modeling adjustment
11 will align the Auction Clearing Price all resources receive with their locational benefit to
12 the MISO system, whether they are internal or external to MISO. That is, all resources
13 would receive prices based on their support of resource adequacy needs, including local
14 needs, based on their physical location.

15 **Q. Why is MISO proposing to adjust its allocation of excess auction revenues?**

16 **A.** Currently, MISO Load Serving Entities could have ownership of, or enter into
17 arrangements with, External Resources without the need to consider price separation risk
18 between the External Resource and load in their Local Resource Zone. Many of these
19 contracts and ownership agreements are long-standing and long-term, with no or limited
20 opportunities for renegotiation during their multi-decade term. The creation of ERZs will
21 introduce price risk that could not have been foreseen, and therefore could not have been
22 contemplated in these agreements at the time in which they were entered. Thus, MISO
23 believes that excess auction revenues should be allocated to offset that unforeseen price
24 separation risk created by ERZs to the extent possible without uplift through the creation

1 of Historic Unit Considerations (“HUCs”). The same logic also applies to similarly
2 situated internal resources, which could not have foreseen risks associated with a capacity
3 construct that was created after their contracts were negotiated. Accordingly, MISO is
4 also including such resources in its HUC proposal.

5 The goal of MISO’s HUC proposal is to allocate excess auction revenues first to
6 load with historic, inter-zonal contracts or ownership agreements, prior to a pro rata
7 allocation to all load in LRZs with higher auction prices.

8 **Q. Why does MISO need to adjust its Capacity Import Limits, and Capacity Export**
9 **Limits?**

10 **A.** As MISO investigated the treatment of External Resources in the Planning Resource
11 Auction, a difference in assumptions between the PRA, CIL, and CEL treatment of
12 resources, including but not limited to External Resources, became apparent. The CIL
13 and CEL are intended to represent the ability of each LRZ to import or export capacity in
14 the PRA. However, not all system flows impacting CIL and CEL may be visible in the
15 PRA. For example, MISO resources that are committed to non-MISO load will use some
16 of the system’s export ability and act as counterflow to increase import ability. However,
17 these resources do not clear the PRA, and as such, do not count against CEL or increase
18 imports allowed before CIL binds. Additionally, import and export limits should align
19 with the treatment of capacity within the PRA, by modeling all capacity within the LRZ
20 or ERZ where they are given local capacity credit.

21 The goal of the modifications to CIL and CEL is to align the assumptions used in
22 calculating auction inputs with their usage in the auction, ensuring that sufficient capacity
23 is cleared in the right locations within MISO.

1 **Q. Why do these changes need to be approved simultaneously?**

2 **A.** As noted previously, changes to the treatment of External Resources impact long-
3 standing ownership and contractual arrangements. This creates financial risk that could
4 not have been foreseen by Market Participants, whether those resources have agreements
5 that predate MISO, predate the PRA, or predate the creation of ERZs within the PRA.
6 Additionally, changes to the modeling of External Resources have impacts on the Loss of
7 Load Expectation process modeling, requiring the joint approval of ERZs and LOLE
8 changes. As such, the increased accuracy and alignment of resources with their physical
9 location and impact throughout the PRA, CIL, CEL, and LCR processes must be paired
10 with the distribution of excess auction revenues to historic arrangements.

11 **Q. How did MISO coordinate with stakeholders on the proposed modifications?**

12 **A.** MISO initially raised concerns regarding the treatment of External Resources in 2014
13 through discussions in the Loss of Load Expectation Working Group (“LOLEWG”).
14 These concerns were then incorporated in MISO’s Resource Adequacy Issues Statement,
15 published in March 2015. A whitepaper was published in July 2015, and stakeholder
16 discussions of the treatment for External Resources continued between 2015 and 2017 in
17 the Supply Adequacy Working Group (“SAWG”), LOLEWG, and Resource Adequacy
18 Subcommittee (“RASC”). This schedule represents an expanded time-frame when
19 compared to other, similar stakeholder processes. This discussion was lengthened to
20 ensure sufficient stakeholder discussion of key issues, especially in light of parallel
21 stakeholder discussions on issues like the Competitive Retail Solution (“CRS”) filing. A
22 list of all stakeholder presentations on MISO’s locational enhancements is attached to this
23 filing as Tab E.

1 In this process, MISO and stakeholders discussed this locational enhancement
2 proposal over thirty-five times, including multiple instances on the proposed Tariff
3 language.² As a result, MISO incorporated a number of modifications based on the input
4 received, which has improved this proposal.

5 **Q. Why is MISO filing at this time?**

6 **A.** MISO's filing anticipates implementation of External Resource changes for the
7 2019/2020 Planning Year PRA. Implementation in that Planning Year should decrease
8 the risk posed by External Resources new to MISO, as several existing resources that are
9 currently committed to PJM may instead offer into MISO by this time. This could lead to
10 a significant increase in the number of External Resources within MISO, increasing
11 reliability risk and the potential for inappropriate credit as local resources and associated
12 payments. MISO's requested effective date of May 22, 2018 will allow for
13 implementation prior to the 2019/2020 PRA. Following is a chart showing the amount of
14 External Resources offered into the last two PRAs, and the potential increase in the
15 amount of External Resources that could offer into the 2019/2020 PRA.³

² See Tab E.

³ Based on new External Network Resource Interconnection Service granted or requested as of February 20, 2018.

MISO Total	External Resources Offered	Potential Border External Resources	Coordinating Owner Resources	Total Offers
Planning Year 2015-16	1,792	1,911	1,356	5,058
Planning Year 2016-17	1,808	1,994	1,352	5,154
Planning Year 2017-18	1,817	1,587	1,386	4,790
Potential new External Resources*	2,632		3,576	N/A

1 **Q. What are the reliability concerns with the current treatment of External Resources?**

2 **A.** Currently, External Resources receive credit in the PRA where their transmission service
3 crosses the MISO border. This creates two potential long-term reliability concerns. First,
4 physically distant External Resources may displace local resources in the PRA, which
5 could impact reliability in a Zone. In this instance, a Zone would appear to clear
6 sufficient resources in the PRA, while in operations, the physically distant External
7 Resources would be unable to contribute to zonal resource adequacy given their remote
8 physical location. Second, imports from External Resources are not currently measured
9 against Capacity Import Limits as they are modeled within a MISO LRZ, leading to the
10 potential for total imports from both internal and External Resources to exceed the
11 defined transfer limit. However, in operations, these combined flows may exceed
12 transmission limits, increasing the risk of curtailment for resources which were cleared in
13 the PRA.

1 While MISO does not believe that the current set of External Resources are
2 sufficient to cause reliability concerns, this may not be true in future years, as new
3 potential External Resources gain the ability to offer in MISO's PRA.

4 **Q. What are the equity concerns with the current treatment of External Resources?**

5 **A.** As noted previously, MISO clears resources to meet both regional and local resource
6 adequacy needs. Local Resource Zones may receive a higher Auction Clearing Price if
7 required to clear sufficient capacity to support their local resource needs. Also, as noted
8 previously, External Resources are currently priced as if they are physically located
9 where their transmission service crosses into MISO. If the Zone in which they are
10 located binds on its Local Clearing Requirements, they would receive a higher Auction
11 Clearing Price. While this higher price is rational for resources physically within the
12 Zone, it is not equitable for External Resource that are electrically distant from the Zone
13 and cannot support local resource needs to receive this same price. By contrast, resources
14 internal to MISO are appropriately precluded from receiving the price of, or offsetting
15 local requirements in, a Zone in which they are not physically located.

16

17 **III. PROCESS DESCRIPTION AND KEY TARIFF REVISIONS**

18 **A. External Resource Modeling**

19 **Q. Please describe the proposed revisions to External Resource modeling.**

20 **A.** MISO proposes to create ERZs that will contain external capacity offering into the PRA.
21 Each electrically distant External Resource will be placed in an ERZ corresponding with
22 its balancing authority ("BA") outside the MISO system.

23 Resources in ERZs may be used towards an LSE's Planning Reserve Margin
24 Requirement ("PRMR"); however, consistent with the treatment of internal Capacity

1 Resources, External Resources will not be able to contribute to the LCR for any LRZ that
2 they are not physically located within. Because these resources are electrically removed
3 from MISO footprint, this means that they will not be able to contribute to the LCR for
4 any LRZ.

5 **Q. Will ERZs be listed in the Tariff, similar to Local Resource Zones?**

6 **A.** No. ERZs are comprised of existing external BAs, based on the External Resources
7 which have qualified for a particular Auction. As such, possible ERZs may be
8 determined through NERC defined BAs and do not need to be further defined in the
9 Tariff. Additionally, these zones do not contain MISO load, and are a small subset of that
10 BA's generation. Layering an ERZ over an external BA might cause confusion and could
11 require updates even the month prior to a given PRA if External Resource registration has
12 changed from the previous Auction.

13 **Q. Should any External Resources have the ability to count towards Local Clearing**
14 **Requirements?**

15 **A.** Yes. External Resources that meet certain physical and operational requirements should
16 have the ability to count towards LCR. As discussed below, both Border External
17 Resources and resources from Coordinating Owners meet both the physical location and
18 operational requirements to obtain local credit.

19 First, resources must meet physical criteria based on their geographic location.
20 That is, they should not be separated from the MISO LRZ by intervening transmission.
21 For example, an Indiana internal resource, due to its physical separation from the Illinois
22 Local Resource Zone, does not receive the Auction Clearing Pricing of the Illinois Zone,
23 regardless of commitments from the Indiana generator to Illinois load.

1 Second, MISO must also be able to operationally rely upon the resources during a
2 capacity emergency to obtain local credit. External Resources have specific recall
3 provisions in Module E-1 and requirements in maximum generation Emergency
4 Operating Procedures which allows MISO to rely on their scheduled capacity when
5 needed during Energy Emergencies.⁴ This ensures that the generators are available to
6 support local capacity needs.

7 **Q. How are Border External Resources treated under MISO's proposal?**

8 **A.** Border External Resources are resources which, although they are located outside of the
9 MISO Balancing Authority, are electrically and contractually equivalent to resources
10 within MISO. This occurs due to both the physical location of Border External
11 Resources and to the resource's ability to meet a unit-specific must offer requirement.
12 These resources must meet specific physical requirements and interconnect at a
13 substation that directly ties to MISO, as further described in Module A. Additionally, the
14 proposed definition⁵ requires unit-specific responses to MISO recall or scheduling
15 instructions during Energy Emergencies, providing assurances that the Border External
16 Resource could support local maximum generation events. As such, Border External
17 Resources will count toward the LCR of the LRZ that they border.

18 **Q. How are Coordinating Owners treated under MISO's proposal?**

19 **A.** MISO proposes to continue to recognize the historical, operational, and topological
20 connection that MISO has with Coordinating Owners in allowing Coordinating Owner
21 Capacity Resources to count towards the LCR of the LRZ in which their transmission

⁴ See MISO Market Capacity Emergency Procedures SO-P-EOP-00-002, available at:
<https://www.misoenergy.org/api/documents/getbymediaid/96737>.

⁵ See revised Tariff Section 1.B, definition of Border External Resource.

1 service crosses into the MISO system. This treatment is based upon an evaluation of the
2 characteristics of Coordinating Owners, their obligations, and their relationship with
3 MISO operations. This proposal would currently only apply to Manitoba Hydro (“MH”),
4 as they are the only Market Participant that meets the required criteria.

5 Physically, Manitoba Hydro borders MISO’s system and has limited ties; their
6 interconnections are predominantly with, and directly to, the MISO region through DC
7 ties, with only small ties to non-MISO areas. Further, MISO provides Reliability
8 Coordination for MH, and directs constraint mitigation through redispatch,
9 reconfiguration, and load shed while managing the interchange with MH. As such, there
10 is no separating transmission from Manitoba Hydro to Local Resource Zone 1, therefore
11 meeting the physical location criteria.

12 The operational criteria is met through strong contingency reserve sharing and
13 emergency procedures, creating an operating environment that provides MISO certainty
14 over the commitment and dispatch of Manitoba Hydro resources. As such, MISO has
15 equivalent visibility into any congestion between MH and MISO as it would within any
16 LRZ.

17 **Q. How are MH assets and Border External Resources different from other External**
18 **Resources?**

19 **A.** MISO has strong Joint Operating Agreements with our neighbors, and we are confident
20 that these procedures will allow for close coordination in emergency procedures.

21 However, other External Resources do not meet physical requirements to obtain local
22 credit; instead, they are separated from the MISO system by intervening transmission
23 lines. Also, MISO does not have assurances that any particular unit would be dispatched
24 during Emergency Operating procedures. As such, and although External Resources

1 from other areas may continue to receive credit towards the MISO regional requirement,
2 they should not receive local credit, as the capacity cannot be assured to support local
3 resource needs.

4 **B. External Resource Auction Mechanics**

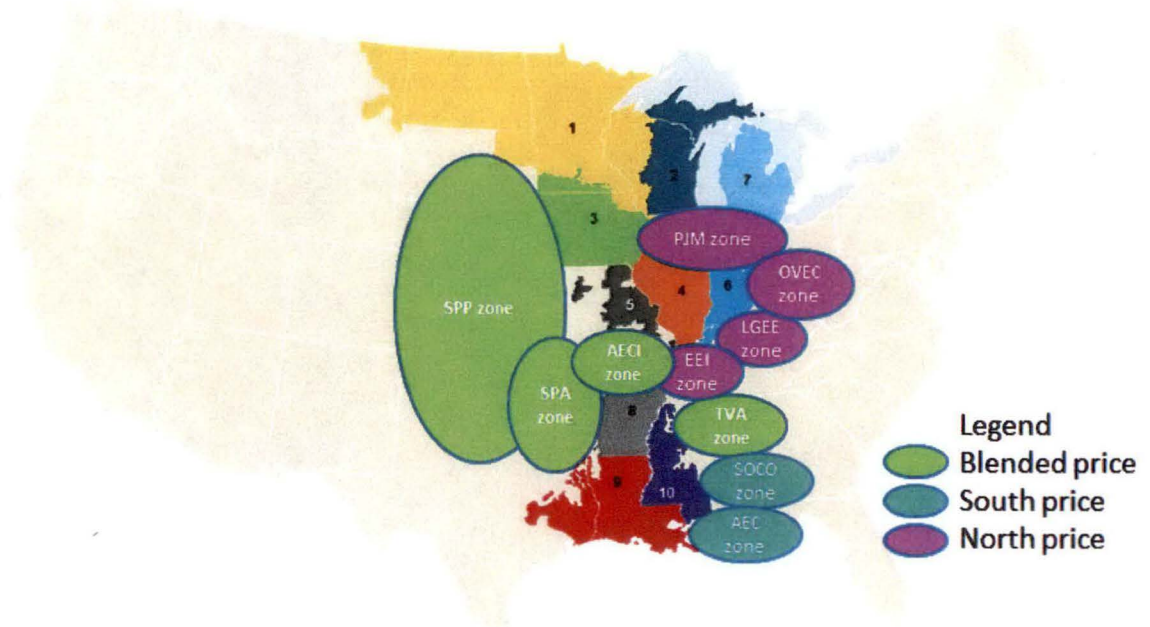
5 **Q. What pricing proposals did MISO consider?**

6 **A.** MISO considered multiple pricing proposals before finalizing its pricing mechanism.
7 These proposals included creating one price applicable to all External Resources, pricing
8 External Resources based on where their transmission service crosses the MISO border,
9 pricing External Resources considering their geographical location, and pricing External
10 Resources based on their balancing authority. After discussing these proposals with
11 stakeholders, a pricing approach supported by the Independent Market Monitor, which
12 considers ties to MISO and external balancing authority boundaries, was selected as
13 described below.

14 **Q. How will the clearing price for External Resource Zones be determined?**

15 **A.** The Auction Clearing Price (“ACP”) of each External Resource Zone will be determined
16 based on its ability to support PRMR in the MISO footprint, similarly to internal Local
17 Resource Zones.

18 More specifically, ERZs will be priced based on their connections to the MISO
19 footprint. ERZ prices will be associated with either: 1) the LRZ 1 – 7 sub-regional
20 unconstrained price (e.g., North unconstrained price); 2) the LRZ 8 – 10 sub-regional
21 unconstrained price (e.g., South unconstrained price); or, 3) a blended sub-regional
22 unconstrained price.



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The sub-regional unconstrained price is equal to the price granted to zones which do not bind on CIL, CEL, or LCR. The system could see two sub-regional unconstrained prices, if the Sub-Regional Import Constraint (“SRIC”) or Sub-Regional Export Constraint (“SREC”) binds in a given PRA. In that event, one sub-regional unconstrained price would be created for LRZs 1 – 7 and a second sub-regional unconstrained price would be created for LRZs 8 – 10.

For ERZs that have connections to both LRZs 1 – 7 and LRZs 8 – 10, or that do not directly border any MISO LRZs (jointly called “dually-connected ERZs”), MISO will calculate a shift factor that describes the expected ratio of flows from each ERZ into LRZs 1 – 7 and LRZs 8 – 10, based on historical real time energy flows. This calculation will be equivalent to the shift factor calculations currently laid out in the MISO-SPP

1 Settlement Agreement for the ERZs which connect to both LRZs 1 – 7 and LRZs 8 – 10.⁶
2 Similar shift factors would be calculated for new ERZs that do not directly border any
3 MISO LRZs, based on their real time energy flows into MISO. This shift factor will be
4 applied to all External Resources in these dually-connected ERZs, impacting both the
5 ACP that resources in these ERZs receive and the percent flows from these resources
6 across the North - South transfer limit.

7 **Q. Why is this pricing appropriate?**

8 **A.** Neighboring balancing authorities operate their systems to manage real time congestion
9 and provide reliable service to their load. In general, imports of capacity into MISO
10 result from the net dispatch of these BAs, not from the dispatch of any particular resource
11 at a given time. As such, MISO focused on the established real time flows from each
12 balancing authority into MISO to determine both the pricing and MW impact of ERZs.
13 This led to adoption of the blended price approach, as it reflects historic operating
14 conditions between the external BAs and the MISO footprint. This approach is supported
15 by the MISO Independent Market Monitor, as described in the Affidavit of David B.
16 Patton, Ph.D.⁷

17 **Q. How will MISO set Offer Caps for External Resources?**

18 **A.** Similar to its pricing, the Offer Cap for an External Resource will be determined based on
19 the location of its balancing authority with respect to the MISO footprint. More
20 specifically,

⁶ See Appendix D of the Offer of Settlement filed in Docket Nos. EL14-21, *et al.*

⁷ See Patton Affidavit at P 6, 14-16, and 18-19.

- 1 1) The offer cap for External Resources in ERZs located around MISO North
- 2 region will be set equal to the highest offer cap of LRZs in the MISO North
- 3 region.
- 4 2) External Resources in ERZs located around MISO South region will be set
- 5 equal to the highest Offer Cap of LRZs in the MISO South region.
- 6 3) Offer caps for External Resources in dual-connected ERZs will be set equal to
- 7 the highest Offer Cap in the MISO footprint.

8 This will ensure that the offer stack used to clear the auction, including offers from

9 External Resources, is bounded in a similar manner to the current PRA, where External

10 Resources have offer caps equivalent to internal resources. Furthermore, this offer cap

11 will allow External Resources to have a level playing field to compete with MISO's

12 internal resources to fulfill the requirement. It will also recognize the regional support

13 granted by these resources, rather than directly tying them to the offer cap of any

14 particular LRZ.

15 **Q. What are the impacts of this proposal on the auction process?**

16 **A. The ERZ proposal will change the way External Resources are treated in the PRA,**

17 changing the auction formulation and resource-clearing. In general, External Resources

18 will: 1) no longer count or be priced as if they can support a Zone's Local Clearing

19 Requirement; 2) the impact of External Resources across the North – South transfer limit

20 will be adjusted; and, 3) External Resources will no longer be measured against the CIL

21 and CEL of LRZs. More specifically:

- 22 1) External Resources will not be counted toward an LRZ's local requirements,
- 23 and they will be priced based on their support of the system PRMR. More
- 24 specifically, they will have a separate price based on the balancing authority in

1 which they are located and its connections to the MISO sub-regions (*e.g.*, MISO
2 North or MISO South). Excluding Border External Resources, all resources in the
3 same external balancing authority will be treated in the same External Resource
4 Zone and be given the same Auction Clearing Price.

5 2) The impact of particular resources against the North – South transfer limit will
6 change, as specific External Resources will no longer be attributed to supporting
7 MISO North or MISO South based on their geographic location. Instead, the
8 flows from all External Resources from a given balancing authority will be
9 recognized for the aggregate flows from their ERZ across the South – North
10 interface.

11 For example, an Arkansas SPP External Resource was previously assumed to
12 directly increase flows from South to North across the North – South interface,
13 and a North Dakota SPP External Resources was assumed to directly increase
14 flows from North – South. In the new pricing paradigm, all External Resources
15 within SPP will be assumed to flow across the South – North transfer limit based
16 on the real time energy flows from SPP into MISO.

17 3) Currently, External Resources are granted credit within the Zone where their
18 transmission service crosses into MISO. As such, cleared capacity from these
19 resources is assumed to increase exports from such zones and act as counterflow
20 from imports. The creation of ERZs will move External Resources into separate
21 zones, and as such, cleared capacity from External Resources will no longer count
22 against the Capacity Export Limit or act as counterflow to increase allowable
23 imports.

1 As such, the formulation will recognize the location of External Resources against the
2 Local Clearing Requirement, Capacity Import and Export Limits, and the North – South
3 transfer limitation in a different way. An example of the impact on auction results is
4 attached to this testimony as Attachment A.

5 **C. Improved Allocation of Excess Auction Revenues**

6 **Q. Please describe Historic Unit Consideration (“HUC”), as proposed by MISO.**

7 **A.** Historic Unit Considerations are a mechanism that will allocate excess auction revenues
8 to recognize various historical ownership and contractual arrangements of Resources that
9 participate in and clear the PRA, based on a recognition that External Resource Zones in
10 particular and the locational capacity construct in general creates unforeseen risks for the
11 load which depends on these arrangements, as described previously.

12 **Q. What alternatives did MISO consider when creating HUCs?**

13 **A.** MISO and stakeholders considered several alternatives to HUCs, including the creation
14 of Capacity Transfer Rights (“CTRs”) and different approaches to the allocation of
15 HUCs. MISO will continue to evaluate additional allocations processes to accommodate
16 stakeholder needs in the future, but felt that the current HUC proposal was the most
17 appropriate and prudent approach at this time.

18 The primary difference between HUCs and CTRs is the focus of HUCs on
19 historic commitments. Under the CTR proposal, both historic and new inter-zonal
20 commitments were eligible for CTRs, and excess auction revenues could be allocated
21 completely to both new and long-term agreements. MISO was concerned that the CTR
22 proposal would provide protection against price separation for new capacity contracts
23 that were entered into with full transparency into capacity price separation risk, therefore
24 muting locational price signals by providing hedges for future capacity arrangements for

1 no cost and with no risk. Additionally, the unbounded number of potential CTRs could
2 have large impacts, both on the Zonal Deliverability Benefit (“ZDB”) allocation of
3 excess auction revenue, and on the value of any particular CTR. If a pool of
4 arrangements are granted eligibility for excess auction revenue through CTRs, and then,
5 at a later time, additional arrangements become eligible, it becomes necessary to
6 determine the feasibility of each arrangement, and re-prioritize arrangements on an
7 ongoing basis. This would further dilute the ZDB benefit and could change the
8 feasibility of existing CTRs.

9 As the need for a hedging mechanism arose because of long-term contractual
10 arrangements will experience unforeseen risk, either due to their execution prior to
11 MISO’s current capacity construct or prior to introduction of ERZs, MISO determined
12 the reasonable approach to focus solely on the allocation of excess auction revenue to
13 these historic arrangements, or HUCs. However, MISO has committed to discussing a
14 more comprehensive capacity hedge for both recent or prospective arrangements not
15 covered by HUCs for a potential future filing.

16 During earlier iterations of HUCs, MISO proposed three stages of HUCs, and
17 proposed a prioritized allocation of excess auction revenue based on those stages. MISO
18 received stakeholder feedback that, given the total potential quantity of HUCs was
19 limited,⁸ and the equivalent level of unforeseen risk for all historic arrangements, having
20 three stages of HUCs was overly complex. As such, MISO proposes just one pool of

⁸ See Resource Adequacy Subcommittee, 201700809 RASC Item 02a Locational Reforms (August 9, 2017 meeting) at p 17, available at <https://cdn.misoenergy.org/20170809%20RASC%20Item%2002a%20Locational%20Reforms87578.pdf>.

1 arrangements eligible for excess auction revenue allocation, inclusive of HUCs and Zonal
2 Deliverability Charge (“ZDC”) Hedges.

3 **Q. How do HUCs vary from the July 2011 Grandmothered Agreement Proposal?**

4 **A.** As described in more detail below, HUCs are different from MISO’s Grandmother
5 Agreement due to three reasons: 1) they will not cause uplift of costs to hold load
6 harmless; 2) they will not result in waiver of transmission constraints; and, 3) they will
7 apply to a small set of resources.

8 1) HUCs will not require uplift
9 HUCs will be settled after the PRA through the allocation of Excess Auction
10 Revenue. In the unlikely event that extent excess auction revenues are
11 insufficient to fund HUCs, a pro rata allocation will be utilized. Costs will not be
12 uplifted to load to ensure the sufficiency of HUC funding.

13 2) HUCs will not waive transmission constraints:
14 The existence of Grandmother Agreements impacted the inputs to the PRA, and
15 specifically the CILs and CELs of impacted LRZs, through guaranteeing the
16 rights of GMA units to clear in the PRA, regardless of transmission constraints.
17 This ensured that capacity from a Resource under a Grandmother Agreement
18 could serve demand in a distant LRZ, removing the ability for the zonal ACP to
19 reflect the underlying transmission limitations between Zones and any
20 transmission limitations on the particular unit with a GMA. HUCs, on the other
21 hand, are not an input into the auction clearing process. CIL and CEL
22 calculations take place without regard to whether HUCs have been awarded and
23 HUCs will not change how the CIL, CEL, or LCR bind in the PRA.

24 3) HUCs apply to a small set of resources:

1 Only resources with long-term arrangements that cross zonal boundaries are
2 eligible for HUCs. As stated previously, MISO estimates no more than five
3 percent of total cleared Capacity Resources would be eligible for HUCs, assuming
4 price separation between every LRZ and ERZ. Barring further zonal boundary
5 changes, this number will not increase in the future.

6 Importantly, HUCs are only used to prioritize allocation of excess auction revenue, and
7 will not uplift costs, or modify ACPs, as compared to an auction without any HUCs.

8 **Q. How were the units eligible for HUCs defined?**

9 **A.** Historic Unit Considerations were designed to especially recognize arrangements that
10 were entered into prior to the creation of ERZs and are longer term, with no or limited
11 opportunities for renegotiation during their multi-decade ownership or contract term. As
12 noted above, the creation of ERZs will introduce price risk that could not have been
13 foreseen, and could not have been included into these agreements. Therefore, MISO
14 believes that a mechanism to protect against price separation risk created by ERZs needs
15 to be paired with the creation of new zones. Similar logic was also applied to internal
16 resources, to avoid creating preferential treatment for external resources. This led to the
17 creation of HUCs for historic contracts between inter-zonal resources within MISO, as
18 well as those with resources external to MISO. Specifically, these arrangements include
19 arrangements entered into prior to the current Resource Adequacy Construct (prior to
20 July 20th, 2011), arrangements from Resources in External Resource Zones entered into
21 prior to March 22, 2018, and Grandfather Agreements.

22 **Q. Will HUCs replace other existing forms of excess auction revenue allocation?**

23 **A.** HUCs will not replace any existing forms of excess auction revenue. However, HUCs
24 will change the prioritization of allocating excess auction revenue. Under the current

1 Resource Adequacy Construct, the Zonal Deliverability Benefit (“ZDB”) mechanism is
2 used to allocate excess auction revenue. Simply stated, the ZDB mechanism is a pro rata
3 distribution of excess auction revenue to Market Participants that serve demand in
4 constrained LRZs. While this allocation will still take place under this proposal, HUCs
5 will be prioritized ahead of allocation of excess auction revenues by the ZDB mechanism.
6 The proposed allocation of excess auction revenue is rational to recognize the impacts of
7 changes to MISO’s Resource Adequacy Construct on pre-existing capacity arrangements.
8 The HUC is intended to minimize MISO’s impact on such agreements.

9 **Q. How will HUCs be awarded and registered?**

10 **A.** HUCs will be awarded to Market Participants that can demonstrate ownership of or
11 contractual arrangements to a Resource, and meet the following requirements:

- 12 1. The arrangement must be one of the following: i) a Grandfather Agreement; ii)
13 an agreement that was entered into prior to July 20th, 2011 (i.e., arrangements that
14 pre-date MISO’s Resource Adequacy Construct); or, iii) an agreement from a
15 Resource in an External Resource Zone executed prior to [March 22, 2018], and
16 the arrangement must have been continuously used to serve load since that that
17 time.
- 18 2. An LSE must have PRMR that is in an LRZ distinct from the ERZ or LRZ
19 where the Planning Resource is located.
- 20 3. HUCs can only be granted in amounts less than or equal to the PRMR being
21 served by the LSE (for example: a 100 MW arrangement contracted by an LSE
22 that serves only 20 MW of load can only be eligible for 20 MW of HUC).

1 4. The arrangement must have either long-term firm transmission service from the
2 Planning Resource to the LRZ containing the LSE's demand and associated
3 PRMR, Network Resource Interconnection Service, or some combination of the
4 two.

5 5. The arrangement must be on-going; HUC eligibility will end at the end of the
6 historic contract term, during unit ownership changes (unless the historic contract
7 for sale of capacity remains intact), or if the Resource retires.

8 HUC registration will take place as part of the annual PRA market registration process.
9 HUC registrations will be evaluated by MISO, and LSEs will be notified of the outcome
10 of the registration process and evaluation against the requirements listed above.

11 **Q. How will HUCs be valued?**

12 **A.** A HUC will be valued based on pricing differences between two zones (either LRZs or
13 ERZs). During the registration process, each HUC will be defined with a source ERZ or
14 LRZ, and a sink LRZ, as well as a MW quantity of capacity. The value of one MW of
15 HUC is calculated to be the ACP of the sink LRZ less the ACP of the source ERZ or
16 LRZ. HUCs can be credits to Market Participants who own them, but not charges.

17 **Q. How would underfunding be addressed?**

18 **A.** Price separation is a fundamental outcome of locational market clearing processes,
19 reflecting both the regional value of capacity and the additional value that local supply
20 provides, beyond that which can be provided by distant supply. This price separation can
21 result in higher prices paid by demand than paid to supply, creating a surplus of auction
22 revenue. MISO's HUC proposal represents a prioritized approach to allocation of excess
23 auction revenue in the event that price separation occurs, and analysis of historic auctions

1 showed no risk to underfunding. In fact, HUC allocations were found to only reduce
2 ZDB allocations by no more than \$0.55 per MW/day.⁹ In these situations, any remaining
3 excess auction revenue will be allocated by the Zonal Deliverability Benefit mechanism
4 described in 69A.7.7(c) of the Tariff.

5 It is possible, although unlikely, that the claims on excess auction revenue, in the form of
6 HUC ownership, could be greater than the excess auction revenue collected. In this
7 event, ownership of HUCs or ZDC Hedges entitles a Market Participant to a pro-rata
8 share of the excess auction revenue, on a per-MW basis.

9 **Q. What are the impacts of this proposal on the auction output?**

10 **A.** There are no direct impacts to the execution of, or outputs to, the PRA. HUCs are an
11 approach to allocated excess auction revenues, as described above, and as such, impact
12 settlements, but not auction outputs.

13 **Q. What are the impacts of this proposal on the auction settlements?**

14 **A.** As described above, HUCs result in credits to Market Participants that own them, and
15 also result in changes to the pool of excess auction revenues available to be allocated via
16 the Zonal Deliverability Benefit mechanism. This impact will vary based upon the
17 specific results of each PRA.

18 **D. Adjustments to Capacity Import Limit, Capacity Export Limits, and Local**

19 **Clearing Requirements**

20 **Q. How are Capacity Import and Export Limits currently calculated?**

⁹ See Resource Adequacy Subcommittee, 20170712 RASC Item 03b Locational Update (July 12, 2017 meeting) at pp 15-16, available at <https://cdn.misoenergy.org/20170712%20RASC%20Item%2003b%20Locational%20Update87556.pdf>.

1 A. Currently, CIL values are calculated as the system's ability to import into a given LRZ,
2 when capacity exports to external Balancing Authority Area load are assumed to be
3 offline. This is achieved through calculating the total ability of the system to import, as
4 represented by the sum of the net imports into the zone and the incremental ability of the
5 zone to import additional capacity.

6 Initial import ability = Base interchange + incremental import ability.

7 The initial import ability is then modified to remove the effect of exporting resources on
8 the Capacity Import Limit from both the initial net imports value and the incremental
9 import ability.

10 CIL = initial import ability + exports to non-MISO load – impact of exports on
11 the incremental import ability.

12 Capacity Export Limits are calculated as a zone's export ability, as measured by the
13 summation of the base interchange in the model and the ability of the zone to export
14 additional capacity.

15 CEL = Base interchange + incremental export ability.

16 Q. How does MISO propose to modify this treatment?

17 A. MISO proposes two modifications to the CIL and CEL calculations:

18 1) Locate all External Resources in the External Resource Zone or Local
19 Resource Zone which they are accredited; and,

20 2) Adjust both CIL and CEL for exporting resources.

21 The first change will modify the initial base interchange of each LRZ to account
22 for the resources that are able to count towards the Zone's requirements. This results in

1 an increase in the export ability and a decrease in the import ability for Zones with
2 Border External Resources and Coordinating Owner resources.

3 The second modification, adjusting CIL and CEL for exporting resources, will
4 reduce the final CEL to account for these exports to non-MISO load that do not have to
5 clear the PRA. Correspondingly, the final CIL will increase to reflect counterflow from
6 these exporting resources.

7 In the models used to calculate the CIL or CEL, exporting resources will be
8 modeled online, to reflect the expected commitments to non-MISO load. Border External
9 Resources and Coordinating Owner resources will continue to be modeled at their
10 physical location and expected output, without being classified as imports into MISO.

11 An example of the CIL and CEL calculations is attached to this testimony as
12 [Attachment B].

13 **Q. Why should MISO locate all resources where they are accredited, for CIL and CEL**
14 **purposes?**

15 **A.** As discussed previously, Coordinating Owner and Border External Resources are
16 electrically equivalent to resources within MISO, and as such, will continue to be granted
17 credit within an LRZ. As such, the PRA will not see these resources as imports to the
18 given zone. The modifications to CIL and CEL will align the resources considered in the
19 base interchange terms above with this auction treatment, resulting in transfer limits that
20 appropriately reflect the capacity which will be cleared in the Auction towards the zone's
21 requirements.

22 **Q. Why will MISO adjust CIL and CEL values to account for exporting resources?**

23 **A.** CIL and CEL values represent the total import and export ability of a zone; that is, they
24 currently show the full ability of the transmission system to import or export capacity.

1 This total ability is then compared against the transfer capacity used in the PRA, to
2 ensure that system reliability is maintained. However, not all expected capacity uses
3 clear in the MISO PRA. Specifically, capacity commitments to non-MISO load utilize
4 some of the export ability for a zone and do not clear the PRA. Conversely, these exports
5 could allow for additional imports in the PRA.

6 **Q. How do these modifications impact the Local Clearing Requirement (“LCR”)?**

7 **A.** Currently, the LCR is calculated as the difference between the amount of resources a
8 zone needs to serve its peak load (Local Reliability Requirement, or “LRR”), the zone’s
9 CIL, and the amount of pseudo-tied exports to non-MISO load, according to the formula
10 below:

$$11 \quad \text{LCR} = \text{LRR} - \text{CIL} - \text{non-pseudo-tied exports}$$

12 In the equation above, CIL represents the total ability of the zone to import
13 capacity. As such, MISO proposes a corresponding edit to the LCR calculation to
14 include the zone’s total import ability, rather than the CIL, as the CIL will be modified to
15 focus only on the capacity which may be imported by a zone in the PRA.

16 Additionally, MISO would like to change references from ‘non-pseudo-tied
17 exports’ to ‘controllable exports’, where controllable exports are defined as firm capacity
18 commitments that may be committed and dispatched up by MISO during capacity
19 emergencies. This will allow MISO to recognize the ability of pseudo-tied resources to
20 meet local requirements and thus reduce LCR, if suitable operating agreements are
21 obtained, without an additional Tariff filing.

22 As such, the formula for LCR would be modified as following:

$$23 \quad \text{LCR} = \text{LRR} - \text{Zonal Import Ability} - \text{controllable exports}$$

24 **Q. Why are pseudo-tied resources currently excluded from reducing LCR?**

1 A. MISO sets local resource adequacy requirements to be equal to the minimum amount of
2 resources that must be located within an LRZ to support that zone's peak load serving
3 needs. These requirements can be set in two ways: through those resources clearing in
4 the PRA; or, through resources under MISO's operational control that are committed to
5 non-MISO load (e.g., resources committed in the PJM resource adequacy construct).

6 In either scenario, resources that reduce local requirements, either through a
7 reduction in the LCR or through clearing against the requirement in the PRA, must be
8 physically within the MISO Zone and must be able to be committed and dispatched by
9 MISO during capacity emergencies. This mirrors the assignment of local credit to Border
10 External and Coordinating Owner Resources, which meet the locational and operational
11 criteria. However, under current joint operating agreements, pseudo-tied resources
12 cannot be dispatch by MISO during capacity emergencies. As such, pseudo-tied exports
13 cannot currently reduce the LCR. However, as stated above, proposed Tariff
14 modifications will allow MISO to recognize the ability of pseudo-tied resources to meet
15 local requirements and thus reduce LCR if suitable operating agreements are obtained,
16 without an additional Tariff filing.

17 **Q. How are these revisions consistent with the FERC December 31, 2015 Order?**

18 A. On December 31, 2015, FERC directed MISO staff to "... file Tariff revisions on
19 compliance to ensure that MISO's calculation of Capacity Import Limits accurately
20 reflects counter-flows resulting from capacity exports to neighboring regions."¹⁰ The
21 combined edits to CIL and CEL align the PRA's limitation with how capacity may clear
22 against these limits in the auction. CILs are increased by capacity exporting from the

¹⁰ *Public Citizen, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,385 (2015) ("December 31 Order") at P 145.

1 Zone, and CELs are decreased by the same. Additionally, the import limits defined by
2 LCR are increased by controllable exports, consistent with MISO's filing in response to
3 the December 31st Order and FERC's subsequent acceptance.
4

5 **IV. CONCLUSIONS AND RECOMMENDATIONS**

6 **Q. How will this proposal enhance reliability, equity, and transparency?**

7 A. Improvements to the modeling of External Resources and alignment between the PRA
8 and its LOLE study inputs will enhance reliability and price formation through: 1)
9 accurately modeling all resources based on the regional and/or local support they can
10 provide for MISO load; and, 2) ensuring that auction inputs appropriately consider the
11 impacts of both MISO capacity resources and resources which may be committed to
12 serve non-MISO load. Historical Unit Considerations will support the alignment of
13 modeling with physical reality through recognizing and allocating excess auction
14 revenues to arrangements between MISO load and capacity resources impacted by risks
15 they could not foresee, without altering Auction Clearing Prices or disregarding
16 limitations on the transmission system. As such, the proposal will enhance reliability,
17 equity, and transparency through creating a framework that acknowledges the impacts of
18 all resources and the long-standing arrangements Load Serving Entities have created to
19 ensure that they may meet their service obligation.

20 **Q. Does this conclude your testimony?**

21 A. Yes it does.

Attachment A: External Resource Zone Pricing

This attachment provides an example of LRZ and ERZ pricing under MISO's locational enhancement proposal. In Figure A1, two LRZs and three ERZs are shown. LRZ A and LRZ B are in separate SRRZs along with ERZ E1 and ERZ E2. Dually connected ERZ E3 is assumed to have a 50% shift factor with both SRRZs and the capacity transfer limit between sub-regions (SRIC and SREC) is set to 200MW. Load requirements and the import/export limits for each LRZ and ERZ, if applicable, are listed in Table A1 under the input columns; resource offer information is listed in separate Table A2 under input columns. The resultant ACP for each LRZ and ERZ is listed in separate Table A2 under input columns. The resultant ACP for each LRZ and ERZ is listed under the output column of Table A1 and the respective cleared MW for each resource is listed under the output column of Table A2.

In this example, utilizing the least cost solution, the marginal resources in the respective SRRZs are resources A and B, which essentially sets the ACP for respective SRRZs and hence associated ERZs (ERZ E1 and ERZ E2). The ACP for dually connected ERZ E3 will be based on its shift factors with the SRRZs and associated ACPs.

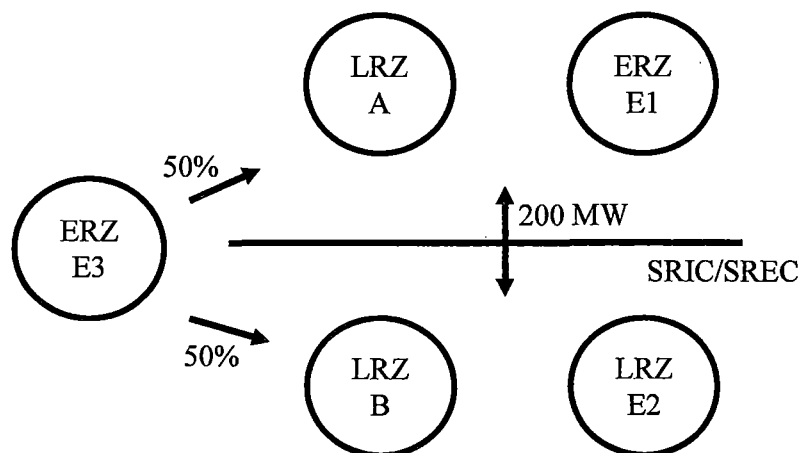


Figure A1: Example System Representation

Table A1: Zonal input-output information

	Input				Output
	PRMR (MW)	LCR (MW)	CIL (MW)	CEL (MW)	ACP (\$/MW.Day)
LRZ A	500	30	460	460	\$70
LRZ B	100	20	60	60	\$50
ERZ E1	-	-	-	100	\$70
ERZ E2	-	-	-	50	\$50
ERZ E3	-	-	-	300	\$60

Table A2: Resource's input offers and output cleared MWs

Resource Name	Input			Output
	Location	Offer MW (MW)	Offer Price (\$)	Cleared MW (MW)
A	LRZ A	100	\$70	50
B	LRZ B	250	\$50	100
E1	ERZ E1	100	\$0	100
E2	ERZ E2	50	\$0	50
E3	ERZ E3	300	\$20	300

Attachment B: CIL and CEL examples

This attachment provides additional information and examples of the impact of Coordinating Owner and Border External Resources on Capacity Import and Export Limits. Currently, these resources are treated as imports to MISO LRZs. The improvements in the locational proposal recognize the electrical equivalency of these resources when compared to internal LRZ resources. Due to the electrical equivalency, the output of these units is considered to be internal to a MISO LRZ. This results in increases to CILs and decreases to CELs as these resources are no longer imported into MISO. An example of the impact is shown below in Table B1.

Coordinating Owner or Border External Resource (MW)	Current CIL (MW)	Proposed CIL (MW)	Current CEL (MW)	Proposed CEL (MW)
[A]	[B]	[C] = [B]-[A]	[D]	[E] = [D]+[A]
500	4,000	3,500	2,500	3,000

Table B1: Indicative example of impact of Coordinating Owner and Border External Resources

CIL and CEL are further impacted by resources exporting to non-MISO load. Current CIL calculations assume these exports are offline, while the CEL calculations assume these are online. The CIL assumptions are driven by the compliance with relevant Commission orders.¹¹ Exports to non-MISO load consume a portion of the LRZ's current CEL, while provide counterflow to LRZ's CIL. MISO's locational enhancement proposal acknowledges the benefit of counterflow, while recognizing the exports will still impact flow on the transmission system, as they can be expected to be utilized by the External BA. Additionally, the proposal extends adjustments to CEL. As a result of MISO's proposal, CIL and CEL values are more applicable

¹¹ See December 31 Order, *order on reh'g and compliance*, 154 FERC ¶ 61,224 (2016), *order on compliance*, 156 FERC ¶ 61,075 (2016).

to units participating in the PRA. Table B2 provides an example how the proposal updates export impacts on CIL and extends to CEL.

Resources exporting to serve non-MISO load (MW)	Total impact of exports on CIL (MW)	Current CIL (MW)	Proposed CIL (MW)	Current CEL (MW)	Proposed CEL (MW)
[A]	[B]	[C]	[E] = [C]+[B]+[A]	[F]	[G] = [F]-[A]
600	-500	4,000	4,100	2,500	1,900

Table B2: CIL and CEL examples detailing impact of exports to non-MISO load

AFFIDAVIT OF LAURA RAUCH

Laura Rauch, being duly sworn, deposes and states that she prepared the Testimony of Laura Rauch, and the statements contained therein are true and accurate to the best of her knowledge and belief.



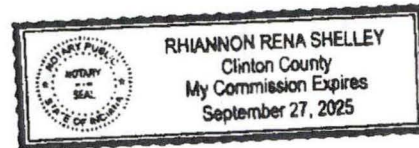
Laura Rauch

SUBSCRIBED AND SWORN BEFORE ME, this 22nd day of March, 2018.



Notary Public

State of Indiana, County of Clinton



My Commission Expires: 9/27/2025

Tab D

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Midcontinent Independent System
Operator, Inc.**

)
)
)

Docket No. ER18-__-000

**AFFIDAVIT OF
DAVID B. PATTON, PH.D.**

I. Qualifications and Purpose

1. My name is David B. Patton. I am an economist and the President of Potomac Economics Ltd. Our offices are located at 9990 Fairfax Boulevard, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets. Potomac Economics has served as the Independent Market Monitor (“IMM”) for Midcontinent Independent System Operator, Inc. (“MISO”) since 2002. Potomac Economics serves in a substantially similar role for the New York Independent System Operator, Inc. (“NYISO”), ISO New England, Inc. (“ISO-NE”), and the Electric Reliability Council of Texas (“ERCOT”).
2. As the Market Monitor for both MISO and NYISO, Potomac Economics is responsible for assessing the competitive performance of the markets that the RTOs administer, including identifying and remedying market design flaws and abuses of market power. This work has included preparing a number of reports that assess the performance of these markets and providing advice on numerous issues related to market design and economic efficiency. Among the issues that we monitor are the interactions between the MISO and NYISO markets and those of neighboring regions, and the impacts of those neighboring regions on the RTOs’ operations. Of particular relevance to this proceeding is the monitoring of capacity markets and the seams of energy markets.
3. I have worked as an energy economist for 26 years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. I have also advised Regional Transmission Organizations on transmission pricing,

market design, and congestion management issues. With regard to competitive analysis, I have provided expert testimony and analysis regarding market power issues in a number of mergers and market-based pricing cases before the Federal Energy Regulatory Commission (“the Commission”), state regulatory commissions, and the U.S. Department of Justice.

4. Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the Commission, advocating on a variety of policy issues including transmission pricing and open-access policies, market design issues, and electric utility mergers. As a member of the Commission’s advisory staff I worked on policies reflected in Order No. 888, particularly on issues related to power pool restructuring, independent system operators (“ISOs”), and functional unbundling. I also analyzed alternative transmission pricing and electricity auctions proposed by ISOs.
5. Before joining the Commission, I worked as an economist for the U.S. Department of Energy. During this time, I helped to develop and analyze policies related to investment in oil and gas exploration, electric utility demand side management, residential and commercial energy efficiency, and the deployment of new energy technologies. I have a Ph.D. in Economics and a M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University.
6. The purpose of this affidavit is to comment on modifications to the Tariff to incorporate External Resource Zones (ERZs). I am generally in support of the changes that MISO is proposing.
7. Capacity markets are a means of facilitating resource adequacy and providing efficient price signals that reflect the locational market fundamentals of supply, demand and

transmission system capability. The resulting price signals should be an input in determining when and where transmission and generation should be added or removed.

8. The capacity market facilitates resource adequacy by modeling supply and demand during the most limiting time periods which is normally the summer peak conditions. The assumptions incorporated in the market are a conservative representation of real-time operations during summer peak conditions, so it is important that it reflect the practices used in real-time for moving energy between Balancing Areas (BAs) and determining the loading on constraints that limit the real-time markets.
9. The proposed Tariff changes to Module E-1, E-2 and related definitions in Module A provide key improvements to the current capacity market construct and do so in a way that respects the real-time transfer limits between MISO South and rest of MISO. It also incorporates participation of resources from external BAs (External Resources) in a way that is consistent with the way energy associated with such capacity is scheduled and delivered into MISO in real-time.

II. The Existing Treatment of External Zones is Problematic

10. Currently, as stated in Tariff Section 69A.7.1.a: *“External Resources will be treated for PRA purposes as if they are located in the LRZ where their firm transmission sinks at the border of the Transmission Provider Region.”*
11. Therefore, if an External Resource had transmission service into Local Resource Zone 4 (LRZ), for example, it would count towards the local clearing requirement (LCR) of LRZ 4 even though it is not physically located in that LRZ. This creates a potential reliability problem because External Resources do not provide the same local benefit as generation

physically located in the LRZ since local generation would generally relieve transmission constraints caused by imports into the zone. In fact, the transfer of the External Resource capacity into the LRZ is not counted against the LRZ Capacity Import Limit (CIL) in the auction clearing process.

12. It also results in prices and settlement that are not efficient and distort of the locational aspects of the market. If LRZ 4 were constrained at its LCR, for example, it would clear at a higher price than surrounding LRZs. The External Resources with transmission into this zone would receive this higher price and the market would procure additional capacity from these resources. This is both inefficient and inequitable because the external resources do not relieve the constraints into the zone and are, therefore, not more valuable than other internal resources that are not located in LRZ 4 that would be paid a lower clearing price.
13. The new Tariff language solves these problems by creating External Resource Zones (ERZs). The External Resources don't count towards the LCR of any LRZ and they only get the auction clearing price of the ERZ where they are physically located.

III. The ERZ Proposal Will Significantly Improve the Pricing of External Resources

14. MISO real-time operations are limited by the energy transfers between MISO South and the MISO North sub-regions by the Settlement Agreement filed with the Federal Energy Regulatory Commission under docket number EL14-21, *et al.* This agreement establishes how to calculate the transfers and places limits on such transfers. In these calculations, schedules from some external BAs that border both MISO South and MISO North are treated as having a blended effect on the constraint. MISO's energy market and dispatch

utilize the methodology agreed in the settlement agreement to calculate the transfer flows associated with imports and exports to and from different external areas.

15. The proposed changes filed by MISO would ensure that the capacity market treat imports and exports in a manner consistent with this treatment in the energy markets. In other words, the new Tariff language properly defines ERZs as being external BAs and models their effects on the transfer limit in the same way that is done for real-time schedules per the Settlement Agreement. The External Resources from ERZs that touch both regions are treated as being partially in MISO South and partially in MISO North. Price separation is driven by binding constraints, the most prevalent of which is the transfer constraint. Hence, the accurate treatment of the ERZ's impact on the transfer constraint enables the ERZ's clearing prices to more efficiently reflect the value of their locations.
16. If the PRA clears with the South to North constraint binding and nothing else, an ERZ that only ties to the South would get the lower South price since it loads the constraint that same as a South region resource. The opposite is true for an ERZ that ties only to MISO North. However, an ERZ that ties to both doesn't fully load or unload the constraint as internal resources do, but has a blended effect based on the Settlement Agreement. Therefore, the efficient locational price for the ERZs that tie to both South and North is a blend between the prices in the South and North sub-regions.
17. Ultimately, I would like to see MISO expand this approach to model other transmission constraints within the PRA. In this case, each ERZ and LRZ would be assigned shift factors that quantify the amount by which increased output in the zone would increase or decrease the flow on the constraint. In the current proposal, only the transfer constraint is

modeled and the shift factors are determined by the Settlement Agreement. However, this approach could be expanded to model other constraints. Although this would produce additional benefits, the current proposal is clearly a big step in the right direction.

IV. MISO's Proposal will also Produce Benefits in the Real-Time Market

18. Although this is a capacity market change, it is important to recognize that this will ultimately affect the operation of the system. MISO is proposing ERZs that match the current definition of its interfaces with external areas. For example, it will establish one ERZ for PJM. This is critical because this is how imports and exports are effectuated in real-time operations. If MISO imports power from PJM in real time, it reduces its output by the import quantity and PJM increases its output by the same amount (excluding transmission losses). Hence, the incremental power could originate from New Jersey or from the Chicago area. This is determined dynamically by the PJM dispatch model, which will increase output in PJM to minimize the cost of the export.
19. Therefore, it is very important that capacity be procured in a comparable manner – from PJM as a whole in this example, rather than allowing procurements from subareas. This will best allow MISO to procure capacity resources in a manner that will prepare it to operate the system reliably.
20. In addition, by providing more efficient price signals and procuring capacity in locations that respect the transfer constraint, MISO will be in a better position to serve its load reliably without overloading the transfer constraint.
21. This is important because the transfer constraint periodically limits MISO's access to resources in a manner that can threaten reliability. For example, during a cold snap on

January 17 and 18 of this year, MISO declared Maximum Generation Events and took a number of emergency actions in the South to continue to serve load and manage the flows on the transfer constraint. These actions included reducing load by calling Load Modifying Resources (a type of Capacity Resource), procuring emergency energy from neighboring regions, and increasing internal transmission ratings in the South. Even with all of these actions, MISO was very close to not having the ability to serve the load in the South without exceeding the normal limit violating the transfer constraint.

22. This highlights the importance of modeling the transfer constraint accurately and procuring capacity from external locations that will likely be accessible when the transfer constraint binds in operation. MISO's proposal will help achieve this objective, along with improving the price signals and associated incentives provided in ERZs. Therefore, I support MISO's proposal and respectfully recommend that the Commission approve the associated Tariff changes.
23. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.



David B. Patton

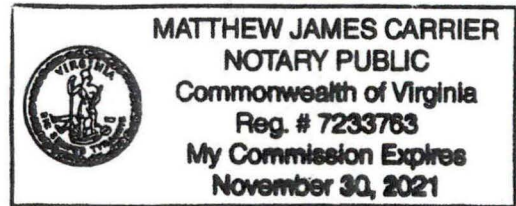
March 26, 2018

Subscribed and sworn to before me in Fairfax, VA
this 26th day of March, 2018



Notary Public

My commission expires: Nov. 30, 2021



Tab E

Tab E – Table of Stakeholder Meetings and Presentations

Meeting Date	Stakeholder Entity - Hyperlink
SAWG	Supply Adequacy Working Group (SAWG)
09/04/2014	20140904 SAWG Item 06 External Resources Work Plan.pdf
10/02/2014	20141002 SAWG Item 02c External Resources Work Plan.pdf
10/30/2014	20141030 SAWG Supplemental Comments.zip
11/06/2014	20141106 LOLEWG SAWG Item 04 External Resources Comments
02/05/2015	20150205 SAWG Item 06 External Zones and Resource Update.pdf
03/05/2015	20150305 SAWG Item 02 Resource Adequacy Issues Statement.pdf
	20150305 SAWG Item 05 External Resources.pdf
	20150305 SAWG Supplemental Feedback.zip
Meeting Date	Stakeholder Entity - Hyperlink
LOLEWG	Loss of Load Expectation Working Group (LOLEWG)
11/06/2014	20141106 LOLEWG SAWG Item 04 External Resources Comments
09/02/2015	20150902 LOLEWG and SAWG Item 06 Locational Considerations
	20150902 LOLEWG Resource Adequacy Straw Proposal
	20150902 LOLEWG and SAWG Locational - Seasonal Feedback Request
	20150902 LOLEWG and SAWG Seasonal and Locational Considerations - Stakeholder Comments
09/30/2015	20150930 LOLEWG SAWG Joint Meeting Item 06 Locational Considerations
	20150930 LOLEWG SAWG Locational - Seasonal Feedback Request
	20150930 LOLEWG SAWG Locational Seasonal Feedback
10/28/2015	20151028 LOLEWG Item 06 Locational and Seasonal Timeline
12/02/2015	20151202 LOLEWG SAWG Joint Meeting Item 08 Locational Detailed Design
02/03/2016	20160203 LOLEWG SAWG Joint Meeting Item 05 Seasonal and Locational Implementation
	20160203 LOLEWG SAWG Joint Meeting Seasonal Locational Stakeholder Comments
05/04/2016	20160504 LOLEWG Item 06a Locational LOLE Signals
06/01/2016	20160601 LOLEWG Item 05 Locational LOLE Signals
06/29/2016	20160629 LOLEWG Item 02 Locational LOLE Signals
07/15/2016	20160715 LOLEWG Item 02 Locational LOLE Signals

Tab E – Table of Stakeholder Meetings and Presentations

08/03/2016	20160803 LOLEWG Item 02 Locational LOLE Signals
08/31/2016	20160831 LOLEWG Item 03 Locational LOLE Signals
Meeting Date	Stakeholder Entity - Hyperlink
RASC	Resource Adequacy Subcommittee (RASC)
03/02/2016	20160302 RASC Item 04g Seasonal and Locational Implementation
	20160302 RASC Item XX Stakeholder Feedback on Seasonal Locational Implementation
04/14/2016	20160414 RASC Item 02c Seasonal and Locational Overview
	20160414 RASC Item 02c Tariff and Feedback
05/04/2016	20160504 RASC Item 06c Seasonal and Locational
06/01/2016	20160601 RASC Item 02e Seasonal and Locational overview
	20160601 RASC Supplemental Stakeholder Comments
06/29/2016	20160629 RASC Item 04c Seasonal and Locational capacity and ERZs
	20160629 RASC Supplemental Stakeholder Comments
08/31/2016	20160831 RASC Item 05e Seasonal Locational Timeline
02/08/2017	20170208 RASC Item 02 Locational Resource Adequacy
03/08/2017	20170308 RASC Item 03a Locational Planning
04/12/2017	20170412 RASC Item 03b Locational Planning
	20170412 RASC Supplemental Stakeholder Comments
05/10/2017	20170510 RASC Item 03bi Locational Planning IMM Proposal
	20170510 RASC Item 03bii Locational Planning Update
	20170510 RASC Supplemental Stakeholder Comments
06/07/2017	20170607 RASC Item 02a Draft Locational Business Rules
	20170607 RASC Item 02a Locational Update Presentation
	20170607 RASC Supplemental Stakeholder Comments
07/12/2017	20170712 RASC Item 03b Locational Module A
	20170712 RASC Item 03b Locational Module E 1
	20170712 RASC Item 03b Locational Module E 2
	20170712 RASC Item 03b Locational Update

Tab E – Table of Stakeholder Meetings and Presentations

	<u>20170712 RASC Supplemental Stakeholder Comments</u>
08/09/2017	<u>20170809 RASC Item 02a Locational Module E 1</u>
	<u>20170809 RASC Item 02a Locational Reforms</u>
	<u>20170809 RASC Supplemental Stakeholder Comments on Locational Draft Tariff Language</u>
09/13/2017	<u>20170913 RASC Item 03a Locational Update</u>
	<u>20170913 RASC Supplemental Stakeholder Comments</u>
10/11/2017	<u>20171011 RASC Item 03ai Locational Update</u>
11/08/2017	<u>20171108 RASC Item 05b Locational Business Rules</u>
	<u>20171108 RASC Item 05b Locational Update</u>
	<u>20171108 RASC Locational Proposal Overview</u>
	<u>20171108 RASC Supplemental Stakeholder Feedback</u>
12/13/2017	<u>20171213 RASC Item 04c Locational Planning</u>
02/07/2018	<u>20180207 RASC Item 04a Locational Enhancement</u>
	<u>20180207 RASC Locational - Module A comparison to current as filed Tariff</u>
	<u>20180207 RASC Locational - Module A comparison to prior RASC posting</u>
	<u>20180207 RASC Locational - Module E 1 comparison to current as filed Tariff</u>
	<u>20180207 RASC Locational - Module E 1 comparison to prior RASC posting</u>
	<u>20180207 RASC Locational - Module E 2 comparison to current as filed Tariff</u>
	<u>20180207 RASC Locational - Module E 2 comparison to prior RASC posting</u>
	<u>20180207 RASC Supplemental Stakeholder Comments on Draft Locational Tariff</u>
3/07/2018	<u>20180307 RASC Item 04a Locational Tariff Review</u>
	<u>20180307 RASC Supplemental Stakeholder Comments on Tariff Language</u>
	<u>Locational - Module A comparison to Jan posting</u>
	<u>Locational - Module A comparison to current as filed Tariff 0228018</u>
	<u>Locational - Module E 1 comparison to Jan posting</u>
	<u>Locational - Module E 1 comparison to current as filed Tariff 02282018</u>
	<u>Locational - Module E 2 comparison to Jan posting</u>
	<u>Locational - Module E 2 comparison to current as filed Tariff 02282018</u>

FERC rendition of the electronically filed tariff records in Docket No. ER18-01173-000
Filing Data:
CID: C001344
Filing Title: 2018-03-26 Enhance Locational Aspect of Resource Adequacy Construct
Company Filing Identifier: 11555
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: FERC Electric Tariff
Tariff ID: 9
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.A, Definitions - A, 50.0.0, A
Record Narrative Name:
Tariff Record ID: 5681
Tariff Record Collation Value: 557908992 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Active Transmission Constraint: Any transmission constraint for which a Resource is committed to avoid exceeding, or to relieve, the constraint limit.

Actual Energy Injections: For a Generation Resource a net Metered volume measured in MWh that flows into the Transmission System during the Operating Day at a specified location that is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day or, for a Stored Energy Resource or External Asynchronous Resource or Stored Energy Resource – Type II, a net Metered volume measured in MWh that flows into or out of (withdrawal positive, injection negative) the Transmission System during the Operating Day at a specified location that is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day. For a Demand Response Resource-Type I, or for a Demand Response Resource-Type II, or an EDR resource, a calculated volume in MWh that is equal to the amount as calculated or Metered according to the specifications and protocols in the Measurement and Verification Procedures. The Actual Energy Injection of the Demand

Response Resource is calculated by the Transmission Provider based on the meter data submitted by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day that is used for Settlement purposes. Given the appropriate qualification, Demand Response Resources-Type I Resources can provide the following products: Energy, Contingency Reserve, and capacity under Module E.

Actual Energy Withdrawal: For a Load Zone where one or more Demand Response Resources Type I are committed for Energy and/or are offered for Contingency Reserve, where one or more Demand Response Resource Type II are committed during a specific Hour, or where an EDR resource has reduced load, a calculated volume in MWh that flows out of the Transmission System during the Operating Day at a specified location that is equal to the time-weighted average of the Metered volume of the Load Zone for that Hour plus Actual Energy Injects within the Load Zone for the Demand Response Resources and EDR resources. For all other Load Zones, a Metered volume measured in MWh that flows out of the Transmission System during the Operating Day at a specified location. The Load Zone Metered volume in MWh that flows out of the Transmission System during the Operating Day, used for the calculation of the Actual Energy Withdrawal, is submitted to the Transmission Provider by a Market Participant or a Market Participant's Meter Data Management Agent for each Hour of the Operating Day that is used for Settlement purposes. For an Hour where the Hourly Ex Post LMP is less than the Net Benefits Price Threshold, the amount of Actual Energy Injections for all DRRs associated with a given Load Zone are added to the Metered volume at the specified Load Zone.

Actual Resource Response: The actual movement, in MWs, relative to Setpoint Instructions

for a Resource within a Dispatch Interval.

Additional Regulating Mileage: Any Regulating Mileage Target for a Resource in a Dispatch Interval beyond the amount considered for the Dispatch Interval during the market clearing.

Adjusted Financial Transmission Rights Capability: The expected available transmission capacity in the FTR Auction, respecting the Simultaneous Feasibility Test, over the Transmission Provider Region during: (1) a given Month, less FTRs held by existing FTR Holders; or (2) a Season, less FTRs held by existing FTR Holders and baseloading assumptions.

Affected Participant: A Market Participant, a person that engages in Market Activities or a person that takes any other service under the Tariff that has provided to the Transmission Provider, Confidential Information that is requested by, or is disclosed to, an Authorized Requestor under a Non-Disclosure Agreement.

Affiliate: With respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity.

Agency Agreement: The agreement that is Appendix G of the ISO Agreement.

Aggregate Annual Transmission Revenue Requirement (Aggregate ATRR): The annual transmission revenue requirement calculated by combining the annual transmission revenue requirements of each individual RFP Respondent and each individual Proposal Participant identified in a Proposal, all as provided in Section VIII.D.4.3 of Attachment FF of the Tariff.

Aggregate Power Supply Curve: The combined Energy Offer curves for all Resources, excluding DRRs, which is the capacity from all such resources at each price offered.

Aggregate Price Node (APNode): An aggregation of Elemental Pricing Nodes whose LMP is calculated as the sum of the products of the LMP at each Elemental Pricing Node defined in the Aggregate Price Node and the associated pre-established normalized weighting factors for the Elemental Pricing Node.

Aggregator of Retail Customers (ARC): A Market Participant that represents demand response on behalf of one or more eligible retail customers, for which the participant is not such customers' LSE, and intends to offer demand response directly into the Transmission Provider's Energy and Operating Reserve Markets, as a Planning Resource or as an EDR resource.

Allowance Level: A description of the mitigation measure described in Module D which allows a Market Participant that is an LSE or represents an LSE, to purchase or schedule a specified portion of its Energy, Operating Reserve, Up Ramp Capability, and Down Ramp Capability requirements in the Real Time Energy and Operating Reserve Market.

Alternate Selected Developer(s): Shall be the RFP Respondent(s) whose Proposal is selected to be the alternate Proposal by the Competitive Transmission Executive Committee, pursuant to Attachment FF of the Tariff, for implementation if the Selected Developer fails to execute or request an unexecuted filing of the Selected Developer Agreement and provide the required Project Financial Security within the timeframe provided in Attachment FF Section VIII.H.

Ancillary Services: Those services that are necessary to support Capacity and the transmission of Energy from Resources to Loads while maintaining reliable operation of the

Transmission System in accordance with Good Utility Practice.

Annual ARR Allocation: The procedure used by the Transmission Provider annually to allocate ARRs and MVP ARRs.

Annual ARR Registration: The annual process for registering ARR Entitlements and MVP ARR Entitlements.

Applicable Laws and Regulations: All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the Parties, their respective facilities and/or the respective services they provide.

Applicable Reliability Standards: Reliability Standards approved by the Federal Energy Regulatory Commission (FERC) under Section 215 of the Federal Power Act relating to operation of the Transmission Provider in carrying out its Reliability Coordinator, Balancing Authority, Market Operator, Transmission Service Provider, and Planning Coordinator functions. In addition to FERC approved standards, any regional reliability criteria and/or standards relating to operation of the Transmission Provider in carrying out the functions listed above.

Applicant: An entity desiring to hold FTRs, take Transmission Service, engage in Market Activities or take any other service under this Tariff, or become a Market Participant, Transmission Customer or Coordination Customer under this Tariff.

Application: A request by an Eligible Customer for Transmission Service pursuant to the provisions of this Tariff.

ARR Delivery Point: The ARR Zone or Interface specified in an ARR where Transmission

Service terminates.

ARR Entitlement(s): Right to nominate and be allocated ARR based on transmission usage, upgrades or other basis.

ARR Holder(s): The Market Participant that receives ARRs, or the Transmission Provider to the extent it receives ARRs, through the Annual ARR Allocation.

ARR Obligation: The financial credit or obligation resulting from the difference between the clearing prices from the annual FTR Auction at the ARR Delivery Point and the clearing prices at the ARR Receipt Point.

ARR Receipt Point: The transaction receipt point specified in an ARR.

ARR Settled Exposure: The potential exposure to non-payment associated with ARRs that have been settled.

ARR Stage Factors: The factors that determine the nomination caps in Stage 1A and Stage 1B of the ARR allocation procedure.

ARR Term: The term specified in the ARR.

ARR Transactions Not Yet Settled: The value of the ARRs based on the clearing price(s) established as a result of the most recent annual FTR Auction which have not been settled.

ARR Zone(s): Geographic areas defined for the purpose of allocating ARRs based upon locations where a Market Participant serves Load.

Area Control Error (ACE): The instantaneous difference between Net Actual Interchange and Net Scheduled Interchange, taking into account the effects of frequency bias, including a correction for meter error, expressed in MW.

Asset Owner: An entity identified by a Market Participant through the Transmission Provider

registration process that is eligible to be represented by the Market Participant in Market Activities.

Auction Clearing Price (ACP): The price, expressed in \$/MW-day, associated with the MW quantity that clears in the Planning Resource Auction for a given LRZ or ERZ for the applicable Planning Year.

Auction Revenue Rights (ARR): Entitlements to a share of the revenues generated in the annual FTR Auction.

Authorized Agency: (i) a State public utility commission within the geographic limits of the Transmission Provider Region that regulates the distribution or supply of electricity to retail customers or is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State; (ii) the Organization of MISO States or any successor organization, formed to act as a regional state committee within the Transmission Provider Region; or (iii) a state agency that has both access to documents in the possession of a state public utility commission pursuant to state statute and the ability to protect those documents in accordance with the Non Disclosure Agreement.

Authorized Requestor: A person who has executed a Non Disclosure Agreement, and is authorized by an Authorized Agency to receive and discuss Confidential Information. Authorized Requestors may include State public utility commissioners, State commission staff, attorneys representing an Authorized Agency, and employees, consultants and/or contractors directly employed by an Authorized Agency, provided, however, that consultants or contractors may not initiate requests for Confidential Information from the Transmission Provider or the IMM.

Available Non-FTR Financial Security: For Credit purposes, any Financial Security held in excess of alternative capitalization requirements and Total FTR Obligations and available for securing Non-FTR Potential Exposure.

Available Transfer Capability: The maximum amount of additional Energy that may be carried by the Transmission System or by the transmission systems of Coordination Customers under current or projected operating conditions.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.B, Definitions - B, 37.0.0, A
Record Narrative Name:
Tariff Record ID: 5682
Tariff Record Collation Value: 557910016 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Balancing Authority: The responsible entity that integrates Resource plans ahead of time, maintains Load-generation balance within a Balancing Authority Area and supports the Eastern Interconnection frequency in real time.

Balancing Authority Agreement: The "Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of the TEMT" which was filed October 5, 2004 in Docket Nos. ER04-691-002 and EL02-104-002, as may be amended from time to time, and is designated as FERC Electric Tariff, Rate Schedule No. 3.

Balancing Authority Area: An electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied within the Balancing Authority in order to: (i) match the power output of the Generation Resources within the electric power system(s) and Energy delivered from or to entities outside the electric power system(s), with the demand (including losses) within the electric power system(s); (ii) maintain scheduled Interchange with other Balancing Authority Areas, within the limits of Good Utility

Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and Applicable Reliability Standards.

Base Penalty Charge: A base sanction that is assessed by the Independent Market Monitor against a Market Participant that is found to have engaged in conduct that is not permitted under the Tariff.

Baseline Reliability Projects: Network Upgrades identified in the MTEP as required to ensure the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Entities and applicable to the Transmission Provider's Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria. Baseline Reliability Projects include projects of 100kV voltage class or above needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers.

Baseline Reliability Study: A study performed by the Transmission Provider as part of the MTEP development to determine whether the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Entities and applicable to the Transmission Provider's or Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria, the result of which is the identification of Baseline Reliability Projects.

Baseload Reserved Source Point (RSP): The Baseload Reserved Source Point for use in the ARR allocation process.

Baseload Reserved Source Set (BRSS): The Baseload Supply Resources that have met the

Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone.

Baseload Supply Resource(s): Generation Resource associated with serving a Market Participant's Baseload Usage and that is used for Baseload Reserved Source Point calculations.

Baseload Usage: Transmission usage that is fifty percent (50%) of Peak Usage of Network Load. For Market Participants utilizing Point-To-Point Transmission Service, fifty percent (50%) of the Point-To-Point Transmission Service MW amount will be assumed to be Baseload Usage. However, this assumption will not require an LSE to pay multiple Transmission Service charges for Loads included in the LSE's Baseload Usage.

Behind the Meter Generation (BTMG): Generation resources used to serve wholesale or retail load located behind a CPNode that are not included in the Transmission Provider's Setpoint Instructions and in some cases can also be deliverable to Load located within the Transmission Provider Region using either Network Integration, Point-To-Point Transmission Service or transmission service pursuant to a Grandfathered Agreement. These resources have an obligation to be made available during Emergencies.

Bid: A request to purchase Energy in the Day Ahead Energy and Operating Reserve Market, including Demand Bids, Price Sensitive Demand Bids, and Fixed Interchange Schedule Export Schedules, Dispatchable Interchange Schedule Export Schedules, and Virtual Bids, at a specified location, quantity, and time period, that is duly submitted to the Transmission Provider pursuant to this Tariff and the Business Practices Manuals.

Bi-Directional Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments at which a Generation Resource or Demand Response Resource -

Type II can respond to either increasing or decreasing Setpoint Instructions.

Bilateral Transaction Schedule: A schedule associated with a Bilateral Transaction.

Bilateral Transactions: Interchange Schedules, Dynamic Interchange Schedules, Financial Schedules and GFA Schedules.

Billing Agent: An entity designated by a Market Participant as the entity to receive from, or forward payment to, the Transmission Provider on the Market Participant's Settlement Statements. The Market Participant shall remain liable for all obligations issued to it in the Settlement Statements.

Binding Reserve Zone Constraint: A constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to meet the Reserve Zone's minimum Operating Reserve requirements.

Binding Settlement Zone: Any Reserve Zone with a Market Clearing Price for Regulating Reserve, Spinning Reserve or Supplemental Reserve, as applicable, derived in the Day-Ahead Energy and Operating Reserve Market or in the Real-Time Energy and Operating Reserve Market that has any non-zero Market Clearing Price Zonal Terms for Operating Reserves.

Binding Transmission Constraints: A transmission constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to avoid exceeding, or to relieve, the constraint limit.

Blackstart Equipment: The equipment that is necessary to make a generation unit a Blackstart Unit capable of reliably providing Blackstart Service.

Blackstart Service: The process used by the Transmission Operator, Load Serving Entities, and Generator operators to reenergize to a fully operational state the entire transmission

network and the remainder of the delivery system to normal operation. This process includes systematic start up of Blackstart Units via Blackstart Equipment, energizing transmission to critical facilities such as larger generating units, energizing to the largest generators to facilitate the restoration of system loads.

Blackstart System Restoration Plan: The plan developed by the Transmission Provider acting in its capacity as the Reliability Coordinator, to coordinate the system restoration plans developed by the individual Transmission Operators to re-energize the Transmission System following a system-wide blackout.

Blackstart Unit: A generation unit that has Blackstart Equipment attached to it, which allows the unit to be started without assistance from any other resource.

Blackstart Unit Owner: An entity that either: (1) owns and controls the output of, or operates a Blackstart Unit; or (2) has contractual rights to direct the operation of a Blackstart Unit and to receive the compensation provided for under Schedule 33 of the Tariff.

Border External Resource: An External Resource that: (i) has interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; and (ii) which will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to such substation.

Branch Facility: A facility located within a pricing Zone having a defined Line Outage Distribution Factor.

Broad Constrained Area: An electrical area in which sufficient competition usually exists even with one or more Binding Transmission Constraints or Binding Reserve Zone Constraints, or into which the transmission constraints or reserve constraints bind

infrequently, but within which a Binding Transmission Constraint or Binding Reserve Zone Constraint can result in substantial locational market power under certain market or operating conditions.

Bulk Electric System: The electrical Generation Resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher as further defined by the applicable Regional Entity.

Bundled Load: The aggregate usage by customers who purchase electric services as a single service or customers who purchase electric services under a retail tariff rate schedule that includes Energy and delivery components, as distinguished from customers who purchase Transmission Service as a separate service.

Bus: A specific electrical location within the Transmission System and/or within other transmission systems within the Eastern Interconnection modeled in the Network Model.

Business Day: A day in which the Federal Reserve System is open for business.

Business Practices Manuals: The instructions, rules, policies, procedures and guidelines established by the Transmission Provider for the operation, planning, accounting and settlement requirements of the Transmission Provider Region.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.C, Definitions - C, 56.0.0, A
Record Narrative Name:
Tariff Record ID: 5683
Tariff Record Collation Value: 557911040 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Calculated Demand Response Resource-Type I Output: The hourly average Actual Energy Injection for each associated Demand Response Resource – Type I for the Hour for the purposes of assessing Excessive/Deficient Energy Deployment Charges.

Calculated Demand Response Resource-Type II Output: For a Demand Response

Resource-Type II, the hourly average Actual Energy Injection for the Hour for the purposes of assessing Excessive/Deficient Energy Deployment Charges.

Calendar Day: Any day of the week, including Saturday, Sunday or a Federal holiday.

Candidate ARR (CARR): ARR nominations submitted by Market Participants to be considered throughout the Annual ARR Allocation process.

Candidate Baseload ARR: Candidate ARR rights equal to each Market Participant's Baseload Usage in an ARR Zone.

Candidate Peak ARR: Candidate ARR rights equal to each Market Participant's Peak Usage in an ARR Zone.

Candidate MVP ARR: MPV ARR nominations submitted by the Transmission Provider to be considered during the Annual ARR Allocation process.

Capacity: The instantaneous rate at which Energy can be delivered, received or transferred, including Energy associated with Operating Reserve, Up Ramp Capability, and Down Ramp Capability, measured in MW.

Capacity Deficiency Charge: A charge that is assessed to an LSE that has not demonstrated to the Transmission Provider that it has sufficient Planning Resources to meet its PRMR.

Capacity Export Limit (CEL): The amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ.

Capacity Import Limit (CIL): The amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ.

Capacity Resources: The Generation Resources, Demand Response Resource- Type I, Demand Response Resource-Type II, Dispatchable Intermittent Resources, External Resources,

Intermittent Generation, or Stored Energy Resources – Type II that are available to meet Demand.

Carved Out GFA(s): Any Grandfathered Agreement(s) that the Commission has identified as “carved out” pursuant to Appendix B of the Commission’s September 16, 2004 order, Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,236 (2004) or that meet the criteria in Section 38.8.3(A).b, and set forth in Attachment P to this Tariff, as that Attachment may be amended from time to time.

Cash Collateral Agreement: A Credit Support Document taking the form found in Exhibit III of Attachment L of this Tariff.

Cash Deposit: Cash collateral provided to Transmission Provider to secure Applicant’s and/or Tariff Customer’s performance under the terms and conditions of Transmission Provider’s Tariff, and/or other agreements.

Category A Tariff Customer: A Tariff Customer who grants a continuing first-priority security interest to the Transmission Provider in all right, title and interest in any and all accounts receivable and other rights of payment of the Tariff Customer for goods and services provided under, or otherwise arising under, pursuant to or in connection with, the Tariff and/or any of the Agreements.

Category B Tariff Customer: Any Tariff Customer who does not grant a Receivable Security Interest to the Transmission Provider.

Change in Total System Cost: The net change in variable operational costs, which include fuel, variable O&M, variable environmental costs, and other variable costs as mutually agreed upon by the Transmission Provider and the Market Participant, measured in dollars as a result of changing the output of one or more units in response to a redispatch request

from the Transmission Provider.

Charge: The withdrawal of energy from the Transmission System by a Stored Energy Resource for the purpose of storing the energy for injection back into the Transmission System at a later time.

Coincident Peak Demand: The Demand in MWs, for an LSE and/or EDC, that occurs coincident to the annual peak Demand in the Transmission Provider Region, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

Combined Reliability Systems: The Reliability Coordination Customer Transmission Facilities and all other transmission facilities for which the Transmission Provider performs Reliability Coordination Services under Part I of Module F.

Commercial Model: A presentation of the relationships between Market Participants and their Resources, Commercial Pricing Nodes and the Network Model in the Energy and Operating Reserve Markets.

Commercial Operation Date: Shall have the meaning set forth in Attachment X of this Tariff.

Commercial Pricing Node (CPNode): An Elemental Pricing Node or an Aggregate Price Node in the Commercial Model used to schedule and settle Market Activities. Commercial Pricing Nodes include Resources, Hubs, Load Zones and/or Interfaces.

Commercially Significant Voltage and Local Reliability Issue: Transmission System voltage or other local reliability concerns that result in Voltage and Local Reliability Commitments. These issues are designated for reasons including, but not limited to, occurrence frequency, monetary impact, or other criteria as defined in Schedule 44. A Local Balancing Authority or an interested Market Participant may request that the

Transmission Provider evaluate a Voltage and Local Reliability Issue for designation as commercially significant.

Commission: The Federal Energy Regulatory Commission, also known as FERC, or its successor.

Common Bus: A single Bus to which two or more Resources are connected in an electrically equivalent manner where such Resources are treated as a single Resource for compliance monitoring purposes.

Common Information Model (CIM): The format adopted by the NERC Data Exchange Working Group that will be used by the Congestion Management Customer and the Transmission Provider to exchange Energy Management System models once a year.

Comparable FTRs: FTRs that are identical in all material respects except for the quantity of MW specified.

Competitive Developer Qualification Process: The process utilized to certify Qualified Transmission Developers pursuant to Section VIII.B of Attachment FF of the Tariff.

Competitive Developer Selection Process: The process utilized to solicit Proposals, evaluate Proposals, and designating a Selected Proposal and Selected Developer(s) pursuant to Section VIII of Attachment FF of the Tariff.

Competitive Substation Facility: A transmission substation facility contained within an Eligible Project that is subject to the Competitive Developer Selection Process in accordance with Section VIII.A of Attachment FF of the Tariff.

Competitive Transmission Executive Committee: A committee consisting of three (3) or more executive staff of the Transmission Provider, including at least one (1) officer, that is charged with overseeing all Transmission Provider staff and consultants involved in

evaluating Transmission Developer Applications and Proposals in response to a posted Request for Proposal. The Competitive Transmission Executive Committee will have exclusive and final decision-making authority over: (i) the certification and termination of Qualified Transmission Developers; and (ii) the evaluation and selection of Proposals, resulting in designating Selected Developers. The Competitive Transmission Executive Committee shall possess the specific technical, financial, and regulatory expertise necessary for evaluation of Transmission Developer Applications and Proposals.

Competitive Transmission Facility: A Competitive Substation Facility or Competitive Transmission Line Facility.

Competitive Transmission Line Facility: A transmission line facility contained within an Eligible Project that is subject to the Competitive Developer Selection Process in accordance with Section VIII.A of Attachment FF of the Tariff.

Competitive Transmission Process: The process utilized to certify Qualified Transmission Developers, identify Competitive Transmission Projects, solicit Proposals, evaluate Proposals, and designating a Selected Proposal and Selected Developer(s) pursuant to Section VIII of Attachment FF of the Tariff. The Competitive Transmission Process includes the Competitive Developer Qualification Process and Competitive Developer Selection Process.

Competitive Transmission Project: The Competitive Transmission Facilities contained within an Eligible Project.

Competitively Sensitive Information: Information that is not public and the unauthorized disclosure of which could have anti-competitive effects, provide a competitor with an unfair or improper competitive advantage, or unfairly or improperly result in competitive

harm, detriment, prejudice, disadvantage or injury to the legitimate proprietary rights, business or commercial interests, market position, or ability to bargain freely, of the lawful owners, possessors or users of such information.

Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Composite Credit Score: A composite numerical score scaled from 1.00 to 6.99, representing the sum of the Qualitative and Quantitative score as calculated by the Transmission Provider's credit scoring model in Attachment L of this Tariff.

Confidential Information: Any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Transmission Customer, Market Participant, or other user, which is designated as confidential by the entity supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by the Transmission Provider and is not disclosed except under the terms of a Confidential Information policy.

Congestion Management Customer: Any entity taking Interconnected Operations and Congestion Management Service under Part II of Module F.

Congestion Management Process (CMP): The process described in Attachment LL of the Tariff.

Constraint Contribution Factor: Factor that represents the impact that an incremental Actual Energy Injection or Actual Energy Withdrawal of one MW has on a given Active Transmission Constraint.

Constraint Generation Shift Factor Cutoff: A Generation Shift Factor level defined for each transmission constraint that determines the generating units to be included in a Broad Constrained Area associated with the constraint. Generation Resources with a Generation Shift Factor whose absolute value is greater than the Constraint Generation Shift Factor Cutoff are included in the Broad Constrained Area.

Constraint Management Charge Allocation Factor: A factor that is used to apportion Real-Time Revenue Sufficiency Guarantee Credits in an Hour between (i) the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge and (ii) the Real-Time Revenue Sufficiency Guarantee Day-Ahead Schedule Deviation Charge and the Real-Time Revenue Sufficiency Guarantee Headroom Charge.

Contingency Reserve: Spinning Reserve and Supplemental Reserve provided by Resources available to the Transmission Provider to use in the event of a system contingency as specified in Schedule 5-Spinning Reserve and Schedule 6– Supplemental Reserve of this Tariff.

Contingency Reserve Deployment Failure Charge: A charge assessed to any Resource that fails to achieve in a Contingency Reserve Deployment Period at least one hundred percent (100%) of the Contingency Reserve Deployment Instruction target.

Contingency Reserve Deployment Instruction: An instruction issued by the Transmission Provider to Resources with cleared Contingency Reserve to deploy a specific MW quantity of cleared Contingency Reserve as communicated via Setpoint Instructions or other electronic means.

Contingency Reserve Deployment Period: The period of time the Resource has to deploy Contingency Reserve following the issuance of a Contingency Reserve Deployment

Instruction that is equal to ten minutes.

Contingency Reserve Offer Price Cap: The maximum price permitted for a Spinning Reserve Offer, an On-Line Supplemental Reserve Offer, an Off-Line Supplemental Reserve Offer or a Supplemental Reserve Offer in the Energy and Operating Reserve Markets.

Control: The possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent (10%) or more shall create a rebuttable presumption of Control.

Controllable Devices: Devices that may include phase shifters, DC lines, and back-to-back AC/DC converters.

Coordinated Flowgate: A Flowgate that is subject to the Transmission Provider's or Coordination Customer's operational control and through which flows are affected by transmission over transmission facilities within its operational control, or with respect to which Transmission Provider serves as a Reliability Authority.

Coordinated Transaction Schedule: An Interchange Schedule to purchase Energy in the Real-Time Energy and Operating Reserve Market from a Source Point in either the MISO Balancing Authority Area or PJM Balancing Authority Area and sell it at a Sink Point in the other balancing authority area that is cleared if the forecasted LMP at the Sink Point minus the forecasted LMP at the Source Point is greater than or equal to the dollar value specified in the bid associated with the Interchange Schedule.

Coordinating Owner: Any entity that is not subject to the jurisdiction of the Commission but participating in the ISO through the execution of a coordination agreement which includes provisions for the elimination of rate pancaking. The terms and provisions of a Coordinating Owner's coordination agreement shall supersede the similar terms and

provisions of this Tariff where applicable.

Coordination Customer: Any customer taking Coordination Services from the Transmission Provider pursuant to Module F of the Tariff. The term Coordination Customer includes: Reliability Coordination Customer, and Congestion Management Customer.

Coordination Services: The services provided by the Transmission Provider pursuant to Module F of the Tariff. Coordination Services include Reliability Coordination Service and Interconnected Operations and Congestion Management Service.

Corporate Guaranty: A legal document taking the form found in Exhibit I of Attachment L of this Tariff used by an Affiliate of an Applicant and/or Tariff Customer that guarantees the obligations of such Applicant or Tariff Customer.

Cost Allocation Zone: The zones identified in Attachment WW of this Tariff used for allocating the costs of Market Efficiency Projects.

Cost of Congestion: The Marginal Congestion Component of LMP at the sink minus the Marginal Congestion Component of LMP at the source.

Cost of Losses: Marginal Losses Component of LMP at the sink minus the Marginal Losses Component of LMP at the source.

Cost of New Entry (CONE): The capital, operating, financial and other costs of acquiring a new Generation Resource within the Transmission Provider Region for any designated LRZ.

Counterflow ARR: ARR allocated during the LTTR Restoration and Termination Stage of an Annual ARR Allocation based on a Counterflow ARR Entitlement.

Counterflow ARR Entitlement: Any Stage 1A eligible ARR Entitlement's portion that was not nominated in Stage 1A of a Market Participant's year 1 Annual ARR Allocation but that

the Transmission Provider deems to provide counterflow necessary to enable curtailed Stage 1A CARRs to be restored (fully or partly) during the LTTR Restoration and Termination Stage of an Annual ARR Allocation.

Credit and Security Agreement: A Credit Support Document taking the form found in Exhibit V of Attachment L of this Tariff.

Credit Policy: The Transmission Provider's creditworthiness requirements and credit evaluation procedures as contained in Attachment L of this Tariff.

Credit Support Documents: Any agreement or instrument in any way guaranteeing or securing any or all of a Tariff Customer's obligations under this Tariff (including, without limitation, the Credit Policy), any agreement entered into under, pursuant to, or in connection with this Tariff or any agreement entered into under, pursuant to, or in connection with this Tariff or the Credit Policy, and/or any other agreement to which the Transmission Provider and the Tariff Customer are parties, including, without limitation, any Corporate Guaranty, Cash Collateral Agreement, Letter of Credit, Credit and Security Agreement or agreement granting a security interest.

Critical Energy Infrastructure Information (CEII): Confidential information described in 18 C.F.R § 388.113(c)(1), as may be amended from time to time.

Curtailement: A reduction in firm or non-firm Transmission Service in response to a transfer capability shortage as a result of system reliability conditions pursuant to Section 14.7 or Section 27A of this Tariff.

Customer Load Aggregation: A Load Zone approved by the Transmission Provider for the purposes of submitting Bids to or scheduling into the Energy and Operating Reserve Markets and for settlement of Market Activities.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

1.E, Definitions - E, 61.0.0, A
Record Narrative Name:
Tariff Record ID: 5685
Tariff Record Collation Value: 557913088 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Eastern Interconnection: The ERO certified Balancing Authorities operating in the eastern part of North America.

Eastern Prevailing Time (EPT): Eastern Daylight Time during periods when the eastern time zone is observing daylight saving time, Eastern Standard Time during periods when the eastern time zone is observing standard time.

Economic Maximum Dispatch: The maximum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Maximum Dispatch will equal the Actual Energy Injections.

Economic Minimum Dispatch: The minimum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Minimum Dispatch will equal the Actual Energy Injections.

Effective Import Tie Capability (EITC): The maximum aggregate level of power in MW that can be reasonably expected to flow on the transmission tie lines into a specified Zone of the Transmission System, while maintaining reliable operation.

Effective Export Tie Capability (EETC): The maximum aggregate level of power in MW that can be reasonably expected to flow outward on the transmission tie lines of a specified Zone of the Transmission System, while maintaining reliable operation.

Electric Distribution Company (EDC): A company that distributes electricity to retail

customers through distribution substations and/or lines owned by the company.

Electric Facility: Equipment used for the generation, transmission, storage, or control of the transmission of electricity and that is connected to or part of the Transmission System operated by the Transmission Provider.

Electric Generation and Transmission Cooperative (Coop): An electric Generation and Transmission cooperative is a not for profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners.

Electric Reliability Organization (ERO): The organization certified by the Commission to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

Elemental Pricing Node (EPNode): A single Bus where LMP is calculated.

Eligible Confirmed Transmission Service Reservation: Any reservation for Transmission Service that has been confirmed and has a start date later than the date a Default first occurs. Any reservation for Transmission Service that has been confirmed remains a conditionally approved request at all times prior to such reservation's start date and may be cancelled if a Default occurs prior to such start date.

Eligible Customer: (i) Any electric utility (including the Transmission Owner(s), ITC Participants(s), and any power marketer), Market Participant, Federal Power Marketing Agency, or any person generating electric Energy for sale or for resale is an Eligible Customer under this Tariff. Electric Energy sold or produced by such entity may be electric Energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by § 212(h) of the Federal Power Act, such entity is eligible only if the service is provided

pursuant to a state requirement that a Transmission Owner or ITC Participant offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant; or (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that a Transmission Owner or ITC Participant offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant, that is an Eligible Customer under this Tariff. Unbundled retail customers that seek to take local distribution service cannot be Eligible Customers under this Tariff with respect to that service.

Eligible Projects: Shall mean any Market Efficiency Projects (“MEP”) and Multi-Value Projects (“MVP”) approved by the Transmission Provider’s Board after December 1, 2015 regardless of whether such project is subject to the Transmission Provider’s Competitive Developer Selection Process.

Emergency: (i) An abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of Emergency procedures as defined in this Tariff.

Emergency Demand Response (EDR): The commitment and dispatch of Load reductions, Behind the Meter Generation Resources and other Demand Resources during an Emergency, in accordance with Schedule 30.

EDR Dispatch Instruction: Directives issued by the Transmission Provider to EDR Participants indicating MW quantities to be reduced during Emergencies.

EDR Initiative: Procedures for EDR Participants to respond to an Emergency through a defined reduction in Load or increase in output from Behind the Meter Generation Resources, as described in Schedule 30 of this Tariff.

EDR Offer: An offer made by an EDR Participant to reduce demand in response to an Emergency event which will not be considered in the clearing of the Day-Ahead Energy and Operating Reserve Market or Real-Time Energy and Operating Reserve Markets.

EDR Participant: A Market Participant capable of reducing demand in response to directives received from the Transmission Provider during an Emergency event.

Emergency Energy: Purchases of Energy coordinated by the Transmission Provider following the issuance of an Energy Emergency Alert in accordance with the procedure set forth in Section 40.2.22 of this Tariff.

Emergency System Conditions: Are (i) situations in which a systemic equipment malfunction, including telecommunications, hardware, or software failures, prevents the Transmission Provider from operating the Energy and Operating Reserve Markets in accordance with the Market Rules; or (ii) widespread electric transmission or generation equipment outages that prevent the Transmission Provider from dispatching the system in accordance with the Market Rules.

Emergency Tier I Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency warning as specified in the Transmission Provider's Emergency operating procedures.

Emergency Tier II Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation

emergency event, step 2 as specified in the Transmission Provider's Emergency operating procedures.

Energy: An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold or transmitted over a period of time and measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Market(s): The Day Ahead and/or Real Time Energy and Operating Reserve Markets operated by the Transmission Provider.

Energy Consumer: Any end-use customer, including but not limited to commercial retail consumers of electricity, located within the Transmission Provider Region.

Energy Deficient Region: An area in which one or more LSEs within the MISO Balancing Authority Area are experiencing or are expected to experience an Emergency under the procedures specified under Section 40.2.20 of this Tariff.

Energy Efficiency Resource (EE Resource): A Planning Resource consisting of installed measures on retail customer facilities that achieves a permanent reduction in electric energy usage while maintaining a comparable quality of service.

Energy Emergency: A condition when a balancing authority can no longer meet the energy requirements of the firm end-use load within its balancing authority area and has initiated its Energy Emergency procedures.

Energy Emergency Alert: An alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area.

Energy Emergency Area: The area within a balancing authority area that is experiencing an

Energy Emergency.

Energy Emergency Alert Level 2 (EEA2): Energy Emergency Alert Level 2 as defined by NERC.

Energy Management System (EMS): The software system used by the Transmission Provider and Transmission Operators for acquisition and processing of operational data.

Energy Market Counterparty: The Transmission Provider as the contracting counterparty to Market Participants for all Market Activities contemplated by this Tariff, solely in the Transmission Provider's capacity as a principal and not as an agent for any other party, consistent with the provisions of Section 6A.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource.

Energy Offer Price Cap: The maximum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Offer Price Floor: The minimum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Resource Interconnection Service: The interconnection of a Generation Resource to the Transmission System or distribution system, as applicable, to be eligible to deliver the Generation Resource's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis.

EPT: Eastern Prevailing Time.

Equity: For credit scoring purposes, the ownership interest in a firm, including the residual dollar value of a futures trading account, assuming its liquidation is at the going trade price of Applicant or Market Participant.

Equivalent Forced Outage Rate Demand (EFORD): The Equivalent Forced Outage Rate Demand, as defined by NERC.

EST: Eastern Standard Time.

Ex Ante MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, and Down Ramp Capability MCP calculated at the beginning of the Dispatch Interval, used for informational purposes in the Real-Time Energy and Operating Reserve Market.

Ex Post MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, and Down Ramp Capability MCP calculated for each Dispatch Interval.

Excess Congestion Charge Fund: A fund established by the Transmission Provider representing, in aggregate, the difference between the total of all Transmission Congestion Payments for a given Hour and the hourly transmission congestion charges.

Excessive/Deficient Charge Rate: The rate used to determine a Resource's Excessive/Deficient Energy Deployment Charge as calculated pursuant to Section 40.3.4.b.

Excessive/Deficient Energy Deployment Charge: A charge assessed to any Resource in an Hour with Excessive Energy and/or Deficient Energy in four (4) or more consecutive Dispatch Intervals within the Hour.

Excessive Energy: The amount of a Generation Resource's, Stored Energy Resource's or

External Asynchronous Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold or, the amount of a Demand Response Resource's Type I Calculated DRR Type I Output, as adjusted for Actual Energy Injection or Demand Response Resource's Type II Calculated DRR Type II Output, as adjusted for Actual Energy Injection at a Commercial Pricing Node in the Real Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold.

Excessive Energy Price: The price used to calculate a Market Participant's credit for Excessive Energy that is equal to the Energy Offer price associated with a Generation Resource's, Demand Response Resource's – Type I, Demand Response Resource's – Type II or External Asynchronous Resource's Excessive Energy.

Excessive Energy Threshold: The maximum value of a Resource's Tolerance Band.

Export Schedule: An Interchange Schedule in which the Interchange Schedule Receipt Point lies within the MISO Balancing Authority Area and the Interchange Schedule Delivery Point lies outside the MISO Balancing Authority Area.

Exporting Entity: A Market Participant that is not a Load Serving Entity with a cleared Export Schedule in the Day-Ahead Energy and Operating Reserve Market or an Export Schedule in the Real-Time Energy and Operating Reserve Market.

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 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.

Extended Transmission Outage: A Planned Transmission Outage that exceeds the original outage schedule previously provided by the Transmission Owner to the Transmission Provider.

External Asynchronous Resource: A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

External Resource: A generator located outside of the metered boundaries of the MISO Balancing Authority Area.

External Resource Zone (ERZ): A grouping of one or more External Resources in the same external balancing authority for purposes of the Planning Resource Auction.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.G, Definitions - G, 38.0.0, A
Record Narrative Name:
Tariff Record ID: 5687
Tariff Record Collation Value: 557915136 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

GAAP: Generally Accepted Accounting Principles.

Generation Interconnection Projects: New Transmission Access Projects associated with the interconnection of or increase in generating Capacity of Generation Resources pursuant to Attachment R and Attachment X of this Tariff.

Generation Offer: An Energy Offer, Start-Up Offer, No-Load Offer, Regulating Capacity Offer and Regulating Mileage Offer (if a Regulation Qualified Resource), Spinning Reserve Offer (if a Spin Qualified Resource), On Line Supplemental Reserve Offer (if not a Spin Qualified Resource), Off Line Supplemental Reserve Offer (if a Quick Start Resource), and Up and Down Ramp Capability dispatch status submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Generation Resource to supply Energy, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability to the Energy and Operating Reserve Market.

Generation Owner: An entity that owns, leases with rights equivalent to ownership in, and controls the output of or operates Generation Resources.

Generation Outage: A forced or planned outage of Generation Resources.

Generation Resource: A Generation Resource is a Generator within the MISO Balancing Authority Area or an External Resource that is Pseudo-tied into the MISO Balancing Authority Area and that (i) is registered to participate in the Energy and Operating Reserve Markets, (ii) is capable of supplying Energy, Capacity, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability, (iii) is capable of complying with the Transmission Provider's Setpoint Instructions and (iv) has the appropriate metering equipment installed.

Generation Shift Factors: Ratios equal to the incremental increase or decrease in flow on a flowgate divided by an incremental increase or decrease in a Generation Resource's output.

Generation Verification Test Capacity (GVTC): The maximum output (MW) that a Generation Resource, External Resource or BTMG can sustain over the specified period of time, if

there are no equipment, operating, or regulatory restrictions, minus any Capacity utilized for On-Site Self-Supply, as detailed in the Business Practices Manual for Resource Adequacy.

Generator: Any generating facility subject to the Transmission Provider's direction hereunder pursuant to either the Operating Protocol for Existing Generators, an IOA or an LGIA.

Generator Forced Outage: An immediate reduction in output, Capacity or removal from service, in whole or in part, of a Generation Resource by reason of an Emergency or threatened Emergency, unanticipated failure, inability to return on schedule from a Planned Transmission Outage, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the Business Practices Manuals. A reduction in output or removal from service of a Generation Resource in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Interconnection Agreement (GIA): The form of interconnection agreement provided in Appendix 6 of Attachment X to the Tariff.

Generator Planned Outage: The scheduled removal from service, in whole or in part, of a Generation Resource for inspection, maintenance or repair with the approval of the Transmission Provider in accordance with the Business Practices Manuals.

Generator Self Supply: For any given period of time, the total Energy taken out of the Transmission System by the Loads designated as Self-Supply by a Market Participant which is a Generation Owner up to an amount equal to the total Energy placed into the Transmission System by the Generators designated as Self-Supply by the same Market Participant and owned by it.

GFA Schedule Delivery Point: The location where a GFA Schedule sinks.

GFA Schedule Receipt Point: The location where a GFA Schedule sources.

Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governmental Authority: Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Transmission Provider.

Grandfathered Agreement(s) (GFA): An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under this Tariff.

Grandfathered Agreement (GFA) Schedule: A Schedule associated with a Grandfathered Agreement.

Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling Transmission Service or Energy transactions related to Grandfathered Agreements under this Tariff.

Guarantor: A guarantor under a Corporate Guaranty.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.H, Definitions - H, 45.0.0, A
Record Narrative Name:
Tariff Record ID: 5688
Tariff Record Collation Value: 557916160 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Headroom: For all Resources committed by the Transmission Provider in any real-time RAC processes or the LAC process conducted for the Operating Day, the difference between (i) the real-time Economic Maximum Dispatch and (ii) the sum of the Real-Time (a) Dispatch Target for Energy, (b) Dispatch Target for Regulating Reserve, (c) Dispatch Target for Spinning Reserve, and (d) Dispatch Target for Supplemental Reserve.

High Utilization Factor Unit (HUFU) Reserved Source Point (RSP): An RSP that does not qualify for inclusion in the BRSS per section 43.2.4.a.i.(b) but has a RSP Utilization Factor of seventy percent (70%) or greater.

Historic Unit Consideration: A right to receive excess Planning Resource Auction revenue based on qualification described in Section 69A.7.7(a).

Hour: A sixty (60) minute clock hour interval commencing the first second of each clock hour.

Hot-to-Cold Time: The number of hours that must elapse between the time a Generation Resource or Demand Response Resource – Type II is desynchronized and the time at

which a cold Start-Up Offer would apply.

Hot-to-Intermediate Time: The number of hours that must elapse between the time a Generation Resource or Demand Response Resource – Type II is desynchronized and the time at which an intermediate Start-Up Offer would apply.

Hourly Bi-Directional Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource, Demand Response Resource - Type II, or Stored Energy Resource can respond to either increasing or decreasing Setpoint Instructions that may be submitted to override the default value submitted during the asset registration process.

Hourly Curtailment Offer: The compensation request, in dollars per Hour, in a Demand Response Resource-Type I Offer by a Market Participant representing the fees required for operating a Demand Response Resource Type I in an interrupted state.

Hourly Economic Maximum Limit: The maximum MW level at which a Generation Resource, Demand Response Resource Type II or External Asynchronous Resource may operate under normal system conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Economic Minimum Limit: The minimum MW level at which a Generation Resource or Demand Response Resource Type II or External Asynchronous Resource may operate under normal system conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Emergency Maximum Limit: The maximum MW level at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource Type II may operate under Emergency conditions that may be submitted to override the default

value submitted during the asset registration process.

Hourly Emergency Minimum Limit: The minimum MW level at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource Type II may operate under Emergency conditions that may be submitted to override the default value submitted during the asset registration process.

Hourly Energy Storage Loss Rate: The rate at which energy is consumed over a one-minute time period to maintain a Stored Energy Resource at its maximum energy storage level assuming no Regulating Reserve deployments, expressed in MWh/min.

Hourly Excessive Energy Price: The weighted average of the Dispatch Interval Energy Offer Price where the weighting factors are determined by normalizing the Excessive Energy in each Dispatch Interval in the Hour. The Dispatch Interval Energy Offer Price is the Energy Offer price at the Dispatch Target for Energy.

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

Hourly Full Charge Energy Withdrawal Rate: The rate at which additional energy can be consumed by a Stored Energy Resource over a one minute time period while at its Maximum Energy Storage Level, expressed in MWh/min.

Hourly Integrated Forecast Maximum Limit: The hourly integration of the Forecast Maximum Limits of a Dispatchable Intermittent Resource as used by the SCED

algorithm in the Real-Time Energy and Operating Reserve Market for a given Hour.

Hourly Maximum Energy Charge Rate: The maximum rate at which a Stored Energy Resource may be Charged, expressed in MWh per Minute, that may be submitted to override the default value submitted during the asset registration process.

Hourly Maximum Energy Discharge Rate: The maximum rate at which a Stored Energy Resource may be Discharged, expressed in MWh per Minute, that may be submitted to override the default value submitted during the asset registration process.

Hourly Maximum Energy Storage Level: The maximum amount of Energy that may be stored by a Stored Energy Resource on a sustained basis, expressed in MWh, that may be submitted to override the default value submitted during the asset registration process.

Hourly Ramp Rate: The MW/minute response rate for a Generation Resource, External Asynchronous Resource, Demand Response Resource Type-II, or Stored Energy Resource that is utilized in the clearing of the Day-Ahead Energy and Operating Reserve Market and all Reliability Assessment Commitment processes that may be submitted to override the default value submitted during the asset registration process.

Hourly Real-Time Ex Post LMP: 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.

Hourly Real-Time Ex Post MCP: The average MCPs for Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, and Down Ramp Capability 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, Up Ramp Capability, and Down Ramp Capability in the Real-Time Energy and Operating Reserve Market.

Hourly Regulation Maximum Limit: The maximum MW output at which a Generation Resource, Demand Response Resource – Type II, External Asynchronous Resource, or Stored Energy Resource can respond to automatic control signals that may be submitted to override the default value submitted during the asset registration process.

Hourly Regulation Minimum Limit: The minimum MW output at which a Generation Resource, Demand Response Resource–Type II, External Asynchronous Resource, or Stored Energy Resource can respond to automatic control signals that may be submitted to override the default value submitted during the asset registration process.

Hourly Single-Directional-Down Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the downward direction only that may be submitted to override the default value submitted during the asset registration process.

Hourly Single-Directional-Up Ramp Rate: The MW/minute rate at which a Generation Resource, an External Asynchronous Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the upward direction only that may be submitted to override the default value submitted during the asset registration process.

Hourly Transmission Congestion Charges Collection: The aggregate amount of Transmission Usage Charge collected in a given Hour.

Hub: A Commercial Pricing Node developed for financial and trading purposes.

HUFU ARR: An ARR allocated during the LTTR Restoration and Termination Stage of an Annual ARR Allocation from a HUFU ARR Entitlement.

HUFU ARR Entitlement: An ARR Entitlement defined from a HUFU RSP to the applicable ARR Zone. The MW amount of a HUFU ARR Entitlement is calculated, and corresponds to, the RSP MW at a fifty percent (50%) implied capacity factor. A HUFU ARR Entitlement is calculated as follows:

HUFU MW Level = (total net generation MWh in the test period) / (50% x Total Hours in the test period).

Hub LMP: The weighted-averaged LMP for an invariant set of Elemental Pricing Nodes that comprise the Hub. The weights are static over time, except for those of Elemental Pricing Nodes constituting ARR Zones administered as Hub Commercial Pricing Nodes. The weights, or weighting factors, for determining ARR Zone LMPs are updated daily based on State Estimator information.

High-Voltage Direct Current Facilities: The high voltage direct current transmission facilities, including associated alternating current facilities, if any, that are subject to Section 27A of this Tariff and that are specifically identified in: (i) any Agency Agreement pertaining to such facilities between the Transmission Provider and the Transmission Owner that owns or operates such facilities, or (ii) in any other contractual arrangement that permits the Transmission Provider to provide HVDC Service over such facilities, as set forth in Section 27A of this Tariff.

High-Voltage Direct Current Facility Upgrades: All or portion of the modifications or additions to any HVDC Facilities for the general benefit of all Users of such HVDC Facilities.

High-Voltage Direct Current Service: Firm and Non-Firm Point-to-Point Transmission Service provided by the Transmission Provider on HVDC Facilities pursuant to Section

27A of this Tariff.

High-Voltage Direct Current Service Agreement: Any executed or unexecuted agreement for HVDC Service, as reflected in Attachment A-3, A-4, and B-1 of this Tariff.

High-Voltage Direct Current Service Charge(s): The charge(s) for HVDC Service, as stated in the relevant HVDC Service Agreement.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.P, Definitions - P, 54.0.0, A
Record Narrative Name:
Tariff Record ID: 5696
Tariff Record Collation Value: 557924352 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Partial-Year FTR Allocation: The procedure used by the Transmission Provider to allocate FTRs to Market Participants in the new ARR Zones added as a result of Transmission Provider Region expansion that becomes effective after the start of the Annual ARR Allocation period. The Partial-Year FTR Allocation will cover the partial year period when the new ARR Zone(s) become effective to the start of the next Annual ARR Allocation. For the partial year period, the Market Participants in the new ARR Zone(s) may request an allocation of FTRs, which will be in lieu of an allocation of ARRs.

Party(ies): The Transmission Provider, ITC where appropriate, Market Participants, Transmission Customers, or any combination of the above.

Past Due Amount: Any amount invoiced by the Transmission Provider that is not paid when due.

Peak Reserved Source Set: Set of Resources including those constituting the Baseload Reserved Source Point that have met the Resource Qualification Requirements for inclusion as a Reserved Source Point for a given ARR Zone.

Peak Usage: A Market Participant's Total Forecasted Peak Load in a given ARR Zone for the

upcoming Annual ARR Allocation period calculated using the immediate prior three year actual peak Loads. The Total Forecast Peak Load is the sum of the forecast Network Integration Transmission Service peak Load for the upcoming allocation period plus peak Load served by Option A – Grandfathered Agreements plus peak Load served by Option B – Grandfathered Agreements.

Penalty Level: A component of a mitigation measure described in Module D that represents the amount of Energy purchased by a Market Participant that is an LSE or represents an LSE in the Real Time Energy Market in excess of the Allowance Level the entity is subject to.

Physical Withholding Threshold Quantity: Threshold employed by the IMM to identify physical withholding by a supplier of Planning Resources for the Planning Resource Auction, expressed in MW.

Plan: The Transmission Provider's Market Monitoring Plan set forth in Module D of this Tariff.

Planned Transmission Outage: Any transmission outage scheduled for the performance of maintenance or repairs or the implementation of a system enhancement which is planned in advance for pre-determined duration and which meets the notification requirements for such outages as specified by the Transmission Provider.

Planning Advisory Committee: A committee of stakeholders established under the ISO Agreement for the purpose of providing input to the planning staff on the development of the MTEP.

Planning Area(s): A collective or alternative reference to the First Planning Area and/or the Second Planning Area.

Planning Coordinator: The entity responsible for the longer term reliability of its planning

coordinator area.

Planning Reserve Margin (PRM): The percentage above forecasted Coincident Peak Demand of Planning Resources for the Transmission Provider Region in order to meet the LOLE. This percentage will include a quantity sufficient to cover transmission losses.

Planning Reserve Margin Requirement (PRMR): The amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements.

Planning Resource: A Capacity Resource, Energy Efficiency Resource, or Load Modifying Resource that can be used to satisfy PRMR.

Planning Resource Auction (PRA): An annual auction that is conducted by the Transmission Provider to determine the ACP and the cleared ZRC Offers for each LRZ and ERZ for the applicable Planning Year.

Planning Year: The period of time from June 1st of one year to May 31st of the following year that is used for developing Resource Plans. The first Planning Year shall commence on June 1, 2009.

PMAX: The maximum Generator real power output reported in MWs on a seasonal basis.

PMIN: The minimum Generator real power output reported in MWs on a seasonal basis.

Point(s) of Delivery: Point(s) on the Transmission System where Capacity and Energy transmitted by the Transmission Provider will be made available to the Receiving Party under Module B and Module C of this Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long Term Firm Point To Point Transmission Service or the HVDC Service Agreement.

Point(s) of Receipt: Point(s) of interconnection on the Transmission System where Capacity

and Energy will be made available to the Transmission Provider by the Delivering Party under Module B and Module C of this Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long Term Firm Point To Point Transmission Service or the HVDC Service Agreement.

Point-To-Point Transmission Service: The reservation of Capacity and of Energy on either a firm or non firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Module B of this Tariff.

Portfolio: For Multi-Value Project purposes, means two or more Multi-Value Projects proposed to be located in one or more Transmission Pricing Zones that, when evaluated together, are expected to result in regional benefits.

Power Purchaser: The entity that is purchasing the Capacity and reserved Energy to be transmitted under this Tariff.

PPA Schedule: Schedule associated with a PPA that is executed after April 3, 2014.

Pre-Confirmed Application: An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Price Sensitive Demand Bids: Demand Bids in which the Market Participant specifies a maximum price (dollars per MWh) at which the Market Participant desires to purchase the designated MWh of Energy.

Price Taker: A Market Participant with an Energy and/or Operating Reserve Offer not capable of setting LMPs or MCPs.

Production Costs: The Energy output cost of a Generation Resource or a Demand Response Resource-Type II based upon Start Up, No Load and Energy Offer cost components set forth in an Offer or the Energy reduction cost of a Demand Response Resource-Type I

based upon Shut Down Offer, Hourly Curtailment Offer and Energy Offer cost components set forth in an Offer.

Project Cost: All costs for Network Upgrades, as determined by the Transmission Provider to be a single transmission expansion project, including those costs associated with seeking and obtaining all necessary approvals for the design, engineering, construction, and testing of the Network Upgrades. These Network Upgrades will include costs classified by the Transmission Owners and Independent Transmission Companies as transmission plant using the Uniform System of Accounts 350 through 359 or equivalent set of accounts for any Coordinating Owner.

Project Financial Security: The Cash Deposit or Irrevocable Letter of Credit described in Appendix 1 to Attachment FF of the Tariff that a Selected Developer is required to provide.

Proposal: A proposal to construct, implement, own, operate, maintain, repair, and restore all Competitive Transmission Facilities associated with a Competitive Transmission Project, in response to a Request for Proposal. Proposals may be submitted in one of two different forms: (i) a Single-Developer Proposal; or (ii) a Joint-Developer Proposal. The term "Proposal" shall include "Single-Developer Proposal" and "Joint-Developer Proposal".

Proposal Cure Period: A period of time, equal to ten (10) Business Days, allowed for a RFP Respondent to correct deficiencies identified by the Transmission Provider in a previously submitted Proposal. The Cure Period commences upon notification by the Transmission Provider of deficiencies in the Proposal.

Proposal Participant(s): Any entity or entities involved in a Proposal, excluding the RFP Respondent(s), that will co-own the Competitive Transmission Project and rely on the

RFP Respondent(s) to be the Selected Developer(s) responsible for constructing and implementing the Competitive Transmission Facilities associated with the Competitive Transmission Project. Proposal Participants may be identified in a Proposal as responsible for one or more aspects of operations, maintenance, repair, or restoration, on terms comparable to those that would apply if the RFP Respondent(s) intended to rely on a third-party contractor.

Proposal Submission Deadline: The date and time Proposals must be submitted to the Transmission Provider by in order to be considered and evaluated by the Transmission Provider. The Submission Deadline shall be no later than 5:00 PM EPT on the date specified in the RFP, which shall not exceed one hundred and eighty (180) Calendar Days from the date the RFP was issued by the Transmission Provider, unless such date falls on a Saturday, Sunday, or MISO observed holiday in which case the Proposal Submission Deadline shall be the next Business Day that is not a MISO observed holiday.

Proposed Generator Planned Outage: The planned removal from service, in whole or in part, of a Generation Resource for inspection, maintenance or repair for which the Generation Owner has sought or will seek approval from the Transmission Provider for such planned removal in accordance with the Business Practices Manuals.

Protected Information: Privileged and non public information to be maintained by the Transmission Provider.

Proxy Offers: The Offers created for resources that are deployed during Emergency operating procedures by the Transmission Provider as specified in Schedule 29A.

Pseudo tie: A telemetered reading or value that is updated in real time and used as a tie line flow in the Area Control Error equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange

accounting purposes. Pseudo tied status of Resources and Loads may only be changed during Network Model updates and the timing of such updates shall be as defined in the Business Practices Manuals.

Public Power: For credit scoring purposes, an Applicant or Market Participant that is a not for profit municipality, cooperative, Joint Action Agency, or agent representing one or more Public Power entities and whose credit quality is directly derived from the credit quality of the Public Power entities represented through the agency relationship.

Public Power Composite Score: For credit scoring purposes, the weighted average value of the Public Power Qualitative Score and the Public Power Quantitative Score. The relative weights are sixty percent (60%) and forty percent (40%).

Public Power Qualitative Score: A component of a Public Power Composite Score which has, for credit scoring purposes, a value ranging from 1 to 6.99, with 1 being the best and 6.99 being the worst. The value is based on a review by the Transmission Provider of qualitative factors relative to an Applicant's business, including but not limited to: i) regulatory; ii) legal; iii) demographic; and iv) energy supply/price factors as provided in Attachment L to this Tariff.

Public Power Quantitative Score: A component of a Public Power Composite Score which has, for credit scoring purposes, a value ranging from 1 to 6.99, with 1 being the best and 6.99 being the worst. The value is based on a review by the Transmission Provider of various financial metrics as detailed in the Transmission Provider's credit scoring model in Attachment L.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.Z, Definitions - Z, 33.0.0, A
Record Narrative Name:
Tariff Record ID: 5706
Tariff Record Collation Value: 557934592 Tariff Record Parent Identifier: 2261
Proposed Date: 2018-05-30
Priority Order: 1000000000

Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Zonal Deliverability Charge (ZDC): A positive charge per ZRC associated with ZRCs in a FRAP that may be assessed to an LSE based upon the congestion contribution to the constraints between LRZs or ERZs of any ZRCs that are located outside of the LRZ where the LSE has Load.

ZDC Hedge: The mechanism that permits an LSE to avoid Zonal Deliverability Charge assessments through the investment in new or upgraded Transmission System facilities which are a result of approved firm transmission service requests where the LSE's Planning Resource and the LSE's Demand are in separate LRZs or the Planning Resource is located in an ERZ.

Zonal Contingency Reserve Requirement: The minimum amount of Contingency Reserve the Transmission Provider shall procure within a Reserve Zone as determined based upon Reserve Zone Studies.

Zonal Export Ability: The ability of an LRZ to export capacity to areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to export generation.

Zonal Import Ability: The ability of an LRZ to import capacity from areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to import generation.

Zonal Operating Reserve: Operating Reserve that is available on a Reserve Zone basis.

Zonal Operating Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is used to calculate the Shadow Price of a particular Operating Reserve requirement constraint when there is a shortage of Operating Reserve cleared on a

Reserve Zone basis.

Zonal Operating Reserve Requirement: The sum of the Zonal Contingency Reserve Requirement and Zonal Regulating Reserve Requirement.

Zonal Regulating Reserve: Regulating Reserve that is available on a Reserve Zone basis.

Zonal Regulating and Spinning Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is utilized to calculate the Zonal Regulating and Spinning Reserve constraint Shadow Price when there is a shortage of the Zonal Regulating and Spinning Reserve cleared.

Zonal Regulating Reserve and Spinning Reserve Requirement: The amount of Zonal Regulating and Spinning Reserve the Transmission Provider is required to procure on a Transmission Provider Region-wide basis in accordance with Applicable Reliability Standards.

Zonal Regulating Reserve Demand Curve: A series of quantity/price points as defined in Schedule 28 that is utilized to calculate the Shadow Price of the Regulating Reserve requirement constraint when there is a shortage of Regulating Reserve cleared on a Reserve Zone basis.

Zonal Regulating Reserve Requirement: The minimum amount of Regulating Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based upon Reserve Zone Studies.

Zonal Resource Credit (ZRC): A MW unit of Planning Resource which has been converted from a MW of Unforced Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and/or to be submitted through a Fixed Resource Adequacy Plan.

ZRC Offer: An offer into the PRA of ZRCs by a Market Participant.

Zonal Spinning Reserve Requirement: The minimum amount of Spinning Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based on a percentage of the Zonal Contingency Reserve Requirements where such a percentage adheres to Applicable Reliability Standards.

Zonal Supplemental Reserve Requirement: The minimum amount of Supplemental Reserve the Transmission Provider needs to procure within a Reserve Zone as determined based upon Zonal Contingency Reserve Requirement and Zonal Spinning Reserve Requirement from Reserve Zone Studies.

Zone: A set of Buses in a geographic area as determined by the Transmission Provider.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
68A, INTRODUCTION, 32.0.0, A
Record Narrative Name:
Tariff Record ID: 4986
Tariff Record Collation Value: 656408576 Tariff Record Parent Identifier: 4985
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over

entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing External Resource Zones and associated limits (*i.e.*, Capacity Export Limits (CEL)); determining the annual Planning Reserve Margin; annual Coincident Peak Demand forecasting; annual Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource Auction process; settlement provisions; and Planning Resource performance requirements.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

68A.3, Establishment of LRZs and ERZs, 32.0.0, A

Record Narrative Name:

Tariff Record ID: 4991

Tariff Record Collation Value: 656867328 Tariff Record Parent Identifier: 4986

Proposed Date: 2018-05-30

Priority Order: 1000000000

Record Change Type: CHANGE

Record Content Type: 1

Associated Filing Identifier:

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of

LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those with only Coordinating Owner and/or Border External Resources.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
68A.4, Establishment of CIL and CEL Limits, 38.0.0, A
Record Narrative Name:
Tariff Record ID: 4992
Tariff Record Collation Value: 657063936 Tariff Record Parent Identifier: 4986
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF. CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO

load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
68A.5, Establishment of Local Reliability Requirement, 34.0.0, A
Record Narrative Name:
Tariff Record ID: 4993
Tariff Record Collation Value: 657260544 Tariff Record Parent Identifier: 4986
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed such that the LRZ would achieve an LOLE of 0.1 day per year, without consideration of the benefit of the LRZ's CIL. The LRR will be determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

The Transmission Provider will model the location of Load and Planning Resources based on

their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak Demand as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
68A.6, Establishment of Local Clearing Requirement, 34.0.0, A
Record Narrative Name:
Tariff Record ID: 4994
Tariff Record Collation Value: 657457152 Tariff Record Parent Identifier: 4986
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Establishment of Local Clearing Requirement

The Transmission Provider will establish the Local Clearing Requirement for each LRZ as $LCR = LRR - \text{Zonal Import Ability} - \text{controllable exports}$, where controllable exports are: (i) from MISO resources that have firm capacity commitments to non-MISO load; and (ii) may be committed and dispatched by the Transmission Provider during a declared Energy Emergency.

The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A, RAR Process, 34.0.0, A
Record Narrative Name:
Tariff Record ID: 4996
Tariff Record Collation Value: 662700032 Tariff Record Parent Identifier: 4985
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, an annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data to be used by the Transmission Provider as described herein. The Transmission Provider will then calculate each LSE's PRMR. LSEs will meet their PRMR by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; and/or (iv) paying the Capacity Deficiency Charge. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in a submitted Fixed Resource Adequacy Plan) must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
 69A.3.1.h, Decommissioning, Retirement, or Substitution of Planning Res, 37.0.0, A
 Record Narrative Name:
 Tariff Record ID: 5034
 Tariff Record Collation Value: 663028992 Tariff Record Parent Identifier: 5026
 Proposed Date: 2018-05-30
 Priority Order: 1000000000
 Record Change Type: CHANGE
 Record Content Type: 1
 Associated Filing Identifier:

Retirement, Suspension and Replacement of Planning Resources

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. As used in this section, “cleared ZRCs” include ZRCs that cleared in the PRA or TPRA, were used in a FRAP, or were used to replace ZRCs in accordance with this section. As used in this section, “uncleared ZRCs” include ZRCs that did not clear in the PRA or TPRA, were not used in a FRAP, or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs is Retired or Suspended prior to the end of the Planning Year, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.9 and 69A.5 any time during the Planning Year, such Market Participant may replace the cleared ZRCs with uncleared ZRCs to relieve the performance requirements applicable to the Planning Resource. A Planning Resource for which a Market Participant converts Unforced Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5 for the balance of the Planning Year. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA/TPRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA/TPRA; (2) does not violate any CEL used in the PRA/TPRA; (3) does not reduce the remaining total ZRCs for

any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

- i. ZRC replacement shall be processed on a first come, first served basis.
- ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, TPRA and FRAPs.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.7, Planning Resource Auction, 33.0.0, A
Record Narrative Name:
Tariff Record ID: 5056
Tariff Record Collation Value: 663552000 Tariff Record Parent Identifier: 4996
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Planning Resource Auction

Within ten (10) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA, in accordance with the following provisions:

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.7.1, PRA Procedures, 40.0.0, A
Record Narrative Name:
Tariff Record ID: 5057
Tariff Record Collation Value: 663553024 Tariff Record Parent Identifier: 5056
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

PRA Procedures

a. Participating ZRCs in the PRA: All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Unforced Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not opted out of the PRA by submitting a FRAP, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in either the PRA or a TPRA. The PRA offer window shall begin at 12:01 am EST three (3) Business Days before the last Business Day in March and shall end at 11:59 pm EST on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The

Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the CONE value for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs

Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Unforced Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner will be granted ZRCs in the LRZ where their firm Transmission Service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities. Generation Resources, Intermittent Generation and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g.

To the extent a Border External Resource is located on the border of two or more LRZs (e.g. has transmission lines from two or more LRZs terminating at the substation containing the Border External Resource's interconnection facilities), the Market Participant may elect the LRZ in which the Border External Resource is granted ZRCs through notice submitted no later than two (2) years prior to February 1 preceding the applicable Planning Year. Such representation will not be modified more frequently than every other year.

b. Participating Demand: All LSEs will be required to meet their PRMR through the PRA process, unless they have opted out of the PRA pursuant to Section 69A.9 and/or have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a fixed reliability target for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to one hundred percent of the PRMR for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1)

conduct the PRA to clear ZRC Offers and satisfy the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to minimize the as-offered overall costs of capacity procurement over the time horizon, subject to network constraints and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of three (3) successive iterations to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the

final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over the next Planning Year for the Transmission Provider Region. Coincident Peak Demand is used to establish LSE's PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to minimize the cost of serving Demand to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the Peak Hour of the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the

Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP for an LRZ will be based on the total PRMR for the LRZ minus any deficiency volumes of PRMR for an LSE that voluntarily chooses to not participate in the Planning Resource Auction. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars

per megawatt-day (\$/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ(s) with which the ERZ interconnects. For ERZs which connect with more than one SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the total PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Unforced Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the PRMR. When more than one resource is marginal and offered at the ACP, then

all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(x) **ACP for Shortage Conditions:** The ACP will be set at CONE when there is an insufficient volume of valid ZRC Offers to cover LCR or the total PRMR for the LRZ minus the amount of PRMR associated with the Capacity Deficiency Charge for an LRZ.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the tenth Business Day following the last Business Day in March.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.7.6, PRA Settlement, 33.0.0, A
Record Narrative Name:
Tariff Record ID: 5062
Tariff Record Collation Value: 663568384 Tariff Record Parent Identifier: 5056
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

PRA Settlement

- a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to

Section 69A.9. The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region divided by the total number of days in the Planning Year.

- b. An LSE that submits a FRAP with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:

The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP.

- c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

Tariff Record Collation Value: 663571456 Tariff Record Parent Identifier: 5056
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Distribution of Excess Auction Revenue

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

- (i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then
- (ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a *pro rata* basis to all HUCs and ZDC Hedges.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.7.7(a), Historic Unit Considerations, 32.0.0, A
Record Narrative Name:
Tariff Record ID: 5064
Tariff Record Collation Value: 663571488 Tariff Record Parent Identifier: 5063
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or

contractual arrangements, including a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or arrangements that predate March 26, 2018, and pertain to External Resource represented in External Resource Zones in which:

- i. The LSE has PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;
- ii. The Planning Resource designated in the arrangement and PRMR obligation span multiple LRZs and/or ERZs;
- iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated PRMR obligation; and
- iv. LSEs must note qualification for HUCs for as part of the annual PRA registration process.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of PRMR that are associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the length of the executed contract (including any evergreen contract extensions), until the owned resource status is changed to retired or until the transmission service is not maintained.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

69A.7.7(b), ZDC Hedges, 32.0.0, A
Record Narrative Name:
Tariff Record ID: 5065
Tariff Record Collation Value: 663571520 Tariff Record Parent Identifier: 5063
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

ZDC Hedges

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent (100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.7.7(c), Zonal Deliverability Benefit, 34.0.0, A
Record Narrative Name:
Tariff Record ID: 5066
Tariff Record Collation Value: 663571552 Tariff Record Parent Identifier: 5063
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Zonal Deliverability Benefit

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\textit{Weighted Average Export ACP} = \frac{\sum(\textit{Net Export}_j \times \textit{ACP}_j)}{\sum \textit{Net Export}_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\textit{ZDB Credit}_k = \textit{Net Import}_k \times (\textit{ACP}_k - \textit{Weighted Average Export ACP})$$

Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

The Transmission Provider will also receive FRAP related revenues derived from FRAP ZRCs that would have received payments greater than the charges to the associated FRAP PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
 69A.7.8, Self-Scheduling Option:, 32.0.0, A
 Record Narrative Name:
 Tariff Record ID: 5067
 Tariff Record Collation Value: 663574528 Tariff Record Parent Identifier: 5056
 Proposed Date: 2018-05-30
 Priority Order: 1000000000
 Record Change Type: CHANGE
 Record Content Type: 1
 Associated Filing Identifier:

Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.7.9, ICAP Deferral Requirements and Charges, 38.0.0, A
Record Narrative Name:
Tariff Record ID: 10125
Tariff Record Collation Value: 663575552 Tariff Record Parent Identifier: 5056
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Installed Capacity (ICAP) Deferral Requirements and Charges

- a. **ICAP Deferral Notice.** Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of May prior to the Planning Year.
- b. **ICAP Deferral Credit Requirements.** A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance

with Section 69A.3.1.h, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

- i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of May prior to the Planning Year, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on June 1st of the Planning Year and continue until ICAP is submitted and verified by the Transmission Provider, or replacement ZRCs are registered per the BPM for Resource Adequacy, or the ICAP value is forfeited, or the end of the Planning Year, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9 and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

- ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs .
- iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to LSEs that have met their PRMR during the Planning Year on a *pro rata* basis, based upon the LSE's share of total PRMR for the Transmission Provider Region.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.9, Opting Out of the Planning Resource Auction, 35.0.0, A
Record Narrative Name:
Tariff Record ID: 5069
Tariff Record Collation Value: 663814144 Tariff Record Parent Identifier: 4996
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Opting Out of the Planning Resource Auction

An LSE electing to opt out of the PRA can continue to use its existing resource planning processes to meet their PRMR by providing the Transmission Provider with a Fixed Resource Adequacy Plan (FRAP), as described below:

- a. An LSE electing to opt out of the PRA must submit a Fixed Resource Adequacy Plan

(FRAP) for each LRZ to the Transmission Provider by the 7th business day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or a portion of the LSE's PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year.

Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two business days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for a Planning Year and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its total PRMR and also its load ratio share of the LCR for each LRZ. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the LSE's PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that an LSE's PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The

LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP.

- b. An LSE that submits a FRAP for an LRZ will be able to opt out of the PRA for such Planning Year for such LRZ, to the extent that the LSE's ZRCs satisfy the LSE's PRMR. To the extent that an LSE that has opted out of the PRA: (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Planning Year; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- c. Any portion of an LSE's PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA. An LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10.
- d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- e. Any ZRCs included in the FRAP from new resources needed to meet an LSE's PRMR will be exempt from application of the minimum offer price provisions.
- f. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

- g. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.11.11, ZDC Charges and ZDC Hedges, 32.0.0, A
Record Narrative Name:
Tariff Record ID: 5418
Tariff Record Collation Value: 673906688 Tariff Record Parent Identifier: 5407
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

A New LSE will be subject to the Zonal Deliverability Charge consistent with Section 69A.7.6(b) if the New LSE submits a Fixed Resource Adequacy Plan to meet all or a portion of its Planning Reserve Margin Requirements. A New LSE will be able to receive excess TPRA revenue if a New LSE qualifies for a ZDC Hedge, consistent with Section 69A.7.7(b). A New LSE will be entitled to a Zonal Deliverability Benefit in accordance with Section 69A.7.7(c). A New LSE will be allocated, as appropriate Local Clearing Requirement Charges in accordance with Section 69A.7.7(d). The Tariff provisions in Module E-1 apply to existing LSEs. New LSEs are only subject to the provisions of Module E-2, except to the extent that Module E-2 Tariff provisions incorporate Module E-1 requirements by reference.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
69A.11.12, Distribution of Excess Auction Revenue, 31.0.0, A
Record Narrative Name:
Tariff Record ID: 5419
Tariff Record Collation Value: 673972224 Tariff Record Parent Identifier: 5407
Proposed Date: 2018-05-30
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

The Transmission Provider will distribute any excess TPRA revenues: first, to Historic Unit

Considerations as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7(b). Any remaining amounts will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a *pro rata* basis to all HUCs and ZDC Hedges.

Document Content(s)

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Tab A - Clean Tariff sheets.PDF.....10-101

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Tab C - Testimony of Laura Rauch.PDF.....197-232

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Case No. 2017-00384

**PSC 1-28b (MSP)(Att2) - BR Motion to Intervene in
FERC Docket No ER18-1173-000**

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Midcontinent Independent System Operator, Inc.) Docket No. ER18-1173-000

**MOTION TO INTERVENE AND LIMITED PROTEST OF
BIG RIVERS ELECTRIC CORPORATION**

Pursuant to Rules 211, 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“FERC” or “Commission”), 18 C.F.R. §§ 385.211, 385.212 and 385.214 (2017), Big Rivers Electric Corporation (“Big Rivers”) hereby files this motion to intervene and limited protest in the above-captioned proceeding. This proceeding involves proposed modifications to the Open Access Transmission, Energy and Operating Reserves Markets Tariff (“Tariff”) of the Midcontinent Independent System Operator, Inc. (“MISO”) to create External Resource Zones (“ERZs”) and to adopt certain additional related changes to the terms of MISO’s Planning Resource Auction (“PRA”).

Big Rivers does not object to the MISO filing in general, but files this limited protest to request that the Commission correct the scope of one proposed new definition in order to ensure that MISO’s proposal is just and reasonable and not unduly discriminatory. The proposed definition of “Border External Resources” (external resources that qualify for local treatment) includes two elements: a physical proximity requirement and a requirement that the resource respond during emergencies. However, by excluding from the definition resources that are sourced both from qualifying generation sources and from some additional sources, the definition is too narrowly drawn (as compared to MISO’s stated intent) and excludes resources that are available for emergency response under comparable circumstances. As discussed below,

Big Rivers requests that the Commission order certain limited changes to the definition to avoid the unnecessary exclusion of these types of resources from the definition.

I. MOTION TO INTERVENE

Big Rivers is a Member-owned, not-for-profit, electric generation and transmission (G&T) cooperative located in Henderson, Kentucky. Big Rivers provides wholesale electric power and services to three distribution cooperative Member-Owners across 22 counties in western Kentucky. The Member-Owners are Jackson Purchase Energy Corporation, headquartered in Paducah, Ky.; Kenergy Corp., headquartered in Henderson, Ky.; and Meade County Rural Electric Cooperative Corporation, headquartered in Brandenburg, Ky. Together, the three Member-Owners distribute retail electric power to approximately 116,000 homes, farms, businesses and industries in western Kentucky. Big Rivers is a transmission owning member of MISO and wholesale transmission services on Big Rivers' transmission facilities are provided pursuant to the terms of the MISO Tariff.

As a member of MISO and both a seller and purchaser under the MISO PRA, Big Rivers has an interest in the matters at issue in this proceeding and should be permitted to participate in this docket as a party. Please include the following individuals on the official service list, and all communications regarding this filing should be addressed to them:

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II. LIMITED PROTEST

Big Rivers purchases energy and capacity from the Southeastern Power Administration (“SEPA”) pursuant to an agreement dated June 30, 1999. Big Rivers has relied on this contract to serve a portion of its Member-Owners’ firm load for close to 20 years. By its terms, the agreement provides for SEPA to source the energy and capacity from eight specifically identified generation facilities, including the Barkley Project, a four-unit hydroelectric power plant with a total capacity of 130 MW. The Barkley Project is directly interconnected with the Barkley substation, which is located within MISO. Moreover, the SEPA agreement specifically includes “the Barkley Project switchyard” as one of two initially identified points of delivery.

MISO’s proposal would modify its treatment of external resources by modeling and pricing them in “External Resource Zones.” Such external resources would receive the unconstrained price for MISO North (if located in balancing authorities with ties solely to the northern part of MISO), for MISO South (if located in balancing authorities with ties solely to the southern part of MISO), or a blended price (if located in a balancing authority with ties to both). The generation sources under the SEPA contract are located in the Tennessee Valley Authority balancing authority, which has ties to both the northern and southern parts of MISO. Currently and historically, the SEPA purchase has been priced the same as capacity located within the local zone that includes Big Rivers (and thus Big Rivers Member-Owner load pays the same price that the SEPA purchase is paid).

MISO acknowledges in its filing that it “recognize[es] the unforeseen risks capacity market changes may impose on pre-existing, long-term capacity arrangements.” ^{1/} One of the

^{1/} Transmittal letter at 1.

primary risks is that external capacity historically relied on to supply load will clear at a price lower than what the affected load is obligated to pay, and the load-serving entity that already pays the capacity supplier will end up having to pay additional amounts in order to make use of that resource for meeting the MISO resource adequacy requirements.

As Laura Rauch, Director of Resource Adequacy Coordination for MISO, explains in her testimony:

Currently, MISO Load Serving Entities could have ownership of, or enter into arrangements with, External Resources without the need to consider price separation risk between the External Resource and load in their Local Resource Zone. Many of these contracts and ownership arrangements are long-standing and long-term, with no or limited opportunities for renegotiation during their multi-decade term. The creation of ERZs will introduce price risk that could not have been foreseen, and therefore could not have been contemplated in these agreements at the time in which they were entered. 2/

One of the mechanisms proposed by MISO to address this risk is to exempt “Border External Resources” from ERZ pricing and to treat them as being located in an individual Local Resource Zone. Such resources would then be entitled to the same prices paid by load within that local zone.

The proposed tariff revisions define a “Border External Resource” as follows:

An External Resource that: (i) has interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider’s functional control; and (ii) which will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to such substation. 3/

As explained above, Big Rivers SEPA contract meets the first of these two elements, as it includes deliveries from the Barkley Project, which connects directly to the Barkley substation within MISO. However, it does not meet the strict language in the second element, because the

2/ Prepared Direct Testimony of Laura Rauch, at p. 5, ll. 16-22.

3/ Tariff filing, Tab A at 1.B (Definitions-B).

SEPA contract provides for supply from other resources as well. Big Rivers believes that this language can be modified slightly to include the SEPA contract within the second element, without sacrificing the intent of MISO in proposing this language. More specifically, Big Rivers respectfully requests that the Commission order the following redlined changes to this definition:

An External Resource that: (i) has interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; and (ii) which ~~will~~can schedule in response to notification by the Transmission Provider during a declared Energy Emergency ~~solely~~ from unit(s) connected to such substation.

MISO witness Laura Rauch identifies in her testimony the two required elements for an external resource to qualify as a Border External Resource as:

- (1) Qualifying resources "should not be separated from the MISO [local resource zone] by intervening transmission;" and
- (2) "MISO must be able to operationally rely upon the resources during a capacity emergency to obtain local credit." 4/

As explained above, Big Rivers SEPA purchase can satisfy both of those requirements. The fact that the purchase also includes supply from some resources that are not directly connected to MISO does not change the physical and operational characteristics of the Barkley Project.

The additional limitation imposed in the definition and by the subsequent portion of Ms. Rauch's testimony -- appearing to exclude purchase resources like Big Rivers' SEPA purchase which include some directly connected units and some that are not -- is neither supported nor explained by MISO. Given that these types of resources are capable of providing the comparable levels of reliable service to local loads as resources located within a local zone, this disparate treatment is unduly discriminatory and thus not consistent with the requirements of Section 205

4/ Prepared Direct Testimony of Laura Rauch, at p. 11, ll. 19-20, p. 12, ll. 1-2.

of the Federal Power Act. Big Rivers is similarly situated, with respect to the SEPA contract resource, to sellers with generation sources located within the same local zone as Big Rivers Member-Owner load, and should be treated comparably with respect to protection from price separation risk.

Such treatment also creates unintended disincentives for future contracts for the purchase of energy and capacity from external resources. A unit-specific purchase from a directly interconnected unit would meet the current definition, and therefore avoid the risk of price separation. However, while expanding the scope of such a contract by adding in additional external sources would improve the overall reliability of supply under such a contract, it would bring such a contract out of the proposed definition of "Border External Resource," thus exposing the contract to the risk of price separation.

III. CONCLUSION

WHEREFORE, for the foregoing reasons, Big Rivers respectfully requests that the Commission grant its motion to intervene and require that MISO modify the definition of “Border External Resource” as described herein.

Respectfully submitted,

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Attorneys for Big Rivers Electric
Corporation

April 16, 2018

CERTIFICATE OF SERVICE

I hereby certify that this 16th day of April, 2018, I served a copy of this Motion to Intervene and Limited Protest on all those listed in the official service list in this proceeding.

/s/ John R. Lilyestrom

John R. Lilyestrom

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Case No. 2017-00384

**PSC 1-28c (MSP)(Att1) - MISO Planning Resource
Auction Results - 2014-2015**

2014/2015 Planning Resource Auction (PRA)

MISO completed its Annual Planning Resource Auction for Planning Year 2014-2015 based on Market Participant Offers submitted between March 27 and 31, and posted final results on April 14, 2014

- This was the second full-year PRA under the Module E-1 Tariff. MISO completed a partial year, Transitional PRA prior to MISO South entities integrating in December 2013.
- The Auction produced three clearing prices:
 1. Local Resource Zone (LRZ) 1 cleared at \$3.29 per MW-Day as its Zonal Capacity Export Limit bound
 2. LRZs 2-7 cleared at \$16.75 per MW-Day
 3. LRZs 8-9 cleared at \$16.44 per MW-Day as constraints related to intra-RTO dispatch ranges bound between the MISO South and the MISO Central/North Regions
- A total of 136,912 MW of Planning Resources were cleared to meet the MISO's resource adequacy requirements. This includes 124,556 MW of Generation Resources, 3,743 MW of Behind-the-Meter Generation (BTMG), 5,457 MW of Demand Response (DR), and 3,156 MW of External Resources (ER).
- The MISO Planning Reserve Margin Requirement (PRMR) increased by 2,475 MW to 136,912 MW from 2013-14 PRA due to; an increase in Coincident Peak Forecast, an increase in Planning Reserve Margin (PRM) from 6.2% to 7.3%, and, an increase in Zone 8's PRMR as the Zonal Local Clearing Requirement was greater than the Zonal PRMR.
- Excess Zonal Resource Credits of 12,201 MW remained after meeting the PRMR, up from 8,659 MW in 2013-14 PRA, but down slightly from the MISO South Transitional PRA, 12,615 MW.

2014/2015 MISO Planning Resource Auction Results

LRZ	Z1 (MN,ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	System
Demand Forecast	16,540	12,347	8,757	9,680	8,106	17,629	20,791	7,363	22,999	124,212
PRMR (based on CPF)	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,043	25,224	136,537
LCR	15,070	11,739	8,971	8,879	5,002	15,457	21,293	8,417	24,080	N/A
Effective PRMR	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,417	25,224	136,912
Total Offer Submitted	7,045	2,879	9,520	11,370	387	17,985	15,190	9,406	25,966	99,747
Total FRAP applied	12,620	12,352	391	874	7,722	1,846	8,449	397	2,372	47,022
Offer Cleared + FRAP	18,522	14,358	9,787	9,316	8,109	19,551	22,627	8,582	26,059	136,912
Import Limit	4,347	3,083	1,591	3,025	5,273	4,834	3,884	1,602	3,585	N/A
Export Limit	286	1,924	1,875	1,961	1,350	2,246	4,517	3,080	3,616	N/A
ACP (\$/MW-Day)	3.29	16.75	16.75	16.75	16.75	16.75	16.75	16.44	16.44	N/A

Participation by Resource Type (System-wide)

Planning Resource Type	UCAP	Unconverted	Fixed Resource Plans	OFFER	Cleared	ZRC Balance
Generation	138,668	3,480	42,394	90,645	82,162	10,632
Behind the Meter Generation	4,071	59	2,141	1,693	1,602	270
Demand Response	5,750	3	1,449	4,298	4,008	290
External Resources	4,238	73	1,038	3,111	2,117	1,009
Energy Efficiency	0	0	0	0	0	0
Total	152,727	3,615	47,022	99,747	89,890	12,201
%UCAP	100%	2%	31%	65%	59%	8%

Appendix - Acronyms

ACP - Auction Clearing Price (\$/MW-Day)
CEL - Capacity Export Limit (MWs)
CIL - Capacity Import Limit (MWs)
CPF – Coincident Peak Forecast (MW)
FRAP - Fixed Resource Adequacy Plan (MWs)
LCR - Local Clearing Requirement (MWs)
LRZ - Local Resource Zone
MP - Market Participant
PRA - Planning Resource Auction
PRM - Planning Reserve Margin
PRMR - Planning Reserve Margin Requirement (MWs)
SFT – Simultaneous Feasibility Test
TPRA – Transitional Planning Resource Auction
UCAP - Unforced Capacity (MWs)
ZRC - Zonal Resource Credit (MWs)

Case No. 2017-00384

**PSC 1-28c (MSP)(Att2) - MISO Planning Resource
Auction Results - 2015-2016**

2015/2016 Planning Resource Auction Results

April 14, 2015

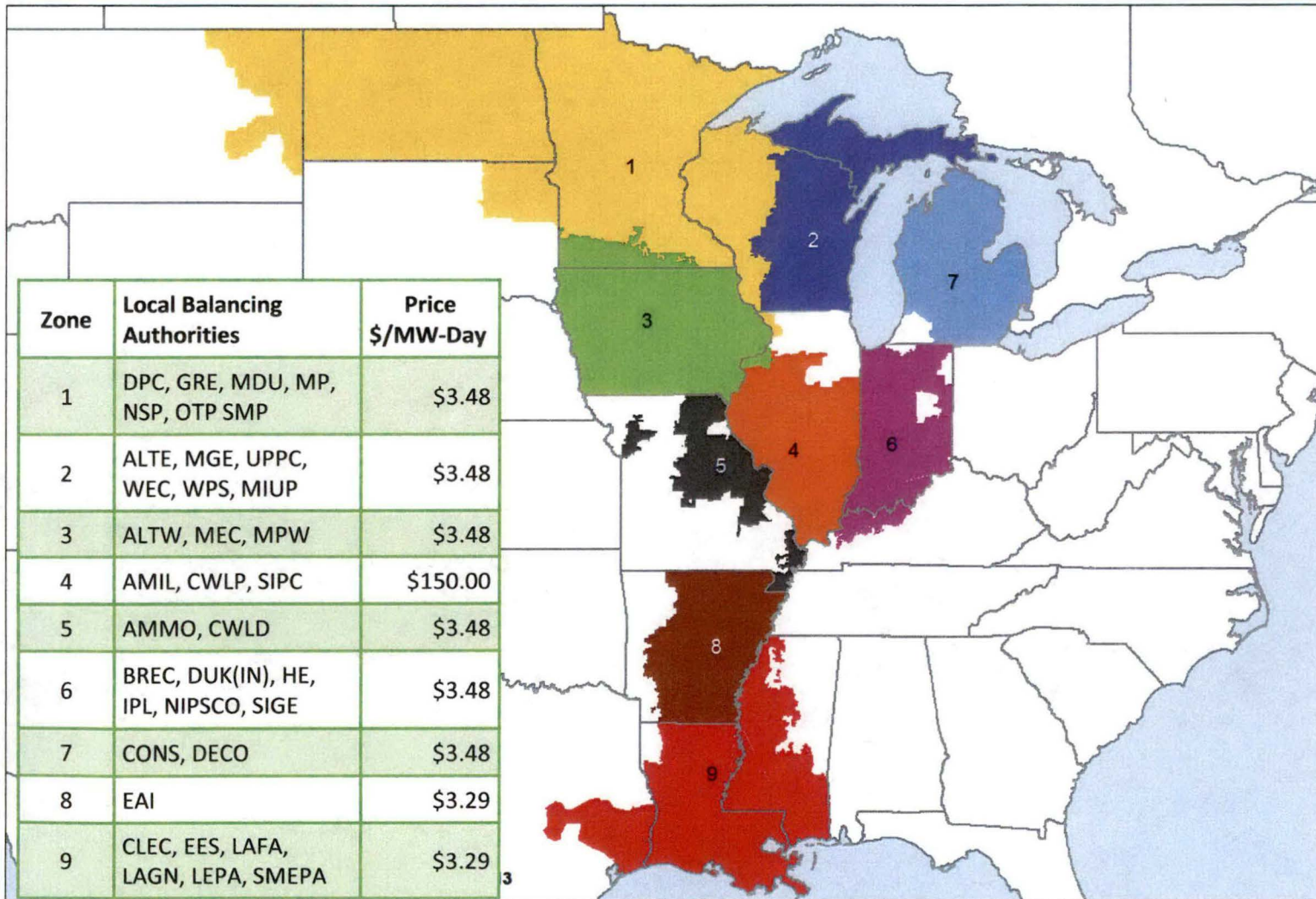
Executive Summary

- **MISO successfully completed its third annual Planning Resource Auction**
- **The MISO region has adequate resources to meet its Planning Reserve Margin Requirements for the 2015/2016 planning year.**
 - Zones 1-3 and 5-7 cleared at \$3.48/MW-day
 - Zone 4 (much of Illinois), cleared at \$150.00/MW-day
 - Zones 8-9 (MISO South), cleared at \$3.29/MW-day

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region as a whole subject to the following:
 - MISO-wide reserve margin requirements
 - Zonal capacity requirements (Local Clearing Requirement)
 - Zonal transmission limitations (Capacity Import/Export Limits)
 - If applicable, Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The zonal capacity requirement must be met with Resources located within the zone
- The MISO-wide reserve margin requirement is shared among the zones, and zones may import capacity to meet this requirement
- The Independent Market Monitor reviews the auction results for physical and economic withholding

2015/2016 Auction Clearing Price Overview



Next Steps: Auction Output and Settlements

- **Key outputs from the auction are:**
 - A commitment of capacity to the MISO region, including performance obligations and
 - The capacity price (Auction Clearing Price) for each zone
- **This price drives the settlements process**
 - Load pays the auction clearing price for the zone in which it is physically located
 - Cleared capacity is paid the auction clearing price for the zone where it is physically located
 - External resources are paid the price of the zone where their firm transmission service crosses into MISO
- **When price separation between zones occurs, a zone's use of resources located outside of its boundaries will result in MISO over collecting auction revenues**
 - This over-collection is allocated, per the MISO tariff, to the Load within the zone(s)

2015/2016 Planning Resource Auction Detailed Results

Local Resource Zone	Z1 (MN, ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	SYSTEM
CPDF (Coincident Peak Demand Forecast)	16,525	12,429	8,876	9,518	8,176	17,592	20,522	7,424	23,035	124,097
PRMR (Planning Reserve Margin Requirement)	18,321	13,566	9,768	10,420	8,910	19,409	22,678	8,118	25,170	136,359
LCR (Local Clearing Requirement)	15,982	12,332	8,695	8,852	6,527	14,677	21,442	7,850	23,609	N/A
Total Offer Submitted	4,867	3,071	5,922	11,156	7,926	14,832	14,103	9,562	26,193	97,632
Total FRAP (Fixed Resource Adequacy Plan)	14,494	11,817	4,113	838	0	4,853	9,456	397	2,261	48,229
Offer Cleared + FRAP	18,495	14,497	9,813	8,852	7,885	19,015	23,515	8,526	25,762	136,359
Import / (Export)	(175)	(931)	(45)	1,568	1,026	394	(837)	(408)	(592)	2,988
CIL (Capacity Import Limit)	3,735	2,903	1,972	3,130	3,899	5,649	3,813	2,074	3,320	N/A
CEL (Capacity Export Limit)	604	1,516	1,477	4,125	0	2,930	4,804	3,022	3,239	N/A
ACP (Auction Clearing Price) \$/MW-Day	\$3.48	\$3.48	\$3.48	\$150.00	\$3.48	\$3.48	\$3.48	\$3.29	\$3.29	N/A

Key Auction Takeaways: Auction Clearing Prices relative to key thresholds

	Zone 1 (MN, ND, Western WI)	Zone 2 (Eastern WI, Upper MI)	Zone 3 (IA)	Zone 4 (IL)	Zone 5 (MO)	Zone 6 (IN, KY)	Zone 7 (MI)	Zone 8 (AR)	Zone 9 (LA, MS, TX)
2014-2015 Auction Clearing Price (ACP)	\$3.29	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.44	\$16.44
2015-2016 Auction Clearing Price (ACP)	\$3.48	\$3.48	\$3.48	\$150.00	\$3.48	\$3.48	\$3.48	\$3.29	\$3.29
2015-2016 Reference Level	\$155.79	\$155.79	\$155.79	\$155.79	\$155.79	\$155.79	\$155.79	\$155.79	\$155.79
2015-2016 Conduct Threshold	\$180.43	\$180.65	\$180.14	\$180.53	\$181.00	\$180.45	\$180.59	\$179.45	\$179.61
2015-2016 Cost of New Entry (CONE)	\$246.41	\$248.63	\$243.48	\$247.40	\$252.05	\$246.60	\$248.03	\$236.55	\$238.22

*All values in \$/MW-day

Key Auction Takeaways

- Price differentials between 2014-15 and 2015-16 results were mainly driven by changes in market participant offers.
- The 2015 price in Zone 4 was also impacted due to the binding of the zonal capacity requirement to procure a certain amount of capacity with the zone (LCR)
 - This requirement for Zone 4 was substantially the same as in the 2014/2015 Auction.
- Zones 8 and 9 cleared at a lower price than the other zones due to the south to north sub-regional power balance constraint binding at 1,000 MW.

Conclusions

- **MISO successfully completed its third annual Planning Resource Auction, demonstrating that the MISO region has adequate resources to meet capacity requirements for the 2015/2016 planning year.**
 - Zones 1-3 and 5-7 cleared at \$3.48/MW-day
 - Zone 4 (much of Illinois), cleared at \$150.00/MW-day
 - Zones 8-9 (MISO South), cleared at \$3.29/MW-day

Acronyms

- ACP - Auction Clearing Price (\$/MW-Day)
- BTMG – Behind The Meter Generator
- DR – Demand Resource
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CPDF – Coincident Peak Demand Forecast (MW)
- FRAP - Fixed Resource Adequacy Plan (MW)
- LCR - Local Clearing Requirement (MW)
- LOLE – Loss Of Load Expectation
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SFT – Simultaneous Feasibility Test
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- UCAP - Unforced Capacity (MW)
- ZDB – Zonal Deliverability Benefits
- ZRC - Zonal Resource Credit (MW)

Case No. 2017-00384

**PSC 1-28c (MSP)(Att3) - MISO Planning Resource
Auction Results - 2016-2017**

2016/2017 Planning Resource Auction Results

April 15, 2016

Revised 4/15/2016 to Include Total Offer Submitted by Zone on Slide 8

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 135,483 MW
 - Zone 1 cleared at \$19.72/MW-day
 - Zones 2-7 cleared at \$72.00/MW-day
 - Zones 8-10 cleared at \$2.99/MW-day
- Implemented FERC's Order in Docket ER16-833-000 that modified Reference Levels, Capacity Import Limits (CILs) and Local Clearing Requirements (LCRs)
- Regional generation supply is consistent with the 2015 MISO OMS Survey

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
 - MISO-wide reserve margin requirements
 - Zonal capacity requirements (Local Clearing Requirement)
 - Zonal transmission limitations (Capacity Import/Export Limits)
 - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The MISO-wide reserve margin requirement is shared among the zones, and zones may import capacity to meet this requirement
- Multiple options exist for Load Serving Entities to demonstrate Resource Adequacy:
 - Submit a Fixed Resource Adequacy Plan
 - Utilize bilateral contracts with another resource owner
 - Participate in the Planning Resource Auction
- The Independent Market Monitor reviews the auction results for physical and economic withholding

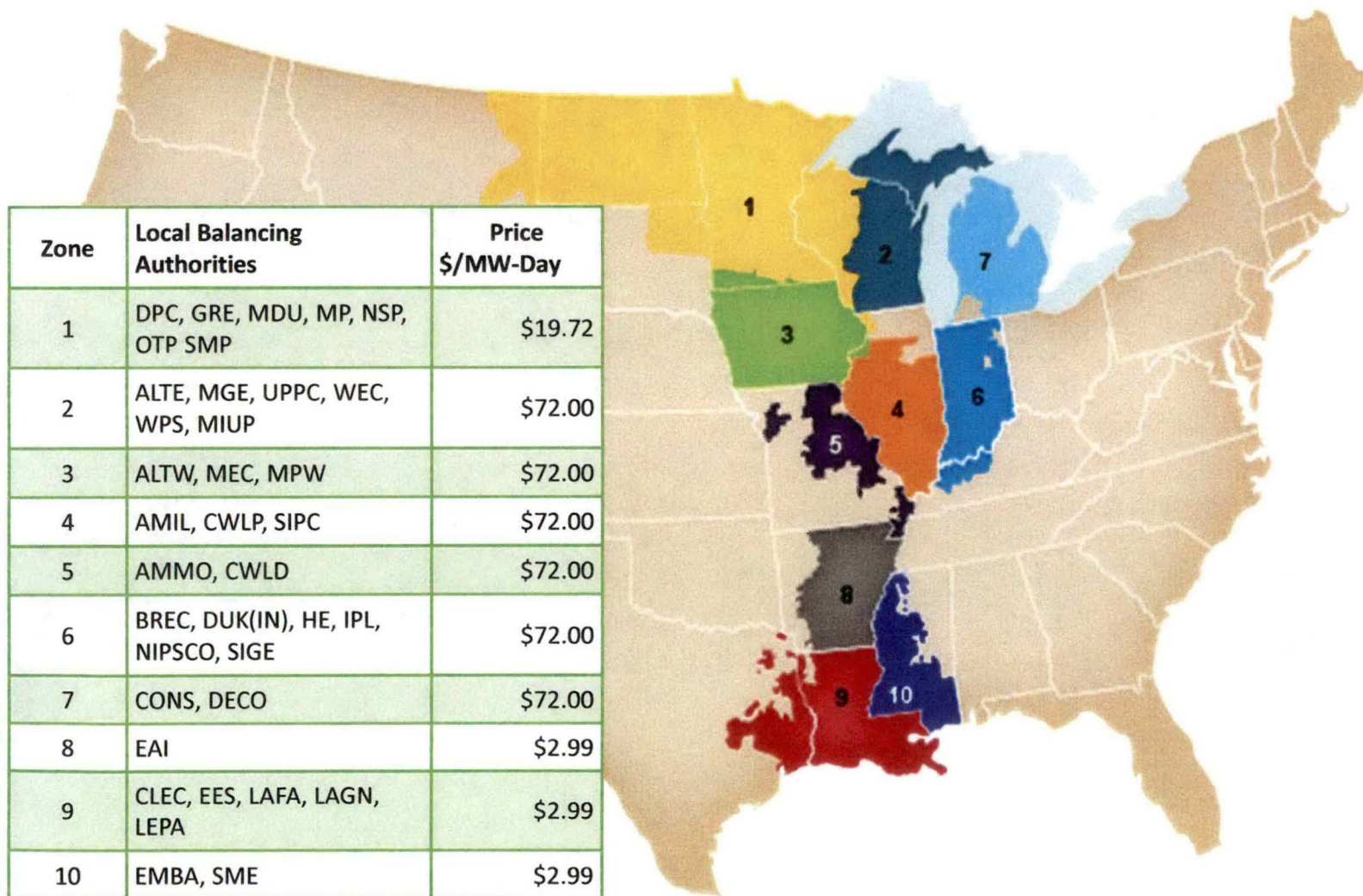
Changes since PRA 2015/2016

- Tariff revisions approved in FERC Docket No. ER16-833-000 implemented, including increased CILs, decreased LCRs, and reduced Initial Reference Level to \$0/MW-day
- Sub-Regional Export Constraint in the South to Midwest direction modified to reflect the Settlement Agreement
- LRZ 10 for the State of Mississippi established – No impact
- Other minor changes:
 - EPA RICE-NESHAP* regulations, which likely led to some additional retirements incremental to our OMS survey results
 - Allocation of Zonal Deliverability Benefit revised – pending FERC decision
 - Suspended units required to participate in the PRA – No impact

Auction Output and Settlements

- Key outputs from the auction are:
 - A commitment of capacity to the MISO region, including performance obligations and
 - The capacity price (Auction Clearing Price) for each Zone
- This price drives the settlements process
 - Load pays the Auction Clearing Price for the Zone in which it is physically located
 - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
 - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

2016/2017 Auction Clearing Price Overview



Auction Clearing Prices

\$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	\$3.29	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.44	\$16.44	N/A
2015-2016 ACP*	\$3.48	\$3.48	\$3.48	\$150.00	\$3.48	\$3.48	\$3.48	\$3.29	\$3.29	N/A
2016-2017 ACP*	\$19.72	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$2.99	\$2.99	\$2.99
<i>Conduct Threshold</i>	\$25.80	\$26.06	\$25.52	\$25.93	\$26.42	\$25.85	\$25.98	\$24.76	\$25.12	\$24.60
<i>Cost of New Entry</i>	\$258.00	\$260.58	\$255.15	\$259.26	\$264.19	\$258.47	\$259.81	\$247.56	\$251.21	\$246.05

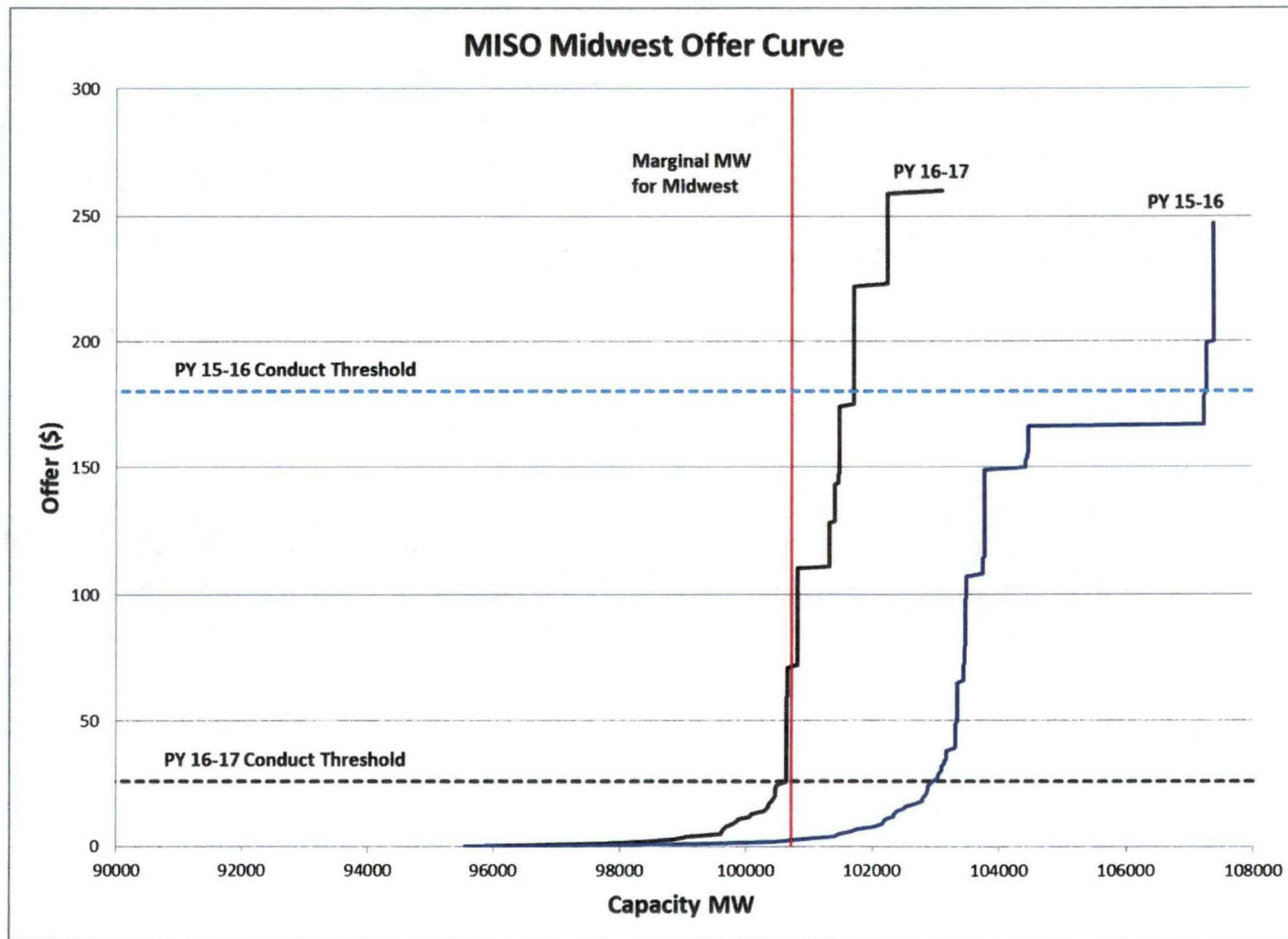
- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is \$0 for a Generation Resource with a Facility Specific Reference Level

* Auction Clearing Price

2016/2017 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,185	13,589	9,879	10,375	8,518	18,750	22,406	8,178	20,713	4,891	135,483
Total Offer Submitted (Including FRAP)	19,430	14,903	10,138	11,371	7,926	18,398	21,615	10,587	20,257	6,899	141,524
FRAP	14,252	12,063	501	910	0	4,338	1,393	318	577	1,641	35,995
ZRC Offer Cleared	4,522	2,840	9,636	8,242	7,927	14,060	20,141	9,676	17,934	4,511	99,488
Total Committed (Offer Cleared + FRAP)	18,775	14,903	10,138	9,152	7,927	18,398	21,534	9,995	18,511	6,151	135,483
LCR	15,918	12,986	8,715	5,476	5,026	13,698	20,851	6,270	17,477	3,978	N/A
CIL	3,436	1,609	1,886	6,323	4,837	5,610	3,521	3,527	4,490	2,653	N/A
Import	0	0	0	1,224	592	352	872	0	2,202	0	5,240
CEL	590	2,996	1,598	7,379	896	2,544	4,541	2,074	1,261	1,857	N/A
Export	590	1,315	258	0	0	0	0	1,817	0	1,260	5,240
ACP (\$/MW-Day)	\$19.72	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$2.99	\$2.99	\$2.99	N/A

Midwest Offer Curve 2015/2016 vs. 2016/2017



Next Steps

- Detailed results review at May 5 RASC
- Posting of PRA offer data 30 days after PRA conclusion – May 13

Acronyms

- ACP - Auction Clearing Price (\$/MW-Day)
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- FRAP - Fixed Resource Adequacy Plan (MW)
- LCR - Local Clearing Requirement (MW)
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint

References

- Sub-Regional Export and Import Constraints discussed at the Supply Adequacy Working Group (SAWG)
 - October 29, 2015
 - December 3, 2015
 - February 4, 2016

Case No. 2017-00384

**PSC 1-28c (MSP)(Att4) - MISO Planning Resource
Auction Results - 2017-2018**

2017/2018 Planning Resource Auction Results

April 14, 2017

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 134,753 MW
 - Zones 1-10 cleared at \$1.50/MW-day
 - Marginal resource is in Zone 1
 - Increased supply and lower demand in Midwest largely responsible for lower Auction Clearing Prices relative to last year
- Regional generation supply is consistent with the 2016 OMS-MISO Survey
- No mitigation for physical or economic withholding by the IMM

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
 - MISO-wide reserve margin requirements
 - Zonal capacity requirements (Local Clearing Requirement)
 - Zonal transmission limitations (Capacity Import/Export Limits)
 - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The MISO-wide reserve margin requirement is shared among the Zones, and Zones may import capacity to meet this requirement
- Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:
 - Submit a Fixed Resource Adequacy Plan
 - Utilize bilateral contracts with another resource owner
 - Participate in the Planning Resource Auction
- The Independent Market Monitor reviews the auction results for physical and economic withholding

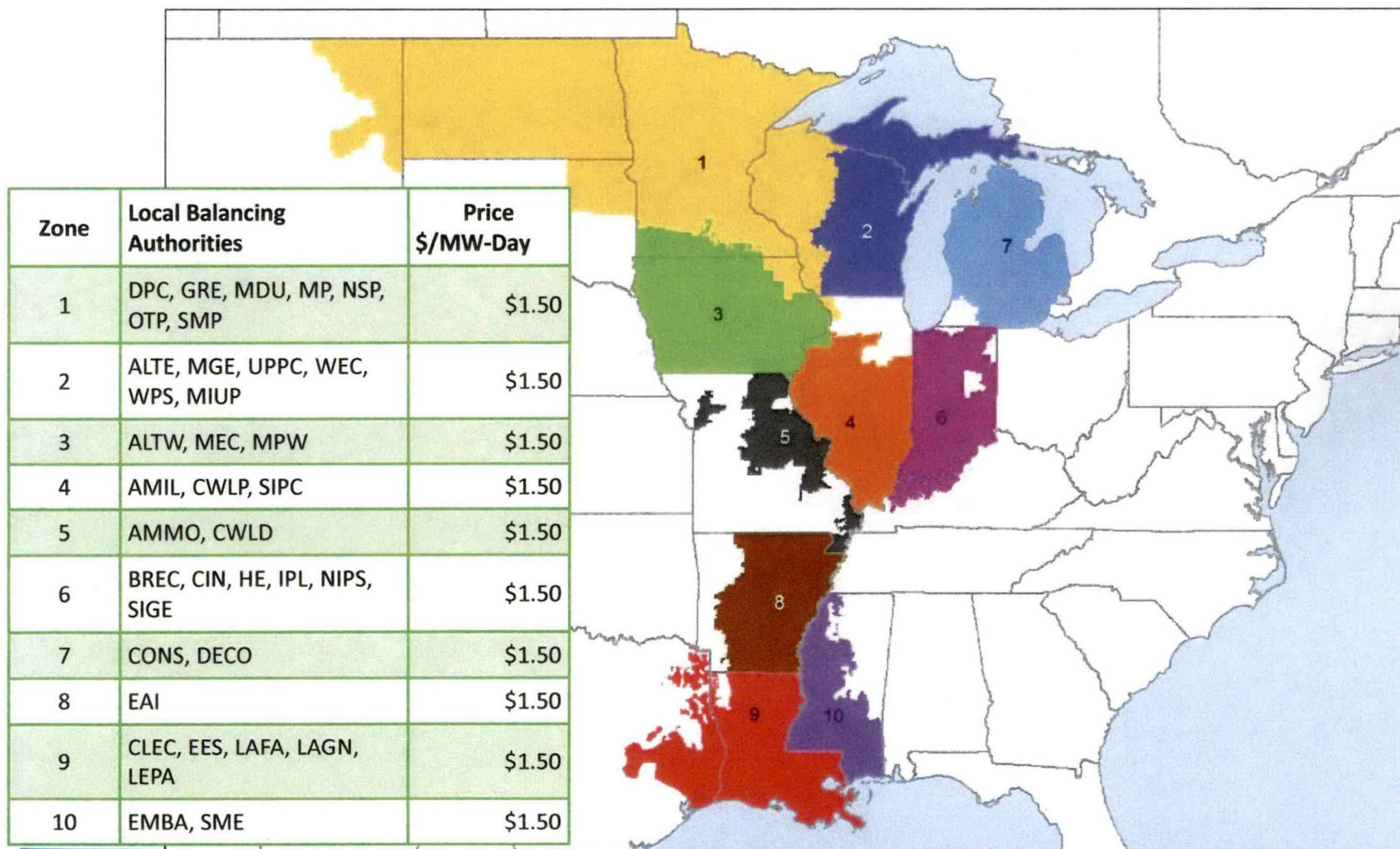
Auction Output and Settlements

- Key outputs from the Auction
 - A commitment of capacity to the MISO region, including performance obligations and
 - The capacity price (Auction Clearing Price) for each Zone
- This price drives the settlements process
 - Load pays the Auction Clearing Price for the Zone in which it is physically located
 - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
 - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

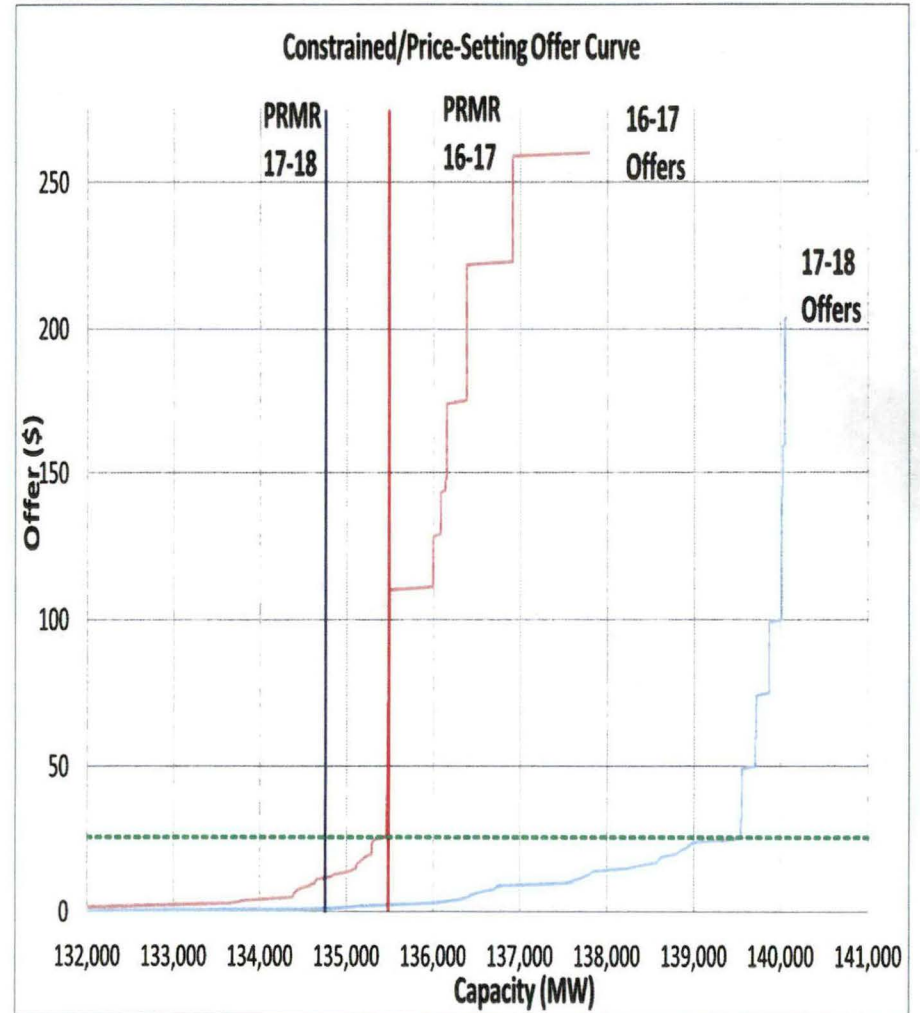
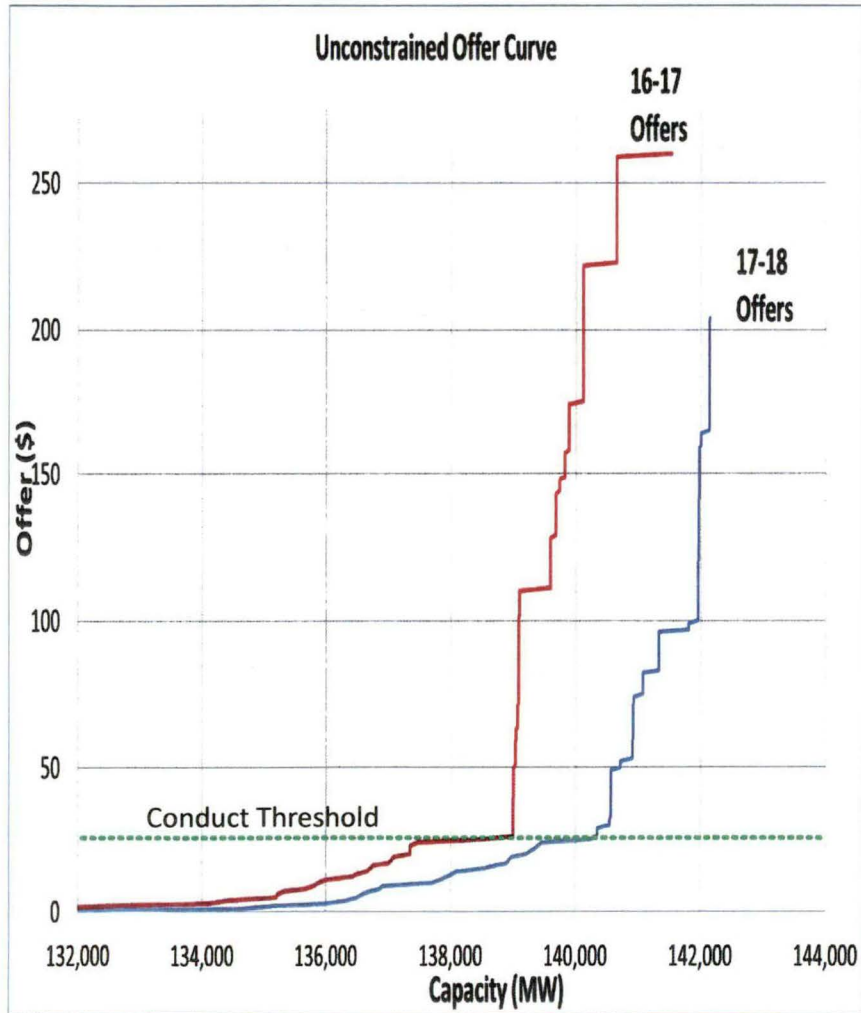
Changes since PRA 2016/2017

- Tariff revisions approved in FERC Docket No. ER17-806-000 exempting Demand Resources (DR), Energy Efficiency Resources (EER) and External Resources (ER) from Market Monitoring and Mitigation in the 2017-18 PRA
- Tariff revisions approved in FERC Docket No. ER17-806-000 modified the application of the Physical Withholding Threshold to include Market Participants and their Affiliates
- Tariff revisions approved in FERC Docket No. ER16-833-004 established default technology specific avoidable costs, in lieu of providing facility specific operating cost information, to request facility specific Reference Levels from the IMM
- Sub-Regional Export Constraint in the South to Midwest direction increased to a 1500 MW limit from 876 MW and increased to a 3000 MW limit from 2794 MW in the Midwest to South direction

2017/2018 Auction Clearing Price Overview



MISO Offer Curve, 2016/2017 vs. 2017/2018



Capacity constrained by export limits from Zone 1 and MISO South

Auction Clearing Prices Since 2014-15 PRA

\$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	\$3.29	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.44	\$16.44	N/A
2015-2016 ACP*	\$3.48	\$3.48	\$3.48	\$150.00	\$3.48	\$3.48	\$3.48	\$3.29	\$3.29	N/A
2016-2017 ACP*	\$19.72	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$2.99	\$2.99	\$2.99
2017-2018 ACP*	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50
<i>Conduct Threshold</i>	\$25.83	\$26.09	\$25.53	\$25.94	\$26.45	\$25.85	\$26.00	\$24.79	\$25.14	\$24.61
<i>Cost of New Entry</i>	\$258.32	\$260.90	\$255.31	\$259.42	\$264.52	\$258.49	\$260.00	\$247.94	\$251.42	\$246.13

- Current Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Current Conduct Threshold is \$0 for a generator with a facility specific Reference Level

* Auction Clearing Price

2017/2018 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,316	13,366	9,781	9,894	8,598	18,422	22,295	8,329	20,850	4,902	134,753
Total Offer Submitted (Including FRAP)	19,635	15,149	11,009	10,618	7,950	18,718	22,031	10,914	20,392	5,732	142,146
FRAP	14,361	11,559	4,197	712	0	4,155	12,374	470	182	1,454	49,463
Self Scheduled	4,004	2,113	5,575	7,723	7,948	13,009	9,462	9,660	16,505	3,556	79,554
ZRC Offer Cleared	4,568	2,207	6,088	8,412	7,950	14,510	9,583	9,669	18,470	3,833	85,290
Total Committed (Offer Cleared + FRAP)	18,929	13,766	10,285	9,124	7,950	18,665	21,956	10,139	18,652	5,287	134,753
LCR	15,975	11,980	7,968	5,839	5,885	13,005	21,109	6,766	17,295	4,831	N/A
CIL	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910	N/A
Import	0	0	0	771	648	0	338	0	2,198	0	3,955
CEL	686	2,290	1,772	11,756	2,379	3,191	2,519	2,493	2,373	1,747	N/A
Export	613	400	503	0	0	243	0	1,810	0	385	3,955
ACP (\$/MW-Day)	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	N/A

Additional Details Regarding Supply

Planning Resource Type	2017-2018 Offered	2016-2017 Offered	2017-2018 Cleared	2016-2017 Cleared
Generation	127,637	127,329	121,807	122,379
Behind the Meter Generation	3,678	3,487	3,456	3,462
Demand Resources	6,704	6,322	6,014	5,819
External Resources	4,029	4,385	3,378	3,823
Energy Efficiency	98	0	98	0
Total	142,146	141,523	134,753	135,483

- Demand Resource quantities include Aggregator of Retail Customers (ARCs) that registered for the 2017-18 PRA
- Registered Energy Efficiency Resources for the 2017-18 PRA for the first time since the 2013-14 PRA

Next Steps

- Detailed results review at May 10 Resource Adequacy Subcommittee (RASC)
- Posting of PRA offer data 30 days after PRA conclusion – May 12

Acronyms

- ACP - Auction Clearing Price (\$/MW-Day)
- ARC - Aggregator of Retail Customers
- BTMG – Behind the Meter Generator
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CONE – Cost of New Entry
- FRAP - Fixed Resource Adequacy Plan (MW)
- FSRL – Facility Specific Reference Level (\$/MW-Day)
- LCR - Local Clearing Requirement (MW)
- LMR – Load Modifying Resource
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- ZRC – Zonal Resource Credit

References

- Sub-Regional Export and Import Constraints discussed at the Resource Adequacy Subcommittee (RASC)
 - November 2, 2016
- Market Monitoring and Mitigation in the Planning Resource Auction
 - February 8, 2017

Case No. 2017-00384

**PSC 1-28c (MSP)(Att5) - MISO Planning Resource
Auction Results - 2018-2019**

2018/2019 Planning Resource Auction Results

April 13, 2018

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 135,179 MW
 - Zone 1 cleared at \$1.00/MW-day
 - Remainder of footprint cleared at \$10.00/MW-day
 - Marginal resources located in multiple Zones
 - Increased demand and lower supply largely responsible for higher Auction Clearing Prices relative to last year
 - ZDB rate of \$0.04 will be credited to load in Zones 2 through 10
- Regional generation supply is consistent with the 2017 OMS-MISO Survey
- No mitigation for physical or economic withholding by the IMM

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
 - MISO-wide reserve margin requirements
 - Zonal capacity requirements (Local Clearing Requirement)
 - Zonal transmission limitations (Capacity Import/Export Limits)
 - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The MISO-wide reserve margin requirement is shared among the Zones, and Zones may import capacity to meet this requirement
- Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:
 - Submit a Fixed Resource Adequacy Plan
 - Utilize bilateral contracts with another resource owner
 - Participate in the Planning Resource Auction
- The Independent Market Monitor reviews the auction results for physical and economic withholding

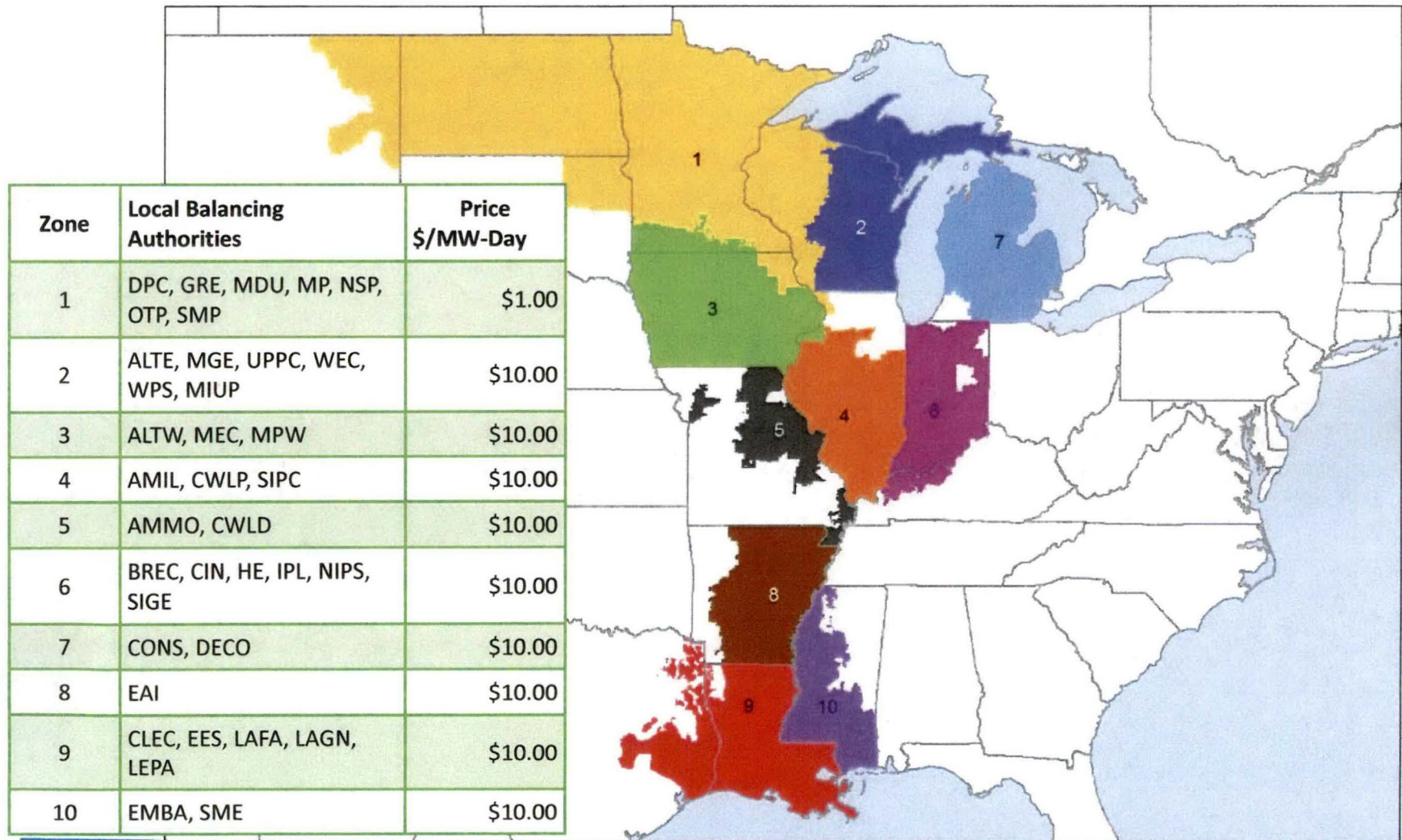
Auction Output and Settlements

- Key outputs from the Auction
 - A commitment of capacity to the MISO region, including performance obligations and
 - The capacity price (Auction Clearing Price) for each Zone
- This price drives the settlements process
 - Load pays the Auction Clearing Price for the Zone in which it is physically located
 - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
 - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

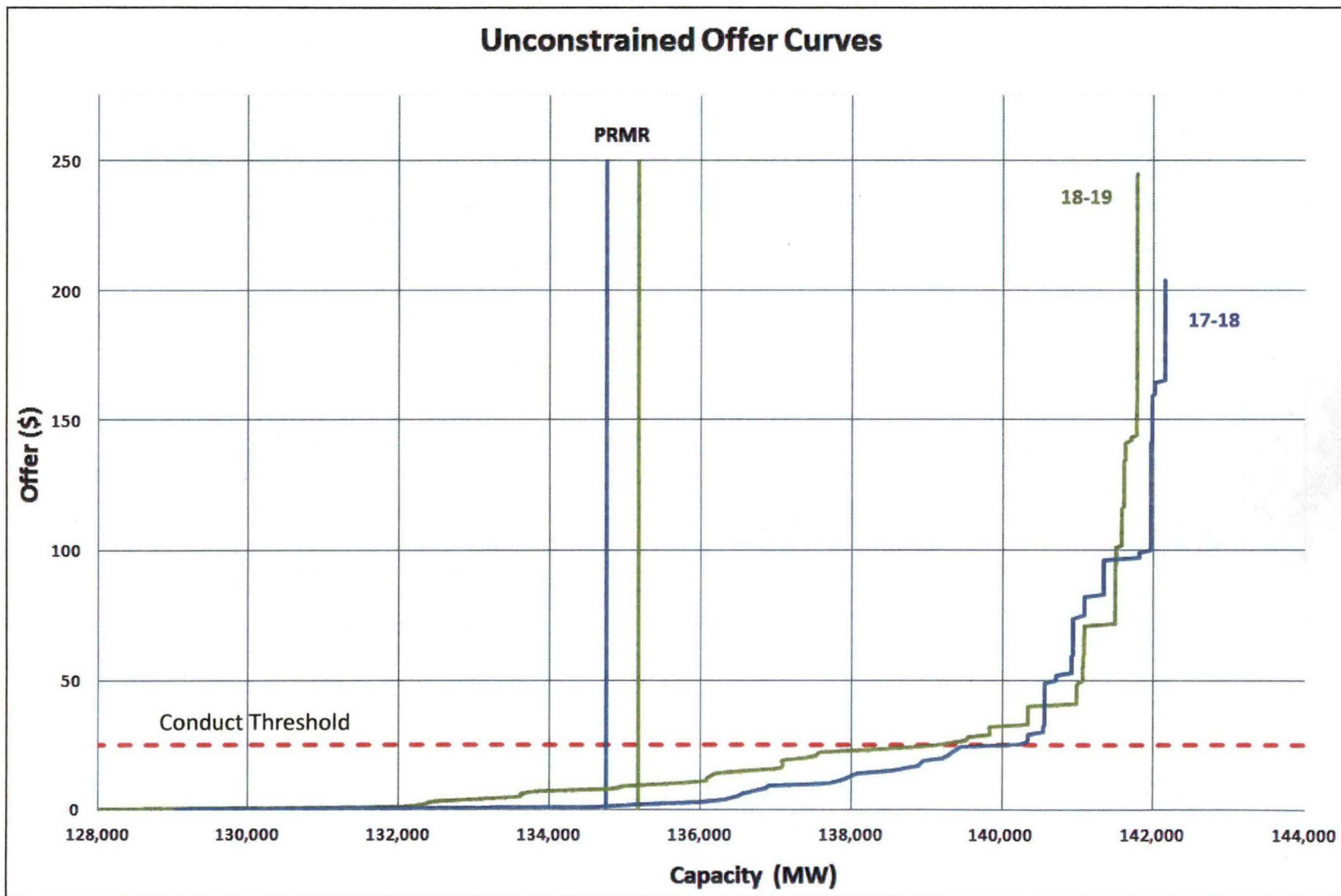
Approved Tariff filings since the 2017/2018 PRA

- Tariff revisions approved in FERC Docket ER17-892-000 and -001 documenting the calculation of Sub-Regional Import and Export Constraints and the Independent Market Monitor's calculation of going-forward costs for Reference Levels.
- Tariff revisions approved in FERC Docket ER17-2112 to authorize the extension or reopening of the Planning Resource Auction ("PRA") offer window when necessitated by unanticipated events.
- Tariff revisions approved in FERC Docket ER18-75-000 to allow Market Participants greater flexibility in the qualification of certain resource types for the Planning Resource Auction, allowing for additional components of Installed Capacity to be deferred in addition to the Generation Verification Test Capacity (GVTC).
- Re-filed Tariff provisions (no changes) regarding Planning Resource Auction re-approved in FERC Docket ER18-462-000.

2018/2019 Auction Clearing Price Overview



MISO Offer Curve, 2017/2018 vs. 2018/2019



Auction Clearing Prices Since 2014-15 PRA

\$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	\$3.29	\$16.75					\$16.44		N/A	
2015-2016 ACP*	\$3.48		\$150.00	\$3.48			\$3.29		N/A	
2016-2017 ACP*	\$19.72	\$72.00					\$2.99			
2017-2018 ACP*	\$1.50									
2018-2019 ACP*	\$1.00	\$10.00								
<i>Conduct Threshold</i>	\$24.76	\$24.25	\$24.35	\$24.62	\$25.07	\$24.45	\$24.86	\$23.63	\$22.81	\$23.63
<i>Cost of New Entry</i>	\$247.59	\$242.47	\$243.48	\$246.22	\$250.66	\$244.52	\$248.60	\$236.30	\$228.11	\$236.30

- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is \$0 for a generator with a facility specific Reference Level

Additional Details Regarding Supply

Planning Resource Type	2018-2019 Offered	2017-2018 Offered	2018-2019 Cleared	2017-2018 Cleared
Generation	126,159	127,637	120,855	121,807
External Resources	3,903	4,029	3,089	3,378
Behind the Meter Generation	4,176	3,678	4,098	3,456
Demand Resources	7,370	6,704	6,964	6,014
Energy Efficiency	173	98	173	98
Total	141,781	142,146	135,179	134,753

- Demand Resource quantities include Aggregators of Retail Customers (ARCs) that registered for the 2018-19 PRA

2018/2019 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,414	13,463	9,805	10,060	8,549	18,741	22,121	8,088	20,976	4,963	135,179
Total Offer Submitted (Including FRAP)	19,560	13,954	10,884	11,002	7,944	19,221	22,036	10,939	21,196	5,046	141,781
FRAP	14,431	11,196	4,170	1,136	0	1,803	12,255	440	172	1,428	47,030
Self Scheduled (SS)	4,046	1,930	5,979	6,636	7,934	16,105	9,193	9,706	16,509	2,858	80,896
Non-SS Offer Cleared	453	215	308	1,155	10	1,179	352	241	2,782	558	7,253
Total Committed (Offer Cleared + FRAP)	18,930	13,342	10,456	8,927	7,944	19,087	21,801	10,387	19,463	4,844	135,179
LCR	15,832	12,373	7,374	4,960	5,693	12,090	20,628	4,744	19,319	4,463	N/A
CIL	4,415	2,595	3,369	6,411	4,332	7,941	3,785	4,834	3,622	2,688	N/A
Import	0	121	0	1,133	606	0	320	0	1,513	120	3,812
CEL	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824	N/A
Export	516	0	651	0	0	346	0	2,299	0	0	3,812
ACP (\$/MW-Day)	\$1.00	\$10.00	\$10.00	\$10.00	\$10.00	\$10.00	\$10.00	\$10.00	\$10.00	\$10.00	N/A



* Values displayed in MW UCAP

Next Steps

- Detailed results review at May 9 Resource Adequacy Subcommittee (RASC)
- Posting of PRA offer data 30 days after PRA conclusion – May 18
- Results from previous Planning Resource Auctions can be found on the MISO website at: Planning-> Resource Adequacy -> PRA Document

Acronyms

- ACP - Auction Clearing Price (\$/MW-Day)
- ARC - Aggregator of Retail Customers
- BTMG – Behind the Meter Generator
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CONE – Cost of New Entry
- FRAP - Fixed Resource Adequacy Plan (MW)
- FSRL – Facility Specific Reference Level (\$/MW-Day)
- LCR - Local Clearing Requirement (MW)
- LMR – Load Modifying Resource
- LRZ - Local Resource Zone
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- ZDB – Zonal Deliverability Benefit
- ZRC – Zonal Resource Credit

BIG RIVERS ELECTRIC CORPORATION
2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1 **Item 29)** *Refer to the IRP, Chapter 7, Section 7.2.1, page 119, regarding*
2 *natural gas prices. Provide the difference in cost between a firm and*
3 *interruptible gas supply.*

4
5 **Response)** Please see the attached schedule, which is partly CONFIDENTIAL,
6 displaying the interruptible gas charge and the firm gas charge. Please note the
7 demand charge (fixed cost) as shown on Table 7.7, page 120, of the IRP would need
8 to be added to the firm gas cost. The cost difference between firm and interruptible
9 gas supply would depend on the gas used as the demand charge (fixed cost) and would
10 be much higher during low gas usage and lower during high gas usage on a \$/MMBtu
11 basis since the demand charge is owed even if no gas is consumed.

12

13

14 **Witness)** Duane E. Braunecker

15

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2020	1		\$ 0.67			\$ 0.05		
2020	2		\$ 0.67			\$ 0.05		
2020	3		\$ 0.67			\$ 0.05		
2020	4		\$ 0.67			\$ 0.05		
2020	5		\$ 0.67			\$ 0.05		
2020	6		\$ 0.67			\$ 0.05		
2020	7		\$ 0.67			\$ 0.05		
2020	8		\$ 0.67			\$ 0.05		
2020	9		\$ 0.67			\$ 0.05		
2020	10		\$ 0.67			\$ 0.05		
2020	11		\$ 0.67			\$ 0.05		
2020	12		\$ 0.67			\$ 0.05		
2021	1		\$ 0.67			\$ 0.05		
2021	2		\$ 0.67			\$ 0.05		
2021	3		\$ 0.67			\$ 0.05		
2021	4		\$ 0.67			\$ 0.05		
2021	5		\$ 0.67			\$ 0.05		
2021	6		\$ 0.67			\$ 0.05		
2021	7		\$ 0.67			\$ 0.05		
2021	8		\$ 0.67			\$ 0.05		

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2021	9		\$ 0.67			\$ 0.05		
2021	10		\$ 0.67			\$ 0.05		
2021	11		\$ 0.67			\$ 0.05		
2021	12		\$ 0.67			\$ 0.05		
2022	1		\$ 0.67			\$ 0.05		
2022	2		\$ 0.67			\$ 0.05		
2022	3		\$ 0.67			\$ 0.05		
2022	4		\$ 0.67			\$ 0.05		
2022	5		\$ 0.67			\$ 0.05		
2022	6		\$ 0.67			\$ 0.05		
2022	7		\$ 0.67			\$ 0.05		
2022	8		\$ 0.67			\$ 0.05		
2022	9		\$ 0.67			\$ 0.05		
2022	10		\$ 0.67			\$ 0.05		
2022	11		\$ 0.67			\$ 0.05		
2022	12		\$ 0.67			\$ 0.05		
2023	1		\$ 0.67			\$ 0.05		
2023	2		\$ 0.67			\$ 0.05		
2023	3		\$ 0.67			\$ 0.05		
2023	4		\$ 0.67			\$ 0.05		

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2023	5		\$ 0.67			\$ 0.05		
2023	6		\$ 0.67			\$ 0.05		
2023	7		\$ 0.67			\$ 0.05		
2023	8		\$ 0.67			\$ 0.05		
2023	9		\$ 0.67			\$ 0.05		
2023	10		\$ 0.67			\$ 0.05		
2023	11		\$ 0.67			\$ 0.05		
2023	12		\$ 0.67			\$ 0.05		
2024	1		\$ 0.67			\$ 0.05		
2024	2		\$ 0.67			\$ 0.05		
2024	3		\$ 0.67			\$ 0.05		
2024	4		\$ 0.67			\$ 0.05		
2024	5		\$ 0.67			\$ 0.05		
2024	6		\$ 0.67			\$ 0.05		
2024	7		\$ 0.67			\$ 0.05		
2024	8		\$ 0.67			\$ 0.05		
2024	9		\$ 0.67			\$ 0.05		
2024	10		\$ 0.67			\$ 0.05		
2024	11		\$ 0.67			\$ 0.05		
2024	12		\$ 0.67			\$ 0.05		

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2025	1		\$ 0.67			\$ 0.05		
2025	2		\$ 0.67			\$ 0.05		
2025	3		\$ 0.67			\$ 0.05		
2025	4		\$ 0.67			\$ 0.05		
2025	5		\$ 0.67			\$ 0.05		
2025	6		\$ 0.67			\$ 0.05		
2025	7		\$ 0.67			\$ 0.05		
2025	8		\$ 0.67			\$ 0.05		
2025	9		\$ 0.67			\$ 0.05		
2025	10		\$ 0.67			\$ 0.05		
2025	11		\$ 0.67			\$ 0.05		
2025	12		\$ 0.67			\$ 0.05		
2026	1		\$ 0.67			\$ 0.05		
2026	2		\$ 0.67			\$ 0.05		
2026	3		\$ 0.67			\$ 0.05		
2026	4		\$ 0.67			\$ 0.05		
2026	5		\$ 0.67			\$ 0.05		
2026	6		\$ 0.67			\$ 0.05		
2026	7		\$ 0.67			\$ 0.05		
2026	8		\$ 0.67			\$ 0.05		

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2026	9		\$ 0.67			\$ 0.05		
2026	10		\$ 0.67			\$ 0.05		
2026	11		\$ 0.67			\$ 0.05		
2026	12		\$ 0.67			\$ 0.05		
2027	1		\$ 0.67			\$ 0.05		
2027	2		\$ 0.67			\$ 0.05		
2027	3		\$ 0.67			\$ 0.05		
2027	4		\$ 0.67			\$ 0.05		
2027	5		\$ 0.67			\$ 0.05		
2027	6		\$ 0.67			\$ 0.05		
2027	7		\$ 0.67			\$ 0.05		
2027	8		\$ 0.67			\$ 0.05		
2027	9		\$ 0.67			\$ 0.05		
2027	10		\$ 0.67			\$ 0.05		
2027	11		\$ 0.67			\$ 0.05		
2027	12		\$ 0.67			\$ 0.05		
2028	1		\$ 0.67			\$ 0.05		
2028	2		\$ 0.67			\$ 0.05		
2028	3		\$ 0.67			\$ 0.05		
2028	4		\$ 0.67			\$ 0.05		

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu							
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu		
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas
2028	5		\$ 0.67			\$ 0.05	
2028	6		\$ 0.67			\$ 0.05	
2028	7		\$ 0.67			\$ 0.05	
2028	8		\$ 0.67			\$ 0.05	
2028	9		\$ 0.67			\$ 0.05	
2028	10		\$ 0.67			\$ 0.05	
2028	11		\$ 0.67			\$ 0.05	
2028	12		\$ 0.67			\$ 0.05	
2029	1		\$ 0.67			\$ 0.05	
2029	2		\$ 0.67			\$ 0.05	
2029	3		\$ 0.67			\$ 0.05	
2029	4		\$ 0.67			\$ 0.05	
2029	5		\$ 0.67			\$ 0.05	
2029	6		\$ 0.67			\$ 0.05	
2029	7		\$ 0.67			\$ 0.05	
2029	8		\$ 0.67			\$ 0.05	
2029	9		\$ 0.67			\$ 0.05	
2029	10		\$ 0.67			\$ 0.05	
2029	11		\$ 0.67			\$ 0.05	
2029	12		\$ 0.67			\$ 0.05	

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2030	1		\$ 0.67			\$ 0.05		
2030	2		\$ 0.67			\$ 0.05		
2030	3		\$ 0.67			\$ 0.05		
2030	4		\$ 0.67			\$ 0.05		
2030	5		\$ 0.67			\$ 0.05		
2030	6		\$ 0.67			\$ 0.05		
2030	7		\$ 0.67			\$ 0.05		
2030	8		\$ 0.67			\$ 0.05		
2030	9		\$ 0.67			\$ 0.05		
2030	10		\$ 0.67			\$ 0.05		
2030	11		\$ 0.67			\$ 0.05		
2030	12		\$ 0.67			\$ 0.05		
2031	1		\$ 0.67			\$ 0.05		
2031	2		\$ 0.67			\$ 0.05		
2031	3		\$ 0.67			\$ 0.05		
2031	4		\$ 0.67			\$ 0.05		
2031	5		\$ 0.67			\$ 0.05		
2031	6		\$ 0.67			\$ 0.05		
2031	7		\$ 0.67			\$ 0.05		
2031	8		\$ 0.67			\$ 0.05		

Big Rivers Electric Corporation
Case No. 2017-00384
Interruptible Gas Charge and Firm Gas Charge

Projected Interruptible and Firm Gas Prices, \$/MMBtu								
Year	Month	Henry Hub Spot Price (5 2-17 Prices)	Interruptible Gas, \$/MMBtu		Firm Gas Supply, \$/MMBtu			
			Delivery Charge	Total	Losses (1% of spot)	Flow Charge	Gas	Demand Charge*
2031	9		\$ 0.67			\$ 0.05		
2031	10		\$ 0.67			\$ 0.05		
2031	11		\$ 0.67			\$ 0.05		
2031	12		\$ 0.67			\$ 0.05		

* Please see Table 7.7 for the Firm Gas Demand charge for Green Station and Station Two

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
First Request for Information
dated June 22, 2018**

July 20, 2018

1 **Item 30) Refer to Chapter 7, Section 7.2.2, Base Case Results, page 123.**
2 **Also refer to the February 27, 2018 supplemental information to Big Rivers**
3 **Electric Corporation's Annual Financial and Statistical Report Pursuant to**
4 **Administrative Case No. 387, Item 8. Reconcile the reserve margins in Table**
5 **1 of the February filing to the Reserve Capacity Margin in Table 7.8 of the**
6 **IRP.**

7

8 **Response)** There are several reasons the reserve margins in Table 1 of the
9 February 28, 2018, filing in Administrative Case No. 387 ("the February 28th filing")
10 and the Reserve Capacity Margin in Table 7.8 of the IRP are different. Table 1 of the
11 February 28th filing requests projected reserve margins as a percentage of demand
12 for the current year and the following four years; Table 7.8 is a calculation of Capacity
13 Margin through 2031.

14 Table 7.8 of the IRP is the result of the *PLEXOS*® LT Plan®-developed optimal
15 portfolio of energy resources and any future capacity for the 15 year period of the IRP,
16 and thus did not include short term executed capacity sales. Table 1 of the February
17 28th filing does include executed short term capacity transactions, as well as the sale
18 to KyMEA. It does not, however, include Nebraska sales in the short term since
19 capacity purchases are more beneficial than delivering Big Rivers' generation to
20 Nebraska over the short term.

21

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
First Request for Information
dated June 22, 2018**

July 20, 2018

1 Table 7.8 used forecasted hourly loads for native load, Nebraska and KyMEA to get
2 a coincidence peak load requirement, while Table 1 of Item 8 in the February 28th
3 filing included KyMEA sales at full capacity.

4 On May 1, 2018, Big Rivers delivered notice to Henderson Municipal Power &
5 Light ("HMP&L") that the Station Two contracts, except for the Joint Facilities
6 Agreement, had terminated. Since that notice had not been made when Table 1 of
7 Item 8 in the February 28th filing, it did not account for the termination of the Station
8 Two contracts. In Table 1, Big Rivers' share of HMP&L Station Two was expected to
9 continue throughout the period, at a reduced share based upon anticipated annual
10 reservation by HMP&L, while Table 8 of the IRP has Big Rivers' share of Station Two
11 dropping to zero in 2020 per the Base Case optimal portfolio.

12 Attached hereto is a reconciliation of the reserve margins between the 2017
13 IRP's Table 7.8 and Table 1 in the Item 8 response of the February 28th filing. When
14 formulating this reconciliation, Big Rivers discovered a calculation error in the
15 February 28th filing. This error resulted in a double-counting of the SEPA allocation
16 for the 5 years presented in the Item 8 table. A new Table 1 with corrected
17 calculations is attached hereto.

18

19 **Witnesses)** Marlene S. Parsley and

20 Duane E. Braunecker (*IRP Table 7.8 – PLEXOS® LT Plan® only*)

21

**Big Rivers Electric Corporation
Case No. 2017-00384**

Reconciliation of Reserve Margins - 2017 IRP Table 7.8 v. Administrative Case No. 387, Item 8, Table 1

Gen ICAP				Peak Load								
Resource Component	IRP Table 7.8	Admin 387 Item 8	ICAP Difference	Load Component	IRP Table 7.8	Admin 387 Item 8	Peak Load Difference					
Wilson 1	417	417	0	Native NCP	645	645	0					
Green 1	231	231	0	Nebraska								
Green 2	223	223	0	KyMEA								
HMP&L 2 (net cap for Big Rivers)	197	197	0	Coincidence Factor	(5)		(5)					
	65	65	0	Executed Capacity Sales Including KyMEA and Short Term Bilateral Capacity Sales	0	291	(291)					
Reid CT SEPA	154	154	0									
Calculation Error (double counted SEPA in Admin 387 spreadsheet)		154	(154)									
2018	Resource ICAP	1,287	1,441	(154)	Load Component	659	936	(277)	628	505	123	2018
Wilson 1	417	417	0	Native NCP	658	658	0					
Green 1	231	231	0	Nebraska								
Green 2	223	223	0	KyMEA								
HMP&L 2 (net cap for Big Rivers)	197	192	5	Coincidence Factor	(21)		(21)					
	65	65	0	Executed Capacity Sales Including KyMEA and Short Term Bilateral Capacity Sales		348	(348)					
Reid CT SEPA	178	178	0									
Calculation Error (double counted SEPA in Admin 387 spreadsheet)		154	(154)									
2019	Resource ICAP	1,311	1,460	(149)	Load Component	793	1,006	(213)	518	454	64	2019

**Big Rivers Electric Corporation
Case No. 2017-00384**

Reconciliation of Reserve Margins - 2017 IRP Table 7.8 v. Administrative Case No. 387, Item 8, Table 1

Gen ICAP				Peak Load								
Resource Component	IRP Table 7.8	Admin 387 Item 8	ICAP Difference	Load Component	IRP Table 7.8	Admin 387 Item 8	Peak Load Difference	2017 IRP Table 7.8	Admin 387 Item 8	Net Difference		
Wilson 1	417	417	0	Native NCP	661	661	0					
Green 1	231	231	0	Nebraska								
Green 2	223	223	0	KyMEA								
HMP&L 2 (net cap for Big Rivers)	0	187	(187)	Coincidence Factor	(27)		(27)					
	65	65	0	Executed Capacity Sales Including KyMEA and Short Term Bilateral Capacity Sales		198	(198)					
Reid CT SEPA	178	178	0									
Calculation Error (double counted SEPA in Admin 387 spreadsheet)		178	(178)									
2020	Resource ICAP	1,114	1,479	(365)	Load Component	809	859	(50)	305	620	(315)	2020
Wilson 1	417	417	0	Native NCP	662	662	0					
Green 1	231	231	0	Nebraska								
Green 2	223	223	0	KyMEA								
HMP&L 2 (net cap for Big Rivers)	0	187	(187)	Coincidence Factor	(18)		(18)					
	65	65	0	Executed Capacity Sales Including KyMEA and Short Term Bilateral Capacity Sales		198	(198)					
Reid CT SEPA	178	178	0									
Calculation Error (double counted SEPA in Admin 387 spreadsheet)		178	(178)									
2021	Resource ICAP	1,114	1,479	(365)	Load Component	820	860	(40)	294	619	(325)	2021

Case No. 2017-00384

Attachment 1 for Response to PSC 1-30

Witnesses: Marlene S. Parsley and Duane E. Braunecker

**Big Rivers Electric Corporation
Case No. 2017-00384**

Reconciliation of Reserve Margins - 2017 IRP Table 7.8 v. Administrative Case No. 387, Item 8, Table 1

Gen ICAP				Peak Load							
Resource Component	IRP Table 7.8	Admin 387 Item 8	ICAP Difference	Load Component	IRP Table 7.8	Admin 387 Item 8	Peak Load Difference				
Wilson 1	417	417	0	Native NCP	663	663	0				
Green 1	231	231	0	Nebraska							
Green 2	223	223	0	KyMEA							
HMP&L 2 (net cap for Big Rivers)	0	187	(187)	Coincidence Factor	(20)		(20)				
				Executed Capacity Sales Including KyMEA and Short Term Bilateral Capacity Sales		198	(198)				
Reid CT											
SEPA	178	178	0								
Calculation Error (double counted SEPA in Admin 387 spreadsheet)		178	(178)								
2022	Resource ICAP	1,114	1,479	(365)	Load Component	828	861	(33)	Reserve Margin MW Differences		
									2017 IRP Table 7.8	Admin 387 Item 8	Net Difference
									286	618	(332)
											2022

BIG RIVERS ELECTRIC CORPORATION

**SUPPLEMENTAL INFORMATION PROVIDED WITH
BIG RIVERS' ANNUAL FINANCIAL AND STATISTICAL REPORT
PURSUANT TO ADMINISTRATIVE CASE NO. 387 –
A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION
CAPACITY AND TRANSMISSION SYSTEM**

**Response to Commission Staff's Information Request
as set forth in
Appendix G of the Commission's Order dated December 20, 2001**

February 28, 2018

1 Item 8) *Projected reserve margins stated in megawatts and as a*
2 *percentage of demand for the current year and the following four years.*
3 *Identify projected deficits and current plans for addressing these. For*
4 *each year identify the level of firm capacity purchases projected to meet*
5 *native load demand.*

6
7 Response) The revised numbers pursuant to Big Rivers' response to Item 30 of
8 Commission Staff's first request for information in Big Rivers' 2017 IRP, Case No.
9 2017-00384, are shown in Table 1 below. Big Rivers is still not projecting any
10 deficits.

11

Table 1

<u>Year</u>	<u>Reserve Margin (MW)</u>	<u>Reserve Margin (%)</u>	<u>Firm Capacity Purchases (MW)</u>	<u>Projected Deficit</u>
2018	<u>351</u>	<u>38%</u>	154 *	
2019	<u>276</u>	<u>27%</u>	154 *	
2020	<u>442</u>	<u>51%</u>	178 *	
2021	<u>441</u>	<u>51%</u>	178 *	
2022	<u>440</u>	<u>51%</u>	178 *	

12

BIG RIVERS ELECTRIC CORPORATION

**SUPPLEMENTAL INFORMATION PROVIDED WITH
BIG RIVERS' ANNUAL FINANCIAL AND STATISTICAL REPORT
PURSUANT TO ADMINISTRATIVE CASE NO. 387 –
A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION
CAPACITY AND TRANSMISSION SYSTEM**

**Response to Commission Staff's Information Request
as set forth in
Appendix G of the Commission's Order dated December 20, 2001**

February 28, 2018

1 * Southeastern Power Administration ("SEPA") is at reduced capacity
2 through 2019, and scheduled to resume full capacity in 2020 and
3 beyond following its expected return from Force Majeure status.
4 Coleman Station is excluded from reserve margin calculations since it
5 was idled in May 2014. Reid Station Unit 1 is excluded from reserve
6 margin calculation due to its idling in April 2016 as noted in Big
7 Rivers' response to Item 11. Big Rivers also filed this information in
8 its Attachment Y notification to MISO.

9
10
11 **Respondent)** Marlene S. Parsley
12

BIG RIVERS ELECTRIC CORPORATION
2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

- 1 **Item 31)** *Refer to the IRP, Chapter 7, Section 7.2.2, page 124, Table 7.9.*
2 *a. Explain the increase in the Kentucky Municipal Energy Association*
3 *("KyMEA") load between 2019 and 2020.*
4 *b. Identify each member of KyMEA and its MW load for 2019 through*
5 *2029.*
6 *c. Also, refer to the IRP, Chapter 7, Section 7.2.3.4, page 132, Table 7.16.*
7 *Explain why the KyMEA peak load is 100 MW given the difference*
8 *between the 2019 and 2029 loads as listed in Table 7.9.*

9
10 **Response)**

- 11 *a. On Table 7.9, Base Case Volume Summary, the increase in KyMEA MWh*
12 *load between 2019 and 2020 is due to Big Rivers' contract with KyMEA*
13 *beginning part way through the year 2019.*
14 *b. Current KyMEA members include the Barbourville Utility Commission,*
15 *the City of Bardwell, the Benham Power Board, the City of Berea, the*
16 *Corbin City Utilities Commission, the City of Falmouth, the Frankfort*
17 *Plant Board, the City of Madisonville, Owensboro Municipal Utilities, the*
18 *City of Paris, and the City of Providence. Big Rivers does not project the*
19 *KyMEA load by KyMEA member.*
20 *c. Table 7.16, New Non-Member Peak Load, MW reflects the summer capacity*
21 *requirements associated with KyMEA load.*

22
23 **Witness)** Marlene S. Parsley

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

**Response to Commission Staff's
First Request for Information
dated June 22, 2018**

July 20, 2018

1 **Item 32)** *Refer to the IRP, Chapter 7, Section 7.2.3.5, Renewable Portfolio*
2 *Standards Scenario, page 133. Provide the amount and type of solar energy*
3 *the long-term plan modeled.*

4

5 **Response)** Please see Table 7.4, page 114 and Table 7.5, page 115 of the IRP. Big
6 Rivers modeled fixed solar at 20 MW capacity increments at the cost provided in
7 Table 7.4. Please see Table 7.18, page 134 of the IRP showing for the Renewable
8 Portfolio Standards Scenario, Big Rivers would build 100 MW (5 units) of solar in
9 2020, 40 MW (2 units) in 2025, and 40 MW (2 units) in 2030 which totals 180 MW (9
10 units) of solar energy.

11

12

13 **Witness)** Duane E. Braunecker

14

BIG RIVERS ELECTRIC CORPORATION

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July 20, 2018

1 **Item 33) *Refer to the IRP, Chapter 9, Section 9.1, page 149, regarding***
2 ***MISO's compliance requirements. If Big Rivers has been assessed any***
3 ***administrative penalties, provide the date(s), amount(s), and an explanation***
4 ***of any penalty levied by MISO.***

5

6 **Response) No such administrative penalties have been assessed to Big Rivers.**

7

8

9 **Witnesses) Marlene S. Parsley and**

10 **Christopher S. Bradley**

11

BIG RIVERS ELECTRIC CORPORATION

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1 **Item 34)** *Refer to the IRP, Chapter 9, Section 9.4.1, page 160, regarding Big*
2 *Rivers' projected reserve margins. Provide a timetable of the projected*
3 *reserve margins since 2010.*

4

5 **Response)** Please see the attached schedule. Based on this analysis, the statement
6 on page 160 of its 2017 IRP should be revised to read (revision underlined), "Big
7 *Rivers projected reserve margins have been between 10% and 149% since 2010 when*
8 *Big Rivers turned over functional control of its transmission system to MISO."*

9

10

11 **Witness)** Marlene S. Parsley.

12

Big Rivers Electric Corporation
Case No. 2017-00384
Reserve Margin History since 2010

Year reported	2011		2012		2013		2014		2015		2016		2017		2018	
Projected Year	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)	Reserve Margin (MW)	Reserve Margin (%)
2011	247	13%														
2012	235	13%	230	13%												
2013	229	12%	207	11%	226	12%										
2014	222	12%	199	11%	686	37%	913	125%								
2015	214	12%	192	10%	1,060	57%	1,086	149%	799	114%						
2016			183	10%	1,052	57%	968	115%	666	80%	649	83%				
2017					1,044	57%	851	89%	553	59%	636	80%	396	38%		
2018							737	69%	482	45%	560	64%	649	83%	351	38%
2019									371	32%	532	53%	520	54%	276	27%
2020											410	36%	464	46%	442	51%
2021													455	44%	441	51%
2022															440	51%

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July 20, 2018

1 Item 35) *Refer to Appendix A, Section 1.5, Load Forecast Summary, page*
2 *5.*

3 *a. Explain how Big Rivers plans to increase sales to direct-serve*
4 *customers.*

5 *b. Explain Big Rivers' plan, should there be a lack of positive impact*
6 *on native sales, if the increase in sales to direct-serve customers is*
7 *less than expected.*

8

9 **Response)**

10 a. Currently, one direct-serve customer is expanding its load under an
11 Economic Development Rate. See Big Rivers' response to Item 38 of the
12 Commission Staff's first request for information in this case for a discussion
13 of Big Rivers' economic development efforts.

14 b. Big Rivers is not forecasting a significant long-term impact from increased
15 sales to direct-serve customers. If the increase in sales is less than
16 expected, Big Rivers may choose to increase economic development
17 incentives, identify additional non-Member load, or adjust its integrated
18 resource plan.

19

20

21 **Witness)** Marlene S. Parsley

22