August 18, 2015

VIA ELECTRONIC FILING

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

Re:  Midcontinent Independent System Operator, Inc.’s Compliance Filing for  
Order No. 1000, Regarding Interregional Coordination with SPP  

Dear Secretary Bose:

Pursuant to Section 206 of the Federal Power Act (“FPA”), 16 U.S.C. 824e, and the requirements of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) February 19, 2015 Order on Compliance¹, the Midcontinent Independent System Operator, Inc. (“MISO”) submits for filing proposed revisions to the Joint Operating Agreement between MISO and the Southwest Power Pool, Inc. (“JOA”)² to comply with the requirements of the February 19 Order regarding Order No. 1000’s³ interregional planning and cost allocation requirements as applicable to MISO and the Southwest Power Pool, Inc. (“SPP”).

MISO and SPP have engaged in extensive outreach and coordination. Significantly, the parties have reached full agreement on all points at issue in this compliance filing and have

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¹ Order on Compliance Filings, 150 FERC ¶ 61,093 (Feb. 19, 2015) (“February 19 Order”).

² The formal name of the JOA is the “Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and Southwest Power Pool, Inc.” The JOA is a FERC-filed rate schedule of both MISO and SPP and is designated as MISO’s Second Revised Rate Schedule FERC No. 6; and as SPP’s Second Revised Rate Schedule FERC No. 9. See Sw. Power Pool, Inc., 109 FERC ¶ 61,008 (2004), reh’g denied, 110 FERC ¶ 61,031 (2005).

collaborated in drafting their transmittal letters. Accordingly, MISO and SPP hereby are submitting (by separate filings made contemporaneously) parallel JOA language to comply with the February 19 Order. MISO requests that the proposed revisions be made effective as of March 30, 2014, consistent with the effective date granted in the February 19 Order.

I. BACKGROUND

A. Order No. 1000’s Interregional Transmission Coordination and Cost Allocation Requirements

Order No. 1000 expanded on the planning requirements of Order No. 890 by requiring each public utility transmission provider to establish procedures with each of its neighboring transmission planning regions for purposes of coordinating and sharing regional transmission plans to identify possible interregional transmission facilities that are more efficient and cost-effective than separate, regional solutions to each region’s needs. Order No. 1000 also required neighboring transmission planning regions to jointly evaluate those interregional facilities that both regions had identified through their regional processes, including those proposed by transmission developers and stakeholders.

To facilitate interregional evaluation and cost allocation, the Commission required each public utility transmission provider to: (1) explain in their Tariffs how stakeholders and developers can propose interregional transmission facilities for joint evaluation; and (2) develop, with each neighboring planning region, a common set of methods for allocating the costs of a new interregional facility among the beneficiaries in each region. The Commission required that the common set of methods satisfy six interregional cost allocation principles. A proposed interregional transmission project would become eligible for interregional cost

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5 Order No. 1000-A at P 493 (citing Order No. 1000 at P 398).

6 Id. at P 522.

7 Id.

8 Order No. 1000 at PP 578, 582.

9 Id. at PP 603, 622-693. The six cost allocation principles are: (1) costs must be allocated in a way that is roughly commensurate with benefits; (2) there must be no involuntary cost allocation to non-beneficiaries; (3) a benefit to cost threshold ratio cannot exceed 1.25; (4) costs must be allocated solely within the transmission planning region or pair of regions unless those outside the region or pair of regions voluntarily assume costs; (5) there must be a transparent method for determining benefits and identifying beneficiaries; and (6) there may be different methods for different types of transmission facilities.
allocation by being selected in the regional plans of the two neighboring planning regions in which the facility is to be located.\(^\text{10}\)

**B. First Compliance Filings**

On July 10, 2013, MISO submitted its compliance with Order No. 1000’s interregional coordination and evaluation requirements in two related filings pursuant to FPA § 206 (collectively the “MISO Compliance Filings”). The first filing, made in Commission Docket No. ER13-1938 (“JOA Filing”), proposed revisions to Article IX of the JOA to implement MISO and SPP’s agreements regarding evaluation and cost allocation of proposed Interregional Projects (“JOA Filing”).\(^\text{11}\) The JOA Filing proposed clarifications and modifications to the existing JOA.\(^\text{12}\) The second filing, made in Commission Docket No. ER13-1945, proposed modifications to Attachment FF of MISO’s Tariff to comply with the Commission’s requirement that the Tariff identify interregional arrangements that are in the form of agreements (“Attachment FF Filing”).\(^\text{13}\) The Attachment FF Filing proposed language identifying the interregional coordination procedures proposed in the JOA Filing.\(^\text{14}\)

On July 10, 2013, SPP made its own, separate compliance filings proposing competing modifications to the JOA\(^\text{15}\) (“SPP Filings”) in Docket Nos. ER13-1937 and ER13-1939. MISO and SPP agreed on most aspects of the JOA revisions but filed separately due to disagreements on certain interregional cost allocation matters.\(^\text{16}\) Specifically, SPP and MISO agreed on all proposed revisions to the JOA, except the proposed language in Sections 9.6.3.1.iii (Criteria for Project Designation as an Interregional Project), 9.6.3.1.1 (Determination of Benefits to each RTO from Interregional Project) and 9.3.3.4.1 (Evaluating Potential Impact of Proposed Interregional Projects to Other Transmission Planning Regions).

MISO’s JOA Filing and Attachment FF Filing proposed JOA and Tariff modifications relating to: (1) interregional coordination in general; (2) data exchange and facility identification;

\(^{10}\) *Id.* at P 400.


\(^{12}\) *Id.*


\(^{14}\) *Id.*


\(^{16}\) *February 19 Order* at P 7.
(3) procedures for joint evaluation of projects; (4) transparency and stakeholder participation; (5) project types eligible for interregional cost allocation; and (6) cost allocation methodologies.\textsuperscript{17}

C. February 19 Order

On February 19, 2015, the Commission entered an Order accepting MISO and SPP’s filings in part, effective March 30, 2014, subject to a further compliance filing to be made within sixty days, as discussed below.\textsuperscript{18}

1. Common Language & Definition of Interregional Projects

MISO and SPP submitted common language related to interregional coordination except for matters relating to cost allocation, on which they disagreed.\textsuperscript{19} MISO and SPP proposed to comply with the interregional transmission coordination requirements of Order 1000 through modifications to the existing JOA.\textsuperscript{20} The Commission partially accepted MISO and SPP’s proposals, holding that the parties had complied with the requirement to coordinate with neighboring transmission providers and proposed substantially similar coordination language with the exception of certain JOA sections relating to cost allocation.\textsuperscript{21} The Commission therefore conditionally accepted much of SPP and MISO’s proposed JOA language, effective March 30, 2014, subject to further compliance due within sixty days.\textsuperscript{22} The Commission directed the parties to agree on a common interregional cost allocation method and reconcile their proposed language on compliance.\textsuperscript{23}

The February 19 Order rejected MISO and SPP’s proposed definition of an “Interregional Project” as unduly limited to facilities that interconnect to existing facilities under the control of SPP and MISO.\textsuperscript{24} The Commission found that this definition would exclude facilities that are currently under development. The Commission directed MISO and SPP to revise this definition on compliance.\textsuperscript{25}

\textsuperscript{17} See generally, JOA Filing; Attachment FF Filing.
\textsuperscript{18} February 19 Order at P 31.
\textsuperscript{19} Id. at P 27
\textsuperscript{20} Id. at P 26.
\textsuperscript{21} Id. at P 29.
\textsuperscript{22} Id. at P 31.
\textsuperscript{23} Id. at P 29.
\textsuperscript{24} Id. at P 30.
\textsuperscript{25} Id.
2. Data exchange and Facility Identification

MISO and SPP proposed to comply with Order No. 1000’s data exchange and facility identification requirements by exchanging, at least annually, planning information including:

1. power flow models for the length of the planning horizon;
2. system stability models;
3. production cost models (including load forecasts and facility plans); and
4. contingency lists and assumptions for these models.  

Additional types of models, studies and data would be exchanged upon request or pursuant to an agreed schedule. MISO and SPP also proposed to share, on an ongoing basis, information developed through each party’s planning process needed for interregional coordination.

MISO and SPP proposed to jointly evaluate Transmission Issues and potential interregional solutions through the JOA’s Coordinated System Plan (“CSP”) study provisions and through evaluations performed by the MISO-SPP Joint Planning Committee (“JPC”). MISO and SPP proposed that the Interregional Planning Stakeholder Advisory Committee (“IPSAC”) will meet at least annually to review and discuss proposed Transmission Issues and interregional solutions, with more frequent meetings when a CSP study is being conducted. Any entity would be allowed to identify Transmission Issues. MISO and SPP also proposed procedures and timelines for triggering a CSP study, determining its scope, and for stakeholder notice and participation on the actions of the IPSAC, JPC and the formulation of CSP studies.

The Commission partially accepted MISO and SPP’s data exchange and facility identification proposals, finding that they included acceptable provisions for identifying and evaluating Transmission Issues, procedures for initiating a CSP study, the types or models and analysis to be used during the CSP study, and procedures for third parties to propose projects. However, the Commission rejected MISO and SPP’s proposal to require an entity to provide the analysis to support a Transmission Issue it proposes, finding this requirement unduly vague and burdensome. Finally, the Commission accepted a proposal by MISO and SPP in their answers.

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26 Id. at P 34.
27 Id. at P 35.
28 Id. at P 36.
29 Id.
30 Id.
31 Id. at PP 37-38.
32 Id. at P 50.
33 Id. at P 52.
to define “Transmission Issue” in the JOA to include issues driven by reliability, economics, and public policy requirements and directed MISO and SPP to implement this change.\textsuperscript{34}

3. Joint Evaluation Procedures & Consideration of Benefits

MISO and SPP proposed to jointly evaluate identified transmission solutions as part of the CSP study process. The JPC would develop joint and common models and analyses for use by both regions, provide a draft CSP study report to the IPSAC for comment, and submit recommended solutions for approval by both MISO and SPP’s regional processes. This joint evaluation process would occur concurrent with the regional processes.\textsuperscript{35}

The Commission partially accepted MISO and SPP’s proposed joint evaluation procedures, finding that they satisfied Order No. 1000’s requirements to describe the types of studies to be conducted, develop a procedure for harmonizing models and assumptions, and evaluate Interregional Projects in the same general timeframe as regional projects, and provide a process for stakeholders to present proposals.\textsuperscript{36} However, the Commission found that MISO’s proposal to use an adjusted production cost savings metric to measure economic benefits would not allow for the evaluation of project benefits associated with reliability or public policy-driven needs and, therefore, did not comply with Order No. 1000.\textsuperscript{37} The Commission found that SPP’s proposal to consider economic benefit by measuring adjusted production cost savings and consider reliability benefits by measuring a combination of avoided costs and adjusted production cost savings would not allow for the evaluation of project benefits associated with public-policy driven needs and, therefore, also did not comply with Order No. 1000.\textsuperscript{38} Accordingly, the Commission directed MISO and SPP to submit, on compliance, JOA revisions to consider proposals that resolve transmission needs driven by reliability and/or public policy.\textsuperscript{39}

4. Transparency and Stakeholder Participation

MISO and SPP proposed that each Regional Transmission Organization (“RTO”) provide its own website for communicating information related to interregional transmission coordination procedures and will coordinate the types of information to be posted to ensure consistency.\textsuperscript{40} Stakeholders could provide feedback through submitting issues to, and reviewing

\textsuperscript{34} \textit{Id.} at P 50.

\textsuperscript{35} \textit{Id.} at PP 557-58.

\textsuperscript{36} \textit{Id.} at PP 67-70.

\textsuperscript{37} \textit{Id.} at P 73.

\textsuperscript{38} \textit{Id.} at P 74.

\textsuperscript{39} \textit{Id.} at P 75.

\textsuperscript{40} \textit{Id.} at P 78.
issues identified by each RTO’s regional processes and through participation in the IPSAC, which will make recommendations to the JPC.  

The Commission held that MISO and SPP’s proposals partly complied with Order No. 1000’s transparency and stakeholder participation requirements. While the Commission accepted the parties’ proposals relating to the posting and coordination of information, confidentiality provisions, and providing opportunities for stakeholder participation, the Commission directed MISO and SPP to clarify the IPSAC voting process.

5. Cost Allocation: Eligible Project Types

MISO and SPP were unable to fully agree on the appropriate criteria for determining whether a project is eligible for interregional cost allocation at the time they made their initial compliance filings. SPP and MISO agreed that to be eligible for interregional cost allocation, a project must:

(1) have a minimum total cost of $5 million;
(2) be evaluated as part of the CSP and recommended by the JPC;
(3) have benefits to SPP and MISO of 5% or greater of the total benefits identified for the combined SPP and MISO region; and
(4) have an in-service date within 10 years from final approval.

However, MISO and SPP’s proposals disagreed on a final criterion. MISO proposed to require that an Interregional Project be approved as a Market Efficiency Project (“MEP”) under MISO’s Tariff and as an Interregional Project under the SPP Tariff. SPP proposed that an Interregional Project must be “approved by both [p]arties in their respective regional planning process as outlined in their respective… Tariffs.”

The Commission accepted the agreed upon criteria but rejected MISO’s proposed MEP limitation, finding that it did not fully capture all potential benefits of an Interregional Project. The Commission directed MISO to adopt SPP’s proposed JOA language and further required that SPP and MISO post a list of all interregional transmission facilities that are proposed for selection in the regional transmission plans but that are found not to meet the relevant thresholds, as well as an explanation of the thresholds not satisfied.

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41 Id. at P 79.
42 Id. at P 84.
43 Id. at P 88.
44 Id. at P 102.
45 Id.
46 Id.
47 Id. at P 131.
48 Id. at P 133.
6. Cost Allocation Method

At the time of their initial filings, MISO and SPP were unable to reach agreement on the cost allocation method to be applied to Interregional Projects and each proposed its own methodology. MISO proposed to use adjusted production cost as the sole benefit metric to evaluate an Interregional Project.\(^49\) SPP proposed using adjusted production cost as the metric for economic projects, a combination of avoided cost and adjusted production cost for reliability projects, and another undetermined metric for public policy projects.\(^50\)

The Commission conditionally accepted MISO’s and SPP’s proposals, finding that they partially complied with Order No. 1000’s requirements that neighboring regions propose a common interregional cost allocation method.\(^51\) The Commission found that MISO’s proposal to use adjusted production cost for interregional facilities that address regional economic transmission needs was consistent with the first five Interregional Cost Allocation Principles but not with principle 6 because it does not include a cost allocation method for regional reliability and public policy needs.\(^52\) The Commission found that SPP’s proposal to use a combination of avoided cost and adjusted production cost for interregional facilities that address regional reliability needs and adjusted production cost for interregional facilities that address regional economic needs also satisfied the first five Interregional Cost Allocation Principles but did not comport with principle 6 because it did not account for public policy-driven needs.\(^53\) Accordingly, the Commission: (1) directed SPP and MISO to submit on compliance a new interregional cost allocation method that applies to interregional facilities addressing regional public policy and are eligible to be selected in both SPP’s and MISO’s regional planning processes for purposes of cost allocation and (2) directed MISO to revise its version of the JOA to adopt SPP’s cost allocation method for facilities addressing reliability needs or propose different agreed cost allocation methods to be considered on compliance.\(^54\)

\(^{49}\) Id. at P 134.

\(^{50}\) Id.

\(^{51}\) Id. at P 148.

\(^{52}\) Id. at P 150. The six cost allocation principles are: (1) costs must be allocated in a way that is roughly commensurate with benefits; (2) there must be no involuntary cost allocation to non-beneficiaries; (3) a benefit to cost threshold ratio cannot exceed 1.25; (4) costs must be allocated solely within the transmission planning region or pair of regions unless those outside the region or pair of regions voluntarily assume costs; (5) there must be a transparent method for determining benefits and identifying beneficiaries; and (6) there may be different methods for different types of transmission facilities. Order No. 1000 at PP 622-693.

\(^{53}\) February 19 Order at P 150.

\(^{54}\) Id. at P 159.
7. Ownership Rights

The SPP Transmission Owners filed comments expressing a concern that Sections 9.7 and 9.7.1 of the JOA could be read to provide that the benefits calculation in JOA Section 9.6.3.1.1 will be used not only to determine whether to build a project, but also the proportion of the project that will be built and operated under each RTO’s tariff. The SPP Transmission Owners requested confirmation that the benefits test will be used only to determine the proportion of an Interregional Project to be built and operated by each RTO, rather than which RTO Tariff will govern the entire project.

On November 4, 2013, MISO and SPP filed separate answers providing identical responses to the SPP Transmission Owners’ concerns. MISO and SPP’s answers clarified that the benefits calculation in JOA Section 9.6.3.1.1 would determine the ownership shares in a project and that, for projects interconnected to facilities under the control of both RTOs, each portion of the facility owned by a transmission owner would be governed by the tariff applicable to that transmission owner. MISO and SPP’s answers further clarified that facilities located entirely within one RTO would be governed by that RTO’s tariff. The answers provided illustrations of how this would work in various situations.

The February 19 Order accepted MISO and SPP’s answers and directed the parties, on compliance, to submit revisions providing the additional detail and examples provided in their answers.

D. Stakeholder Involvement & Extension Requests

MISO and SPP have engaged in extensive discussion with each other and with their respective stakeholders in the months since the February 19 Order was issued. On April 2, 2015, MISO and SPP filed a Joint Motion requesting a 120-day extension of time to submit their compliance filings. The Commission granted the extension of time on April 17, extending the

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56 Id.
58 MISO Answer at 18-19; SPP Answer at 12-13.
59 MISO Answer at 19; SPP Answer at 13.
60 February 19 Order at P 166.
deadline to submit the compliance filing until August 18, 2015.\textsuperscript{62} This additional time has allowed MISO, SPP, and their respective stakeholders to conduct numerous meetings, reach agreement on all aspects of this filing, and coordinate the drafting of their transmittal letters.

II. COMPLIANCE WITH THE DIRECTIVES OF THE FEBRUARY 19 ORDER

MISO addresses each of the Commission’s directives from the February 19 Order below:

A. Revisions to the Definition of Interregional Projects and Criteria for Interregional Project Designation in the JOA

The February 19 Order rejected MISO and SPP’s proposed definition of an “Interregional Project” as unduly limited to facilities that interconnect to existing facilities under the control of SPP and MISO.\textsuperscript{63} The Commission found that this definition would exclude interconnection to facilities that are currently under development and directed MISO and SPP to revise the definition of an Interregional Project consistent with Order No. 1000, which defines an interregional transmission facility as one that is located in two or more transmission planning regions.\textsuperscript{64}

MISO and SPP have agreed to revise JOA Section 9.6.3.1 by adding new subjection (vi):

\begin{quote}
The project may interconnect to facilities in both the MISO and SPP regions or be wholly within the MISO or SPP region. The facilities to which the project is proposed to interconnect may be either existing facilities or transmission projects that have been approved in a Party’s regional transmission plan.\textsuperscript{65}
\end{quote}

This definition addresses the Commission’s concerns by expressly allowing an Interregional Project to connect to approved facilities that are still under development.

The Commission also directed MISO to remove the requirement that a project be approved as an MEP in MISO and as an Interregional Project under the terms of the SPP Tariff.\textsuperscript{66} In its place, the Commission directed MISO to revise JOA Section 9.6.3.1(iii) to incorporate language suggested by SPP. MISO has complied with this requirement by proposing to revise Section 9.6.3.1(iii) to state:

\begin{footnotesize}
\textsuperscript{63} February 19 Order at P 30.
\textsuperscript{64} Id.
\textsuperscript{65} See Proposed JOA Section 9.6.3.1.
\textsuperscript{66} February 19 Order at P 132.
\end{footnotesize}
(iii) “The project is approved by both Parties in their respective regional planning processes as outlined in their respective OATTs, pursuant to Section 9.3.3.6;”

MISO and SPP have agreed on this language, which implements the Commission’s directive and points to JOA Section 9.3.3.6 to reference the applicable regional processes.

B. Revisions to Include a Definition of “Transmission Issues” in the JOA

The February 19 Order directed MISO and SPP to include “Transmission Issue” as a defined term in the JOA to clarify that the RTOs will consider regional transmission needs driven by reliability, economics, and public policy requirements.67

MISO and SPP have complied with this requirement by each proposing to add Section 2.2.56 to the definitions section of the JOA, which provides:

“Transmission Issue” shall mean transmission needs driven by reliability, economic, and/or public policy requirements.68

The words “Transmission Issue” have also been capitalized throughout the JOA in order to reference this definition. SPP and MISO agree upon the text of this definition and the capitalization of Transmission Issue as a defined term.

C. Removal of the Requirement to Provide Supporting Analysis for Recommended Transmission Issues

The Commission accepted MISO’s and SPP’s proposals allowing stakeholders to propose Transmission Issues and potential interregional solutions to the IPSAC in years where a CSP study is not being performed.69 However, the Commission rejected MISO’s and SPP’s proposal to require submitting entities to provide the analysis supporting the Transmission Issues they propose for consideration, as vague and potentially unduly burdensome on third party stakeholders. The Commission directed MISO and SPP to eliminate this requirement on compliance.

MISO and SPP have complied with the Commission’s directive by revising JOA Section 9.3.2.1 to state:

If a Third Party submits an identified transmission issue Transmission Issue to the JPC, then that Third Party is responsible for providing analysis to support the a detailed description of the recommended transmission issue Transmission Issue. These

67 February 19 Order at P 50.
68 See Proposed JOA Section 2.2.56.
69 February 19 Order at PP 50-51.
This revised language, upon which MISO and SPP agree, removes the requirement that proponents of a Transmission Issue or proposed solution provide analysis to support their recommendation before it is considered by the JPC. Instead, the entity recommending the Transmission Issue for consideration will need only to provide a detailed description of the recommended Transmission Issue in order to enable the JPC to understand what is being proposed. MISO submits that this revision complies with the Commission’s directive by removing the potentially onerous analysis requirement while still ensuring that the JPC captures the issue as the recommending entity understands it.

D. Revisions to Coordination Procedures to allow for Consideration and Cost Allocation of Interregional Facilities that Address Regional Reliability and Public Policy Needs

The February 19 Order rejected MISO’s proposal to use an adjusted production cost savings metric to measure the economic benefits of Interregional Projects, finding that this would not allow for the evaluation of project benefits associated with reliability or public policy-driven needs. Although the Commission accepted SPP’s competing proposal for regional reliability needs, the Commission rejected SPP’s competing proposal for public-policy driven needs finding that it would not allow for the evaluation of project benefits associated with public policy-driven needs. Accordingly, the Commission directed MISO and SPP to submit, on compliance, common JOA revisions that would allow the RTOs to consider proposals and cost allocate Interregional Projects that resolve transmission needs driven by reliability and/or public policy.

MISO and SPP have worked closely together and with their stakeholders since the February 19 Order was issued to develop a set of metrics for evaluating proposed Interregional Projects that address reliability, public policy, and/or economic needs and allocate costs to each RTO. These discussions have allowed MISO and SPP to agree on revisions to JOA Sections 2.2.56, 9.3, 9.3.3.1, 9.6.3.1(iii), 9.3.6.1.1, and 9.3.6.2 that, in the aggregate, allow for the effective consideration and cost allocation of projects addressing reliability, public policy and economic needs.

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70 See Proposed JOA Section 9.3.2.1. MISO and SPP propose to correct the word “Party’s” to read “Parties” because such change is necessary to convey the intended meaning of this sentence (i.e. that the Parties exchange information with each other).

71 Id. at P 73.

72 Id. at P 74.

73 February 19 Order at P 75.
1. Consideration of Public Policy and Reliability Driven Projects

The proposed revisions to the definition of Transmission Issues in JOA Section 2.2.56, discussed more fully in section II.B of this filing, provide that public policy, reliability and economic benefits all can be considered in every JOA section and process that incorporates this definition. The revisions to JOA Section 9.3 (“Coordinated System Planning”) and 9.3.3.1 (“Coordinated System Plan Study Scope Development”) expressly add a mandate to identify public policy-driven expansions or enhancements as part of Coordinated System Planning and includes public policy needs in the scope, models, and analysis of the CSP study. The revisions to Sections 9.6.3.1(iii) (“Criteria for Project Designation as an Interregional Project”) remove the requirement that projects qualify as MEPs in MISO and, instead, allow for the consideration of other project types approved in each RTO’s regional process, as directed by the Commission.

2. Quantification of Interregional Project Benefits

MISO and SPP’s proposed revisions to Section 9.6.3.1.1 (“Determination of Benefits to each RTO from Interregional Projects”) address the Commission’s directives relating to the use of benefit metrics to evaluate proposed Interregional Projects. MISO and SPP, with the agreement of SPP, proposes to apply an adjusted production cost analysis to economics-driven Interregional Projects, an avoided cost plus adjusted production cost analysis for reliability driven Interregional projects and an avoided cost analysis for public policy-driven Interregional Projects, as discussed below.

MISO, in agreement with SPP, proposes in JOA Section 9.6.3.1.1(a) that its previous adjusted production cost metric will continue to apply for Interregional Projects identified by the JPC as primarily addressing economic issues. For Interregional Projects identified by the JPC, as primarily addressing reliability issues, MISO proposes new subsections 9.6.3.1.1(b)(i) & (ii):

b. Projects identified by the JPC as primarily addressing a reliability issue(s):

i. When an Interregional Project would replace a Party’s regional project to address a reliability issue, the reliability benefit is the avoided cost of each Party’s regional project(s) addressing the reliability issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-

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74 See Proposed JOA Sections 9.3 & 9.3.3.1. Existing language already provides a mandate to identify projects to address reliability and efficiency goals.

75 See Proposed JOA Section 9.6.3.1(iii).

76 Id. at proposed Section 9.6.3.1.1(a).
effectively meet the identified need than the displaced project.

ii. Because reliability projects may also provide APC benefits, the APC will be calculated pursuant to Section 9.6.3.1.1a. If the project identified by the JPC as primarily addressing a reliability issue also provides APC benefits to either Party, the APC benefit value will be added to the reliability benefit value. Negative APC benefit values will not be considered.

MISO’s agreement with SPP to incorporate both reliability project replacement benefit and adjusted production cost benefits reflected in the language the Commission accepted in 9.6.3.1.1(b)(i) gives the JPC the ability to recommend an interregional project that may replace a reliability project in one RTO and provide only adjusted production cost for the other RTO. It is important to note that due to the inclusion of two metrics for an Interregional Project primarily addressing a reliability issue that such project does not have to replace a regional reliability project in both RTOs.

The use of an avoided cost benefit metric is appropriate for reliability projects because it will capture all of the costs considered in approving the regional reliability project that the Interregional Project will displace. This evaluation framework builds on existing regional evaluations but also allows for the analysis of benefits over and above the avoidance of a regional reliability project. To the extent that primarily reliability-oriented Interregional Project also provides APC benefits to either RTO, the value of these benefits will be added to the avoided cost benefit value. MISO and SPP have agreed to remove the calculation of benefits for delayed projects. This change simplifies the metric and better aligns the SPP and MISO processes for calculating the reliability metric. The removal of project deferment is not expected to be substantive, as over the 20-year benefit calculation of a project any project deferment benefit is extremely minor.

For Interregional Projects identified by the JPC, as primarily addressing a public policy issue, MISO and SPP have agreed upon language and propose new subsection 9.6.3.1.1(c)(i):

c. Projects identified by the JPC as primarily addressing public policy issue(s):

i. When an Interregional Project would replace a Party’s regional project to address a public policy issue, the public policy benefit is the avoided cost of each Party’s regional project(s) addressing the public policy issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-
effectively meet the identified need than the displaced project.

By evaluating different Interregional Projects using a metric that is appropriate to the type of need that such project addresses, MISO and SPP’s interregional evaluation framework: (1) comports with Cost Allocation Principle 6, and (2) will be able to more fully capture and consider the benefits offered by proposed Interregional Projects addressing reliability, economic, or public policy needs.

3. Interregional Cost Allocation

MISO and SPP’s cost allocation language in JOA Section 9.6.3.2 (“Cost Allocation and Recovery for Interregional Projects”) relies and builds upon the benefits determination provisions of the preceding section. Pursuant to existing—Commission-approved—JOA language, “Interregional Projects… shall be allocated to the respective Parties’ transmission customers in proportion to the net present value of the total benefits calculated for each Party pursuant to Section 9.6.3.1.1.”

To the extent that the determination of an Interregional Project’s benefits is based on the replaced regional project’s avoided costs and such costs are calculated pursuant to differing formulae contained in each RTO’s approved tariff, MISO and SPP have agreed to work together to harmonize their displaced cost determination. To effectuate this coordination, MISO and SPP propose to add a paragraph to JOA Section 9.6.3.2, providing that

A replaced project’s estimated costs shall be determined by the Parties in accordance with their respective procedures for defining estimated project costs. Notwithstanding the foregoing, both Parties shall work to ensure that their cost estimates for displaced projects are determined in a similar manner.

This language will help avoid disputes between MISO and SPP regarding the choice of whose Commission-approved formula should apply to determine an Interregional Project’s displaced cost and, thus, promote the consistent, joint evaluation of Interregional Projects presented to the parties for consideration. Taken together these revisions will allow for the integration of reliability and public policy-driven projects into the Interregional Project analysis and facilitate a uniform evaluation and cost allocation process.

E. Revisions to Explain Stakeholder Participation and Voting in the IPSAC

The February 19 Order, directed MISO and SPP to provide transparency into the IPSAC voting process. Specifically, the Commission directed MISO and SPP to revise the JOA to

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77 See Proposed JOA Section 9.6.3.2.
78 Id.
79 February 19 Order at P 88.
“explain how all stakeholders can participate in the [IPSAC], which stakeholders will participate in the Interregional [IPSAC] voting process and how their votes will be considered.”

To comply with this obligation MISO and SPP have agreed on revisions to Sections 9.1.2.1 (“IPSAC Structure”) and 9.1.2.3 of the JOA (“IPSAC Voting Process”) and propose to add two sentences to Section 9.1.2.1 stating, “All IPSAC meetings will be public. At an IPSAC meeting any stakeholder may provide comments or ask questions.” This revision will address the first required clarification by explaining how all stakeholders may participate in the IPSAC. With regard to the second and third clarifications, MISO and SPP propose to modify Section 9.1.2.3 to read:

Each Party shall define the voting process representing their stakeholders on items requiring votes in IPSAC meetings. Each Party’s defined voting group shall represent one vote, and each Party’s respective voting group may provide a recommendation to the JPC on behalf of the IPSAC. The voting members of the SPP portion of the IPSAC are the members of the SPP Seams Steering Committee, along with a representative from each SPP Transmission Owner that interconnects to MISO but does not have a representative on the Seams Steering Committee. The voting members of the MISO portion of the IPSAC are the sector representatives from the MISO Planning Advisory Committee.

These proposed revisions provide the second and third clarifications required by the February 19 Order by identifying the voting members of the IPSAC for both MISO and SPP and explaining how the votes are aggregated for each RTO. As such, MISO and SPP submit that these revisions fully comply with the Commission’s directive.

In addition to these changes, MISO, with the agreement of SPP, proposes to amend the caption for the definition of “Inter-regional Planning Stakeholder Advisory Committee in JOA Section 2.2.26 to remove the hyphen in “Inter-regional” to match SPP’s version. As proposed, this section would now read:

2.2.26 “Inter-Regional Interregional Planning Stakeholder Advisory Committee” shall have the meaning given under Section 9.1.2.

SPP’s version of this definition omits the hyphen, which also already is omitted in Section 9.1.2 and in all other JOA sections where the full name of the IPSAC is spelled out. However, MISO inadvertently included the hyphen in its original JOA Filing. MISO submits that the change to Section 2.2.26 is not substantive and complies with the Commission’s

80 Id.
81 See Proposed JOA Section 9.1.2.3.
82 See Proposed JOA Section 2.2.26.
directive that MISO and SPP “develop the same language to describe the interregional transmission coordination procedures for that particular pair of regions.”

**F. Revisions to Clarify Ownership Rights and Construction Obligations for Interregional Projects**

The February 19 Order directed MISO and SPP to provide the additional detail and examples regarding ownership rights and construction obligations for Interregional Projects that the parties provided in their answers to the comments of the SPP Transmission Owners regarding JOA Sections 9.7 and 9.7.1. MISO and SPP propose to comply with this directive by adding the additional detail and examples to JOA Section 9.7.1 that the Commission accepted in the MISO Answer and the SPP Answer.

**G. Miscellaneous Revisions and Clarifications**

1. **Addition of Section 9.3.3.4.1 to the MISO Version of the JOA**

   The February 19 Order noted that the SPP Filings proposed adding Section 9.3.3.4 to the JOA, which section addressed consideration of an Interregional Project’s potential adverse impacts on the systems of other neighboring transmission planning regions. MISO’s JOA Filing omitted this provision. MISO committed in its answer to include this section on compliance and the Commission directed MISO to make this change. Accordingly MISO proposes new JOA Section 9.3.3.4.1, which matches the proposed language in SPP’s version of the JOA.

2. **Clarification Regarding Consideration of Interregional Facilities**

   The Commission found that the annual review of Transmission Issues provided in the JOA is sufficient for a stakeholder to present its proposals for consideration. However, the Commission stated that it expected interregional transmission facilities considered in both regional transmission planning processes to also be analyzed jointly in the interregional transmission coordination process. MISO confirms that Interregional Projects considered in the regional processes of both RTOs also will be considered in the interregional coordination process.

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83 *February 19 Order* at P 29.
84 *February 19 Order* at P 166.
85 See Proposed JOA Section 9.7.1. MISO and SPP’s agreed changes to JOA Section 9.7.1 substantially track the language provided in their answers. While the clarification provided in MISO and SPP’s answers addressed the issue in terms of transmission owners, the proposed JOA language has added references to qualified transmission developers to acknowledge the uniform application of these examples regardless of incumbent status.
86 *February 19 Order* at P 154.
87 See Proposed JOA Section 9.3.3.4.1.
3. **Revisions to Information Posting for Unqualified Projects**

The February 19 Order requires MISO to post a list of all interregional transmission facilities that are proposed for selection in the regional transmission plans but that are found not to meet the relevant thresholds, as well as an explanation of the thresholds not satisfied.\(^{88}\)

MISO commits to complying with this directive by including the required information in CSP Study Reports required by JOA Section 9.3.3.5.1 and to make these reports available on its website.\(^{89}\) SPP is similarly making this commitment in its transmittal letter.

### III. REQUEST FOR WAIVER

MISO makes this filing in compliance with the Commission’s directives in the February 19 Order. By making this filing in compliance with the February 19 Order, MISO believes that it has satisfied all applicable Commission requirements and regulations. Should the Commission determine that any additional regulations or requirements apply, MISO respectfully requests waiver of any such regulation or requirement not specifically addressed herein.

### IV. SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all persons listed on the Commission’s service list for the above-referenced proceeding, Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, MISO Advisory Committee participants, as well as all state commissions within the Region, and the Organization of MISO States. In addition, the filing has been posted electronically on MISO’s website at [https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx](https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx) for other interested parties in this matter.

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\(^{88}\) *February 19 Order* at P 133.

\(^{89}\) MISO and SPP already provide most of this information in the form of IPSAC presentations posted on their websites. For MISO’s posting, see, e.g., February 25, 2015 IPSAC Presentation Materials; (www.misoenergy.org/Events/Pages/IPSAC20150224.aspx); May 6 IPSAC Presentation Materials (www.misoenergy.org/Events/Pages/IPSAC20150506.aspx); June 18 ISPAC Presentation Materials (www.misoenergy.org/Events/Pages/IPSAC20150618.aspx). MISO will continue to post such information as part of IPSAC presentations in addition to its commitment to include the required information in CSP Study Reports.
V. SUPPORTING DOCUMENTS

In addition to this Transmittal Letter, the following documents are being submitted with this filing:

- Tab A – Redlined Version of Tariff Sheets effective 3/30/2014
- Tab B – Clean Version of Tariff Sheets effective 3/30/2014\textsuperscript{90}
- Tab C – Clean Version of Tariff Sheets effective 3/1/ 2015\textsuperscript{91}

VI. PROPOSED EFFECTIVE DATE

MISO respectfully requests that the proposed Tariff revisions be made effective March 30, 2014, consistent with the effective date ordered by the Commission in the February 19 Order.

VII. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to the following persons, who shall also be authorized to receive notice in this docket:

Matthew R. Dorsett
Jacob Krouse
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Telephone: (317) 249-5400
Fax: (317) 249-5912
mdorsett@misoenergy.org
jkrouse@misoenergy.org

Jim Holsclaw
Christopher D. Supino
The Holsclaw Group, LLC
303 E. Main St.
Plainfield, IN 46168
Telephone: (317) 839-1140
Fax: (317) 381-6576
jim@thglaw.com
csupino@thglaw.com

\textsuperscript{90} The Tariff sheets contained in Tab B reflect a 3/30/2014 effective date and includes all Tariff language effective through that date.

\textsuperscript{91} The Tariff sheets contained in Tab C reflect a 3/1/2015 effective date and includes all Tariff language effective through that date, including language approved by the Commission in Docket No. ER15-1145-000.
VIII. CONCLUSION

Wherefore, MISO respectfully requests that the Commission accept this compliance filing and proposed Tariff revisions, effective March 30, 2014.

Sincerely,

Matthew R. Dorsett
Jacob Krouse
Midcontinent Independent System Operator, Inc.

Jim Holsclaw
Christopher D. Supino
The Holsclaw Group, LLC

Counsel to the Midcontinent Independent System Operator, Inc.
CERTIFICATE OF SERVICE

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

Dated this 18th day of August, 2015.

/s/ Amy Jones
Amy Jones
2.2.1 “a & b multipliers” shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC. The “a” multiplier is applied to TRM in the planning horizon to determine non-firm AFC. The “b” multiplier is applied to TRM in the operating horizon to determine non-firm AFC. The “a & b” multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability concerns.

2.2.2 “Affected System” shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

2.2.3 “Agreement” shall have the meaning stated in the preamble.

2.2.4 “Available Flowgate Capability” shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

2.2.5 “Balancing Authority” shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time. For Midwest ISO references to BA may be applicable to a BA and/or an LBA.

2.2.6 “Balancing Authority Area” shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. For Midwest ISO references to BA may be applicable to a BAA and/or an LBAA.

2.2.7 “Bulk Electric System” shall mean the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving load with only one transmission source are generally not included in this definition.

2.2.8 “Confidential Information” shall have the meaning stated in Section 18.1.

2.2.9 “Congestion Management Process” means that document which is Attachment 1 to this Agreement as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.10 “Coordinated Flowgate(s)” shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the attached document entitled “Congestion Management Process.” For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion
Management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

2.2.11 “Coordinated Operations” means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.12 “Coordinated System Plan” shall have the meaning stated in Section 9.3.

2.2.13 “Economic Dispatch” shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.14 “Effective Date” shall have the meaning stated in Section 13.1.

2.2.15 “Extra High Voltage” shall mean be defined as 230 KV facilities and above.

2.2.16 “Facilities Study” shall mean a study conducted by the Transmission Service Provider, or its agent, for the interconnection customer to determine a list of facilities, the cost of those facilities, and the time required to interconnect a generating facility with the transmission system or enable the sale of firm transmission service.

2.2.17 “Feasibility Study” shall mean a preliminary evaluation of the system impact of interconnecting a generating facility to the transmission system or the initial review of a transmission service request.

2.2.18 “Firm Flow” shall mean the estimated impacts of Firm Transmission Service on a particular Coordinated Flowgate.

2.2.19 “Firm Flow Limit” shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate based on procedures defined in Sections 4 and 5 of the Congestion Management Process (Attachment 1 of the Joint Operating Agreement).

2.2.20 “Flowgate” shall mean a representative modeling of facilities or group of facilities that may act as significant constraint points on the regional system.

2.2.21 “Intellectual Property” shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including without limitation copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.22 “Interconnection Service” shall mean the service provided by the Transmission Service Provider associated with interconnecting the generating facility to the transmission system and enabling it to receive electric energy and capacity from the
generating facility at the point of interconnection, pursuant to the terms of the generator interconnection agreement and, if applicable, the tariff.

2.2.23 “Interconnection Study” shall mean any of the following studies: the interconnection Feasibility Study, the interconnection System Impact Study, and the interconnection Facilities Study, or the restudy of any of the above, described in the generator interconnection procedures.

2.2.24 “Interconnected Reliability Operating Limit” shall mean a System Operating Limit that if violated could lead to instability, uncontrolled separation(s) or cascading outages that adversely impact the reliability of the Bulk Electric System.

2.2.25 “Intermittent Generation” shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.26 “Inter-regional Planning Stakeholder Advisory Committee” shall have the meaning given under Section 9.1.2.

2.2.27 “Interregional Project” shall have the meaning given under Section 9.6.3.1.

2.2.28 “Local Balancing Authority” shall mean an operational entity which is: (i) responsible for compliance to NERC for the subset of NERC Balancing Authority reliability standards defined for its local area within the Midwest ISO Balancing Authority Area, and (ii) a party (other than the Midwest ISO) to the Balancing Authority Amended Agreement which, among other things, establishes the subset of NERC Balancing Authority reliability standards for which the LBA is responsible.

2.2.29 “Local Balancing Authority Area” shall mean the collection of generation, transmission, and loads that are within the metered boundaries of an LBA.

2.2.30 “Market” shall mean the energy and/or ancillary services market facilitated by the Parties pursuant to FERC Order No. 2000.

2.2.31 “Market-Based Operating Entity” shall mean an Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

2.2.32 “Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market.

2.2.33 “Market Monitor” shall monitor market power and other competitive conditions in the Markets and make reports and recommendations as appropriate.
2.2.34 “Memorandum of Understanding” shall mean that certain predecessor agreement between the Parties to develop this Joint Operating Agreement dated February 27, 2004.

2.2.35 “Midwest ISO” has the meaning stated in the preamble of this Agreement.

2.2.36 “Network Upgrades” shall have the meaning as defined in the Midwest ISO and SPP tariffs.

2.2.37 “NERC Compliance Registry” shall mean a listing of all organizations subject to compliance with the approved reliability standards.

2.2.38 “Notice” shall have the meaning stated in Section 18.10.

2.2.39 “Operating Entity” shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.40 “Outages” shall mean the planned unavailability of transmission and/or generation facilities operated by the Parties, as described in Article VII of this Agreement.

2.2.41 “Party” or “Parties” refers to each party to this Agreement or both, as applicable.

2.2.42 “Purchasing-Selling Entity” shall mean the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services.

2.2.43 “Reciprocal Coordination Agreement” shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the Congestion Management Process.

2.2.44 “Reciprocal Coordinated Flowgate(s)” shall mean a Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. A RCF is:

- A Coordinated Flowgate that is (a) (i) within the operational control of a Reciprocal Entity or (ii) may be subject to the supervision of a Reciprocal Entity as RC, and (b) affected by the transmission of energy by the Parties or by either Party or both Parties and one or more Reciprocal Entities; or
- A Coordinated Flowgate that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to Congestion Management Process reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or
- A Coordinated Flowgate that is designated by agreement of both Parties as a RCF.
2.2.45 “Reciprocal Entity” shall mean any entity that coordinates the future-looking management of Flowgate capability in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.46 “Reliability Coordinator” shall mean that party approved by NERC to be responsible for reliability for a RC Area.

2.2.47 “Reliability Coordinator Area” (“RC Area”) shall mean the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

2.2.48 “SCADA Data” shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Standard TOP-005.

2.2.49 “SPP” Has the meaning stated in the preamble of this Agreement.

2.2.50 “State Estimator” shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.51 “System Impact Study” shall mean an engineering study that evaluates the impact of a proposed interconnection or transmission service request on the safety and reliability of transmission system and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the generating facility were interconnected or transmission service commenced without project modifications or system modifications.

2.2.52 “System Operating Limit” shall mean the value (such as MW, MVAR, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

2.2.53 “Third Party” refers to any entity other than a Party to this Agreement.

2.2.54 “Third Party Operating Entity” shall refer to a Third Party entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.55 “Total Flowgate Capability” shall mean the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the Flowgate. The Flowgate capability is in units of megawatts. If the Flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.
2.2.56 “Transmission Issue” shall mean transmission needs driven by reliability, economic, and/or public policy requirements.

2.2.57 “Transmission Loading Relief” shall mean the procedures used in the Eastern Interconnection as specified in NERC Standards IRO-006 and the NAESB Business Practices WEQ-008.

2.2.58 “Transmission Operator” shall mean the entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

2.2.59 “Transmission Owner” shall mean a Transmission Owner as defined under the Parties’ respective tariffs.

2.2.60 “Transmission Reliability Margin” shall mean that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.2.61 “Transmission Service Provider” shall mean the entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

2.2.62 “Transmission System Emergencies” are conditions that have the potential to exceed or would exceed an IROL.

2.2.63 “Voltage and Reactive Power Coordination Procedure” are the procedures under Article XI for coordination of voltage control and reactive power requirements.
The JPC is the decision making body for coordinated interregional transmission planning. The Interregional Planning Stakeholder Advisory Committee (IPSAC) and other stakeholder groups may provide guidance and recommendations to the JPC. The JPC is responsible for all aspects of coordinated interregional transmission planning, including the development of a Coordinated System Plan.

The JPC will determine if a Coordinated System Plan study should be performed for any particular interregional study cycle as part of the annual transmission issues review performed pursuant to Section 9.3.2. If it is determined that a transmission study should be performed, the JPC with input from the IPSAC, will perform a Coordinated System Plan study pursuant to Section 9.3.3.

The JPC will verify that the results of the study are accurate and meet the expectations of the JPC based on the study scope.

In addition, the JPC responsibilities include:

i. Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed, the JPC shall develop common power system analysis models to perform coordinated system planning, as well as models for power flow analysis, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the Parties, the JPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

ii. Assure that the models used in the interregional evaluation by each planning region are sufficiently similar. The models that are used must be agreed upon by the JPC to ensure confidence in the results.

iii. Coordinate all planning activities under this Article IX including the exchange of data.

iv. Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

v. Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.

vi. Establish working groups as necessary to provide adequate review and development of the regional plans.

vii. Establish a schedule for the rotation of responsibility for data management, coordination of IPSAC meetings including producing meeting minutes, coordination of analysis activities, report preparation, and other activities.
IPSAC participation is open to all stakeholders. All IPSAC meetings will be public. At an IPSAC meeting any stakeholder may provide comments or ask questions. For the purpose of interregional transmission coordination, the IPSAC shall meet no less than once per year. The IPSAC shall meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

If a Coordinated System Plan study is not in progress, the IPSAC will meet in the third quarter of the calendar year, or at an otherwise mutually agreeable date determined by the JPC, to review identified transmission issues and make a recommendation on whether a Coordinated System Plan study should be performed.
Each Party shall define the voting process representing their stakeholders on items requiring votes in IPSAC meetings. Each Party’s defined voting group shall represent one vote, and each Party’s respective voting group may provide a recommendation to the JPC on behalf of the IPSAC. The voting members of the SPP portion of the IPSAC are the members of the SPP Seams Steering Committee, along with a representative from each SPP Transmission Owner that interconnects to MISO but does not have a representative on the Seams Steering Committee. The voting members of the MISO portion of the IPSAC are the sector representatives from the MISO Planning Advisory Committee.
The primary purpose of coordinated system planning is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, address public policy requirements, improve operational performance, or enhance the efficiency of electricity markets. Any such expansions or enhancements shall be described in a Coordinated System Plan.
On an annual basis, unless a Coordinated System Plan study is in progress, the Parties agree to review Transmission issues identified by each Party or any Third Party. During an ongoing Coordinated System Plan study, the Parties may review Transmission issues identified by each Party or any Third Party upon agreement of the JPC. This annual review of Transmission issues will be administrated by the JPC in coordination with the IPSAC to determine the need for a Coordinated System Plan study.
No later than thirty (30) calendar days prior to the annual IPSAC meeting, each Party and Third Parties shall submit Transmission Issues, and may include related transmission solutions, to the JPC that such Party or Third Party determines are appropriate for interregional evaluation, including the analysis to support the recommended Transmission Issues, for consideration by the JPC and IPSAC.

A notification of the annual IPSAC meeting for Transmission Issues review shall be placed on each Party’s interregional coordination webpage, and circulated through applicable electronic distribution list(s), sixty (60) calendar days in advance of the annual IPSAC meeting inviting Third Parties to submit Transmission Issues, and may include any related transmission solutions, for interregional evaluation. All Third Party submissions must be received no later than thirty (30) calendar days prior to the annual IPSAC meeting. Each Party will distribute to the JPC Transmission Issues and supporting analysis submitted by Third Parties.

If a Third Party submits an identified Transmission Issue to the JPC, then that Third Party is responsible for providing analysis to support the a detailed description of the recommended Transmission Issue. These submissions shall be exchanged between the Party’s JPC representatives.
During the annual issues evaluation process, the IPSAC will meet no less than once. The IPSAC will meet to review identified Transmission issues submitted to the JPC. If a second meeting is scheduled by the JPC, the IPSAC will review the determination of the JPC on the need to perform a Coordinated System Plan study.
The JPC shall schedule an IPSAC meeting to review the identified Transmission Issues annually, except when there is an ongoing Coordinated System Plan study being performed. During an ongoing Coordinated System Plan study the JPC may schedule an IPSAC meeting to review the identified Transmission Issues upon agreement of the JPC. The JPC shall post any meeting materials to each Party’s respective interregional coordination webpage fourteen (14) calendar days in advance of the meeting for the IPSAC review of identified Transmission Issues.

During the meeting to review identified Transmission Issues, the IPSAC shall review and discuss the identified Transmission Issues provided by the Parties and any Third Party to the JPC, including the analysis to support recommended issues for evaluation. Based on this review, the IPSAC will provide a recommendation to the JPC on the need to perform a Coordinated System Plan study. This IPSAC recommendation shall be determined by an IPSAC vote, in accordance with Section 9.1.2.3.

The IPSAC representatives for each Party may provide information to the JPC supporting their respective positions.
The JPC will review the recommendation from the IPSAC and all submitted transmission issues to determine the need for a Coordinated System Plan study. Within forty-five (45) calendar days after the IPSAC provides the recommendation to the JPC, the JPC will vote in accordance with Section 9.1.1.3 whether to perform a Coordinated System Plan study.

A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JPC votes in favor of performing the Coordinated System Plan study; or (ii) if after two consecutive years in which a Coordinated System Plan study has not been initiated, and one Party votes in favor of performing a Coordinated System Plan study.

The JPC will document its determination of the need to perform a Coordinated System Plan study, including the recommendation of each Party and the IPSAC, which will be provided to the IPSAC through posting on each Party’s interregional coordination webpage within thirty (30) calendar days after the JPC determination to perform a Coordinated System Plan study.

The JPC will agree to the start date of the Coordinated System Plan study, which shall not exceed 180 calendar days from the date of the JPC’s determination to perform the Coordinated System Plan study.
At the beginning of the Coordinated System Plan study, the JPC will develop, with input from the IPSAC, the scope for the Coordinated System Plan study, which shall include, but is not limited to: 1) identification of Transmission Issues to be evaluated; 2) joint model(s) that shall be developed including assumptions; 3) types of analysis, including, but not limited to, joint futures development, congestion analysis, reliability analysis, \textit{evaluation of public policy requirements}, and stability analysis; 4) study timeline, which shall not exceed 18 months from the first IPSAC meeting discussing the study scope; and 5) deliverables.

Either Party may include an issue in the scope that was reviewed at the IPSAC annual Transmission Issues evaluation meeting pursuant to Section 9.3.2.
The type of analysis that is performed during a Coordinated System Plan study shall be based on the transmission issues identified in the scope and the metrics used to determine the benefits of the solutions being evaluated. The potential solutions will be evaluated to determine if they address the identified transmission issue(s) and the benefits to each Party.
During the Coordinated System Plan study each Party may propose interregional solutions for evaluation. The JPC shall request through each Party’s applicable distribution lists and each Party’s respective interregional coordination webpage suggestions for transmission solutions from Third Parties to address the transmission issues identified in the Coordinated System Plan study. The proposed transmission solutions shall be considered by the JPC and reviewed with the IPSAC.
Section 9.3.3.4.1 Evaluating Potential Impact of Proposed Interregional Projects to Other Transmission Planning Regions

As part of the evaluation of any proposed Interregional Project, the Parties will determine whether the proposed Interregional Project has potential adverse impacts on the systems of other transmission planning regions. If the evaluation identifies any such potential adverse impact, the Parties will contact and coordinate with the other potentially affected transmission planning region on the further evaluation of the potential adverse impact(s).
Section 9.3.3.5.1 Coordinated System Planning Study Report and IPSAC Recommendation

At the completion of the Coordinated System Plan study, the JPC shall produce a draft report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, the recommended Interregional Projects with the associated interregional cost allocation. The JPC shall provide the draft Coordinated System Plan study report to the IPSAC for review. The IPSAC will provide feedback on a draft report and a recommendation on any proposed Interregional Project(s) to the JPC as determined by an IPSAC vote, in accordance with Section 9.1.2.3.
A project that meets all of the following criteria shall be designated as an approved Interregional Project:

i. The estimated project cost is $5,000,000 or greater, provided that this minimum project cost threshold required to qualify a project under either the MISO or SPP OATT shall apply to the total project cost of the Interregional Project and not the allocated cost;

ii. The project is evaluated as part of a Coordinated System Plan and recommended by the JPC, as described in Section 9.3.3;

iii. The project is approved as a market efficiency project under the terms of the MISO OATT and approved as an Interregional Project under the terms of the SPP OATT. The project is approved by both Parties in their respective regional planning processes as outlined in their respective OATTs, pursuant to Section 9.3.3.6;

iv. The benefits to MISO and SPP must each represent 5% or greater of the total benefits identified for the combined MISO and SPP region in accordance with Section 9.6.3.1.1; and

v. The estimated in-service date is within 10 years from the date the project is approved by the respective Boards of Directors of MISO and SPP, and if approved on different dates, on the date of the latest approval; and

vi. The project may interconnect to facilities in both the MISO and SPP regions or be wholly within the MISO or SPP region. The facilities to which the project is proposed to interconnect may be either existing facilities or transmission projects that have been approved in a Party’s regional transmission plan.
The Parties shall jointly evaluate the benefits to the combined Parties’ region, and to each region individually, using the agreed upon benefit metric(s) over a multi-year analysis to determine whether a proposed project qualifies as an Interregional Project. The Parties shall perform this evaluation as follows:

a. Projects identified by the JPC as primarily addressing an economic issue(s):

i. The Parties shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed Interregional Project to transmission customers of each Party. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on adjusted production cost (APC), which is adjusted to account for purchases and sales. Each Party’s adjusted production cost represents the summation of the adjusted production cost for the defined areas in each Party’s region. Each area’s production cost shall be adjusted for purchases and sales as follows: 1) for each simulation hour in which an area is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the area’s generation-weighted LMP and then subtracting this value from the area’s production cost; and 2) for each simulation hour in which an area is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the area’s load-weighted LMP and then adding this value to the area’s production cost.

ii. The benefit metric shall be calculated for each Party for each simulated year. Benefits for intermediate years between simulated years will be based on interpolation. Benefits for years beyond the last simulated year will be based on extrapolation. The total project benefit shall be determined by calculating the present value of annual benefits for the first 20 years of project life after the projected in-service date.

b. Projects identified by the JPC as primarily addressing a reliability issue(s):

i. When an Interregional Project would replace a Party’s regional project to address a reliability issue, the reliability benefit is the avoided cost of each Party’s regional project(s) addressing the reliability issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-effectively meet the identified need than the displaced project.

ii. Because reliability projects may also provide APC benefits, the APC will be calculated pursuant to Section 9.6.3.1.1a. If the project identified by the JPC as primarily addressing a reliability issue also provides APC benefits to either Party,
the APC benefit value will be added to the reliability benefit value. Negative APC benefit values will not be considered.

c. Projects identified by the JPC as primarily addressing public policy issue(s):

i. When an Interregional Project would replace a Party’s regional project to address a public policy issue, the public policy benefit is the avoided cost of each Party’s regional project(s) addressing the public policy issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-effectively meet the identified need than the displaced project.
For Interregional Projects that meet all of the qualifications in Section 9.6.3.1, the applicable project costs shall be allocated to the respective Parties’ transmission customers in proportion to the net present value of the total benefits calculated for each Party pursuant to Section 9.6.3.1.1.

A replaced project’s estimated costs shall be determined by the Parties in accordance with their respective procedures for defining estimated project costs. Notwithstanding the foregoing, both Parties shall work to ensure that their cost estimates for displaced projects are determined in a similar manner.

The recovery of any share of cost of an Interregional Project allocated to either Party shall be recovered by each Party according to the applicable OATT provisions of the Party to which such cost recovery is allocated.
For an Interregional Project approved for interregional cost allocation under Section 9.6.3 that is solely interconnected to transmission facilities under the control of one Party, that Party’s OATT shall be used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable Interregional Project.

For all or part of an Interregional Project approved for interregional cost allocation under Section 9.6.3 that will interconnect to transmission facilities under the control of each Party, the applicable OATT used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable Interregional Project shall be determined based on the proportion of benefits as calculated pursuant to Section 9.6.3.1.1, unless jurisdictional limitations preclude a Party’s Transmission Owner from constructing and/or owning transmission facilities in proportion to the benefits as calculated pursuant to Section 9.6.3.1.1.

For example, if based on the benefits of the Interregional Project the ownership would be split 50/50 between the Parties but, due to the geographic location of the Interregional Project, only a Transmission Owner or qualified transmission developer from one Party is permitted to construct and own projects in that location, then that portion of the project would be 100% owned by the Transmission Owner or qualified transmission developer constructing the project. For Interregional Projects that are solely located within one Party’s region, the designation of the Transmission Owner(s) or qualified transmission developer(s) responsible for constructing the project will be determined in accordance with the Party’s tariff.

Parties agree to coordinate on the designation of the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable portion of an Interregional Project that will interconnect to the transmission facilities under the control of each Party.

After approval of an Interregional Project, the Parties may negotiate the advancement of the in-service date of a project.
MISO
MISO RATE SCHEDULES

Section 2.2
Definitions.

2.2.1 “a & b multipliers” shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC. The “a” multiplier is applied to TRM in the planning horizon to determine non-firm AFC. The “b” multiplier is applied to TRM in the operating horizon to determine non-firm AFC. The “a & b” multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability concerns.

2.2.2 “Affected System” shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

2.2.3 “Agreement” shall have the meaning stated in the preamble.

2.2.4 “Available Flowgate Capability” shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

2.2.5 “Balancing Authority” shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time. For Midwest ISO references to BA may be applicable to a BA and/or an LBA.

2.2.6 “Balancing Authority Area” shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. For Midwest ISO references to BA may be applicable to a BAA and/or an LBAA.

2.2.7 “Bulk Electric System” shall mean the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving load with only one transmission source are generally not included in this definition.

2.2.8 “Confidential Information” shall have the meaning stated in Section 18.1.

2.2.9 “Congestion Management Process” means that document which is Attachment 1 to this Agreement as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.10 “Coordinated Flowgate(s)” shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the attached document entitled “Congestion Management Process.” For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion
Management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

2.2.11 “Coordinated Operations” means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.12 “Coordinated System Plan” shall have the meaning stated in Section 9.3.

2.2.13 “Economic Dispatch” shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.14 “Effective Date” shall have the meaning stated in Section 13.1.

2.2.15 “Extra High Voltage” shall mean be defined as 230 KV facilities and above.

2.2.16 “Facilities Study” shall mean a study conducted by the Transmission Service Provider, or its agent, for the interconnection customer to determine a list of facilities, the cost of those facilities, and the time required to interconnect a generating facility with the transmission system or enable the sale of firm transmission service.

2.2.17 “Feasibility Study” shall mean a preliminary evaluation of the system impact of interconnecting a generating facility to the transmission system or the initial review of a transmission service request.

2.2.18 “Firm Flow” shall mean the estimated impacts of Firm Transmission Service on a particular Coordinated Flowgate.

2.2.19 “Firm Flow Limit” shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate based on procedures defined in Sections 4 and 5 of the Congestion Management Process (Attachment 1 of the Joint Operating Agreement).

2.2.20 “Flowgate” shall mean a representative modeling of facilities or group of facilities that may act as significant constraint points on the regional system.

2.2.21 “Intellectual Property” shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including without limitation copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.22 “Interconnection Service” shall mean the service provided by the Transmission Service Provider associated with interconnecting the generating facility to the transmission system and enabling it to receive electric energy and capacity from the...
generating facility at the point of interconnection, pursuant to the terms of the generator interconnection agreement and, if applicable, the tariff.

2.2.23 “Interconnection Study” shall mean any of the following studies: the interconnection Feasibility Study, the interconnection System Impact Study, and the interconnection Facilities Study, or the restudy of any of the above, described in the generator interconnection procedures.

2.2.24 “Interconnected Reliability Operating Limit” shall mean a System Operating Limit that if violated could lead to instability, uncontrolled separation(s) or cascading outages that adversely impact the reliability of the Bulk Electric System.

2.2.25 “Intermittent Generation” shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.26 “Interregional Planning Stakeholder Advisory Committee” shall have the meaning given under Section 9.1.2.

2.2.27 “Interregional Project” shall have the meaning given under Section 9.6.3.1.

2.2.28 “Local Balancing Authority” shall mean an operational entity which is: (i) responsible for compliance to NERC for the subset of NERC Balancing Authority reliability standards defined for its local area within the Midwest ISO Balancing Authority Area, and (ii) a party (other than the Midwest ISO) to the Balancing Authority Amended Agreement which, among other things, establishes the subset of NERC Balancing Authority reliability standards for which the LBA is responsible.

2.2.29 “Local Balancing Authority Area” shall mean the collection of generation, transmission, and loads that are within the metered boundaries of an LBA.

2.2.30 “Market” shall mean the energy and/or ancillary services market facilitated by the Parties pursuant to FERC Order No. 2000.

2.2.31 “Market-Based Operating Entity” shall mean an Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

2.2.32 “Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market.

2.2.33 “Market Monitor” shall monitor market power and other competitive conditions in the Markets and make reports and recommendations as appropriate.
2.2.34 “Memorandum of Understanding” shall mean that certain predecessor agreement between the Parties to develop this Joint Operating Agreement dated February 27, 2004.

2.2.35 “Midwest ISO” has the meaning stated in the preamble of this Agreement.

2.2.36 “Network Upgrades” shall have the meaning as defined in the Midwest ISO and SPP tariffs.

2.2.37 “NERC Compliance Registry” shall mean a listing of all organizations subject to compliance with the approved reliability standards.

2.2.38 “Notice” shall have the meaning stated in Section 18.10.

2.2.39 “Operating Entity” shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.40 “Outages” shall mean the planned unavailability of transmission and/or generation facilities operated by the Parties, as described in Article VII of this Agreement.

2.2.41 “Party” or “Parties” refers to each party to this Agreement or both, as applicable.

2.2.42 “Purchasing-Selling Entity” shall mean the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services.

2.2.43 “Reciprocal Coordination Agreement” shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the Congestion Management Process.

2.2.44 “Reciprocal Coordinated Flowgate(s)” shall mean a Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. A RCF is:

- A Coordinated Flowgate that is (a) (i) within the operational control of a Reciprocal Entity or (ii) may be subject to the supervision of a Reciprocal Entity as RC, and (b) affected by the transmission of energy by the Parties or by either Party or both Parties and one or more Reciprocal Entities; or
- A Coordinated Flowgate that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to Congestion Management Process reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or
- A Coordinated Flowgate that is designated by agreement of both Parties as a RCF.
2.2.45 “Reciprocal Entity” shall mean any entity that coordinates the future-looking management of Flowgate capability in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.46 “Reliability Coordinator” shall mean that party approved by NERC to be responsible for reliability for a RC Area.

2.2.47 “Reliability Coordinator Area” (“RC Area”) shall mean the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

2.2.48 “SCADA Data” shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Standard TOP-005.

2.2.49 “SPP” Has the meaning stated in the preamble of this Agreement.

2.2.50 “State Estimator” shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.51 “System Impact Study” shall mean an engineering study that evaluates the impact of a proposed interconnection or transmission service request on the safety and reliability of transmission system and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the generating facility were interconnected or transmission service commenced without project modifications or system modifications.

2.2.52 “System Operating Limit” shall mean the value (such as MW, MVAR, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

2.2.53 “Third Party” refers to any entity other than a Party to this Agreement.

2.2.54 “Third Party Operating Entity” shall refer to a Third Party entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.55 “Total Flowgate Capability” shall mean the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the Flowgate. The Flowgate capability is in units of megawatts. If the Flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.
2.2.56 “Transmission Issue” shall mean transmission needs driven by reliability, economic, and/or public policy requirements.

2.2.57 “Transmission Loading Relief” shall mean the procedures used in the Eastern Interconnection as specified in NERC Standards IRO-006 and the NAESB Business Practices WEQ-008.

2.2.58 “Transmission Operator” shall mean the entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

2.2.59 “Transmission Owner” shall mean a Transmission Owner as defined under the Parties’ respective tariffs.

2.2.60 “Transmission Reliability Margin” shall mean that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.2.61 “Transmission Service Provider” shall mean the entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

2.2.62 “Transmission System Emergencies” are conditions that have the potential to exceed or would exceed an IROL.

2.2.63 “Voltage and Reactive Power Coordination Procedure” are the procedures under Article XI for coordination of voltage control and reactive power requirements.
The JPC is the decision making body for coordinated interregional transmission planning. The Interregional Planning Stakeholder Advisory Committee (IPSAC) and other stakeholder groups may provide guidance and recommendations to the JPC. The JPC is responsible for all aspects of coordinated interregional transmission planning, including the development of a Coordinated System Plan.

The JPC will determine if a Coordinated System Plan study should be performed for any particular interregional study cycle as part of the annual Transmission Issues review performed pursuant to Section 9.3.2. If it is determined that a transmission study should be performed, the JPC with input from the IPSAC, will perform a Coordinated System Plan study pursuant to Section 9.3.3.

The JPC will verify that the results of the study are accurate and meet the expectations of the JPC based on the study scope.

In addition, the JPC responsibilities include:

i. Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed, the JPC shall develop common power system analysis models to perform coordinated system planning, as well as models for power flow analysis, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the Parties, the JPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

ii. Assure that the models used in the interregional evaluation by each planning region are sufficiently similar. The models that are used must be agreed upon by the JPC to ensure confidence in the results.

iii. Coordinate all planning activities under this Article IX including the exchange of data.

iv. Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

v. Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.

vi. Establish working groups as necessary to provide adequate review and development of the regional plans.

vii. Establish a schedule for the rotation of responsibility for data management, coordination of IPSAC meetings including producing meeting minutes, coordination of analysis activities, report preparation, and other activities.
IPSAC participation is open to all stakeholders. All IPSAC meetings will be public. At an IPSAC meeting any stakeholder may provide comments or ask questions. For the purpose of interregional transmission coordination, the IPSAC shall meet no less than once per year. The IPSAC shall meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

If a Coordinated System Plan study is not in progress, the IPSAC will meet in the third quarter of the calendar year, or at an otherwise mutually agreeable date determined by the JPC, to review identified Transmission Issues and make a recommendation on whether a Coordinated System Plan study should be performed.
Each Party’s defined voting group shall represent one vote, and each Party’s respective voting group may provide a recommendation to the JPC on behalf of the IPSAC. The voting members of the SPP portion of the IPSAC are the members of the SPP Seams Steering Committee, along with a representative from each SPP Transmission Owner that interconnects to MISO but does not have a representative on the Seams Steering Committee. The voting members of the MISO portion of the IPSAC are the sector representatives from the MISO Planning Advisory Committee.
The primary purpose of coordinated system planning is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, address public policy requirements, improve operational performance, or enhance the efficiency of electricity markets. Any such expansions or enhancements shall be described in a Coordinated System Plan.
On an annual basis, unless a Coordinated System Plan study is in progress, the Parties agree to review Transmission Issues identified by each Party or any Third Party. During an ongoing Coordinated System Plan study, the Parties may review Transmission Issues identified by each Party or any Third Party upon agreement of the JPC. This annual review of Transmission Issues will be administrated by the JPC in coordination with the IPSAC to determine the need for a Coordinated System Plan study.
No later than thirty (30) calendar days prior to the annual IPSAC meeting, each Party and Third Parties shall submit Transmission Issues, and may include related transmission solutions, to the JPC that such Party or Third Party determines are appropriate for interregional evaluation, including the analysis to support the recommended Transmission Issues, for consideration by the JPC and IPSAC.

A notification of the annual IPSAC meeting for Transmission Issues review shall be placed on each Party’s interregional coordination webpage, and circulated through applicable electronic distribution list(s), sixty (60) calendar days in advance of the annual IPSAC meeting inviting Third Parties to submit Transmission Issues, and may include any related transmission solutions, for interregional evaluation. All Third Party submissions must be received no later than thirty (30) calendar days prior to the annual IPSAC meeting. Each Party will distribute to the JPC Transmission Issues and supporting analysis submitted by Third Parties.

If a Third Party submits an identified Transmission Issue to the JPC, then that Third Party is responsible for providing a detailed description of the recommended Transmission Issue. These submissions shall be exchanged between the Parties’ JPC representatives.
During the annual issues evaluation process, the IPSAC will meet no less than once. The IPSAC will meet to review identified Transmission Issues submitted to the JPC. If a second meeting is scheduled by the JPC, the IPSAC will review the determination of the JPC on the need to perform a Coordinated System Plan study.
The JPC shall schedule an IPSAC meeting to review the identified Transmission Issues annually, except when there is an ongoing Coordinated System Plan study being performed. During an ongoing Coordinated System Plan study the JPC may schedule an IPSAC meeting to review the identified Transmission Issues upon agreement of the JPC. The JPC shall post any meeting materials to each Party’s respective interregional coordination webpage fourteen (14) calendar days in advance of the meeting for the IPSAC review of identified Transmission Issues.

During the meeting to review identified Transmission Issues, the IPSAC shall review and discuss the identified Transmission Issues provided by the Parties and any Third Party to the JPC, including the analysis to support recommended issues for evaluation. Based on this review, the IPSAC will provide a recommendation to the JPC on the need to perform a Coordinated System Plan study. This IPSAC recommendation shall be determined by an IPSAC vote, in accordance with Section 9.1.2.3.

The IPSAC representatives for each Party may provide information to the JPC supporting their respective positions.
The JPC will review the recommendation from the IPSAC and all submitted Transmission Issues to determine the need for a Coordinated System Plan study. Within forty-five (45) calendar days after the IPSAC provides the recommendation to the JPC, the JPC will vote in accordance with Section 9.1.1.3 whether to perform a Coordinated System Plan study.

A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JPC votes in favor of performing the Coordinated System Plan study; or (ii) if after two consecutive years in which a Coordinated System Plan study has not been initiated, and one Party votes in favor of performing a Coordinated System Plan study.

The JPC will document its determination of the need to perform a Coordinated System Plan study, including the recommendation of each Party and the IPSAC, which will be provided to the IPSAC through posting on each Party’s interregional coordination webpage within thirty (30) calendar days after the JPC determination to perform a Coordinated System Plan study.

The JPC will agree to the start date of the Coordinated System Plan study, which shall not exceed 180 calendar days from the date of the JPC’s determination to perform the Coordinated System Plan study.
At the beginning of the Coordinated System Plan study, the JPC will develop, with input from the IPSAC, the scope for the Coordinated System Plan study, which shall include, but is not limited to: 1) identification of Transmission Issues to be evaluated; 2) joint model(s) that shall be developed including assumptions; 3) types of analysis, including, but not limited to, joint futures development, congestion analysis, reliability analysis, evaluation of public policy requirements, and stability analysis; 4) study timeline, which shall not exceed 18 months from the first IPSAC meeting discussing the study scope; and 5) deliverables.

Either Party may include an issue in the scope that was reviewed at the IPSAC annual Transmission Issues evaluation meeting pursuant to Section 9.3.2.
The type of analysis that is performed during a Coordinated System Plan study shall be based on the Transmission Issues identified in the scope and the metrics used to determine the benefits of the solutions being evaluated. The potential solutions will be evaluated to determine if they address the identified Transmission Issue(s) and the benefits to each Party.
During the Coordinated System Plan study each Party may propose interregional solutions for evaluation. The JPC shall request through each Party’s applicable distribution lists and each Party’s respective interregional coordination webpage suggestions for transmission solutions from Third Parties to address the Transmission Issues identified in the Coordinated System Plan study. The proposed transmission solutions shall be considered by the JPC and reviewed with the IPSAC.
Section 9.3.3.4.1 Evaluating Potential Impact of Proposed Interregional Projects to Other Transmission Planning Regions

As part of the evaluation of any proposed Interregional Project, the Parties will determine whether the proposed Interregional Project has potential adverse impacts on the systems of other transmission planning regions. If the evaluation identifies any such potential adverse impact, the Parties will contact and coordinate with the other potentially affected transmission planning region on the further evaluation of the potential adverse impact(s).
Section 9.3.3.5.1 Coordinated System Planning Study Report and IPSAC Recommendation

At the completion of the Coordinated System Plan study, the JPC shall produce a draft report documenting the Coordinated System Plan study, including the Transmission Issues evaluated, studies performed, solutions considered, and, if applicable, the recommended Interregional Projects with the associated interregional cost allocation. The JPC shall provide the draft Coordinated System Plan study report to the IPSAC for review. The IPSAC will provide feedback on a draft report and a recommendation on any proposed Interregional Project(s) to the JPC as determined by an IPSAC vote, in accordance with Section 9.1.2.3.
A project that meets all of the following criteria shall be designated as an approved Interregional Project:

i. The estimated project cost is $5,000,000 or greater, provided that this minimum project cost threshold required to qualify a project under either the MISO or SPP OATT shall apply to the total project cost of the Interregional Project and not the allocated cost;

ii. The project is evaluated as part of a Coordinated System Plan and recommended by the JPC, as described in Section 9.3.3;

iii. The project is approved by both Parties in their respective regional planning processes as outlined in their respective OATTs, pursuant to Section 9.3.3.6;

iv. The benefits to MISO and SPP must each represent 5% or greater of the total benefits identified for the combined MISO and SPP region in accordance with Section 9.6.3.1.1;

v. The estimated in-service date is within 10 years from the date the project is approved by the respective Boards of Directors of MISO and SPP, and if approved on different dates, on the date of the latest approval; and

vi. The project may interconnect to facilities in both the MISO and SPP regions or be wholly within the MISO or SPP region. The facilities to which the project is proposed to interconnect may be either existing facilities or transmission projects that have been approved in a Party’s regional transmission plan.
The Parties shall jointly evaluate the benefits to the combined Parties’ region, and to each region individually, using the agreed upon benefit metric(s) over a multi-year analysis to determine whether a proposed project qualifies as an Interregional Project. The Parties shall perform this evaluation as follows:

a. Projects identified by the JPC as primarily addressing an economic issue(s):
   
i. The Parties shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed Interregional Project to transmission customers of each Party. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on adjusted production cost (APC), which is adjusted to account for purchases and sales. Each Party’s adjusted production cost represents the summation of the adjusted production cost for the defined areas in each Party’s region. Each area’s production cost shall be adjusted for purchases and sales as follows: 1) for each simulation hour in which an area is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the area’s generation-weighted LMP and then subtracting this value from the area’s production cost; and 2) for each simulation hour in which an area is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the area’s load-weighted LMP and then adding this value to the area’s production cost.

   ii. The benefit metric shall be calculated for each Party for each simulated year. Benefits for intermediate years between simulated years will be based on interpolation. Benefits for years beyond the last simulated year will be based on extrapolation. The total project benefit shall be determined by calculating the present value of annual benefits for the first 20 years of project life after the projected in-service date.

b. Projects identified by the JPC as primarily addressing a reliability issue(s):
   
i. When an Interregional Project would replace a Party’s regional project to address a reliability issue, the reliability benefit is the avoided cost of each Party’s regional project(s) addressing the reliability issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-effectively meet the identified need than the displaced project.

   ii. Because reliability projects may also provide APC benefits, the APC will be calculated pursuant to Section 9.6.3.1.1a. If the project identified by the JPC as primarily addressing a reliability issue also provides APC benefits to either Party,
the APC benefit value will be added to the reliability benefit value. Negative APC benefit values will not be considered.

c. Projects identified by the JPC as primarily addressing public policy issue(s):

i. When an Interregional Project would replace a Party’s regional project to address a public policy issue, the public policy benefit is the avoided cost of each Party’s regional project(s) addressing the public policy issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-effectively meet the identified need than the displaced project.
For Interregional Projects that meet all of the qualifications in Section 9.6.3.1, the applicable project costs shall be allocated to the respective Parties’ transmission customers in proportion to the net present value of the total benefits calculated for each Party pursuant to Section 9.6.3.1.1.

A replaced project’s estimated costs shall be determined by the Parties in accordance with their respective procedures for defining estimated project costs. Notwithstanding the foregoing, both Parties shall work to ensure that their cost estimates for displaced projects are determined in a similar manner.

The recovery of any share of cost of an Interregional Project allocated to either Party shall be recovered by each Party according to the applicable OATT provisions of the Party to which such cost recovery is allocated.
For an Interregional Project approved for interregional cost allocation under Section 9.6.3 that is solely interconnected to transmission facilities under the control of one Party, that Party’s OATT shall be used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable Interregional Project.

For all or part of an Interregional Project approved for interregional cost allocation under Section 9.6.3 that will interconnect to transmission facilities under the control of each Party, the applicable OATT used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable Interregional Project shall be determined based on the proportion of benefits as calculated pursuant to Section 9.6.3.1.1, unless jurisdictional limitations preclude a Party’s Transmission Owner from constructing and/or owning transmission facilities in proportion to the benefits as calculated pursuant to Section 9.6.3.1.1.

For example, if based on the benefits of the Interregional Project the ownership would be split 50/50 between the Parties but, due to the geographic location of the Interregional Project, only a Transmission Owner or qualified transmission developer from one Party is permitted to construct and own projects in that location, then that portion of the project would be 100% owned by the Transmission Owner or qualified transmission developer constructing the project. For Interregional Projects that are solely located within one Party’s region, the designation of the Transmission Owner(s) or qualified transmission developer(s) responsible for constructing the project will be determined in accordance with the Party’s tariff.

Parties agree to coordinate on the designation of the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable portion of an Interregional Project that will interconnect to the transmission facilities under the control of each Party.

After approval of an Interregional Project, the Parties may negotiate the advancement of the in-service date of a project.
2.2.1 “a & b multipliers” shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC. The “a” multiplier is applied to TRM in the planning horizon to determine non-firm AFC. The “b” multiplier is applied to TRM in the operating horizon to determine non-firm AFC. The “a & b” multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability concerns.

2.2.2 “Affected System” shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

2.2.3 “Agreement” shall mean this document, as amended from time to time, including all attachments, appendices, and schedules.

2.2.4 “Available Flowgate Capability” shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

2.2.5 “Balancing Authority” shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time. For Midwest ISO references to BA may be applicable to a BA and/or an LBA.

2.2.6 “Balancing Authority Area” shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. For Midwest ISO references to BA may be applicable to a BAA and/or an LBAA.

2.2.7 “Bulk Electric System” shall mean the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving load with only one transmission source are generally not included in this definition.

2.2.8 “Confidential Information” shall have the meaning stated in Section 18.1.

2.2.9 “Congestion Management Process” means that document which is Attachment 1 to this Agreement as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.10 “Coordinated Flowgate(s)” shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the attached document entitled “Congestion Management Process.” For a Market-Based Operating
Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

2.2.11 “Coordinated Operations” means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.12 “Coordinated System Plan” shall have the meaning stated in Section 9.3.

2.2.13 “Economic Dispatch” shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.14 “Effective Date” shall have the meaning stated in Section 13.1.

2.2.15 “Extra High Voltage” shall mean be defined as 230 KV facilities and above.

2.2.16 “Facilities Study” shall mean a study conducted by the Transmission Service Provider, or its agent, for the interconnection customer to determine a list of facilities, the cost of those facilities, and the time required to interconnect a generating facility with the transmission system or enable the sale of firm transmission service.

2.2.17 “Feasibility Study” shall mean a preliminary evaluation of the system impact of interconnecting a generating facility to the transmission system or the initial review of a transmission service request.

2.2.18 “Firm Flow” shall mean the estimated impacts of Firm Transmission Service on a particular Coordinated Flowgate.

2.2.19 “Firm Flow Limit” shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate based on procedures defined in Sections 4 and 5 of the Congestion Management Process (Attachment 1 of the Joint Operating Agreement).

2.2.20 “Flowgate” shall mean a representative modeling of facilities or group of facilities that may act as significant constraint points on the regional system.

2.2.21 “Intellectual Property” shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including without limitation copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.22 “Interconnection Service” shall mean the service provided by the Transmission Service Provider associated with interconnecting the generating facility to the transmission system and enabling it to receive electric energy and capacity from the
generating facility at the point of interconnection, pursuant to the terms of the generator interconnection agreement and, if applicable, the tariff.

2.2.23 “Interconnection Study” shall mean any of the following studies: the interconnection Feasibility Study, the interconnection System Impact Study, and the interconnection Facilities Study, or the restudy of any of the above, described in the generator interconnection procedures.

2.2.24 “Interconnected Reliability Operating Limit” shall mean a System Operating Limit that if violated could lead to instability, uncontrolled separation(s) or cascading outages that adversely impact the reliability of the Bulk Electric System.

2.2.25 “Intermittent Generation” shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.26 “Interregional Coordination Process” shall mean the market-to-market coordination document incorporated herein as Attachment 2 to this Agreement, as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.27 “Interregional Planning Stakeholder Advisory Committee” shall have the meaning given under Section 9.1.2.

2.2.28 “Interregional Project” shall have the meaning given under Section 9.6.3.1.

2.2.29 “Local Balancing Authority” shall mean an operational entity which is: (i) responsible for compliance to NERC for the subset of NERC Balancing Authority reliability standards defined for its local area within the Midwest ISO Balancing Authority Area, and (ii) a party (other than the Midwest ISO) to the Balancing Authority Amended Agreement which, among other things, establishes the subset of NERC Balancing Authority reliability standards for which the LBA is responsible.

2.2.30 “Local Balancing Authority Area” shall mean the collection of generation, transmission, and loads that are within the metered boundaries of an LBA.

2.2.31 “Market” shall mean the energy and/or ancillary services market facilitated by the Parties pursuant to FERC Order No. 2000.

2.2.32 “Market-Based Operating Entity” shall mean an Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

2.2.33 “Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market.
2.2.34 “Market Monitor” shall monitor market power and other competitive conditions in the Markets and make reports and recommendations as appropriate.

2.2.35 “Memorandum of Understanding” shall mean that certain predecessor agreement between the Parties to develop this Joint Operating Agreement dated February 27, 2004.

2.2.36 “Midwest ISO” has the meaning stated in the preamble of this Agreement.

2.2.37 “Network Upgrades” shall have the meaning as defined in the Midwest ISO and SPP tariffs.

2.2.38 “NERC Compliance Registry” shall mean a listing of all organizations subject to compliance with the approved reliability standards.

2.2.39 “Notice” shall have the meaning stated in Section 18.10.

2.2.40 “Operating Entity” shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.41 “Outages” shall mean the planned unavailability of transmission and/or generation facilities operated by the Parties, as described in Article VII of this Agreement.

2.2.42 “Party” or “Parties” refers to each party to this Agreement or both, as applicable.

2.2.43 “Purchasing-Selling Entity” shall mean the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services.

2.2.44 “Reciprocal Coordination Agreement” shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the Congestion Management Process.

2.2.45 “Reciprocal Coordinated Flowgate(s)” shall mean a Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. A RCF is:

- A Coordinated Flowgate that is (a) (i) within the operational control of a Reciprocal Entity or (ii) may be subject to the supervision of a Reciprocal Entity as RC, and (b) affected by the transmission of energy by the Parties or by either Party or both Parties and one or more Reciprocal Entities; or
- A Coordinated Flowgate that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to Congestion Management Process reciprocal coordination.
procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or

- A Coordinated Flowgate that is designated by agreement of both Parties as a RCF.

2.2.46 “Reciprocal Entity” shall mean any entity that coordinates the future-looking management of Flowgate capability in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.47 “Reliability Coordinator” shall mean that party approved by NERC to be responsible for reliability for a RC Area.

2.2.48 “Reliability Coordinator Area” (“RC Area”) shall mean the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

2.2.49 “SCADA Data” shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Standard TOP-005.

2.2.50 “SPP” Has the meaning stated in the preamble of this Agreement.

2.2.51 “State Estimator” shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.52 “System Impact Study” shall mean an engineering study that evaluates the impact of a proposed interconnection or transmission service request on the safety and reliability of transmission system and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the generating facility were interconnected or transmission service commenced without project modifications or system modifications.

2.2.53 “System Operating Limit” shall mean the value (such as MW, MVAR, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

2.2.54 “Third Party” refers to any entity other than a Party to this Agreement.

2.2.55 “Third Party Operating Entity” shall refer to a Third Party entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.56 “Total Flowgate Capability” shall mean the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis)
any element of the Flowgate. The Flowgate capability is in units of megawatts. If the Flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.

2.2.57 “Transmission Issue” shall mean transmission needs driven by reliability, economic, and/or public policy requirements.

2.2.58 “Transmission Loading Relief” shall mean the procedures used in the Eastern Interconnection as specified in NERC Standards IRO-006 and the NAESB Business Practices WEQ-008.

2.2.59 “Transmission Operator” shall mean the entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

2.2.60 “Transmission Owner” shall mean a Transmission Owner as defined under the Parties’ respective tariffs.

2.2.61 “Transmission Reliability Margin” shall mean that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.2.62 “Transmission Service Provider” shall mean the entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

2.2.63 “Transmission System Emergencies” are conditions that have the potential to exceed or would exceed an IROL.

2.2.64 “Voltage and Reactive Power Coordination Procedure” are the procedures under Article XI for coordination of voltage control and reactive power requirements.