VIA ELECTRONIC DELIVERY

July 10, 2013

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 Transmission Project Coordination and Cost Allocation with Southwest Power Pool, Inc.
Docket No. ER13-___-000

Dear Secretary Bose:

Pursuant to section 206 of the Federal Power Act (“FPA”), 16 U.S.C. § 824e, and Order Nos. 1000, 1000-A, and 1000-B\(^1\) of the Federal Energy Regulatory Commission (“FERC” or “Commission”), the Midcontinent Independent System Operator, Inc. (“MISO”\(^2\)) respectfully submits this compliance filing proposing revisions to the Joint Operating Agreement between MISO and Southwest Power Pool, Inc. (“SPP”) (“MISO-SPP JOA”),\(^3\) to address the interregional coordination and cost allocation requirements of Order No. 1000. Concurrently, in connection with these JOA revisions, MISO is also submitting related amendments to its Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”); and SPP is separately submitting related revisions to its tariff. MISO and SPP agree on many aspects of their proposed compliance with Order No. 1000’s interregional requirements, but they disagree on certain matters, as discussed below. Given such disagreement, MISO and SPP are making

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\(^1\) Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), order on reh’g, Order No. 1000-A, 139 FERC ¶ 61,132, order on reh’g and clarification, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) (hereinafter also collectively referred to as “Order No. 1000,” unless otherwise indicated by the text or the context).

\(^2\) Formerly the Midwest Independent Transmission System Operator, Inc., until its name changed effective April 26, 2013.

\(^3\) Joint Operating Agreement between MISO and SPP, designated as MISO’s Second Revised Rate Schedule FERC No. 6; and as SPP’s Second Revised Rate Schedule FERC No. 9. See Southwest Power Pool, Inc., 109 FERC ¶ 61,008 (2004), reh’g denied, 110 FERC ¶ 61,031 (2005).
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separate interregional compliance filings, so that the Commission can consider the parties’ respective proposals on the areas of disagreement.

MISO and SPP agree on the JOA revisions related to interregional coordination, although they disagree on some proposed revisions regarding interregional cost allocation. To facilitate the Commission’s consideration, MISO and SPP have developed an essentially common description of the JOA revisions on which they agree, with minor adjustments in their respective filings (herein, Part III.A and III.B.1) to reflect that the discussion is being provided from the perspective of either MISO or SPP. MISO and SPP have also agreed to use substantially the same language in describing the stakeholder process that led to the development of the proposals discussed herein, which MISO discusses in Part II of this letter.

Despite engaging each other and each other’s stakeholders on numerous occasions, as evidenced in Part II.A below, MISO and SPP both use a partly different basis for cost allocation, and, given the difficulties inherent in bridging the differences between the two approaches, were unable to reach complete agreement regarding the cost allocation of interregional transmission projects. Notwithstanding, given that in MISO’s experience cost allocation has historically been an iterative and evolutionary process, MISO anticipates working in coordination with SPP and its other regional neighbors as the interregional planning process continues to develop.

In light of the linkages between MISO’s and SPP’s regional processes, on the one hand, and the proposed interregional process, on the other hand, MISO requests that the revisions proposed in this filing become effective on the effective date the Commission ultimately approves for the tariff revisions proposed by SPP’s regional compliance filing, as further explained below.

I. BACKGROUND

A. Interregional Coordination and Cost Allocation Requirements of Order No. 1000

Order No. 1000 amended the regional transmission planning and cost allocation requirements of Order No. 890 by imposing a number of requirements regarding new

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4 MISO and SPP agree to all proposed revisions to the JOA included in Tab D to this letter, with the exception of the changes MISO proposes to Sections 9.6.3.1.iii (“Criteria for Project Designation as an Interregional Project”) and 9.6.3.1.1 (“Determination of Benefits to each RTO from Interregional Project”), with which SPP disagrees. MISO has also been informed that SPP plans to include a proposed Section 9.3.3.4.1 which is not included in MISO’s proposed JOA revisions.

transmission facilities selected in a regional transmission plan for purposes of cost allocation and the interregional coordination, and cost allocation of transmission facilities that involve interregional benefits. The Commission required jurisdictional transmission providers to make compliance filings concerning Order No. 1000’s regional planning and cost allocation requirements, and its interregional coordination and cost allocation requirements, respectively.

The original due date for compliance filings for regional requirements was extended to October 25, 2012, and the due date for compliance filings for interregional requirements was extended to July 10, 2013. As a Regional Transmission Organization (“RTO”), MISO submitted on October 25, 2012, its Order No. 1000 regional compliance filing, which in large part was conditionally accepted by the Commission on March 22, 2013. The March 22 Order also accepted MISO’s proposal in Docket No. ER13-186-000 to remove, effective June 1, 2013, the regional cost allocation for MISO’s Baseline Reliability Projects (“BRPs”). On November 13, 2012, SPP, which is also an RTO, submitted its Order No. 1000 regional compliance filing in Docket No. ER13-366-000, where it remains pending.

The present filing addresses Order No. 1000’s interregional coordination and cost allocation requirements, as between MISO and SPP. Unless otherwise indicated, MISO and SPP agree on the aspects of the interregional compliance proposal described herein. Such agreed aspects will be reflected both in MISO’s current filing and in SPP’s concurrent interregional compliance filing. Accordingly, to facilitate discussion, this filing will often describe such agreed to matters as having been proposed or otherwise addressed by both MISO and SPP, albeit separately, meaning that their concurrent filings have proposed common JOA revisions that they agree on. This filing includes the testimony of Ms. Jennifer Curran, MISO’s Vice-President for

reh’g and clarification, Order No. 890–B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), order on reh’g, Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), order on clarification, Order No. 890–D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

6 Order No. 1000 at P 393-404, 415-21, 435-50, 454-55, 458, 465-67, 475-81; Order No. 1000-A at P 500-05, 509-12, 518-22; Order No. 1000-B at P 64.

7 Order No. 1000 at P 578-84, et seq.; Order No. 1000-A at P 634, et seq.; Order No. 1000-B at P 72.


11 Id. at P 518-29. The filing in Docket No. ER13-186 was accepted subject to two minor compliance requirements.
Transmission, who will explain MISO’s position regarding the matters on which no agreement was reached with SPP.

B. Existing MISO-SPP Joint Operating Agreement

On February 10, 2004, the Commission conditionally granted SPP’s application to be an RTO, subject, among other things, to the requirement to file a seams agreement with MISO. On July 2, 2004, the Commission found, among other things, that SPP’s submission of a memorandum of understanding with MISO was not fully compliant with the requirement to file a seams agreement. On October 1, 2004, an unexecuted JOA with MISO filed by SPP was accepted by the Commission as an interim solution, subject to the condition that SPP file by December 1, 2004, a JOA with MISO that included market-to-non-market provisions. On January 1, 2005, the Commission conditionally accepted an executed JOA between SPP and MISO. MISO and SPP filed the JOA as their respective Rate Schedules.

On March 24, 2011, pursuant to Order No. 714, MISO submitted the JOA as its Rate Schedule, and SPP concurrently filed a Tariff Record and Certificate of Concurrence designating MISO as the filing utility for the JOA. On May 16, 2011, the Commission accepted MISO’s filing of the JOA. On June 27, 2013, SPP filed a baseline electronic tariff filing of the JOA in its Tariff and cancelled its Certificate of Concurrence. MISO and SPP are each referred to in the JOA as a “Party” (and collectively, “Parties”), and will also be occasionally referred to as such in this letter.

16 Midwest ISO, Second Revised Rate Schedule FERC No. 6; Southwest Power Pool, Inc., Second Revised Rate Schedule FERC No. 9.
II. DEVELOPMENT OF COMPLIANCE FILING THROUGH STAKEHOLDER PROCESSES OF MISO AND SPP

As required by Order No. 1000, MISO provided its stakeholders with reasonable opportunity to provide inputs for the development of the interregional compliance proposal submitted herein. On information and belief, SPP also provided its stakeholders with the opportunity to provide such inputs.

A. Joint Stakeholder Discussion

MISO and SPP held joint meetings with their respective stakeholders on the following dates:

<table>
<thead>
<tr>
<th>Date</th>
<th>Primary Discussion Items</th>
<th>Meeting Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/12/2012</td>
<td>1) Reviewed Order No. 1000 interregional compliance requirements.</td>
<td>Oklahoma City, OK</td>
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<tr>
<td></td>
<td>2) MISO and SPP presented principles to guide the discussions on developing the MISO-SPP Order No. 1000 interregional compliance proposal.</td>
<td></td>
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<tr>
<td>7/9/2012 &amp; 7/10/2012</td>
<td>1) MISO and SPP each presented proposals to address the Order No. 1000 interregional coordination and cost allocation compliance requirements.</td>
<td>St. Louis, MO</td>
</tr>
<tr>
<td>09/20/2012</td>
<td>1) MISO and SPP presented a joint proposal to address the interregional coordination compliance requirements.</td>
<td>Carmel, IN</td>
</tr>
<tr>
<td></td>
<td>2) MISO and SPP presented each RTO’s preferred approach to interregional cost allocation.</td>
<td></td>
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<tr>
<td></td>
<td>3) Requested stakeholder feedback due on 10/26/2012.</td>
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</tbody>
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21 Order No. 1000 at P 466.
22 Link to MISO’s Order 1000 website:
   https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/FERCOrder1000.aspx.
12/17/2012 | 1) Reviewed stakeholder feedback from the 9/20/2012 meeting.  
2) Provided an update on interregional cost allocation discussions between MISO and SPP. | Conference Call  

2/22/2013 | 1) MISO and SPP reviewed with stakeholders the proposed revisions to Article IX of the MISO-SPP JOA.  
2) Each RTO also reviewed their preferred provisions for interregional cost allocation.  
3) Requested stakeholder feedback due on 3/15/2013. | Dallas, TX  

3/29/2013 | 1) Reviewed stakeholder feedback on the initial draft revisions presented at the 2/22/2013 meeting.  
2) Continued discussions on the differences in each RTO’s preferred interregional cost allocation method.  
3) Requested stakeholder feedback due on 4/12/2013. | Conference Call  

B. MISO Regional Stakeholder Discussion

MISO provided updates on the discussions with SPP regarding the Order No. 1000 interregional compliance requirements in numerous meetings with its Planning Advisory Committee (“PAC”), Planning Sub-Committee (“PSC”), and its RECB Task Force (“RECB TF”). A list of these meeting can be found in Tab A to this letter.

C. SPP Regional Stakeholder Discussion

SPP also engaged its stakeholders in discussions related to compliance with the interregional requirements of Order No. 1000. MISO has been informed that SPP has included as an attachment to its interregional filing a list of all SPP stakeholder meetings much like MISO has done in Tab A to the instant filing.

III. DISCUSSION OF JOA REVISIONS

A. Interregional Coordination and Planning

Order No. 1000 set forth the following requirements for interregional coordination:

(1) A commitment to coordinate and share the results of each transmission planning region’s regional transmission plans to identify possible
interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process. 23

As discussed below, the JOA revisions proposed herein satisfy all of the above requirements.

1. Coordination Commitment and Procedure

As required by Order No. 1000, 24 MISO and SPP, through the proposed JOA and tariff revisions governing their respective regional transmission planning processes, have established further procedures with each other for the purpose of coordinating and sharing the results of their respective regional transmission plans, to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. As further required by Order No. 1000, 25 aside from making a commitment to share regional transmission planning information, MISO and SPP have developed and will implement additional procedures that provide for the sharing of information regarding the respective needs of their respective regions, and potential solutions to those needs, as well as the identification and joint evaluation of interregional transmission alternatives to those regional needs by MISO and SPP. As also required by Order No. 1000, 26 the methods and studies used by such procedures are further described below.

Order No. 1000 requires not only interregional coordination, but also allows neighboring regions to choose to engage in interregional planning. 27 MISO’s and SPP’s existing JOA already provides for coordinated regional planning, principally under Article IX (“Coordinated Regional Transmission Expansion Planning”) of the JOA. In response to Order No. 1000, MISO and SPP

23 Appendix C to Order No. 1000 (“Interregional Transmission Coordination” provisions of Attachment K to Pro Forma OATT).

24 Order No. 1000 at P 396.

25 Id. at P 396, 398.

26 Id. at P 398.

27 Id. at P 399.
propose to continue and enhance their interregional planning framework. The interregional planning procedures are mainly enhanced through revisions to Article IX of the JOA. Article II of the JOA has also been revised to provide a definition of Interregional Projects\(^ {28}\) and to adjust a cross-reference in the definition of Coordinated System Plan.\(^ {29}\) Through coordinated interregional planning, MISO and SPP will assess, on an ongoing basis, the need for a Coordinated System Plan identifying Interregional Projects that could maintain reliability, improve operations, or enhance market efficiency.\(^ {30}\)

In addition, as required by the Commission,\(^ {31}\) limited revisions will be made in MISO’s and SPP’s respective tariffs, to make changes to their regional transmission planning processes related to the implementation of their proposed interregional transmission coordination procedures. In MISO’s Tariff, such revisions will mainly be in Attachment FF (“Transmission Expansion Planning Protocol”), governing the development of MISO’s Transmission Expansion Plans (“MTEP”). In SPP’s Tariff, such revisions will mainly be in Attachment O, which governs SPP’s planning process, as well as in Attachments H, J, and L of the SPP Tariff.

2. **Identification and Joint Evaluation of Proposed Interregional Transmission Projects**

As required by Order No. 1000,\(^ {32}\) MISO and SPP have developed a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in their neighboring transmission planning regions.

**(a) Process Overview**

MISO and SPP’s proposed procedure for jointly identifying and evaluating interregional transmission facilities is illustrated by a process diagram attached under Tab B to this letter. In general, the interregional process includes the following phases:

i. **Information**: Exchange of transmission planning models and other information.

ii. **Issues**: Identification of transmission issues, and determination of the need for further study of interregional solutions.

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\(^{28}\) Section 2.2.27 of JOA.

\(^{29}\) Section 2.2.12 of JOA.

\(^{30}\) Section 9.3 of JOA (“Coordinated System Planning”).

\(^{31}\) Order No. 1000 at P 441.

\(^{32}\) *Id.* at P 435.
iii. **Solutions:** Joint evaluation and study of interregional solutions, and determination of any solution(s) to be recommended.

iv. **Recommendation:** Joint recommendation of Interregional Project(s) to be considered for approval in the respective regional planning processes.

The interregional process is implemented by the Joint Planning Committee (“JPC”), the decision-making body consisting of representatives from the staff of MISO and SPP.\(^{33}\) The JPC considers stakeholder inputs, as facilitated by the Interregional Planning Stakeholder Advisory Committee (“IPSAC”).\(^{34}\) Any recommended interregional solution would then be considered by MISO’s and SPP’s respective regional transmission planning processes. Each proposed Interregional Project needs to be approved by both regional processes in order to be implemented as an Interregional Project as part of a Coordinated System Plan. The interregional process is further described below.

**(b) Sharing of Regional Transmission Planning Data**

As required by Order No. 1000,\(^{35}\) MISO and SPP will exchange at least annually their respective transmission planning models, and related information and data.\(^{36}\) Pursuant to the Commission’s directive,\(^{37}\) such information sharing shall be obligatory on MISO and SPP. In addition, as allowed by the Commission,\(^{38}\) other transmission planning information may be exchanged between MISO and SPP upon each Party’s request.\(^{39}\) This includes the sharing, on an ongoing basis, of each Party’s regional planning information that could further facilitate coordination.\(^{40}\)

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\(^{33}\) See Section 9.1.1 of JOA.

\(^{34}\) See Section 9.1.2 of JOA.

\(^{35}\) Order No. 1000 at P 454.

\(^{36}\) Section 9.2.1 of JOA (“Annual Data and Information Exchange Requirement”).

\(^{37}\) Order No. 1000 at P 455.

\(^{38}\) Id. at P 454.

\(^{39}\) Section 9.2.2 of JOA (“Data and Information Exchange Upon Request”).

\(^{40}\) Section 9.3.1 of JOA (“Single Party Planning”).
i. Types of Data Exchanged Annually

During the first quarter of each calendar year, MISO and SPP shall exchange the following kinds of data:

1) Power flow models for system conditions projected for the planning horizon (up to the next 10 years), including planned generation development and retirements, planned transmission facilities, and projected seasonal loads;

2) System stability models, with detailed dynamic modeling of generators and other active elements;

3) Production cost models, including planned generation development and retirements, planned transmission facilities, and load forecasts;

4) Assumptions used in the development of the power flow, stability, and production cost models; and

5) Contingency lists for use in power flow, stability, and production cost analyses.

ii. Types of Data Available Upon Request

The following kinds of data may be exchanged between MISO and SPP upon either Party’s request, and shall be provided within 30 calendar days after such a request:

1) Updates to data exchanged in accordance with section 9.2.1 of the JOA.

2) Short-circuit models for transmission systems.

3) Regional plans, including the timing, estimated completion dates, and likelihood of completion, of each planned enhancement.

4) Status of expansion studies, and any commitment made to a system enhancement as a result of such studies.

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41 Section 9.2.1 of JOA.

42 Examples of active elements include: static VAR compensators (SVCs), static synchronous compensators (STATCOMs), synchronous condensers, and HVDC Converter facilities.

43 Sections 9.2.1(a) through 9.2.1(e) of JOA.
5) Transmission system maps, in electronic format, for each Party’s bulk transmission system, and lower voltage transmission system maps relevant to coordination of planning.

6) Breaker diagrams for the specified portion(s) of the Party’s transmission system.

7) Identification and status of interconnection and long-term firm transmission service requests, including associated studies.

8) Long-term or short-term reliability assessment documents and any operating assessment reports.

9) Other data and information needed for each Party to plan its own system accurately and reliably, and to assess the impact of conditions existing on the system of the other Party.\footnote{Section 9.2.2 of JOA.}

iii. Protection of Shared Confidential Data

As required by Order No. 1000,\footnote{Order No. 1000 at P 437.} the information shared between MISO and SPP as part of the interregional process shall be subject to appropriate protection of confidential information and Critical Energy Infrastructure Information (\textquote{CEII}).\footnote{Sections 9.1.1.1.i, 9.1.1.1.ii of JOA.}

iv. Harmonization of Differences in Planning Frameworks and Data

As required by Order No. 1000,\footnote{Order No. 1000 at n.365.} any differences between MISO’s and SPP’s respective transmission planning data, models, assumptions, planning horizons, and criteria shall be identified by the JPC, and reviewed in consultation with stakeholders through the IPSAC.\footnote{Section 9.2.1 of JOA, second paragraph; Section 9.2.2 of JOA, second paragraph.} Any such differences shall be resolved by the JPC and IPSAC as part of the development of a joint and common model for the joint study of transmission issues and potential interregional solutions.\footnote{Section 9.3.3.1(2) of JOA (\textquote{Coordinated System Plan Study Scope Development}), providing for the development of joint models; Section 9.3.3.2 of JOA (\textquote{Model Development for a Coordinated System Plan Study}).}
(c) Transparency of Interregional Process

As required by Order No. 1000,\(^{50}\) for purposes of the transparency of the interregional coordination process, MISO and SPP shall each host distinct webpages on their respective websites dedicated to the communication of information on interregional coordination procedures.\(^ {51}\) To ensure consistency, the Parties shall, under the JPC’s direction, coordinate the documents and information to be posted on such webpages.\(^ {52}\) At a minimum, each Party’s interregional coordination webpage shall include the following information:

i. Link to the JOA;

ii. Notice of scheduled IPSAC meetings;

iii. Links to materials for IPSAC meetings;\(^ {53}\) and

iv. Documents relating to Coordinated System Plan studies,\(^ {54}\) including final study reports,\(^ {55}\) describing, among other things, the analyses performed for, and the results of, such studies.\(^ {56}\)

(d) Stakeholder Inputs Through Regional Processes and IPSAC

As required by Order No. 1000,\(^ {57}\) through the regional processes of MISO and SPP, their respective stakeholders shall have an opportunity to participate fully in the evaluation of any proposed Interregional Projects.\(^ {58}\)

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\(^{50}\) Order No. 1000 at P 458.

\(^{51}\) Section 9.1.1.4 of JOA (“Interregional Coordination Webpage”).

\(^{52}\) Id.

\(^{53}\) Section 9.1.1.4 of JOA.

\(^{54}\) Id.

\(^{55}\) Section 9.3.3.6 of JOA (“Regional Approval Process”), third paragraph.

\(^{56}\) See Section 9.3.3.3 of JOA (“Coordinated System Plan Study”), describing the details of the report which will ultimately be posted on each Party’s webpage.

\(^{57}\) Order No. 1000 at P 465.

\(^{58}\) Under MISO’s regional process, stakeholder inputs are considered in the evaluation of potential Interregional Projects pursuant to section I.C.2 of Attachment FF of MISO’s Tariff. Under SPP’s regional process, stakeholder inputs are considered in the evaluation of potential Interregional Projects pursuant to proposed Section IV.6 of Attachment O of SPP’s Tariff.
In addition, their stakeholders will be represented in, and able to provide inputs through, the IPSAC.\(^{59}\) The IPSAC advises the JPC regarding the identification and evaluation of transmission issues and potential solutions in connection with the determination and development of a Coordinated System Plan.\(^{60}\) The IPSAC shall meet at least once a year, during the third quarter of each year, and more frequently when necessary during the development of a Coordinated System Plan.\(^{61}\) Each Party shall be represented by its respectively defined voting group, each of which shall represent one vote.\(^{62}\) The IPSAC can make recommendations to the JPC concerning both the need to study transmission issues and solutions\(^{63}\) and the appropriate action on any solutions identified by the draft of the JPC’s report on the results of a study.\(^{64}\)

**(e) Review of Transmission Issues**

Under the revised JOA, the JPC, in coordination with the IPSAC, shall review transmission issues at least annually, when no Coordination System Plan study is being performed, or more frequently, as determined by the JPC, when such a study is ongoing.\(^{65}\) Transmission issues can be identified by either Party or by other entities.\(^{66}\) Sixty calendar days before the annual meeting of the IPSAC, a notification of the meeting shall be posted on each Party’s website, and circulated by e-mail, inviting interested entities to submit transmission issues, which can also include related solutions.\(^{67}\) Transmission issues, which may include associated solutions, must be submitted at least 30 calendar days before the annual IPSAC meeting,\(^{68}\) together with any supporting analysis.\(^{69}\) The IPSAC shall review transmission issues

\(^{59}\) Section 9.1.2 of JOA (“Interregional Planning Stakeholder Advisory Committee (IPSAC)”).

\(^{60}\) Section 9.1.2.2 of JOA (“IPSAC Responsibilities”).

\(^{61}\) Section 9.1.2.1 of JOA (“IPSAC Structure”).

\(^{62}\) Section 9.1.2.3 of JOA (“IPSAC Voting”).

\(^{63}\) Section 9.3.2.3 of JOA (“IPSAC Review of Identified Transmission Issues”); Section 9.3.2.5 of JOA (“IPSAC Review of JPC Determination of the Need for a Coordinated System Plan Study”).

\(^{64}\) Section 9.3.3.5.1 of JOA (“Coordinated System Plan Study Report and IPSAC Recommendation”).

\(^{65}\) Section 9.3.2 of JOA (“Annual Transmission Issues Evaluation”).

\(^{66}\) *Id.*

\(^{67}\) Section 9.3.2.1 of JOA (“Process for Submitting Transmission Issues for Review”), second paragraph.

\(^{68}\) *Id.*, first and second paragraphs.

\(^{69}\) *Id.*, last paragraph.
at its annual meeting,\textsuperscript{70} and in other meetings called by the JPC with 14 calendar days’ advance notice.\textsuperscript{71} ‘The IPSAC shall vote on whether to submit to the JPC a recommendation to perform a Coordinated System Plan study.’\textsuperscript{72}

(f) Initiation and Type of Studies

A Coordinated System Plan study can be initiated in either of two ways: by the affirmative vote of both Parties’ representatives in the JPC; or, if no such study has been initiated for two consecutive years, by the affirmative vote of one Party’s representatives in the JPC.\textsuperscript{73} Potential Interregional Projects can be proposed by MISO and SPP and by their respective stakeholders, as well as other entities.\textsuperscript{74} As required by Order No. 1000,\textsuperscript{75} transmission developers that wish to propose Interregional Projects located in both MISO and SPP must first submit each such project to the regional processes of both RTOs, to be eligible for consideration by the JPC.\textsuperscript{76} Upon the proposal of a Party’s JPC representative, the IPSAC can meet within 30 calendar days after the JPC’s determination whether or not to conduct a Coordinated System Plan study, to review such determination.\textsuperscript{77}

As required by Order No. 1000,\textsuperscript{78} MISO and SPP’s proposal includes a description of the type of transmission studies that will be conducted to evaluate conditions on their neighboring systems for the purpose of determining whether interregional transmission facilities are more efficient or cost-effective than regional facilities, which may include, but are not limited to, joint futures development, congestion analysis, reliability analysis, and stability analysis.\textsuperscript{79} The type

\begin{itemize}
  \item Section 9.3.2.2 of JOA (“IPSAC Annual Issues Evaluation Meeting(s)”).
  \item Section 9.3.2.3 of JOA (“IPSAC Review of Identified Transmission Issues”).
  \item \textit{Id.}, second paragraph.
  \item Section 9.3.2.4 of JOA (“JPC Decision Process”), second paragraph.
  \item Section 9.3.3.4 of JOA (“Identifying Interregional Solutions”). The JOA defines entities other than MISO and SPP as “Third Parties.” \textit{See} Section 2.2.53 of JOA.
  \item Order No. 1000 at P 376, 436.
  \item \textit{See} Section 9.3.2.1 of JOA (“Process for Submitting Issues for Review”), describing Third Parties’ opportunities to submit projects for consideration.
  \item Section 9.3.2.5 of JOA (“IPSAC Review of JPC Determination of the Need for a Coordinated System Plan Study”).
  \item Order No. 1000 at P 398.
  \item Section 9.3.3.1(3) of JOA (“Coordinated System Plan Study Scope Development”), providing for the development of types of analysis; Section 9.3.3.3 of JOA (“Study Analysis”).
\end{itemize}
of analysis or study shall be based on the transmission issues to be studied and the applicable benefit metrics for evaluating potential solutions.\(^{80}\)

(g) Inclusion in Regional Plans for Purposes of Cost Allocation

As required by Order No. 1000,\(^{81}\) to be eligible for implementation (including cost allocation) as an Interregional Project, a project recommended by the JPC must be approved by the respective Boards of Directors of MISO and SPP.\(^{82}\)

(h) Time Frame of Joint Evaluation

As required by Order No. 1000,\(^{83}\) MISO and SPP have developed a timeline for the joint evaluation of Interregional Projects that is within the same general timeframe as their respective regional processes. This will give the interregional process a meaningful opportunity to review and evaluate relevant information developed through the regional processes and will similarly provide the regional processes with a meaningful opportunity to review and use information developed through the interregional process. Essentially, the interregional process will proceed in parallel to the regional processes.

Attached under Tab C of this letter is a diagram of the timeline for the interregional process. The time periods for completing various steps in the interregional process are as follows:

i. JPC determination to conduct a Coordinated System Plan study: within 45 calendar days from IPSAC’s recommendation to perform such a study.\(^{84}\)

ii. JPC’s notification of IPSAC regarding JPC’s determination whether or not to conduct a study: within 30 calendar days from JPC’s determination whether or not to perform a study.\(^{85}\)

iii. Start date of study: within 180 calendar days (6 months) from JPC’s determination to conduct a study.\(^{86}\)

\(^{80}\) Section 9.3.3.3 of JOA (“Study Analysis”).

\(^{81}\) Order No. 1000 at P 581-82.

\(^{82}\) Section 9.3.3.6 of JOA (“Regional Approval Process”).

\(^{83}\) Order No. 1000 at P 436, 438-40.

\(^{84}\) Section 9.3.2.4 of JOA (“JPC Decision Process”), first paragraph.

\(^{85}\) Id., third paragraph.
iv. Interregional study to be completed within 18 months depending on the study scope.\textsuperscript{87}

v. Each RTO’s review and Board approval of an Interregional Project recommended by the JPC: within 6 months from JPC’s recommendation of the project.\textsuperscript{88} If not approved within that period, or during an extension approved by the JPC, the project shall be deemed automatically rejected. A rejected project may be reevaluated and subsequently recommended again by the JPC.\textsuperscript{89}

This timeline will enable the interregional process to consider Interregional Projects proposed to benefit MISO and SPP, while such regional processes individually consider those proposals. The interregional process will also be able to jointly evaluate other proposed Interregional Projects by Third Parties, including transmission developers.\textsuperscript{90} Interregional Projects recommended by the JPC, in turn, can be considered in the regional processes at the points in time in their transmission planning cycles when proposed Interregional Projects are to be individually considered by MISO and SPP, respectively.

B. Interregional Cost Allocation

1. Ownership and Construction Obligations

While MISO and SPP disagree on certain aspects of the cost allocation of Interregional Projects, they agree on the proposed provisions regarding the determination of ownership rights and construction obligations with respect to Interregional Projects. Under such provisions, MISO will enforce obligations to construct Interregional Projects in accordance with the basic agreement among its Transmission Owners (“Transmission Owners Agreement”),\textsuperscript{91} as it may be amended or restated from time to time. For its part, SPP will enforce obligations to construct and own or finance Interregional Projects in accordance with the basic agreement among its

\textsuperscript{86} Id., fourth paragraph.

\textsuperscript{87} Section 9.3.3.1 of JOA (“Coordinated System Plan Study Scope Development”), first paragraph.

\textsuperscript{88} Section 9.3.3.6 (“Regional Approval Process”), first paragraph.

\textsuperscript{89} Id., second paragraph.

\textsuperscript{90} See Section 9.3.2.1 of JOA (“Process for Submitting Issues for Review”), describing Third Parties’ opportunities to submit projects for consideration.

\textsuperscript{91} Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1.
members (“SPP Membership Agreement”), and SPP’s tariff, as both may be amended or restated from time to time.\textsuperscript{92}

\textbf{(a) Located in Only One Region}

Where an approved Interregional Project will be solely interconnected to transmission facilities under the control of only one Party, the latter’s tariff shall be used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the Interregional Project.\textsuperscript{93}

\textbf{(b) Tie-Lines}

Where all or part of an approved Interregional Project will interconnect to transmission facilities under the respective control of both Parties \textit{(i.e., to one or some facilities under MISO’s control, and another or others under SPP’s control)}, the applicable OATT used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the Interregional Project shall be determined based on the proportion of benefits calculated pursuant to section 9.6.3.3.1 of the JOA (discussed \textit{infra}), unless otherwise precluded by any applicable jurisdictional limitation.\textsuperscript{94} MISO and SPP will coordinate on the designation of the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable portion of an Interregional Project interconnected to both of their regions.\textsuperscript{95}

\textbf{2. Compliance with Order No. 1000’s Six Interregional Cost Allocation Principles}

MISO proposes to rely on Market Efficiency Projects (“MEPs”) as the sole regionally cost-allocated project category, and adjusted production cost (“APC”) as the sole benefit metric (further described below), for purposes of its interregional cost allocation arrangements with SPP.\textsuperscript{96} MISO submits that its proposal satisfies the six interregional cost allocation principles set forth in Order No. 1000.\textsuperscript{97} MISO therefore requests the Commission to approve the MEP/APC proposal as compliant with the interregional cost allocation requirements of Order No. 1000 as between MISO and SPP.

\textsuperscript{92} Section 9.7 of JOA (“Network Upgrade Construction and Ownership”).
\textsuperscript{93} Section 9.7.1 of JOA (“Interregional Project Construction and Ownership”), first paragraph.
\textsuperscript{94} \textit{Id.}, second paragraph.
\textsuperscript{95} \textit{Id.}, third paragraph.
\textsuperscript{96} Tab F, Testimony of Jennifer Curran at 6-7, 11-12 (“Curran Testimony”)
\textsuperscript{97} \textit{See} Order No. 1000 at P 578, \textit{et seq.}; \textit{see also} Curran Testimony at 13-18.
SPP disagrees with MISO’s proposal to rely solely on the MEP project classification, and the APC benefit metric, for purposes of the JOA. Instead, SPP has proposed using adjusted production cost savings as the metric for projects mainly involving economic benefits; avoided reliability project cost for projects chiefly involving reliability benefits; and another metric, yet to be determined, for projects primarily addressing transmission needs driven by public policy requirements. MISO will address below SPP’s views about these matters.

(a) Interregional Cost Allocation Principle 1: Costs Allocated Roughly Commensurate with Benefits

Interregional Cost Allocation Principle 1 states:

The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.

Order No. 1000-A also noted that an interregional cost allocation method should “clearly and definitively specify the benefits and the class of beneficiaries.”

MISO believes its MEP/APC proposal complies with Interregional Cost Allocation Principle 1 because the proposed approach provides for the interregional cost allocation of MEPs, as Interregional Projects, in a manner at least roughly commensurate with estimated benefits.

i. Interregional Project Classification Criteria

For purposes of ensuring that the cost allocation of Interregional Projects is commensurate to estimated benefits, MISO proposes the following minimum eligibility criteria for the classification of an Interregional Project:

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98 Curran Testimony at 11-12.

99 Order No. 1000 at P 622.

100 Order No. 1000-A at P 678.

101 Curran Testimony at 14.
i. **Cost:** Minimum total project cost of $5,000,000;

ii. **Joint Evaluation and Recommendation:** Evaluation, and recommendation by the JPC, as part of a Coordinated System Plan;

iii. **Regional Classification:** Approval as a Market Efficiency Project under MISO’s Tariff and as an Interregional Project under SPP’s tariff;

iv. **Benefits:** MISO’s and SPP’s respective benefits of at least 5 percent of the total benefits for the combined regions; and

v. **In-Service Date:** Estimated in-service date within 10 years from the project’s approval by the respective Boards of Directors of MISO and SPP.  

SPP agrees with all but the third criteria enumerated above. In particular, SPP disagrees with MISO’s proposal to use only MEPs as MISO’s regional category for approving Interregional Projects. In discussions with MISO, SPP indicated that MEPs may not adequately account for benefits relating to reliability and public policy requirements. However, MISO believes MEPs allow for consideration of reliability and public policy benefits.

Under MISO’s Tariff, if a proposed project meets the criteria for both MEPs and BRPs, the project will be classified as an MEP. The Tariff therefore recognizes that MEPs can also address reliability issues. Further, if an Interregional Project includes any upgrades that are required to address reliability issues, the cost of the associated reliability-related upgrades will be included in the overall costs of the project, to ensure the project will provide the expected economic benefits to both regions.

Moreover, transmission needs driven by public policy requirements will also be considered during the evaluation of Interregional Projects because the assessment will be based on jointly developed future scenarios that will include such transmission needs that have been identified in each region. In addition, when MISO considers the Interregional Project for approval as an MEP, the evaluation will include multiple future scenarios that would likewise include the public policy requirement-driven transmission needs identified through the MISO regional planning process.

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102 Section 9.6.3.1 of JOA (“Criteria for Project Designation as an Interregional Project”).

103 Section III.A.2.h of Attachment FF of MISO’s Tariff.

104 Curran Testimony at 10.

105 *Id.* at 11.
As explained by Ms. Curran, the MVP project category is not suitable for interregional coordination, planning, and cost allocation with SPP, as well as with MISO’s other neighboring transmission planning regions. MVPs are required to be evaluated on a portfolio basis to ensure that the benefits are spread broadly across the MISO region in line with the 100% system-wide allocation of costs for MVPs. To be approved under MISO’s regional cost allocation methods as an MVP, an Interregional Project would have to meet this same requirement tied to 100% regional cost allocation, which does not align with the current regional cost allocation methods of the SPP planning region. Taking into account the requirements for regional approval of MVPs, and the differences with the cost allocation processes and methods of the SPP planning region, MISO believes the MEP methodology better aligns with the processes of SPP at this time, and provides a more likely path towards the approval of Interregional Projects to the benefit of customers in both regions given the current difference in MISO’s and SPP’s regional cost allocation mechanisms. For example, MEPs would make it more feasible for MISO and SPP, to resolve any differences between their modeling and other data that could otherwise hamper the effective joint evaluation of transmission needs and the benefits of potential Interregional Projects.

ii. Adjusted Production Cost Benefit Metric

The APC metric calculates production cost savings, adjusted to account for purchases and sales. Based on the multi-year analysis of adjusted production cost savings for an Interregional Project, each region would be allocated a percentage of the Interregional Project costs in proportion to the net present value of the total benefits calculated for each region for the first 20 years of the project’s life.\(^\text{107}\)

Under MISO’s proposed revisions to the JOA, the costs of Interregional Projects, including MEPs in MISO, are allocated to beneficiaries in MISO and SPP in a manner that is at least roughly commensurate with the estimated benefits of these projects, as calculated based on adjusted production cost savings. Although MEPs are focused on addressing congestion relief, they can also provide reliability benefits.\(^\text{108}\) In addition, the JOA ensures that the allocation of costs of Interregional Projects between MISO and SPP is roughly commensurate with the benefits created by these projects by allocating costs in proportion to the net present value of the total benefits calculated for each RTO. Thus, each RTO is allocated Interregional Project costs that directly correspond to the resulting benefits calculated for that RTO. The benefit metric is calculated for each RTO using the APC benefit metrics as inputs. In combination with the 1.25 to 1 benefits-to-costs threshold for MEPs, and the requirement of a 5 percent minimum benefit to each region, MISO’s proposal ensures that each RTO’s benefit in terms of production cost

\(^\text{106}\) Id. at 7.

\(^\text{107}\) Id. at 11.

\(^\text{108}\) Id. at 5, 10.
savings and congestion relief is large enough to justify the interregional allocation of the project’s cost.\textsuperscript{109} The MISO-SPP JOA, therefore, clearly defines the benefits and beneficiaries of Interregional Projects, thereby ensuring that the cost allocation of Interregional Projects is at least roughly commensurate with the estimated benefits provided by such facilities.

Public policy-related benefits can also be addressed by the APC benefit metric because inclusion of each region’s public policy requirements in the jointly developed future scenarios used to identify and evaluate Interregional Projects will capture the potential economic benefits provided by the resources included to address the public policy requirements.\textsuperscript{110}

(b) Interregional Cost Allocation Principle 2: No Involuntary Allocation to Non-Beneficiaries

Interregional Cost Allocation Principle 2 states:

A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.\textsuperscript{111}

The allocation to each JOA party of the cost of any Interregional Project located in that party’s region is based on the voluntary agreement of both parties, and the outcome of benefit determination processes, under the JOA. Under this voluntary arrangement, both parties will participate in the parallel regional and interregional processing and approval of Interregional Projects. The goal of the process, and the basis of such approval, is the determination of the regional and interregional benefits that the parties are expected to receive from proposed Interregional Projects.\textsuperscript{112}

To be eligible for interregional cost allocation, a proposed Interregional Project needs to successfully undergo these regional and interregional processes. First, the proposed Interregional Project should go through the JOA’s joint interregional study and evaluation

\textsuperscript{109} Section 9.6.3.1.iv of JOA.

\textsuperscript{110} Curran Testimony at 10-11.

\textsuperscript{111} Order No. 1000 at P 637.

\textsuperscript{112} See Section 9.6.3.1.1 of JOA (“Determination of Benefits to Each RTO from Interregional Projects”), which provides: “The Parties shall jointly evaluate the benefits to the combined Parties’ regions, 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.”
process, which will assess expected present or likely future benefits; and a resulting Coordinated System Plan study report must recommend the project for approval in the regional processes of both parties. Second, the project must be approved and included in both parties’ regional plans for purposes of regional and interregional cost allocation, at which point the Interregional Project will become part of a Coordinated System Plan. Accordingly, the allocation to MISO of an Interregional Project in its region, or to SPP of such a project in its region, is premised on their voluntary undertakings, and the determination of their respective benefits, under the JOA.

Further, as MISO noted in its regional compliance filing, the Commission has previously found that MISO’s transmission planning process is appropriately designed to reasonably identify and estimate the benefits expected from MEPs. MEPs are planned based on “future scenarios,” and the MEP benefit metric was in fact recently renamed from “Weighted Gain/No Loss” to “Weighted Futures/No Loss,” stressing the analysis of future scenarios. Since any Interregional Project in MISO, or the portion of such project (if a tie-line) located in MISO, must be approved as an MEP to be eligible for interregional cost allocation, any allocation of the cost of such a project to MISO would be based on an expectation of benefits from the project at present or in likely future scenarios.

(c) Interregional Cost Allocation Principle 3: Permissible Benefit-to-Cost Threshold Ratio

Interregional Cost Allocation Principle 3 states:

If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of

113 Sections 9.3.3.1 through 9.3.3.4.1 of JOA.
114 Section 9.3.3.5 of JOA.
115 Section 9.3.3.6 of JOA.
117 Section II.B.1 of Attachment FF.
118 MEP Order at P 21-23 (“MISO considers alternative future scenarios in its planning analysis”).
benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.\textsuperscript{119}

While there is not an explicit benefit-to-cost ratio for Interregional Projects within the JOA, consistent with the third interregional cost allocation principle, MISO proposes to comply with Order No. 1000’s interregional requirements by evaluating and classifying Interregional Projects as MEPs, which are subject to a cost-benefit threshold of 1.25.\textsuperscript{120} In addition, the Commission recently found that the MEP “fixed benefit-cost ratio of 1.25 is just and reasonable because it balances the economic uncertainty of transmission projects with the prospect of approving and constructing projects that provide benefits.”\textsuperscript{121} The same is true of the application of the 1.25 benefit-to-cost ratio to MEPs that are Interregional Projects.

(d) Interregional Cost Allocation Principle 4: Allocation Solely Within Transmission Planning Region Unless Those Outside Agree to Share Costs

Interregional Cost Allocation Principle 4 states:

Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located. However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.\textsuperscript{122}

As in the case of the allocation to a JOA party of the cost of any Interregional Project located in that party’s region (discussed under Interregional Cost Allocation Principle 2), the allocation to a JOA party of the cost of such a project located in the other party’s region is also based on voluntary agreement and benefit determination under the JOA. MISO further notes that its JOA with SPP is patterned after the MISO-PJM JOA, which Order No. 1000 recognized as

\textsuperscript{119} Order No. 1000 at P 646.
\textsuperscript{120} Section II.B.1.e of Attachment FF.
\textsuperscript{121} MEP Order at P 32.
\textsuperscript{122} Order No. 1000 at P 657.
including a cross-border cost allocation method that properly permits the parties to allocate to one RTO the cost of a transmission facility physically located entirely within the other RTO.\footnote{Id. at P 662.} Similarly, MISO’s JOA with SPP appropriately provides for the allocation to each party of the cost of approved Interregional Projects located solely in the other party’s region.\footnote{Section 9.7.1 of JOA (“Interregional Project Construction and Ownership”).}

In this manner, the JOA will provide for the identification of consequences for other transmission planning regions arising out of Interregional Projects, and MISO’s and SPP’s coordination with those other regions to address such impacts.

MISO further notes that, pursuant to Order No. 1000-A,\footnote{Order No. 1000-A at P 714.} any MISO Transmission Owner that withdraws from MISO will remain responsible for its share of the cost of any Interregional Project that is an MEP approved by MISO’s Board of Directors before the effective date of such Transmission Owner’s withdrawal, even if no portion of the MEP is located in the transmission planning area to which the Transmission Owner will transfer.\footnote{See MISO’s Transmission Owners Agreement (Article Five, Section II); Attachment FF (section III.A.2.f) of MISO’s Tariff.}

\textbf{(e) Interregional Cost Allocation Principle 5: Transparency of Method for Determining Benefits and Identifying Beneficiaries}

Interregional Cost Allocation Principle 5 states:

The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility.\footnote{Order No. 1000-A at P 668.}

The JOA’s interregional cost allocation process meets the transparency requirement of Order No. 1000. First, the JOA specifies the data requirements,\footnote{Section 9.2 of JOA (“Data and Information Exchange”).} benefit and beneficiary determination,\footnote{Section 9.6.3.1.1 of JOA (“Determination of Benefits to each RTO from Interregional Project”).} and cost allocation methods\footnote{Section 9.6.3.2 of JOA (“Cost Allocation and Recovery for Interregional Projects”).} applicable to Interregional Projects.
Second, the cost allocation method will be applied in the context of the JOA’s interregional process and MISO’s and SPP’s respective regional processes, which are open to, and provide procedures for, stakeholder participation. Stakeholders will be able to review and elicit the documentation and details of the benefit determination and cost allocation of each proposed Interregional Project, from proposal through approval or disapproval.

Third, the requirements, status, studies, and results of MISO’s and SPP’s benefit analysis and cost allocation determinations are appropriately documented and reported, with approved Interregional Projects ultimately identified in the Coordinated System Plan, and the associated information and documentation will be publicly posted on the interregional planning webpages on MISO’s and SPP’s respective websites, subject to appropriate protection of any confidential information and CEII. Thus, the proposed interregional cost allocation and benefit/beneficiary determination methods are duly transparent.

(f) Interregional Cost Allocation Principle 6: Permissibility of Using Different Methods for Different Types of Facilities

Interregional Cost Allocation Principle 6 states:

The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.

Order No. 1000 allows, but does not require, the adoption of different cost allocation methods for different types of interregional transmission projects. Consistent with these parameters, MISO has elected to use the MEP project category, and the adjusted production cost benefit metric, for Interregional Projects. As previously discussed, under MISO’s Tariff, MEPs will account for economic, reliability, and/or public policy-related project benefits. This approach is clearly explained in detail above.

IV. SUPPORTING DOCUMENTS

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

131 Section 9.3.3 of JOA (“Coordinated System Plan Study”).
132 Section 9.1.1.4 of JOA (“Interregional Coordination Webpage”).
133 Order No. 1000 at P 685.
V. PROPOSED EFFECTIVE DATE AND REQUEST FOR EXTENDED COMMENT PERIOD

A. Requested Effective Date

MISO respectfully requests that the proposed JOA and Tariff revisions be made effective on the effective date the Commission ultimately approves for the tariff revisions proposed by SPP’s regional compliance filing, in light of the linkages between MISO’s and SPP’s regional processes described in their Order No. 1000 regional compliance filings in Docket Nos. ER13-187-000 and ER13-366-000, respectively, on the one hand, and their interregional process proposed herein, on the other hand. SPP’s regional compliance filing requests an effective date of March 30th following the Commission’s acceptance of such filing.

B. Request for Extended Comment Period

In addition, MISO respectfully requests that the Commission provide an extended period for parties to file comments on this filing until September 9, 2013. Given the complexity, extent, and importance of the proposed JOA changes, and the areas of disagreement with SPP, MISO believes an extended comment period is appropriate to permit all interested parties adequate opportunity to analyze and submit comments on the proposed JOA changes.

VI. 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:

Daniel M. Malabonga*
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Venable LLP
575 7th Street, N.W.
Washington, D.C. 20004

Matthew R. Dorsett*
Attorney
Midcontinent Independent System Operator, Inc.
P.O. Box 4202
VII. NOTICE AND SERVICE

MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, 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 at https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx, on MISO’s website, for other interested parties in this matter.

VIII. CONCLUSION

MISO respectfully requests that the Commission accept this filing and the proposed revisions to the MISO-SPP JOA, and the concurrently filed revisions to MISO’s Tariff, as compliant with the interregional coordination and cost allocation requirements of Order Nos. 1000, 1000-A, and 1000-B, as discussed above.

Sincerely,

/s/ Matthew R. Dorsett
Matthew R. Dorsett
Attorney
Midcontinent Independent System Operator, Inc.

/s/ Daniel M. Malabonga
Daniel M. Malabonga
Bryan M. Likins
Venable LLP

Attorneys for MISO

/Attachments
Tab A

Table of MISO’s Order No. 1000 Interregional Stakeholder Meetings
<table>
<thead>
<tr>
<th>MISO Stakeholder Forums</th>
<th>Dates of Meetings and Conference Calls</th>
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Tab B

Diagram of Order No. 1000 Interregional Planning and Cost Allocation Process
Proposed Order 1000 Interregional Planning and Cost Allocation Process

Annual Model Exchange
- Exchange agreed to planning data and information based on best available data (additional data may be requested)
  - MISO: Planning Model Data
  - SPP: Planning Model Data
  - MISO: Input from regional planning process
  - SPP: Input from regional planning process
  - MISO: Identify Transmission Issues
  - SPP: Identify Transmission Issues
  - Annual evaluation of identified Transmission Issues through IPSAC
  - Does identified Transmission Issues require evaluation of interregional transmission solutions?
    - YES: Report on identified issues and need for further study
    - NO: Produce report why additional study this cycle is not needed
  - Other Stakeholders: Identify Transmission Issues (including analysis to support recommended issues for evaluation)
  - Annual Issues Evaluation
  - Annual Model Exchange
Proposed Order 1000 Interregional Planning and Cost Allocation Process

Joint Evaluation

Input from Annual Issues Identification Process → Study scope and assumption development → Joint Model Development

Evaluate proposed interregional solution(s) using joint criteria

Does project(s) meet interregional project criteria?

NO → Joint Coordinated System Plan Report

YES → Determine Interregional Cost Allocation → Joint Coordinated System Plan Report

- MISO: Proposed Interregional Solution(s)
- SPP: Proposed Interregional Solution(s)
- Other Stakeholders: Proposed Interregional Solution

Regional Review

- MISO Regional Review → MISO Approval
- SPP Regional Review → SPP Approval
- Approved Interregional Project
Tab C

Diagram of Order No. 1000
Interregional Process Timeline
Interregional Process Timeline

- JPC decides on need for Interregional Study
- IPSAC Annual Issues Review Meeting
- Flexibility in determining start date for study
- Interregional Study: 1) Scope Development; 2) Joint Mode Development; 3) Issues Verification; 4) Solution Identification and Evaluation; 5) Determine Interregional Cost Allocation
- Completed within 12-18 months depending on scope
- 45 days
- Regional Review (process may begin prior to end of study)
- up to 6 months
- Approved Interregional Project
Tab D

Redlined Version of JOA Provisions
Section 2.2 Definitions. Version: 1.0.0.0 Effective: 3/30/2014 25/2011

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.

2.2.13 “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 Joint Coordinated System Plan” shall have the meaning given under Section 9.6.3.1.2.

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 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.

2.2.57 “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.

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

2.2.59 “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.

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

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

2.2.62 “Voltage and Reactive Power Coordination Procedure” are the procedures under Article XI for coordination of voltage control and reactive power requirements.
Section 9.1.1 Joint Planning Committee. Version: 1.0.0.0 Effective: 3/30/2014

The SACC shall form a Joint Planning Committee (JPC) comprised of representatives of the Parties’ respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, alternating every two years, to designate a Chairman of the JPC to serve a two-year calendar term beginning in 2014. The first two-year chairmanship shall commence on January 1, 2014 and end December 31, 2015. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings.

For the purpose of interregional transmission planning coordination, the JPC shall meet no less than twice per year. The JPC shall meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

The SACC shall form, as a subcommittee, a JPC, comprised of representatives of the Parties’ respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JPC to serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and end December 31, 2004. The SACC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings. The JPC shall coordinate the coordinated system planning under this Agreement, including the following:

(a) 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 analyses, 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.

(b) Prepare, on a regular basis, a Coordinated System Plan as required under Section 9.3.

(c) Coordinate all planning activities under this Article IX, including the exchange of data provided under this Article.

(d) Maintain and share the cost of maintaining an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

(e) Meet at least semi-annually to review and coordinate transmission planning activities. Such meetings shall include, as determined by either Party to be necessary based on internal discussions, discussion of any
system operations or market operations issues as they impact long range planning and the coordination of planning between the systems.

(f) Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

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

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

(i) Establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

(j) The JPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective inter-regional planning coordination.

Section 9.1.1.1 JPC Responsibilities Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.1.1.2 Participating in Multi-Party Studies Version: 0.0.0 Effective: 3/30/2014

The JPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective coordinated interregional planning.

Section 9.1.1.3 JPC Voting Process Version: 0.0.0 Effective: 3/30/2014

While the JPC may have multiple representatives from each Party, each Party shall on matters requiring a vote of the JPC be permitted to cast one vote. For a matter to be approved by the JPC, both planning regions must vote in the affirmative, except as provided in sub-paragraph (ii) of the second paragraph of section 9.3.2.4.

Section 9.1.1.4 Interregional Coordination Webpage Version: 0.0.0 Effective: 3/30/2014

Each Party shall maintain in its own website a webpage dedicated to the communication of information related to interregional transmission coordination procedures.

Under the direction of the JPC, the Parties shall coordinate on the documents and information that is posted to each Party’s respective interregional coordination webpage to ensure consistency of information.

Each Party’s interregional coordination webpage shall contain, at a minimum, the following information:
The Parties shall form an IPSAC. The IPSAC shall facilitate stakeholder review and input into coordinated system planning for the development of the Coordinated System Plan. IPSAC members shall consist of the stakeholder review and provide stakeholders the opportunity to advise the JPC on matters related to coordinated system planning for the development of the Coordinated System Plan. IPSAC participants in joint stakeholder meetings shall be facilitated by the JPC.

IPSAC participation is open to all stakeholders. 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.

The IPSAC’s primary role is to advise the JPC on all matters relating to the development of a Coordinated System Plan as established by this Article IX.

The IPSAC will provide input and a recommendation to the JPC as to whether a Coordinated System Plan study should be performed pursuant to Section 9.3.2. If it is determined by the JPC that a study should be performed, the IPSAC will provide input to the JPC during the performance of the Coordinated System Plan study pursuant to Section 9.3.3.

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.

Section 9.2 Data and Information Exchange. Version: 1.0.0.0 Effective:

3/30/2014 25/2011

In support of coordinated system planning, each Party shall provide the other with the following data and information. Unless otherwise indicated, such data and information shall be provided as requested by either Party and as available, on a mutually agreed to schedule but no longer than 60 days from the date of such request.

(a) —— Data required for the development of load flow cases, short circuit cases, and stability cases, including ten year load forecasts, and all critical assumptions that are used in the development of these cases.

(b) —— Fully detailed planning models (up to the next ten (10) years), as requested by either Party and on a mutually agreed schedule as a part of the development of any joint planning studies provided for under this Article IX or as otherwise agreed to.

(c) —— The regional plan document produced by the Party, any long term or short term reliability assessment documents produced by the Party, and any operating assessment reports produced by the Party.

(d) —— The status of expansion studies, system impact studies and generation interconnection studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

(e) —— Transmission system maps for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two systems.

(f) —— Contingency lists for use in load flow and stability analyses, including lists of all single contingency events and multiple facility tower line contingencies, as well as breaker diagrams for the portions of the Party’s transmission system that are relevant to the coordination of planning between the two systems.

(g) —— The timing of each planned enhancement, including estimated completion dates and project mobilization schedules, and indications of the likelihood a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and all related
applications for regulatory approval and the status thereof. This information shall be provided annually and from time to time upon changes in status.

(h) Identification of and status of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party’s system in a manner that affects the other Party’s system, shared on the earlier of the identification of the potential impact, within 30 days of such request by the other Party or on a regular schedule as otherwise agreed to by the Parties.

(i) Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between the systems, shared on the earlier of the identification of the potential impact, within 30 days of such request by the other Party, or on a regular schedule as otherwise agreed to by the Parties.

(j) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

(k) Load flow and short-circuit data initially will be exchanged in PSS/E format. To the extent practical the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Parties. Formats for the exchange of other data will be agreed upon by the Parties from time to time.

Section 9.2.1 Annual Data and Information Exchange Requirement Version: 0.0.0

Effective: 3/30/2014

In support of interregional transmission planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below:

a) Powerflow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections;

b) System stability models with detailed dynamic modeling of generators and other active elements;
c) Production cost models that include planned generation development and retirements, load forecasts, and planned transmission facilities;

d) Assumptions used in development of above powerflow, stability and production cost models; and

e) Contingency lists for use in powerflow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party’s planning processes. Formats for the exchange of data will be agreed upon by the JPC. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this JOA. The Parties agree to maintain the data and information received under Section 9.2.1 in accordance with each Party’s applicable Critical Energy Infrastructure Information (“CEII”) and confidentiality policies. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of Section 9.2 as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of each calendar year, unless Parties agree in writing to a different timeline.

Section 9.2.2 Data and Information Exchange Upon Request Version: 0.0.0 Effective: 3/30/2014

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request as noted below:

(a) Any updates to data exchanged in accordance with Section 9.2.1:

(b) Short-circuit models for transmission systems:

(c) The regional plan document produced by the Party, the timing of each planned enhancement, estimated completion dates, and indications of the likelihood a system enhancement will be completed;

(d) The status of expansion studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies;

(e) Transmission system maps in electronic format for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties;

(f) Breaker diagrams for the specified portion(s) of the Party’s transmission system;

(g) Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies;
(h) Long-term or short-term reliability assessment documents produced by the Party and any operating assessment reports produced by the Party; and

(i) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

The Parties agree to maintain the data and information received under Section 9.2.2 in accordance with each Party’s applicable CEII and confidentiality policies. Any data shared between the Parties that are market sensitive shall be clearly identified as such. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within thirty (30) calendar days from the date of such request or on a mutually agreed to schedule.
Section 9.3 Coordinated System Planning. Version: 1.0.0.0 Effective:

3/30/2014

The primary purpose of coordinated system transmission planning is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the efficiency competitiveness of electricity markets. Any such expansions or enhancements shall be described in a Coordinated System Plan.

Section 9.3.1 Single Party Planning. Version: 1.0.0.0 Effective: 3/30/2014

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its agreements and open access transmission tariff (“OATT”). Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report and document the procedures, methodologies, and business rules that are utilized in preparing and completing this transmission planning report. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

Section 9.3.2 Annual Transmission Issues Evaluation Version: 0.0.0 Effective:

3/30/2014

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 administered by the JPC in coordination with the IPSAC to determine the need for a Coordinated System Plan study.
Section 9.3.2.1 Process for Submitting Transmission Issues for Review Version: 0.0.0 Effective: 3/30/2014

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 recommended transmission issue. These submissions shall be exchanged between the Party’s JPC representatives.

Section 9.3.2.2 IPSAC Annual Issues Evaluation Meeting(s) Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.2.3 IPSAC Review of Identified Transmission Issues Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.2.4 JPC Decision Process Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.2.5 IPSAC Review of JPC Determination of the Need for a Coordinated System Plan Study

If a Party’s JPC representative proposes to hold an IPSAC meeting to review the JPC’s determination of the need to perform a Coordinated System Plan study, an IPSAC meeting shall be held within thirty (30) calendar days after the JPC’s determination.
In the event a Coordinated System Plan study is initiated pursuant to Section 9.3.2.4, the study shall be performed in accordance with this Section 9.3.3.

The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan. The Coordinated System Plan shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1 (k), the Coordinated System Plan may be integrated into any Joint Coordinated System Plan engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such Joint Coordinated System Plan.

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, 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 JPC shall be responsible for facilitating the development of a joint and common model(s) that shall be used for the Coordinated System Plan.
study. The joint and common model(s) shall be used by the JPC to perform all analysis related applicable to the joint evaluation and shall be based on the assumptions defined in the scope for Parties’ systems. Each Party’s annual transmission planning reports will be incorporated into the Coordinated System Plan study. Stakeholders may provide input on the joint and common model(s) developed for; however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Article, to obtain financial compensation due to the impact of another Party’s plans or additions. The IPSAC will have an opportunity to review and comment before the Coordinated System Plan study through the IPSAC is finalized:

(a) Integrate the Parties’ respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and transmission system upgrades identified jointly by the Parties, together with alternatives to upgrades that were considered.

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to such system additions or upgrades; and

(c) Describe results of the analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules that were utilized in preparing and completing the joint transmission analysis.

Section 9.3.35.2 Coordinated System Plan Steps Study Analysis Version: 1.0.0.0 Effective: 3/30/20145/2011

The type Coordination of analysis that is performed during a studies required for the development of the Coordinated System Plan study shall be will include the following steps:

(a) Every three years, the Parties shall perform a comprehensive, coordinated regional transmission expansion planning study. Sensitivity analyses will be performed, as required, during the off years based on the transmission a review by the JPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions. Ad hoc study groups may be formed as needed to address localized seams issues identified in the or to perform targeted studies of particular areas, needs, or
potential expansions and to ensure the coordinated reliability and efficiency of the systems.

(b) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(c) The JPC will develop a 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 procedure for the interregional planning assessment. The scope of the study will include evaluations of the transmission issues and the benefits system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party. Each Party will provide a baseline model that includes all transmission enhancements included in the Party’s regional transmission expansion plan, and all of the committed interconnection projects and any associated transmission upgrades.

Section 9.3.3.4 Identifying Interregional Solutions Version: 0.0.0 Effective: 3/30/2014

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 9.3.3.5 Interregional Project Recommendation Process Version: 0.0.0 Effective: 3/30/2014

Section 9.3.3.5.1 Coordinated System Planning Study Report and IPSAC Recomm... Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.3.5.2 JPC Interregional Project Recommendation Version: 0.0.0 Effective: 3/30/2014

Taking into consideration the recommendation of the IPSAC, in accordance with Section 9.3.5.1, the JPC shall meet and vote in accordance with Section 9.1.1.3 whether to recommend the Interregional Project(s) and the associated interregional cost allocation identified in the Coordinated System Plan study report to each Party’s regional process for review and approval. The Coordinated System Plan study report will be updated to include the recommendation of the JPC and IPSAC. The updated Coordinated System Plan study report shall be posted on each Party’s respective interregional coordination webpage after determining whether to recommend the Interregional Project to each Party’s regional process for review and approval.

Section 9.3.3.6 Regional Approval Process Version: 0.0.0 Effective: 3/30/2014

The JPC recommendation of an Interregional Project(s) and associated cost allocation shall be reviewed by each Party through its respective regional processes within six (6) months of the JPC recommendation. In accordance with Section 9.1.1.3, the JPC may vote to grant one or both of the Parties additional time for regional review.

Approval of the Interregional Project by each Party’s Board of Directors is required for the Interregional Project to qualify for interregional cost allocation. If the recommended Interregional Project(s) and associated cost allocation is not approved by the Parties within six (6) months or any JPC approved extension, the proposed Interregional Project is deemed rejected. The rejected Interregional Project may be reevaluated and recommended by the JPC as part of a future Coordinated System Plan study.

The JPC shall inform the IPSAC of the outcome of each Party’s regional review of the recommended Interregional Project(s). Each Party shall post a final version of the Coordinated System Plan study report on their respective interregional coordination webpage in accordance with Section 9.1.1.4.
Section 9.43.3 Analysis of Interconnection Requests. Version: 1.0.0.0 Effective: 3/30/2014 25/2011

In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies and upgrades will include the following:

(a) Upon either the posting to the OASIS of a request for interconnection or the review of the study results related to that request for interconnection, the Party receiving the request (“direct connect system”) will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the directly connected system will notify the other Party and convey the information provided in the posting.

(b) Following the results of either the Feasibility Study or the System Impact Study, the direct connect system will notify the other Party if the study shows potential reliability concerns on the other Party’s system. After reviewing the results, if the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate and mutually agree on with respect to the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party, who will perform the studies. If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV. The Parties will strive to minimize the costs associated with the coordinated study process.

(c) Any coordinated studies will be performed in accordance with the study scope and timeline mutually agreed to in 9.43.3 (b) above utilizing the responsibility options outlined in 9.43.3 (d) below.

(d) The potentially impacted Party may participate in the coordinated study at the System Impact Study or Feasibility Study stage, either by taking responsibility for performance of studies of its system, or by providing input to the studies to be performed by the direct connect system. If the constraints found require infrastructure additions to mitigate them, then
the potentially impacted Party will perform its own Facilities Study as part of the direct connect Party’s Facilities Study. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants including the potentially impacted Party. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(e) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(f) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the System Impact Study prepared for the interconnection customer.

(g) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(h) In the event that Network Upgrades are required on the potentially impacted Party’s system, then interconnection service will commence on a schedule mutually agreed upon between the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(i) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The Parties will post this listing on the Internet site maintained for the communication of information related to the coordinated planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.
Section 9.53.4 Analysis of Long Term Firm Transmission Service Requests.

Version: 1.0.0.0 Effective: 3/30/201425/2011

In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon either the posting to the OASIS of a request for service or the review of studies related to the evaluation of that service request, the Party receiving the request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will notify the other Party and convey the information provided in the posting.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party’s OASIS is unnecessary (i.e., the potentially impacted Party is “off the path”), then that Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to maximize the cost efficiency of the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) During the System Impact Study, the potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of their system, or by providing input to the studies to be performed by the Party receiving the request. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study
as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the system receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the applicable Party’s OATs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.
Section 9.64 Allocation of Costs of Network Upgrades. Version: 1.0.0.0 Effective: 3/30/2014 25/2011

Section 9.64.1 Network Upgrades Associated with Interconnections. Version: 19.0.0 Effective: 3/30/2014 25/2011

When under Section 9.43.3, it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties’ Order No. 2003 compliance filings as accepted by the FERC.

Section 9.64.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.53.4, it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

Section 9.64.3 Network Upgrades Under Coordinated System Plan. Version: 1.0.0.0 Effective: 3/30/2014 25/2011

The Cost responsibility for the transmission upgrades identified in the Coordinated System Plan to resolve thermal or reactive system constraints related to reliability criteria or...
operational or economic system performance will identify Network Upgrades under the Coordinated System Plan as Interregional Projects. Consistent with the applicable OATT provisions, be assigned to the Coordinated System Plan will designate the portion Parties equitably, based on the nature of the project cost for each such project that is to be allocated to each Party on behalf of its transmission customers, constraint being resolved.

The JPC will develop procedures for evaluating, on a case-by-case basis, the relative contribution of the Party’s systems to the constraint and the relative benefits derived by the parties by the resolution of the constraint. The JPC will determine the interregional propose an allocation of costs to be shared by the Parties’ for such transmission customers for such Interregional Project(s) based on the procedures developed pursuant to this Section 9.6.3. Each Party will then determine regional allocation of the costs of the Interregional Project pursuant to its respective OATT, system upgrades. The proposed allocation of costs will be reviewed with the IPSAC, and the appropriate multi-state entities. Stakeholder input will be solicited and taken into consideration by the JPC in arriving at an agreed to allocation of costs, a consensus allocation of costs. Upgrade proposals and cost allocations are subject to the approval process of both Parties for transmission upgrades. Each Party’s allocation and the recovery of the costs of such Network Upgrades shall be consistent with the terms and conditions of its own OATT, as it may be modified from time to time pursuant to the rights of various parties under the Federal Power Act.

Section 9.6.3.1 Criteria for Project Designation as an Interregional Project Version: 0.0.0 Effective: 3/30/2014

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;

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
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.

Section 9.6.3.1.1 Determination of Benefits to each RTO from Interregional... Version: 0.0.0

Effective: 3/30/2014

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. 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.

b. 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.
Section 9.6.3.2 Cost Allocation and Recovery for Interregional Projects Version: 0.0.0 Effective: 3/30/2014

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.

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.

Section 9.6.3.3 Quarterly Status Reporting of Interregional Projects Version: 0.0.0 Effective: 3/30/2014

Each Party shall provide to the JPC for posting on each respective Party’s interregional coordination webpage a quarterly status report on approved Interregional Projects, including at a minimum the current estimated project cost and in-service date.

Section 9.7.5 Agreement to Enforce Duties to Network Upgrade Construction and Ownership Version: 1.0.0.0 Effective: 3/30/2014

To obtain Network Upgrades under this Article IX, SPP will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the SPP Membership Agreement and the SPP OATT, as both may be amended or restated from time to time, and Midwest ISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

Section 9.7.1 Interregional Project Construction and Ownership Version: 0.0.0 Effective: 3/30/2014

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.

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.

Section 9.8 CMP Allocation Adjustments for Interregional Project Version: 0.0.0

Effective: 3/30/2014

[Reserved for Future Use]
Tab E

Clean Version of JOA Provisions
Section 2.2 Definitions. Version: 1.0.0 Effective: 3/30/2014

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 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.
2.2.57 “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.

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

2.2.59 “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.

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

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

2.2.62 “Voltage and Reactive Power Coordination Procedure” are the procedures under Article XI for coordination of voltage control and reactive power requirements.
Section 9.1.1 Joint Planning Committee. Version: 1.0.0 Effective: 3/30/2014

The SACC shall form a Joint Planning Committee (JPC) comprised of representatives of the Parties’ respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, alternating every two years, to designate a Chairman of the JPC to serve a two-year calendar term beginning in 2014. The first two-year chairmanship shall commence on January 1, 2014 and end December 31, 2015. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings.

For the purpose of interregional transmission planning coordination, the JPC shall meet no less than twice per year. The JPC shall meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

Section 9.1.1.1 JPC Responsibilities Version: 0.0.0 Effective: 3/30/2014

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.

**Section 9.1.1.2 Participating in Multi-Party Studies Version: 0.0.0 Effective: 3/30/2014**

The JPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective coordinated interregional planning.

**Section 9.1.1.3 JPC Voting Process Version: 0.0.0 Effective: 3/30/2014**

While the JPC may have multiple representatives from each Party, each Party shall on matters requiring a vote of the JPC be permitted to cast one vote. For a matter to be approved by the JPC, both planning regions must vote in the affirmative, except as provided in sub-paragraph (ii) of the second paragraph of section 9.3.2.4.

**Section 9.1.1.4 Interregional Coordination Webpage Version: 0.0.0 Effective: 3/30/2014**

Each Party shall maintain in its own website a webpage dedicated to the communication of information related to interregional transmission coordination procedures.

Under the direction of the JPC, the Parties shall coordinate on the documents and information that is posted to each Party’s respective interregional coordination webpage to ensure consistency of information.

Each Party’s interregional coordination webpage shall contain, at a minimum, the following information:

i. Link to this Joint Operating Agreement (JOA);

ii. Notice of scheduled IPSAC meetings;

iii. Links to materials for IPSAC meetings; and

iv. Documents relating to Coordinated System Plan studies.
Section 9.1.2 Interregional Planning Stakeholder Advisory Committee. Version: 1.0.0
Effective: 3/30/2014

The Parties shall form an IPSAC. The IPSAC shall facilitate stakeholder review and provide stakeholders the opportunity to advise the JPC on matters related to coordinated system planning for the development of the Coordinated System Plan. IPSAC meetings shall be facilitated by the JPC.

Section 9.1.2.1 IPSAC Structure Version: 0.0.0 Effective: 3/30/2014

IPSAC participation is open to all stakeholders. 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.

Section 9.1.2.2 IPSAC Responsibilities Version: 0.0.0 Effective: 3/30/2014

The IPSAC’s primary role is to advise the JPC on all matters relating to the development of a Coordinated System Plan as established by this Article IX.

The IPSAC will provide input and a recommendation to the JPC as to whether a Coordinated System Plan study should be performed pursuant to Section 9.3.2. If it is determined by the JPC that a study should be performed, the IPSAC will provide input to the JPC during the performance of the Coordinated System Plan study pursuant to Section 9.3.3.

Section 9.1.2.3 IPSAC Voting Process Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.2 Data and Information Exchange. Version: 1.0.0 Effective: 3/30/2014
Section 9.2.1 Annual Data and Information Exchange Requirement Version: 0.0.0

Effective: 3/30/2014

In support of interregional transmission planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below:

a) Powerflow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections;

b) System stability models with detailed dynamic modeling of generators and other active elements;

c) Production cost models that include planned generation development and retirements, load forecasts, and planned transmission facilities;

d) Assumptions used in development of above powerflow, stability and production cost models; and

e) Contingency lists for use in powerflow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party’s planning processes. Formats for the exchange of data will be agreed upon by the JPC. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this JOA. The Parties agree to maintain the data and information received under Section 9.2.1 in accordance with each Party’s applicable Critical Energy Infrastructure Information (“CEII”) and confidentiality policies. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of Section 9.2 as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of each calendar year, unless Parties agree in writing to a different timeline.

Section 9.2.2 Data and Information Exchange Upon Request Version: 0.0.0 Effective:

3/30/2014

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request as noted below:

(a) Any updates to data exchanged in accordance with Section 9.2.1:

(b) Short-circuit models for transmission systems:
(c) The regional plan document produced by the Party, the timing of each planned enhancement, estimated completion dates, and indications of the likelihood a system enhancement will be completed;

(d) The status of expansion studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies;

(e) Transmission system maps in electronic format for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties;

(f) Breaker diagrams for the specified portion(s) of the Party’s transmission system;

(g) Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies;

(h) Long-term or short-term reliability assessment documents produced by the Party and any operating assessment reports produced by the Party; and

(i) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

The Parties agree to maintain the data and information received under Section 9.2.2 in accordance with each Party’s applicable CEII and confidentiality policies. Any data shared between the Parties that are market sensitive shall be clearly identified as such. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within thirty (30) calendar days from the date of such request or on a mutually agreed to schedule.
Section 9.3 Coordinated System Planning. Version: 1.0.0 Effective: 3/30/2014

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, improve operational performance, or enhance the efficiency of electricity markets. Any such expansions or enhancements shall be described in a Coordinated System Plan.

Section 9.3.1 Single Party Planning. Version: 1.0.0 Effective: 3/30/2014

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its agreements and open access transmission tariff (“OATT”). Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report and document the procedures, methodologies, and business rules that are utilized in preparing and completing this transmission planning report. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

Section 9.3.2 Annual Transmission Issues Evaluation Version: 0.0.0 Effective: 3/30/2014

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.
Section 9.3.2.1 Process for Submitting Transmission Issues for Review Version: 0.0.0 Effective: 3/30/2014

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 recommended transmission issue. These submissions shall be exchanged between the Party’s JPC representatives.

Section 9.3.2.2 IPSAC Annual Issues Evaluation Meeting(s) Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.2.3 IPSAC Review of Identified Transmission Issues Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.2.4 JPC Decision Process Version: 0.0.0 Effective: 3/30/2014

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.

Section 9.3.2.5 IPSAC Review of JPC Determination of the Need for a Coordinated System Plan Study

If a Party’s JPC representative proposes to hold an IPSAC meeting to review the JPC’s determination of the need to perform a Coordinated System Plan study, an IPSAC meeting shall be held within thirty (30) calendar days after the JPC’s determination.
Section 9.3.3  Coordinated System Plan Study Version: 1.0.0 Effective: 3/30/2014

In the event a Coordinated System Plan study is initiated pursuant to Section 9.3.2.4, the study shall be performed in accordance with this Section 9.3.3.

Section 9.3.3.1 Coordinated System Plan Study Scope Development  Version: 1.0.0 Effective: 3/30/2014

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, 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.

Section 9.3.3.2 Model Development for a Coordinated System Plan Study  Version: 1.0.0 Effective: 3/30/2014

The JPC shall be responsible for facilitating the development of a joint and common model(s) that shall be used for the Coordinated System Plan study. The joint and common model(s) shall be used by the JPC to perform all analysis related to the joint evaluation and shall be based on the assumptions defined in the scope for the Coordinated System Plan study. Stakeholders may provide input on the joint and common model(s) developed for the Coordinated System Plan study through the IPSAC.
Section 9.3.3.3 Study Analysis Version: 1.0.0 Effective: 3/30/2014

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.

Section 9.3.3.4 Identifying Interregional Solutions Version: 0.0.0 Effective: 3/30/2014

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 9.3.3.5 Interregional Project Recommendation Process Version: 0.0.0 Effective: 3/30/2014

Section 9.3.3.5.1 Coordinated System Planning Study Report and IPSAC Recomm... Version: 0.0.0 Effective: 3/30/2014

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.
Taking into consideration the recommendation of the IPSAC, in accordance with Section 9.3.5.1, the JPC shall meet and vote in accordance with Section 9.1.1.3 whether to recommend the Interregional Project(s) and the associated interregional cost allocation identified in the Coordinated System Plan study report to each Party’s regional process for review and approval. The Coordinated System Plan study report will be updated to include the recommendation of the JPC and IPSAC. The updated Coordinated System Plan study report shall be posted on each Party’s respective interregional coordination webpage after determining whether to recommend the Interregional Project to each Party’s regional process for review and approval.

The JPC recommendation of an Interregional Project(s) and associated cost allocation shall be reviewed by each Party through its respective regional processes within six (6) months of the JPC recommendation. In accordance with Section 9.1.1.3, the JPC may vote to grant one or both of the Parties additional time for regional review.

Approval of the Interregional Project by each Party’s Board of Directors is required for the Interregional Project to qualify for interregional cost allocation. If the recommended Interregional Project(s) and associated cost allocation is not approved by the Parties within six (6) months or any JPC approved extension, the proposed Interregional Project is deemed rejected. The rejected Interregional Project may be reevaluated and recommended by the JPC as part of a future Coordinated System Plan study.

The JPC shall inform the IPSAC of the outcome of each Party’s regional review of the recommended Interregional Project(s). Each Party shall post a final version of the Coordinated System Plan study report on their respective interregional coordination webpage in accordance with Section 9.1.1.4.
In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies and upgrades will include the following:

(a) Upon either the posting to the OASIS of a request for interconnection or the review of the study results related to that request for interconnection, the Party receiving the request (“direct connect system”) will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the directly connected system will notify the other Party and convey the information provided in the posting.

(b) Following the results of either the Feasibility Study or the System Impact Study, the direct connect system will notify the other Party if the study shows potential reliability concerns on the other Party’s system. After reviewing the results, if the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate and mutually agree on with respect to the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party, who will perform the studies. If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV. The Parties will strive to minimize the costs associated with the coordinated study process.

(c) Any coordinated studies will be performed in accordance with the study scope and timeline mutually agreed to in 9.4 (b) above utilizing the responsibility options outlined in 9.4 (d) below.

(d) The potentially impacted Party may participate in the coordinated study at the System Impact Study or Feasibility Study stage, either by taking responsibility for performance of studies of its system, or by providing input to the studies to be performed by the direct connect system. If the constraints found require infrastructure additions to mitigate them, then
the potentially impacted Party will perform its own Facilities Study as part of the direct connect Party’s Facilities Study. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants including the potentially impacted Party. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(e) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(f) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the System Impact Study prepared for the interconnection customer.

(g) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(h) In the event that Network Upgrades are required on the potentially impacted Party’s system, then interconnection service will commence on a schedule mutually agreed upon between the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(i) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The Parties will post this listing on the Internet site maintained for the communication of information related to the coordinated planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.

Section 9.5 Analysis of Long Term Firm Transmission Service Requests. Version:
In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon either the posting to the OASIS of a request for service or the review of studies related to the evaluation of that service request, the Party receiving the request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will notify the other Party and convey the information provided in the posting.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party’s OASIS is unnecessary (i.e., the potentially impacted Party is “off the path”), then that Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to maximize the cost efficiency of the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) During the System Impact Study, the potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of their system, or by providing input to the studies to be performed by the Party receiving the request. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party
receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the system receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the applicable Party’s OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.
Section 9.6 Allocation of Costs of Network Upgrades. Version: 1.0.0 Effective:

3/30/2014

Section 9.6.1 Network Upgrades Associated with Interconnections. Version: 1.0.0

Effective: 3/30/2014

When under Section 9.4, it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties’ Order No. 2003 compliance filings as accepted by the FERC.

Section 9.6.2 Network Upgrades Associated with Transmission Service Requests. Version: 1.0.0

Effective: 3/30/2014

Section 9.6.2  Network Upgrades Associated with Transmission Service Requests.

When under Section 9.5, it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

Section 9.6.3 Network Upgrades Under Coordinated System Plan. Version: 1.0.0

Effective: 3/30/2014
The Coordinated System Plan will identify Network Upgrades under the Coordinated System Plan as Interregional Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the project cost for each such project that is to be allocated to each Party on behalf of its transmission customers. The JPC will determine the interregional allocation of costs to be shared by the Parties’ transmission customers for such Interregional Project(s) based on the procedures developed pursuant to this Section 9.6.3. Each Party will then determine regional allocation of the costs of the Interregional Project pursuant to its respective OATT. The proposed allocation of costs will be reviewed with the IPSAC. Stakeholder input will be solicited and taken into consideration by the JPC in arriving at an agreed to allocation of costs.

Section 9.6.3.1 Criteria for Project Designation as an Interregional Project Version: 0.0.0 Effective: 3/30/2014

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;

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.

Section 9.6.3.1.1 Determination of Benefits to each RTO from Interregional... Version: 0.0.0 Effective: 3/30/2014
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. 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.

b. 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.

Section 9.6.3.2 Cost Allocation and Recovery for Interregional Projects Version: 0.0.0 Effective: 3/30/2014

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.

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.
Section 9.6.3.3 Quarterly Status Reporting of Interregional Projects Version: 0.0.0 Effective: 3/30/2014

Each Party shall provide to the JPC for posting on each respective Party’s interregional coordination webpage a quarterly status report on approved Interregional Projects, including at a minimum the current estimated project cost and in-service date.

Section 9.7 Network Upgrade Construction and Ownership Version: 1.0.0

Effective: 3/30/2014

To obtain Network Upgrades under this Article IX, SPP will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the SPP Membership Agreement and the SPP OATT, as both may be amended or restated from time to time, and Midwest ISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

Section 9.7.1 Interregional Project Construction and Ownership Version: 0.0.0

Effective: 3/30/2014

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.

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.

**Section 9.8 CMP Allocation Adjustments for Interregional Project Version: 0.0.0**

**Effective: 3/30/2014**

[Reserved for Future Use]
Tab F

Testimony of Jennifer Curran
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. ) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF JENNIFER CURRAN
ON BEHALF OF

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

July 10, 2013
I. INTRODUCTION

A. Witness Background

Q: Please state your name, current position and business address.
A: My name is Jennifer Curran. I am employed by the Midcontinent Independent System Operator, Inc. (“MISO”) (formerly, Midwest Independent Transmission System Operator, Inc.), and my business address is at 720 City Center Drive, Carmel, Indiana 46032.

Q: Please briefly describe your educational background and professional experience.
A: I hold a Bachelor of Science degree in Mechanical Engineering from Rice University, and a Master of Business Administration from Duke University. Prior to joining MISO in July 2004, I was Manager of Power Generation and Supply Strategy for the Mid-Atlantic and Mid-Continent Regions at what was then known as Reliant Resources.

Q: Please describe your current position and responsibilities, and your background with MISO.
A: I was recently appointed Vice-President for Transmission of MISO. My previous title was Executive Director of Transmission Infrastructure Strategy, a position I held since October 2009. From February 2007 to October 2009, I was Director of Transmission Infrastructure Strategy.

As Vice-President for Transmission of MISO, I retained my previous functions, and my additional responsibilities include oversight of the generator interconnection and transmission service queue tariff processes. I am currently responsible for directing the development and execution of strategies to enable necessary transmission infrastructure
investment through the MISO transmission planning process. In this role, I focus on supporting the state and federal regulatory and business case requirements for transmission infrastructure. In addition, I am responsible for leading the development of effective transmission cost allocation methodologies. I also serve as the MISO staff liaison to the Board of Directors System Planning Committee, which is responsible for providing overall direction to the MISO planning staff and reviewing the MISO Transmission Expansion Plan.

I previously served as the MISO staff liaison to the stakeholder committee charged with improvement of MISO’s cost allocation method, the Regional Expansion Criteria and Benefits Task Force (“RECB TF”). Also, I previously served as the MISO staff liaison to the Planning Advisory Committee (“PAC”), which is the stakeholder committee that provides advice to the MISO planning staff on policy matters related to the process, integrity, and fairness of the MISO-wide transmission expansion plan and cost allocation. I have also served as the Director of Performance Assurance at MISO, responsible for business and financial planning for the operations areas of the company.

Q: **Have you sponsored any other testimony before regulatory commissions?**

A: Yes. I have submitted prepared testimony before the Federal Energy Regulatory Commission (“FERC” or “Commission”) involving matters specific to MISO. In particular, I have submitted testimony in support of the revisions to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) that MISO and certain of its Transmission Owners filed in Docket No. ER10-1791-000,
where the Commission approved MISO’s Tariff provisions on the establishment of Multi-Value Projects (“MVPs”) and the regional (i.e., system-wide) allocation of MVP costs. In addition, I have submitted testimony in Docket Nos. ER12-715-000 and ER12-715-003, relating to Schedule 39 of the Tariff, as well as in Docket Nos. ER13-187-000, relating to regional compliance with Order No. 1000, and ER13-186-000, relating to MISO’s modification of the cost allocation methodology for Baseline Reliability Projects (“BRPs”). I have also submitted testimony in support of MISO in other proceedings before the Commission and state regulatory commissions.

B. Purpose of Testimony

Q: What is the purpose of your testimony?
A: My testimony will discuss and support MISO’s proposed compliance with the interregional cost allocation requirements of Order No. 1000, as affirmed on rehearing by Order Nos. 1000-A and 1000-B, through revisions to MISO’s joint operating agreement (“JOA”) with Southwest Power Pool, Inc. (“SPP”).

II. MISO-SPP JOA’S BACKGROUND

Q: Please describe briefly the background of the JOA, including whether the existing JOA includes interregional cost allocation provisions for Interregional Projects.
A: As a condition for recognizing SPP as a Regional Transmission Organization (“RTO”), the Commission required SPP to enter into a seams agreement with MISO. SPP accordingly entered into the JOA with MISO. The JOA includes provisions regarding data exchange, coordinated planning, and cost allocation of network upgrades involving interconnection, transmission service, or coordinated plans between MISO and SPP.
These provisions partly address the interregional coordination and cost allocation requirements of Order No. 1000. The present compliance filing further addresses such requirements of Order No. 1000.

III. Background on MISO’s Order No. 1000 Approved Regional Cost Allocation Methods

Q: What project types in MISO have regional cost allocation?
A: Under MISO’s Tariff, the project types with regional cost allocation currently include Market Efficiency Projects (“MEP”) and MVPs. The Commission previously approved MISO’s cost allocation methodologies for MEPs and MVPs. In addition, in its March 22, 2013 order conditionally approving MISO’s Order No. 1000 regional compliance filing, the Commission approved MISO’s proposal to use the MEP and MVP project categories as MISO’s means of complying with the regional planning and cost allocation requirements of Order No. 1000.¹

Q: Please explain the MEP category of transmission projects.
A: MEPs are primarily economic upgrades that meet specific criteria, including that the project costs $5 million or more, primarily involves facilities with a voltage of 345 kV or greater, and meets a benefit-to-cost requirement of 1.25 or greater. MEPs are evaluated against multiple future scenarios to capture a range of potential future outcomes based on a number of key drivers, such as: demand and energy growth rates, demand response and infrastructure development.

energy efficiency programs, fuel prices, public policy requirements, generation retirements, etc.

Although MEPs are primarily economic upgrades, they can also address reliability issues. For example, under the MISO Tariff, if a project meets both the BRP and MEP criteria, then the project is approved as an MEP. Also, as part of the MEP evaluation, a reliability “no harm” test is performed, and, if reliability upgrades are identified, the costs of those upgrades would be included in the MEP. For projects that meet the MEP criteria, 80% of the costs are allocated to all Transmission Customers in the appropriate Local Resource Zones based on the distribution of benefits across the Local Resource Zones, and 20% of the costs are allocated on a system-wide basis to all Transmission Customers.3

Q: Please explain the MVP category of transmission projects.

A: MVPs are defined as one or more Network Upgrades that address a common set of Transmission Issues and satisfy the conditions listed in Sections II.C.1, II.C.2, and II.C.3 of Attachment FF of the Tariff.4 MVPs are evaluated on a portfolio basis, with benefits

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2 Under Section II.A.1 of Attachment FF to the Tariff BRPs are defined as Network Upgrades designed to ensure that the MISO Transmission System remains in compliance with applicable national Electric Reliability Organization (“ERO”) reliability standards, and reliability standards adopted by Regional Reliability Organizations that are applicable within MISO.

3 The cost allocation across the Local Resource Zones is determined using the distribution of adjusted production cost savings. Adjusted production cost is defined as the total production cost of the generation fleet adjusted for import costs and export revenues. Tariff, Attachment FF, Sections II.B.1.a, III.A.2.f.ii.

4 Attachment FF, Section II.C.
that are spread broadly across the MISO footprint, based on one of three benefit criteria: (1) to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation; (2) to provide multiple types of economic value across multiple pricing zones; or (3) to address, through the development of a robust Transmission System, multiple Transmission Issues associated with reliability and economic issues affecting multiple pricing zones. The costs of approved MVPs are allocated 100% on a system-wide basis. The MVP transmission project category, with its associated broad-based cost allocation, is designed to, among other things, enable MISO to address multiple reliability needs and provide economic value through regional transmission development, while addressing identified transmission needs driven by public policy requirements.

Q: What type of regionally cost-allocated project is MISO proposing to use to evaluate and approve Interregional Projects with SPP, which will be subject to interregional cost allocation?

A: MISO is proposing to evaluate and approve as MEPs all proposed Interregional Projects subject to interregional cost allocation with SPP. This is consistent with the requirement of Order No. 1000 that, to be eligible for interregional cost allocation, an Interregional

5 Attachment FF, Sections II.C.1, II.C.2, II.C.3.

6 Attachment FF, Section III.A.2.g.
Project must also be approved and included in the neighboring transmission regions’ respective regional plans for purposes of cost allocation.

**Q:** Why is MISO not proposing to use the regional project type of MVPs to approve Interregional Projects with interregional cost allocation with SPP?

**A:** MVPs are required to be evaluated on a portfolio basis to ensure that the benefits are spread broadly across the MISO region in line with the 100% system-wide allocation of costs for MVPs. To be approved under MISO’s regional cost allocation methods as an MVP, an Interregional Project would have to meet this same requirement tied to 100% regional cost allocation, which does not align with the current regional cost allocation methods of the SPP planning region. Taking into account these requirements for regional approval of MVPs, which differ from the cost allocation processes and methods of the SPP planning region, MISO believes the MEP methodology better aligns with the processes of SPP at this time, and provides a more likely path towards the approval of Interregional Projects to the benefit of customers in both regions given the current difference in MISO’s and SPP’s regional cost allocation mechanisms. For example, MEPs would make it more feasible for MISO and SPP to resolve any differences between their modeling and other data that could otherwise hamper the effective joint evaluation of transmission needs and the benefits of potential Interregional Projects.

**IV. Cost Allocation**

**A. MISO’s Proposal for Interregional Cost Allocation with SPP**

**Q:** Were MISO and SPP able to come to an agreement with regard to Cost Allocation for Interregional Projects?
A: Not completely. MISO and SPP engaged each other and each other’s stakeholders on numerous occasions to discuss the interregional requirements of Order No. 1000 and were able to agree on the interregional coordination procedures being submitted as part of their respective compliance filings and, as discussed below, on most of the criteria proposed by MISO to qualify as a MISO-SPP Interregional Project. However, MISO and SPP were not able to come to complete agreement with regard to certain aspects of the cost allocation for Interregional Projects. While other factors may have contributed, I believe that MISO and SPP’s inability to reach complete agreement with regard to the cost allocation of interregional transmission projects is likely based upon the fact that the parties have different approaches to regional cost allocation within their respective Tariffs that could be applied to interregional transmission projects.

Q: Please explain the criteria to qualify as a MISO-SPP Interregional Project.

A: Under MISO’s proposal, for an Interregional Project to qualify for interregional cost allocation it must meet specific criteria, including: 1) a project cost of $5 million or greater; 2) evaluation as part of a Coordinated System Plan; 3) a minimum level of benefits to each planning region; 4) approval as an MEP in the MISO regional plan and as an Interregional Project in the SPP regional plan; and 5) an estimated in-service date within 10 years of the date the project is approved by each region. A MISO-SPP Interregional Project can be located solely within MISO or SPP and is not limited to the tie-line situation covered by Order No. 1000’s requirement of an interregional cost allocation methodology.
Q: Does SPP agree with all of the criteria proposed by MISO to qualify as a MISO-SPP Interregional Project? Why?

A: During discussions preceding the present filing, SPP has indicated to MISO that it agrees with all of the criteria, including allowing for Interregional Projects beyond just tie-lines between the two planning regions, except for the requirement that a MISO-SPP Interregional Project must be approved in the MISO regional planning process as an MEP. Specifically, MISO understands that SPP does not agree with the criteria and benefit metrics used in the evaluation of MEPs, including the minimum voltage threshold applicable to MEPs. MISO also understands that SPP does not agree with MISO’s conclusion that MEPs, as approved as part of MISO’s Order No. 1000 regional compliance filing, adequately provide for the consideration of transmission needs driven by reliability and public policy requirements, in addition to economic considerations.

Q: Why does MISO believe there should be a voltage threshold for Interregional Projects?

A: In MISO’s experience it is reasonable to expect that it will require extra-high voltage type transmission facilities, i.e., 345 kV or above, to provide the broad benefits required to ensure that for MISO’s share, which would be allocated within MISO with a 20% system-wide cost allocation, and for SPP’s share, which would be allocated within SPP as a 100% system-wide cost allocation, of Interregional Projects is appropriately commensurate with their respective benefits. Thus, MISO’s proposal to use the primarily 345 kV MEP threshold for Interregional Projects as well is consistent with Order
No. 1000’s requirement that interregional cost allocation be at least roughly commensurate to the associated benefits. MISO also notes that a MISO-SPP Interregional Project can include transmission facilities that are below 345 kV, to the extent that the lower-voltage facilities are needed in conjunction with 345 kV facilities to address applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities of the project, so long as the lower voltage facilities constitute less than 50% of the combined project cost for the associated MEP.  

Q: How does MISO’s proposal to use MEPs for regional approval allow for consideration of transmission needs driven by reliability?

A: Under MISO’s Tariff, if a proposed project meets the criteria for both MEPs and BRPs, the project will be classified as an MEP. The Tariff therefore recognizes that MEPs can also address reliability issues and, therefore, an Interregional Project also can address reliability issues. Further, any upgrades that are required to address reliability issues in connection with the MISO-SPP Interregional Project will be included in the overall costs of the project to ensure the project is able to provide the expected economic benefits to both regions.

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7 See Attachment FF, Section II.B
Q: **How does MISO’s proposal to use the MEP project category for regional evaluation and approval of Interregional Projects allow for consideration of transmission needs driven by public policy requirements?**

A: Although MISO’s proposal does not include a specific benefit metric or project type for transmission needs driven by public policy requirements, the joint evaluation of proposed Interregional Projects will use jointly developed future scenarios that will include the transmission needs driven by public policy requirements that have been identified through MISO’s and SPP’s respective regional planning processes. Inclusion of each region’s public policy-driven transmission needs in the jointly developed future scenarios used to identify and evaluate MISO-SPP Interregional Projects will capture the potential economic benefits provided by the resources included in the RTOs’ respective regional planning processes to address these transmission needs driven by public policy requirements. In addition, when MISO considers the MISO-SPP Interregional Project for approval as an MEP, the evaluation will include multiple future scenarios that would include the public policy requirement-driven transmission needs identified through the MISO regional planning process, established in Attachment FF of MISO’s Tariff.

Q: **What benefit metric is MISO proposing to use to determine the interregional cost allocation for a MISO-SPP Interregional Project?**

A: The benefit metric MISO is proposing to use for determining the interregional cost allocation of a MISO-SPP Interregional Project is production cost savings adjusted to account for purchases and sales. Based on the multi-year analysis of adjusted production
cost savings for the Interregional Project, each region would be allocated a percentage of the Interregional Project costs in proportion to the net present value of the total benefits calculated for each region for the first 20 years of the project’s life.

Q: **Do you believe SPP agrees with using the benefit metric of adjusted production cost savings for the interregional cost allocation of a MISO-SPP Interregional Project? Why?**

A: Yes, it is my understanding that SPP agrees with using the adjusted production cost savings metric in some instances, but that they do not agree with MISO’s proposal that it be the only benefit metric used in determining interregional cost allocation between the MISO and SPP regions. SPP has proposed using adjusted production cost savings for primarily economic projects, avoided reliability project cost for primarily reliability projects, and a to be determined benefit metric for primarily public policy projects.

Q: **Can you explain why MISO believes it is appropriate to use adjusted production cost savings, without an avoided reliability project cost benefit metric?**

A: As discussed previously, the MISO proposal will consider reliability needs and does not require the addition of an avoided reliability project cost benefit metric. For example, if a MISO-SPP Interregional Project is addressing a reliability issue and meets the economic criteria for regional approval in MISO and SPP, then that project would be cost-shared in proportion to the adjusted production cost savings between MISO and SPP. This is consistent with how MISO treats regional projects that are addressing a reliability issue
and meet the MEP criteria. The currently effective MEP methodology does not include an avoided reliability project cost benefit metric proposed by SPP. If an avoided reliability project cost metric were to be included in determining the portion of Interregional Project costs allocated to MISO customers, without having an analogous benefit metric in MISO’s MEP process, it could result in a cost allocation that is not roughly commensurate with benefits for MISO customers.

**Q:** Please explain why MISO does not believe a separate project type for primarily public policy projects with a yet to be determined benefit metric is appropriate.

**A:** As noted above, MISO’s proposal does not include a specific benefit metric or project type for public policy requirements because its proposal captures public policy requirements through the joint models and future scenarios that will be developed as part of the Coordinated System Plan study to evaluate potential Interregional Projects and does not require a distinct project type for a project primarily addressing public policy-driven transmission needs, as proposed by SPP. I would note that in MISO’s discussions on Order No. 1000 SPP did not propose an actual benefit metric to determine the cost allocation for Interregional Projects that primarily address transmission needs driven by public policy requirements indicating that on a case-by-case basis the JPC would identify the metric(s) to use for primarily public policy projects.

**B. Compliance with Order No. 1000’s Six Interregional Cost Allocation Principles**

**Q:** Do MISO-SPP Interregional Projects satisfy Order No. 1000’s requirements for interregional cost allocation?
A: Yes, under MISO’s proposal, MISO-SPP Interregional Projects (i.e., those jointly-evaluated projects approved as MEPs in MISO’s regional process and as Interregional Projects in SPP’s regional process) satisfy all six of the interregional cost allocation principles set forth by the Commission in Order No. 1000. In addition, the Commission has previously found that MEPs employ a just and reasonable method of allocating costs.

1. Interregional Cost Allocation Principle 1: Costs Allocated Roughly Commensurate with Benefits

Q: Do MISO-SPP Interregional Projects satisfy cost allocation principle 1?

A: Yes. Cost allocation principle 1 requires that the cost of transmission facilities be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. Under MISO’s proposal, in Section 9.6.3.1.1, benefits will be determined on an adjusted production cost (“APC”) basis, which is adjusted to account for purchases and sales. After calculating the benefits for each simulated year, MISO and SPP will determine the total Interregional Project benefit by calculating the present value of annual benefits for the first 20 years of project life after the projected in-service date. Under Section 9.6.3.2, Interregional Project costs would be allocated in proportion to the net present value of the total benefits calculated for MISO and SPP pursuant to Section 9.6.3.1.1. This cost allocation is roughly commensurate with benefits and compliant with Order No. 1000.
2. **Interregional Cost Allocation Principle 2: No Involuntary Allocation to Non-Beneficiaries**

**Q:** Do MISO-SPP Interregional Projects satisfy cost allocation principle 2?

**A:** Yes. Cost allocation principle 2 requires that a transmission planning region that receives no benefit from an interregional transmission facility located in that region, either at present or in a likely future scenario, not be involuntarily allocated any of the costs of that transmission facility. Interregional Project costs would not be allocated involuntarily to non-beneficiaries, because interregional cost allocation would be based on identified benefits. MISO-SPP Interregional Projects fully comply with this requirement, as they must be selected both by MISO and SPP in their regional transmission planning processes.\(^8\) They must also be evaluated jointly pursuant to the JOA’s Coordinated System Plan process.\(^9\) These procedural considerations ensure that neither MISO nor SPP will be involuntarily allocated any of the costs of an Interregional Project located within its respective region.


**Q:** Do MISO-SPP Interregional Projects satisfy cost allocation principle 3?

**A:** Yes. Cost allocation principle 3 requires that if a benefit-to-cost ratio threshold is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, it must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The

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\(^8\) See Section 9.3 of JOA.

\(^9\) See Section 9.3.3.5 of JOA.
Commission also stated that such a threshold may not exceed 1.25 unless the Commission approves a higher ratio. While there is not an explicit benefit-to-cost ratio for MISO-SPP Interregional Projects within the JOA, consistent with the Commission’s explicit allowance for a benefit-to-cost ratio threshold of 1.25 or less, MISO will employ a benefit-to-cost ratio threshold of 1.25 for all MEPs that are also MISO-SPP Interregional Projects.

The Commission explicitly noted in an order last year that, in the context of MEPs, a benefit-to-cost ratio threshold of 1.25 is just and reasonable because it balances the economic uncertainty of transmission projects with the prospect of approving and constructing projects that provide benefits.\(^\text{10}\) The Commission’s March 22 Order that accepted MISO’s Order No. 1000 regional compliance filing found that the 1.25 benefit-to-cost ratio for MEPs meets the regional variant of principle 3. The same logic applies with equal force in the interregional context.


Q: Do MISO-SPP Interregional Projects satisfy cost allocation principle 4?

A: Yes. Cost allocation principle 4 requires that costs allocated for an interregional transmission facility be assigned only to transmission planning regions in which the transmission facility is located. Consistent with Interregional Cost Allocation Principle 4, the cost of MISO-SPP Interregional Projects would be allocated only within the regions of MISO and SPP, based on their agreement to do so under the JOA.

MISO further notes that, pursuant to Order No. 1000-A, any MISO Transmission Owner that withdraws from MISO will remain responsible for its share of the cost of any Interregional Project that is an MEP approved by MISO’s Board of Directors before the effective date of such Transmission Owner’s withdrawal, in accordance with MISO’s Transmission Owners Agreement (Article Five, Section II), and section III.A.2.f of Attachment FF of MISO’s Tariff.

5. Interregional Cost Allocation Principle 5: Transparency of Method for Determining Benefits and Identifying Beneficiaries

Q: Do MISO-SPP Interregional Projects satisfy cost allocation principle 5?

A: Yes. Cost allocation principle 5 requires that the cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility. The proposed cost allocation process for Interregional Projects is fully compliant with this principle. The cost allocation and benefit determination methods for Interregional Projects are described in detail in Sections 9.6.3.2 and 9.6.3.1.1 of the JOA respectively. These processes would also be applied in the context of MISO’s and SPP’s Coordinated System Plan process, which means that stakeholders have the opportunity to review and provide input regarding these determinations via the Interregional Planning Stakeholder Advisory Committee (“IPSAC”). In addition, these determinations, as well
as the underlying calculations and other analyses, are posted on each RTO’s interregional planning coordination webpage for the IPSAC, and the resulting recommendations are included in the Coordinated System Plan, which is also posted on each RTO’s webpage pursuant to proposed Section 9.1.1.4 of the JOA.


Q: Do MISO-SPP Interregional Projects satisfy cost allocation principle 6?
A: Yes. Cost allocation principle 6 states that public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities. MISO’s proposal is consistent with Interregional Cost Allocation Principle 6, which allows but does not require different cost allocation methods for different types of interregional transmission facilities. The adjusted production cost metric appropriately applies to all Interregional Projects between MISO and SPP.

V. Conclusion

Q: Does this complete your testimony?
A: Yes.
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. ) Docket No. ER13-____-000

AFFIDAVIT

STATE OF INDIANA
COUNTY OF HAMILTON

Jennifer Curran, being first duly sworn, deposes and says she is the same Jennifer Curran, whose Affidavit accompanies this Prepared Direct Testimony, that such testimony was prepared by her, that she is familiar with the contents thereof; and the facts set forth herein are true and correct to the best of her knowledge, information, and belief; and that she does adopt the same as her sworn testimony in this proceeding.

Jennifer Curran

SUBSCRIBED AND SWORN to me this 10th day of July, 2013.

Amy R. Jones
Notary Public for Madison County, Indiana

My Commission Expires:

[Sticker: AMY R. JONES
Notary Public, State of Indiana
Madison County
Commission # 885378
My Commission Expires
November 16, 2014]