# SEAMS WHITE PAPER FOR ORGANIZATION OF MISO STATES (OMS) AND SPP REGIONAL STATE COMMITTEE (RSC) LIAISON COMMITTEE

November 2, 2018

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# PURPOSE

The OMS and RSC Liaison Committee requested MISO and SPP jointly draft a white paper to illustrate the dynamics of various issues related to planning and operations between the two Regional Transmission Organizations (RTOs). The Liaison Committee specifically asked MISO and SPP to identify barriers to more efficient seams operations and transmission planning and, to the extent possible, offer solutions to those problems, including identification of current enhancements/improvements being discussed in markets and operations, transmission planning and resource integration. Included below is MISO and SPP's jointly-developed initial response to this request.

# MISO-SPP SEAMS COORDINATION OVERVIEW

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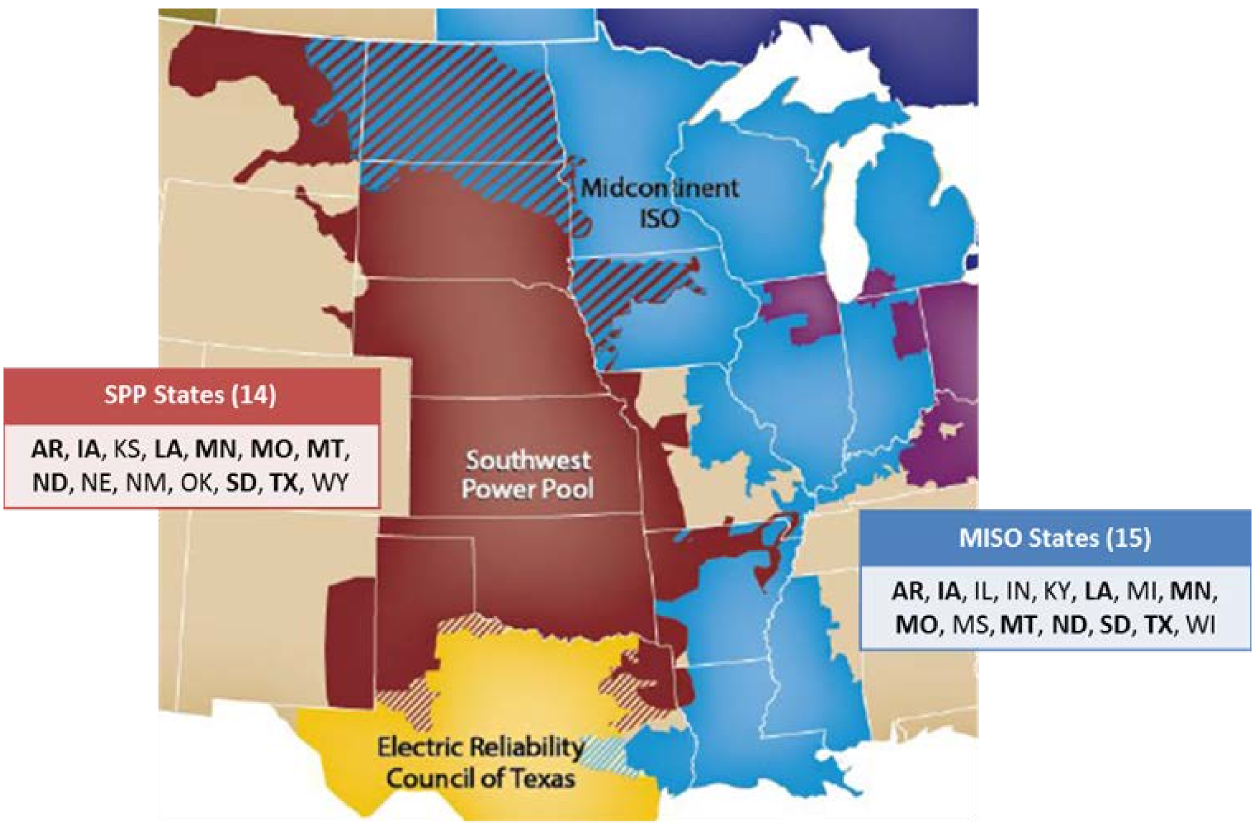
*Figure 1: Map of MISO and SPP RTO Footprints*




**Bold** = Sates common to both RTO footprints.

MISO and SPP's respective RTO footprints each cover a large geographic area in the central United States that serves 60 million end-use customers over a transmission network totaling 130,000 miles. As shown in Figure 1 above, MISO includes all or part of 15 states and the Canadian province of Manitoba and SPP includes all or part of 14 states, which includes 9 states that are common to both

RTO footprints. Dozens of transmission interconnections exist between the RTO regions at varying voltage levels along the lengthy MISO-SPP seam spanning from the Canadian border to Texas. Table 1 below shows the extent of the interconnections between the RTOs:

*Table 1: Number of Tie-lines by Voltage*

| VOLTAGE LEVEL (KV) | # OF TIE-LINES |
|---|---|
| 69 | 78 |
| 115 | 28 |
| 138 | 4 |
| 161 | 24 |
| 230 | 20 |
| 345 | 14 |
| 500 | 3 |
| Total | 171 |

Since the early 2000s when FERC separately approved MISO and SPP as RTOs, the membership of both RTOs have grown and the seam between the two regions has expanded multiple times. The following list highlights the significant membership expansions experienced by each RTO:

- **April 1, 2009** – SPP added Lincoln Electric Systems, Nebraska Public Power District, and Omaha Public Power District.
- **September 1, 2009** – MISO added MidAmerican Energy Company
- **December 19, 2013** – MISO added the MISO South region (Cleco, Entergy, East Texas, Cooperative Energy)
- **October 1, 2015** – SPP added the Integrated System (WAPA-Upper Great Plains, Basin Electric Power Cooperatives, Heartland Consumers Power District, and Northwestern Energy)

## SPP MISO JOINT OPERATING AGREEMENT (JOA) OVERVIEW

The JOA between SPP and MISO helps to ensure coordinated reliable and efficient operation of the transmission system along the MISO and SPP seam. Maintaining a high degree of reliability is of the utmost importance to the RTOs and coordinated planning and operations is a fundamental requirement of North American Energy Reliability Corporation (NERC) standards that apply to the functions performed by MISO and SPP. The RTOs ensure coordination on the seams through compliance with a number of existing NERC Standards, as well as the JOA, which encompasses processes and procedures for how the parties coordinate as neighboring Reliability Coordinators, Balancing Authorities, and transmission Planning Coordinators, in addition to other arrangements.

### *History*

FERC has long recognized that with the expansion of regional markets, some inefficiencies may arise that prevent the economic transfer of capacity and energy between neighboring markets. These inefficiencies are "seams issues" and the provisions of joint operating agreements are designed to address and minimize these seams issues. In fact, one primary goal of joint operating agreements is to advance the creation of "seamless" markets and eliminate the inefficiencies that inhibit economic transfers between the neighboring regions.

Seams issues always have existed between control areas and they became more acute after the formation of electric markets. FERC recognized these issues with the development of RTOs and maintained that the benefits of RTOs outweigh any potential problems created by seams issues, particularly with the development and implementation of joint operating agreements between the RTOs. In addition to the RTO scope and configuration requirements of FERC's Order No. 2000,[1] FERC directed the RTOs to address issues of coordination, reliability, efficiency, and equity through joint operating agreements. PJM Interconnection, L.L.C. (PJM) and MISO were the first RTOs to enter into a FERC-approved joint operating agreement. The PJM-MISO joint operating agreement originally was developed when PJM had a market in place, but prior to MISO setting up its market.

In 2004, when SPP applied to FERC for regional transmission organization status, the Commission conditioned its approval on SPP entering into a seams agreement with MISO.[2] The MISO-SPP JOA was modeled on the PJM-MISO joint operating agreement. MISO and SPP originally executed the JOA with a CMP (Congestion Management Process) on December 1, 2004. While not identical, the terms of the MISO-SPP JOA regarding data exchange and congestion management are essentially the same as the joint operating agreement previously accepted by FERC between MISO and PJM. While originally implemented as a MISO market to SPP non-market seams agreement, the JOA has been revised numerous times as the MISO and SPP markets have evolved to become the market-to-market seams agreement in place today.

[1] *Regional Transmission* Organizations, FERC Order No. 2000, 89 FERC ¶ 61,285 (2000).
[2] *Sw. Power Pool, Inc.*, 106 F, 90 FERC ¶ 61,110 (2004).

### *JOA Key Objectives and Procedures*

The JOA obligates the parties to exchange real-time and day ahead operating and planning information to increase both reliability and market coordination. The JOA spells out how outage coordination, voltage control, and emergency operations will be handled between the two entities and adopts the highly detailed CMP to govern congestion management between the markets and non-markets. The JOA contains the following standard provisions:

1) Definition of key terms and acronyms
2) Exchange Operating Data, SCADA, Models, Planning Data
3) Exchange ATC/AFC methodologies, and data inputs
4) Define and agree to manage Reciprocal Coordinated Flowgates
5) Outage Coordination
6) Joint Operations in Emergencies
7) Coordination of Transmission Planning
8) Joint Scheduling Checkout Procedures
9) Voltage Control and Reactive Power Coordination
10) Dispute Resolution
11) Common Legal Provisions: Indemnity, Accounting for Costs, Confidentiality of Data, Intellectual Property, Termination, Choice of Law, etc.
12) The CMP: Detailed attachment to each seams agreement containing technical requirements for managing market-to-non market congestion using RCFs
13) The Interregional Coordination Process (ICP): Detailed attachment to MISO-SPP seams agreement containing technical requirements for managing market-to-market congestion using RCFs but allowing each RTO to optimize its congestion relief obligation engaging the other RTO to redispatch when that is the cost effective solution

As this list of provisions demonstrates, the RTOs closely coordinate across planning, markets, and operations functions. Several of these provisions are discussed in detail throughout the remainder of this whitepaper.

# MARKETS AND OPERATIONS

## OUTAGE COORDINATION (GENERATION AND TRANSMISSION)

MISO and SPP have an interregional outage coordination process for coordinating transmission and generation outages to ensure reliability and to promote optimally efficient market operations. Both RTOs have had a positive experience implementing the outage coordination process. As part of the process, MISO and SPP will analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each entity's respective analysis of generation and transmission outages consider the impact on the reliability of the other entity's system.

Frequent communication between the parties plays a significant role in the outage coordination process. On a weekly basis, or daily if requested by one of the RTOs, the operations planning staff of each RTO jointly discuss any anticipated outages to identify potential impacts. These discussions include an indication of either concurrence with the anticipated outage or identification of significant impacts due to the anticipated outage.

MISO and SPP also notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known (not to exceed thirty (30) minutes). The RTOs will evaluate the impact of emergency and forced outages on their respective transmission systems and work with one another and affected Transmission Operators or Generator Operators to develop remedial actions as necessary.

Outage schedule changes, both before or after the work has started, may require additional review. Each RTO will consider the impact of these changes on the other RTO's system reliability, in addition to its own. MISO and SPP will contact each other as soon as possible if these changes result in unacceptable system conditions and will work with one another to develop remedial actions as necessary.

## CONGESTION MANAGEMENT

There are two key processes included in Attachment 1 and Attachment 2 of the MISO-SPP JOA that have been the subject of recent efforts to enhance market and operational effectiveness between the two RTOs. The Congestion Management Process (CMP) and the Interregional Coordination Process (ICP, also commonly referred to as "market-to-market coordination" or M2M) are utilized by the RTOs to manage congestion along the seam on flowgates upon which both RTOs have a material impact. While the two processes are different, they are related. The CMP manages congestion between markets and non-markets, while the ICP manages congestion between two markets. MISO, SPP, and PJM through their FERC-filed JOAs all use the CMP, as well as certain other neighboring parties. Together, these parties constitute the CMP Council.

The CMP has several key features, including:

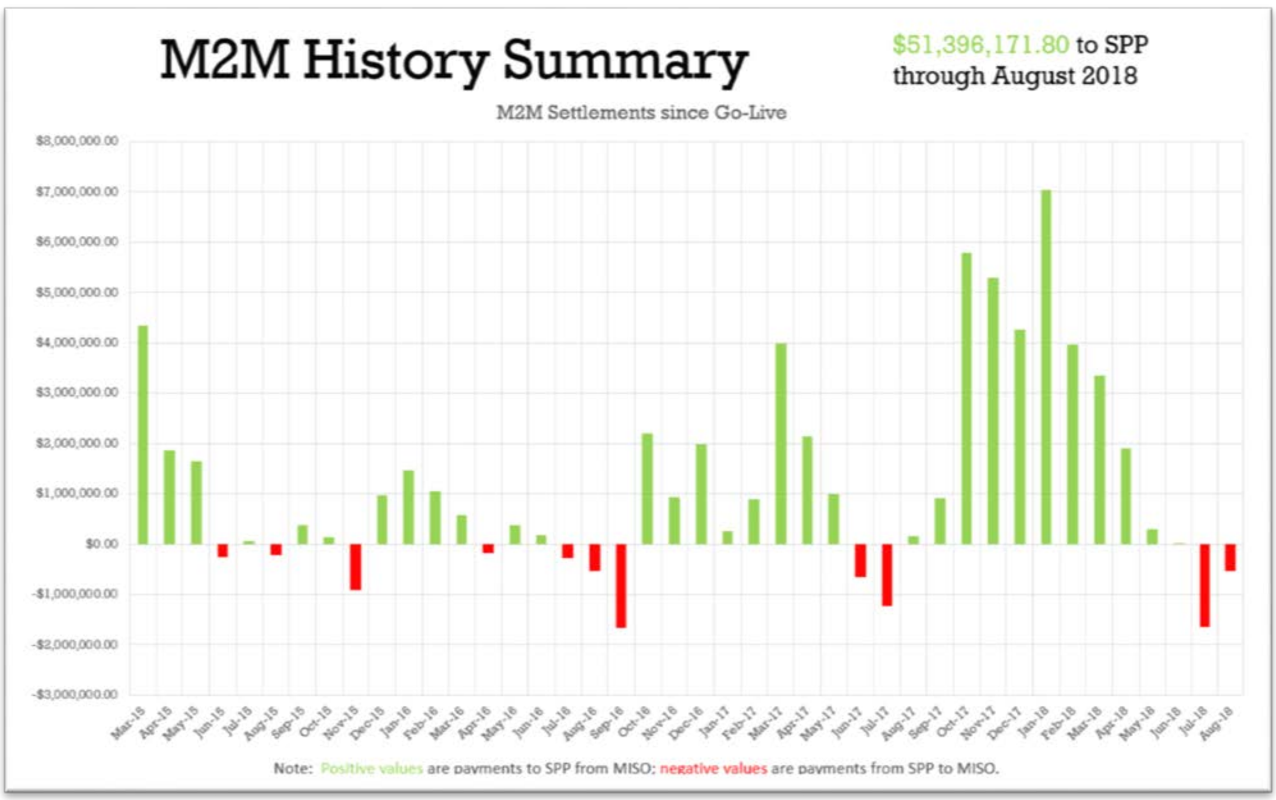
- Interregional coordination process between a market region that uses a Locational Market Price (LMP)-based congestion management regime and a region that uses a Transmission Loading Relief (TLR)-based congestion management regime
- Determination of the amount of firm allocations each party's parallel flows have on the other party's transmission system
- Definition of Reciprocal Coordinated Flowgates (RCFs), the set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market. These RCFs are monitored to measure the impact of market flows and parallel flows from adjacent regions
- Process for managing market flow impacts will be managed on an interregional basis within the existing NERC Interchange Distribution Calculator (IDC) to enhance the effectiveness of the NERC interregional congestion management process. The CMP also describes a process for calculating firm allocations used to determine firm flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region

- Establishment of the CMP Council[3] composed of representatives who meet on a periodic basis and provide policy guidance on matters related to the CMP.

The ICP builds on the CMP, by adapting the coordination provisions of the CMP for use by SPP and MISO to jointly dispatch their respective energy markets to manage congestion on RCFs impacted by both markets. The fundamental philosophy of the ICP is to allow any flowgates significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. This joint management of flowgates near the market borders is intended to provide a more efficient and lower cost transmission congestion management solution, while providing coordinated pricing at the market boundaries.

In addition, to coordinated dispatch between the two markets, the ICP includes a financial settlement process where MISO and SPP compensate each other by using calculated market flows to measure each RTO's utilization of firm flow entitlements (FFE) on M2M constraints.. Shown in Figure 2 below is a month-by-month history of M2M settlements between MISO and SPP since going live on March 1, 2015:

*Figure 2: Monthly M2M Settlements since M2M Go-Live*




[3] CMP members currently include MISO, PJM, SPP, TVA, Manitoba Hydro, Minnkota Power Cooperative, AECI, and LGE/KU.

Jointly managing transmission constraints near the MISO-SPP seam provides a more efficient, cost effective and responsive congestion management tool than traditional TLR. Table 2 below summarizes the differences between TLR and the MISO-SPP M2M process:

*Table 2: Differences between TLR and MISO-SPP M2M Processes*

| | TLR | M2M |
|---|---|---|
| Relief Calculation Granularity | Hourly | 5 minute |
| Relief Source | Cuts lowest priority schedule | Redispatch of lowest cost generation |
| Data Quality | Static (except for market's reporting real-time market flow) | Real-time, sub-second |
| Usage | RC discretion | Upon constraint activation in market |
| Settlement | None | Based on Firm Flow Entitlement (FFE) usage |
| Regulation | NERC ORC / NAESB | JOA (FERC) |

### *Ongoing Enhancements*

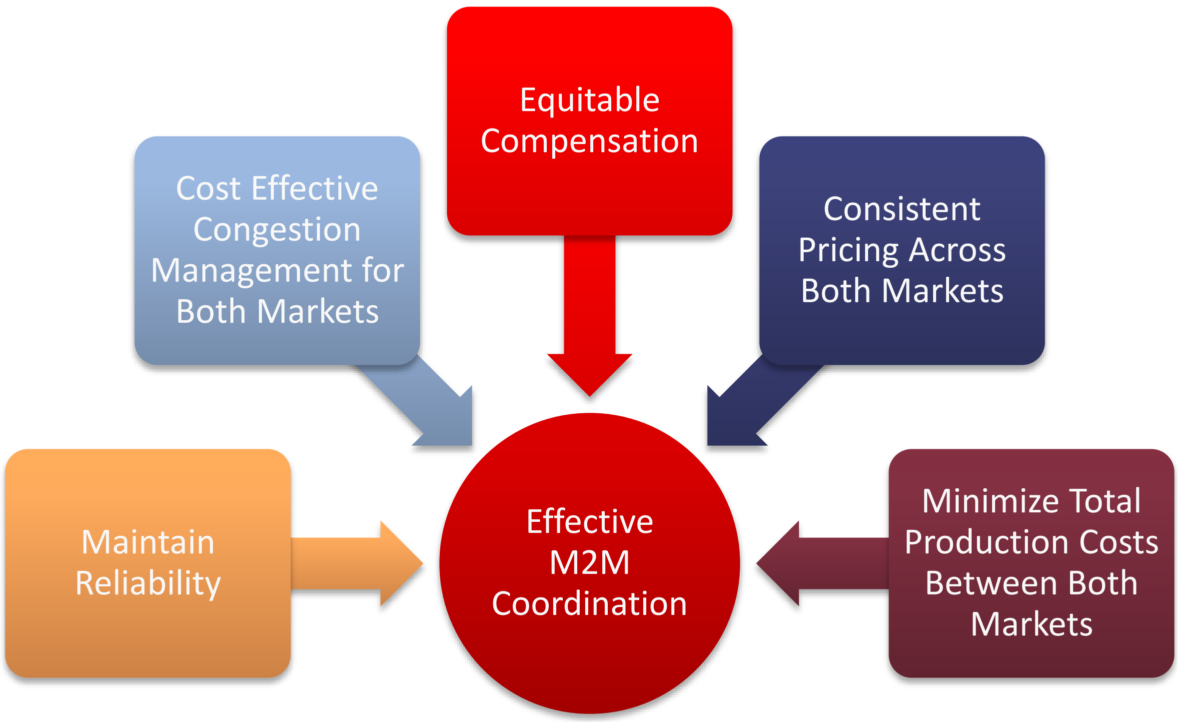
#### Memorandum of Understanding

In 2017, MISO and SPP signed a Memorandum of Understanding (MOU) designed to enhance M2M coordination. The MOU was designed to resolve the following issues:

- Ineffective real-time congestion management on certain M2M flowgates
- Errors in the calculation of certain data used in M2M settlements
- Lack of criteria on the implementation of specific M2M provisions
- Difficulties finding common interpretation of certain sections of the ICP

MISO and SPP also agreed upon a set of principles designed to gauge the effectiveness of the M2M process. The illustration below reflects those five principles.

*Figure 3: Principle to Gauge Effectiveness of Market to Market process*




Since executing the MOU in June 2017, the RTOs have spent considerable effort implementing the revised procedures and corresponding software changes to realize the benefits of the improved M2M process. Specifically, the parties have increased administrative efficiency through additional cooperation, data quality, and implementation of criteria that specify when resettlement is appropriate. Software and procedures to address certain operational issues observed with the implementation of M2M have helped to ensure the objectives of M2M are being met, and criteria for the application of hold-harmless provisions and addressing FFE calculation errors help to ensure equitable compensation between the parties. As evidence of continued cooperation and collaboration, MISO and SPP recently executed an additional revision to the MOU that memorializes the resettlement of certain M2M events once approval from FERC has been received to permit those resettlements to take place.

### Historical Flowgate Allocation Calculation

The CMP describes the allocation process for firm and non-firm capacity and flows on applicable flowgates among participating entities. These allocations are critical inputs used in the M2M and TLR congestion management processes. A key component of the current calculation preserves the historic firm rights of the transmission system prior to the formation of organized markets in 2004. This component of the calculation is commonly referred to as "Freeze Date". The Freeze Date uses a snapshot of both generators and transmission service reservations that existed in 2004, based on the Balancing Authorities configurations at the time.

Since the development and evolution of RTOs, significant changes have occurred to the way in which the transmission system is planned and operated. However, the Freeze Date process has not evolved since it was originally implemented in 2004. The CMP members have agreed the Freeze Date calculation needs to be modified, while also preserving the historic rights to usage of the transmission system. Since early 2014 the CMP Council has been discussing methods for updating the Freeze Date calculation. Those discussions have been complicated by the varied interests of the number of parties involved, as well as by concerns over preserving equity.. To guide negotiations regarding potential changes to the original Freeze Date calculations, the CMP members agreed to the following guiding principles:

- Coordination
  - Coordinate the long term planning process, short term planning process and real-time operations to promote efficient utilization of the transmission system
  - Acknowledge the inter-regional impacts of delivering Network resources to load in the long term planning such that upgrades are planned to efficiently utilize the interconnected system. Utilize these impacts as an input to the establishment of rights that are then consistently recognized in short term planning and real-time operations.

- Reliability
  - Ensure reliable operation of the transmission system

- Equity
  - Protect current and future transmission investments through a process that may or may not recognize historic BA configurations
  - Recognize incremental transmission upgrades and investments
  - Equitable treatment for market and non-market entities
  - Equitable assignment of congestion costs

- Efficiency
  - Encourage interregional economic and operational efficiencies
  - Provide transparent, appropriate and consistent price signals across the seams

While discussions continue on a comprehensive package of improvements to the firm allocation process, the CMP members reached agreement on an incremental update, implemented on June 14, 2018, that modifies the dispatch of pre- and post-Freeze Date resources in the calculation of firm flowgate allocations. The CMP members are actively working with each other and with their respective stakeholders to finalize a more comprehensive redesign by the end of 2018.[4]

### Congestion Overlap for Interchange Transactions [Interface Pricing, Pseudo Tie Load and Generation]

MISO and SPP market participants facilitate the interchange of energy across the BA borders using interchange transactions. These interchange transactions are integrated into the security constrained unit commitment models for each associated RTO, as such, they affect each RTO's generator dispatch and pricing outcomes. Because both RTOs are accounting for the impact of the transaction in their markets, MISO's Independent Market Monitor identified that the current process can lead to an overlap of M2M flowgate impacts and result in exaggerated congestion pricing for market participants involved in these interchange transactions.

#### Interface Pricing as a Solution to Congestion Overlap

MISO and SPP have coordinated on an initial joint analysis to identify the impact of congestion overlap during the first year of the M2M process. The results were shared with MISO and SPP stakeholders during a joint stakeholder meeting on May 31, 2017. Based on this analysis MISO and SPP agree additional collaborative analysis is needed to determine whether there is a more appropriate solution for the MISO-SPP interface, however resource constraints and higher priority market improvement initiatives have delayed work on the analysis necessary to resolve this issue.

#### Pseudo-Ties (Load and Generation)

The congestion overlap issue for M2M flowgates also affects pseudo-ties between SPP and MISO. Pseudo-ties refer to generation or load assets that are physically located within one BA ("native BA"), but are operationally controlled and dispatched by a different BA ("attaining BA"). Pseudo-tied resources send their energy out of the native BA's footprint to the attaining BA using transmission facilities which are under the native BA's functional control.

On August 26, 2016, Tilton Energy, LLC filed a formal complaint[5] with FERC against MISO related to a generation facility owned and operated by Tilton Energy that is physically connected to MISO facilities but pseudo-tied into PJM. This case is currently pending before FERC.

MISO and PJM have experienced several situations where pseudo-tied resources located deep within the interior portions of the native BA's footprint have been requested and implemented. This causes an issue as the attaining BA typically lacks a detailed and comprehensive ability to model power flows, transmission congestion, and other dynamics in the innermost portions of the native BA's region that may be located electrically distant from the seam between the native BA and the attaining BA. MISO and PJM have performed significant joint analysis and solution development related to the pseudo-ties between the two RTOs. Following coordination with MISO and PJM stakeholders through the MISO-PJM Joint and Common Market (JCM), MISO and PJM have put in place the first phase of a FERC-approved solution that enables the attaining BA to fund congestion hedges/rebates to the pseudo-tied resource for the overlapping sections of the transaction.

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[4] See status update for more details on the outstanding design components provided at 10/23 MISO-SPP JOA meeting: https://cdn.misoenergy.org/20181023%20MISO-SPP%20JOA%20Item%2005%20Freeze%20Date%20Replacement286504.pdf

[5] *Formal Complaint of Tilton Energy* LLC, FERC Docket No. EL16-108 (Aug. 25, 2016).

Historically, the pseudo-tie requests received by MISO and SPP have involved generation and load assets located near the seams and have not led to significant reliability impacts. This has been due to the limited volume of pseudo-ties between SPP and MISO as well as the fact that the pseudo-ties are generally located in close electrical proximity to the attaining BA's border with the native BA. However, even pseudo-tied units located near the seams could potentially give rise to issues such as complicating the unit commitment/de-commitment process. At this time a complaint has been submitted to FERC on the issue of congestion overlap by load pseudo-tied from MISO to SPP located in the City of Minden, Louisiana. MISO and SPP are parties to the complaint and have provided responses in the docket.[6] The complaint currently is pending before FERC.

## CONTRACT PATH CAPACITY SHARING

The JOA contains a provision addressing the concept of "contract path capacity sharing." Section 5.2 of the JOA currently states, in part, "Section 5.2 – Sharing Contract Path Capacity. If [MISO and SPP] have contract paths to the same entity, the combined contract path capacity will be made available for use by both [MISO and SPP]." The history and recent amendments made to this provision are discussed below. MISO and SPP still interpret this provision differently.

### *History and Background*

In 2010, the Arkansas Public Service Commission expanded its inquiry into successor arrangements for Entergy Arkansas, Inc. after its anticipated exit from the Entergy System Agreement and the increased likelihood that the Entergy Operating Companies would join MISO. In support of MISO's expansion to include the Entergy Operating Companies and consistent with the interpretation and application of the same language in the MISO-PJM agreement, MISO construed the then-existing capacity-sharing language of the JOA to allow contract patch capacity sharing. It is MISO's view that either MISO or SPP could use the available system capacity of the other's system. SPP disagreed with MISO's interpretation. SPP interpreted the contract path capacity sharing language of the JOA to allow either MISO or SPP to use shared capacity for the purpose of reaching external third parties, and not for the purpose of serving its own internal load.

After further discussions between MISO and SPP, MISO filed with FERC a petition for declaratory order over the meaning of the contract path capacity-sharing provisions. MISO maintained the provisions permitted sharing of contract path capacity when the entities connected by that path are the transmission-owning members of one of the RTOs. SPP maintained that contract path capacity sharing is permitted only with respect to third-party entities that are not members of either RTO. FERC granted MISO's petition in 2011. SPP appealed that decision to the U.S. Court of Appeals for the District of Columbia Circuit. In December 2013, the court granted SPP's appeal, vacated FERC's orders on the matter and remanded the case back to FERC.

While the remand was pending at FERC, SPP filed a complaint and an unexecuted transmission service agreement at FERC in order to assess charges for flows above MISO's contract path capacity (1,000MW) between the north and south regions of MISO. In March 2014, FERC accepted the service agreement for filing, subject to refund and hearing proceedings. MISO, SPP, and several other parties engaged in extensive settlement negotiations that resulted in a settlement

[6] *Formal Complaint of American Electric Power Service Corporation*, FERC Docket No. EL17-89 (Sep. 15, 2017).

agreement that, among other things, revised the contract path capacity-sharing provisions of the JOA to the current provisions.

The latest JOA includes a revised section 5.2 as a result of the settlement agreement. The following language was added to section 5.2: No Party will exceed the combined contract path capacity. Any use of the combined contract path capacity shall be subject to all NERC reliability requirements and the terms of the Congestion Management Process and Section 5.3. Additionally, a new section 5.3 was added to the JOA which outlines when it could be necessary for one RTO to compensate the other if a party exceeds its own contract path capacity and relies on combined contract path capacity during normal operating conditions as a result of changes in RTO membership after December 19, 2013.

MISO and SPP continue to have differing interpretations of the current contract path capacity-sharing provisions in Section 5.2 of the JOA. SPP's interpretation of Section 5.2 is that it allows either MISO or SPP to use shared capacity for the purpose of reaching external third parties, and not for the purpose of serving its own internal load. For example, SPP has taken the position that MISO transmission customers must purchase transmission service from SPP in accordance with the SPP open access transmission tariff when those MISO transmission customers are dependent on the SPP transmission system to serve their load. On the other hand, MISO takes the position that there are situations where it is to the mutual benefit of MISO and SPP to maximize the use of the interconnected transmission system by using the combined contract path capacity to provide a more cost-effective delivery of energy to end-use customers. For example, MISO believes during transmission outage situations if combined contract path capacity is available it should be used instead of MISO transmission customers being charged SPP transmission service.

***Settlement Agreement in EL14-21-000, et al.***

The settlement agreement contains several key provisions: (1) provides MISO the ability to use on a non-firm, as-available basis, available system transmission capacity of the other Parties' system subject to a transfer limit between MISO North to MISO South of 3,000MW and MISO South to MISO North of 2,500MW;[7] (2) terms for payment from MISO to SPP and the Joint Parties[8] for usage above MISO's 1,000 MW contract path, including compensation adjustments for the increase or decrease to MISO's contract path; (3) amendments to the JOA as described above; and (4) system operating requirements pertaining to available system capacity usage and the transfer limits.

[7] Settlement agreement does allow for temporary increases and decreases to the Regional Directional Transfer Limits to avoid a system emergency or during actual system emergencies, provided that such temporary increases or decreases do not create an emergency on another system.

[8] Joint Parties include AECI, LG&E/KU, PowerSouth, Southern Co., and TVA

Under the settlement agreement, MISO has paid SPP and the Joint Parties the following amounts:

*Table 3: Amounts Paid Pursuant to the Settlement Agreement*

| TIME PERIOD | SPP ($M) | JOINT PARTIES ($M) | TOTAL ($M) |
|---|---|---|---|
| 1/29/2014 to 1/31/2016 | $9.6 | $6.4 | $16.0 |
| 2/1/2016 to 1/31/2017 | $13.5 | $13.5 | $27.0 |
| 2/1/2017 to 1/31/2018 | $13.5 | $13.5 | $27.0 |
| 2/1/2018 to 1/31/2019 | $13.5 | $13.5 | $27.0 |

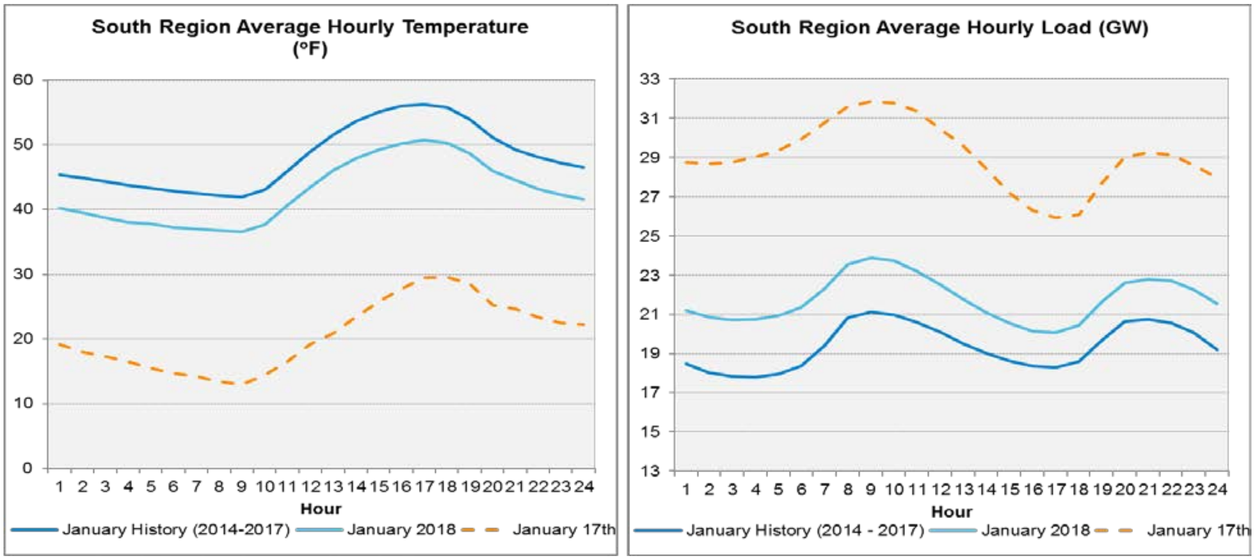
### *Post-Settlement Agreement Operations*

## JANUARY 17, 2018 COLD WEATHER EVENT

### *MISO Reliability Coordinator Area*

On 01/17/2018 and 01/18/2018, MISO and its members managed operations during a period of record cold in the MISO South Region. Record low temperatures in the MISO South region drove significantly higher load than normal for January, see Figure 4. MISO South region peak load of 32.1 GW on January 17th was only 2% lower than the region's all-time peak of 32.7 GW set in August 2015. Operating conditions were further complicated by a significant number of unplanned generator outages and de-rates in real time. A total of 4.5 GW of generation was lost overnight on January 16th and into the morning of January 17th.

*Figure 4: MISO South Temperature and Load*




Prior to the morning of January 17th MISO issued Conservative Operations and Cold Weather Alerts allowing MISO to commit all available resources and restore all possible transmission outages. Due to significant forced generator outages, MISO advanced to Maximum Generation Event Step 2c/d on the morning of January 17th. MISO took all action short of load shed to maintain reliability, including emergency generation, load management, and emergency energy purchases from neighboring Reliability Coordinators. The amount of Load Modifying Resources deployed was 700 MW on the 17th and 930 MW on the 18th. Ultimately what helped MISO avoid shedding load on the morning of January 17 was the emergency energy purchases from neighbors, which were acquired from Georgia System Operations Corp. (150 MW), Southern Co. (700 MW) and TVA (300 MW).

On the morning of January 17th, due to load conditions and the significant number of forced generation outages in the MISO South Region, the Regional Directional Transfer (RDT) flow[9] between the MISO North and Central regions and MISO South region exceeded the North-South Regional Directional Transfer Limit (RDTL)[10] of 3,000 MW, with a maximum exceedance during this timeframe of 936 MW. During this event, there was a divergence between the calculated values of the Regional Directional Transfer using MISO UDS data and transfer values based on state estimator data.[11] As

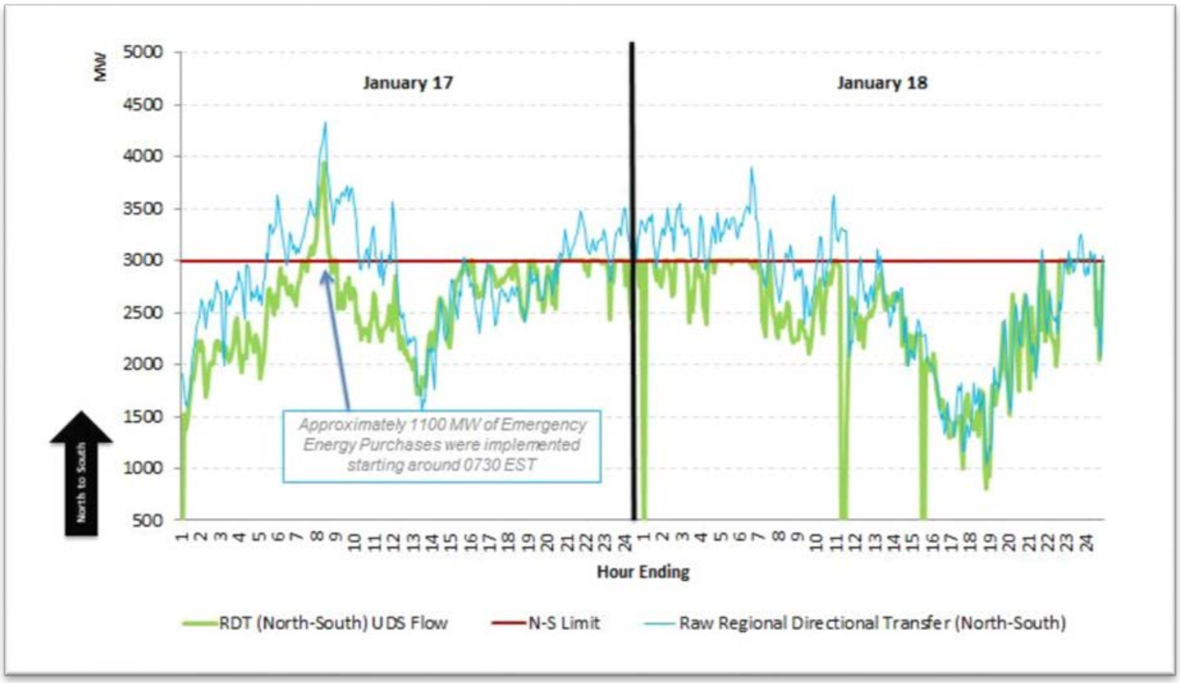
[9] RDT flow is a calculated value defined in the Settlement Agreement entered into between MISO, SPP, and the Joint Parties (AECI, LG&E/KU, PowerSouth, Southern Co., and TVA). The RDT flow calculation at a high-level includes three components to determine the amount and direction of flows between the MISO North and MISO South regions: 1) MISO South region total generation and total load balance; 2) transactions between MISO South and physically connected entities; and 3) pseudo-tie generation flow. The RDT flow is calculated by MISO using data from the latest MISO Unit Dispatch System (UDS) case in accordance with the Settlement Agreement, which represents where load and generation is forecasted to be in the next five-minutes. The results using UDS are intended to serve as a representative proxy for actual flows.

[10] RDTL amount of 3,000 MW for transfers from MISO North to South is defined in the Settlement Agreement, and states if the limit is exceeded that MISO will take action consistent with Good Utility Practice to return RDT flow to the limit within 30 minutes.

[11] The state estimator based transfer flow (blue line in Figure 5) is calculated using real-time load and generation telemetered values instead of data sourced from MISO's Unit Dispatch System.

shown in Figure 5 below there were periods over January 17 and 18 where the transfer values based on state estimator data (blue line) exceeded 3,000 MW with a maximum value of 4,331 MW on the morning of January 17, while the RDT flow (green line) calculation using UDS showed exceeding 3,000 MW from 0635-0745 EST on January 17. Subsequent examination indicates that the key drivers for the observed divergence between these calculated transfer flows (UDS versus state estimator data) were largely due to differences in actual and forecasted load.

*Figure 5: January 17-18 Regional Directional Transfer Values (UDS vs. State Estimator)*




***SPP Reliability Coordinator Area***

SPP RC issued a Cold Weather Alert that was in effect from January 15th until 11:00 on the 18th. Loading for SPP RC on January 17th resulted in a new winter peak of 43.5 GW. Due to the high loads in SPP and neighboring systems, combined with the high MISO North to South RDT flows, SPP had numerous flowgates that were above their SOL on a post-contingent basis, and even had some flowgates where SPP and the Transmission Operators (TOPs) were depending on post-contingent load shed plans to mitigate the SOL exceedance. In addition to post-contingent exceedances, SPP experienced real-time loading on line sections and was forced to reconfigure transmission to mitigate loading on these elements. SPP also experienced voltage issues during this period in the northeast Oklahoma and southwest Missouri areas.

To reliably manage SPP's SOL exceedances and low voltages observed on Jan 17th, SPP put into place post-contingent reconfiguration and load-shed plans, in addition to utilizing market redispatch, additional resource commitments, and other pre- and post-contingent manual actions. As a result of these actions, SPP operators were able to maintain reliability for the SPP footprint while also supporting the reliability of neighboring systems. SPP's review of the events of Jan 17th does not indicate any violation of NERC reliability standards for SPP or its members.

Additionally, SPP remains committed to working with neighboring RCs as all strive to improve operational practices and assistance procedures during extreme weather events.

***Lessons Learned and Subsequent Events***

MISO, SPP, TVA, and Southeastern Reliability Coordinators have met on several occasions to review the event that occurred on January 17, 2018, and to discuss lessons learned and potential coordination enhancements. The list of lessons learned and coordination enhancements includes:

- More clarity and mutual understanding of the non-firm, as-available nature of MISO's RDT flows and of the expectations for congestion management processes

- Advanced preparation and planning for purchases of emergency energy schedules and RC training exercises for readiness to implement emergency energy schedules

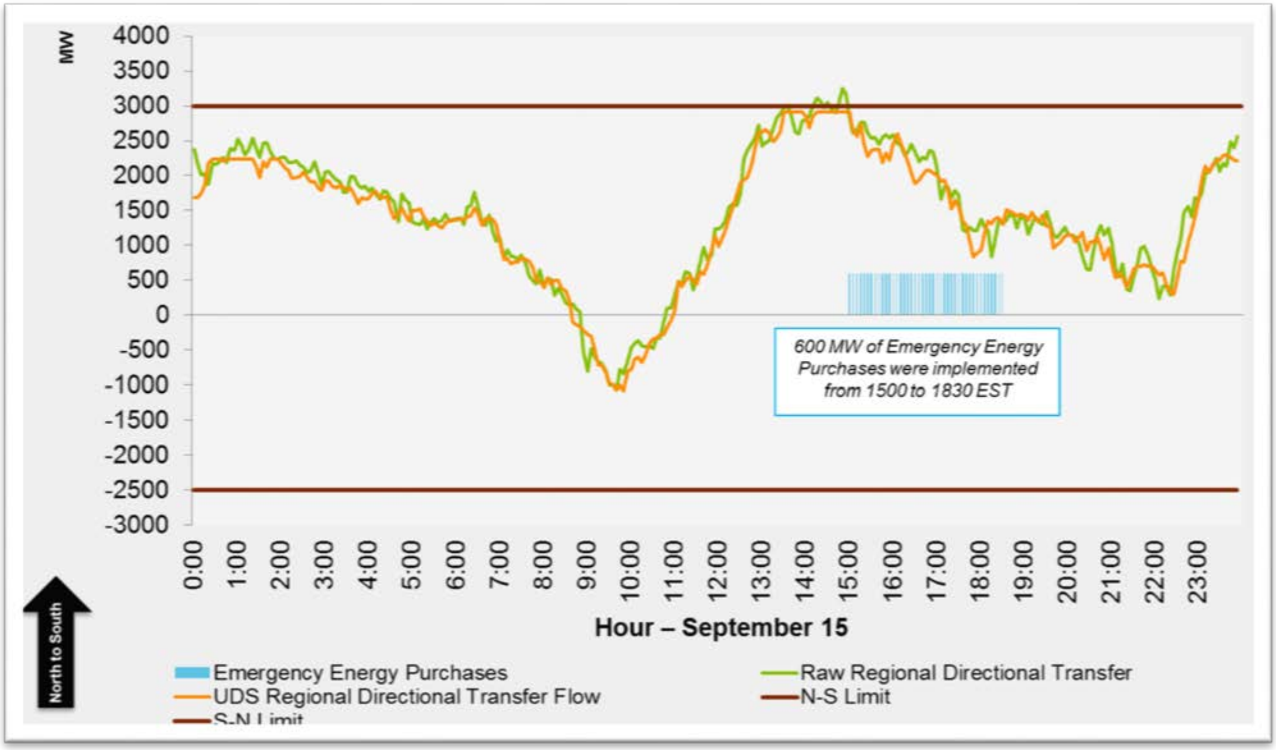
- Increased communication, pre-planning, and information exchange regarding MISO's RDT flows

- Operational control of RDT to ensure UDS and real-time based flows do not exceed limits

***MISO Conservative Operations and Emergency Energy Alert on September 15, 2018***

On September 15, 2018, MISO experienced a maximum generation event due to rapidly increasing temperatures and under-forecasting of load coupled with planned and unplanned generation outages in the MISO South Region. Two days prior, on September 13, 2018, SPP received a notice from MISO informing SPP that MISO could exceed the 3000 MW RDT limit in the North to South direction on September 17, 2018. This was due to the combination of high temperatures and generation outages in the MISO South Region. SPP assessed the situation and performed analyses with different loop flow assumptions in RUC and Day Ahead Market studies, in case the projections from the September 13 notification for high North to South RDT flows on September 17 actually occurred. Ultimately, the situation led to MISO having limited RDT flows on September 17. However, MISO did experience issues two days earlier, on September 15. The problems experienced on September 15 led to an Emergency Energy Alert 2 declaration from MISO and a request for emergency energy from SPP and other MISO neighbors. Because MISO was proactive in providing notifications of the possible RDT exceedances and the overall improvement in communication and coordination between MISO, SPP, and other neighboring RCs, SPP and neighboring RCs were better able to plan for and preempt reliability concerns of the potential MISO RDT exceedance. Furthermore, SPP was able to assist MISO with its request for emergency energy and maintain sufficient headroom before and during the event. SPP and MISO attribute the improved coordination procedures to the lessons learned after the cold weather event on January 17, 2018.

*Figure 6: September 15 Regional Directional Transfer Flows*




# TRANSMISSION PLANNING

## SPP-MISO JOINT TRANSMISSION PLANNING HISTORY

Since the SPP-MISO Joint Operating Agreement (JOA) was executed and filed at the Federal Energy Regulatory Commission (FERC)[12] in 2004, SPP and MISO have conducted coordinated transmission planning activities. These coordinated planning activities include sharing regional transmission expansion plans, exchanging regional planning models, and coordinating the impacts on each Regional Transmission Organizations' (RTO) systems caused by requests for new generator interconnections and transmission service. While there have been incremental improvements in coordination of the impacts of requests for new generator interconnections and transmission service since 2004, FERC Order No. 1000 (Order 1000)[13] caused the greatest evolution of the coordination of SPP and MISO's regional planning models and the interactions of each RTO's respective regional transmission plans. Order 1000 required the following of neighboring transmission planning regions:[14]

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[12] *Joint Operating Agreement with Midwest Independent Transmission System Operator,* Southwest Power Pool, Inc., FERC Docket No. ER04-1096(Aug. 2, 2004).

[13] FERC Order 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 136 FERC ¶ 61,051 (2011).

[14] *Id.*

- Information and Data Sharing
    - Annual Data Sharing
    - Sharing of Regional Models, Needs, and Solutions
- Planning Coordination
    - Joint Evaluation of Interregional Solutions
    - Use of Common Models, Assumptions, and Criteria
- Transparency
    - Stakeholder Input into Interregional Coordination Procedures
    - Website for Interregional Materials

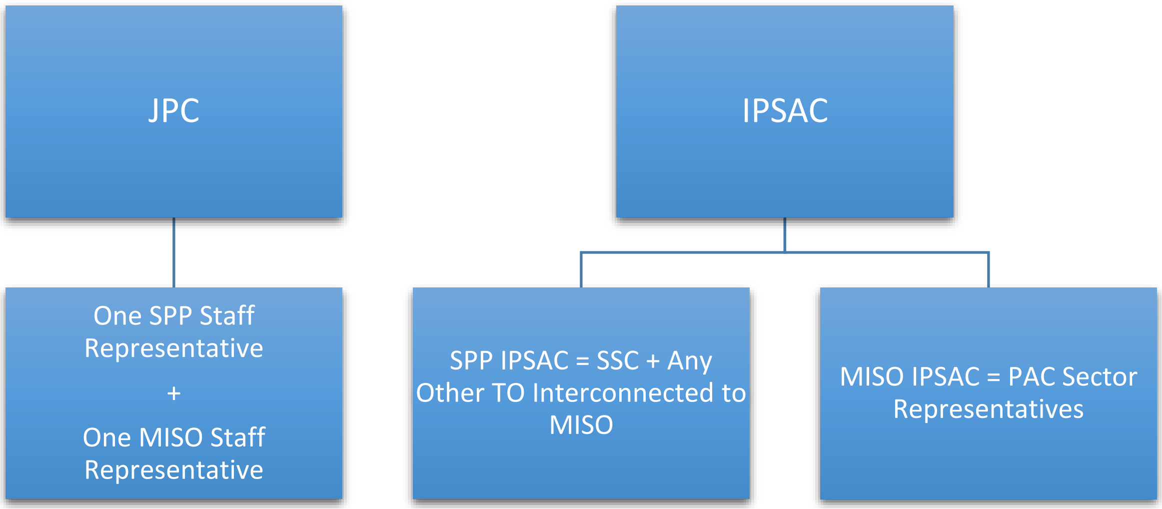
In 2013, in response to the compliance filing required by Order 1000, SPP and MISO developed and filed at FERC the SPP-MISO Coordinated System Plan (CSP).[15] SPP and MISO made separate compliance filings required by Order 1000 due to differing opinions on which transmission projects should be eligible for approval under the interregional planning process and how cost allocation for those projects would be determined. Specifically, MISO's initial compliance filing proposed that only projects with a voltage level higher than 300 kV and projects that were primarily driven by economics could be considered as interregional projects, and SPP's initial compliance filing supported considering interregional projects at voltage levels down to 100 kV and allowing projects driven not only by economics, but also reliability and public policy. In 2016, after several iterations of compliance filings, FERC issued its final orders approving SPP and MISO's CSP, which will be described in detail below.[16]

## SPP-MISO COORDINATED SYSTEM PLAN PROCESS

The SPP-MISO CSP process is outlined in the JOA in Article IX.[17] SPP and MISO's respective stakeholders engage in the CSP process through the open meetings of the Interregional Planning Stakeholder Advisory Committee (IPSAC), and the process is administered by SPP and MISO staff through a Joint Planning Committee (JPC). MISO's portion of the IPSAC is represented by the sector representatives of MISO's Planning Advisory Committee (PAC). SPP's portion of the IPSAC is represented by SPP's Seams Steering Committee (SSC) members and any SPP Transmission Owner with an interconnection to MISO that isn't already a member of the SSC. The JPC is comprised of one staff representative each from both SPP and MISO. While the IPSAC's authority is limited to providing advisory recommendations to the JPC, the JPC gives significant weight to those recommendations when making decisions throughout the CSP process.

[15] *Sw. Power Pool, Inc. submits tariff filing per Order No. 1000 Interregional Compliance Joint Operating Agreement with MISO,* Southwest Power Pool Inc., ER13-1937 (Jul. 10, 2013); *Midcontinent Independent System Operator, Inc. submits tariff filing per MISO-SPP Order 1000 Interregional,* Midcontinent Independent System Operator, Inc., Docket ER13-1938 (Jul. 10, 2013).
[16] *Sw. Power Pool, Inc.,* Letter Order, Docket No. ER13-1937-003 (Apr. 6, 2016); *Midcontinent Independent System Operator, Inc.*, Letter Order, Docket No. ER13-1938-002 (Apr. 6, 2016).
[17] *Joint Operating Agreement between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc.*, Article 9, Docket ER16-1305 (May 30, 2016).

*Figure 7: JPC and IPSAC*




***Determination of the Need for a Coordinated System Plan***

The first step in the CSP process is to determine whether to perform a new CSP in any given year. The goal of the CSP would be to determine if interregional projects can more cost-effectively or efficiently address regional needs as compared to regional projects approved through SPP and MISO's regional transmission planning. This determination is made during an annual issues review meeting, which is required by the JOA to be held at least annually when there is not a CSP already under way. The purpose of these annual issues review meetings is for SPP and MISO staff, along with the IPSAC, to present and discuss potential issues to be studied in an upcoming CSP. At the conclusion of the annual issues review meeting, the IPSAC makes a recommendation to the JPC on whether they wish to initiate a new CSP. Once the IPSAC makes its recommendation, the JPC has 45 days to vote on whether to perform a new CSP. A new CSP can be initiated by each party voting in favor of performing a coordinated study or, if after two consecutive years of a CSP not being initiated, one party voting in favor will initiate a new CSP. There is no requirement to initiate a CSP if no party votes in favor of performing a CSP study. Once the decision is made to perform a new CSP, the CSP must start within 180 days of the JPC's decision.

***CSP Requirements***

Section 9.3.3 of the JOA specifically outlines the requirements a CSP must follow and are summarized below in Table 4:

*Table 4: SPP-MISO CSP Requirements*

| JOA Section | CSP Process | Requirements |
|---|---|---|
| **9.3.3.1** | Scope Development | CSP scope must include:<br>• Transmission Issues<br>• Joint Model Assumptions<br>• Types of Analysis<br>• Study Timeline<br>    o 18 Month Maximum Length<br>• Deliverables |
| **9.3.3.2** | Joint Model Development | SPP and MISO must develop a joint and common model that shall be used for all analysis related to the joint evaluation. |
| **9.3.3.3** | Study Analysis | The type of analysis performed in the CSP is based on the transmission issues identified in scope development. |
| **9.3.3.4** | Project Identification | Transmission solutions shall be developed by SPP and MISO staff as well as third parties. |
| **9.3.3.5** | Project Recommendation | SPP and MISO must develop a study report.<br>• Transmission Issues Evaluated<br>• Studies Performed<br>• Solutions Considered<br>• Recommended Interregional Projects<br>    o Associated Interregional Cost Allocation<br><br>Projects must pass interregional approval by the JPC with consideration of the IPSAC's recommendations. |
| **9.3.3.6** | Regional Approval Process | Any projects recommended by the JPC shall be reviewed by each part through its respective regional process. Projects must then be approved by each RTO's respective Board of Directors<br><br>This must be done within 6 months of the JPC recommendation. |

***Interregional Project Criteria and Cost Allocation***

Section 9.6.3 of the JOA outlines how to identify and cost allocate potential Interregional Projects identified under the CSP. Section 9.6.3.1 of the JOA prescribes six different project criteria, as shown in Table 5 below, which must be met in order for a project to be eligible to be designated as an approved interregional projects.

*Table 5: Interregional Project Criteria*

| Interregional Project Criteria |
|---|
| Minimum Project Cost Threshold of $5,000,000 |
| Evaluated in a CSP and Recommended by the JPC |
| Approved by both RTO's Regional Planning Processes |
| SPP and MISO Must Receive At Least 5% of the Total Benefits |
| Estimated In-service Date Within 10 Years |
| Not Required to be a Tie-line and may be Wholly within one Region |

If a proposed transmission project satisfies all of the applicable Interregional Project criteria, the JPC will decide whether to approve a recommendation that the proposed project be further reviewed by each RTO individually, also called the "regional review". The benefit metrics calculated for any potential interregional Project is determined by the primary project driver of that potential interregional project as outlined in Table 6.

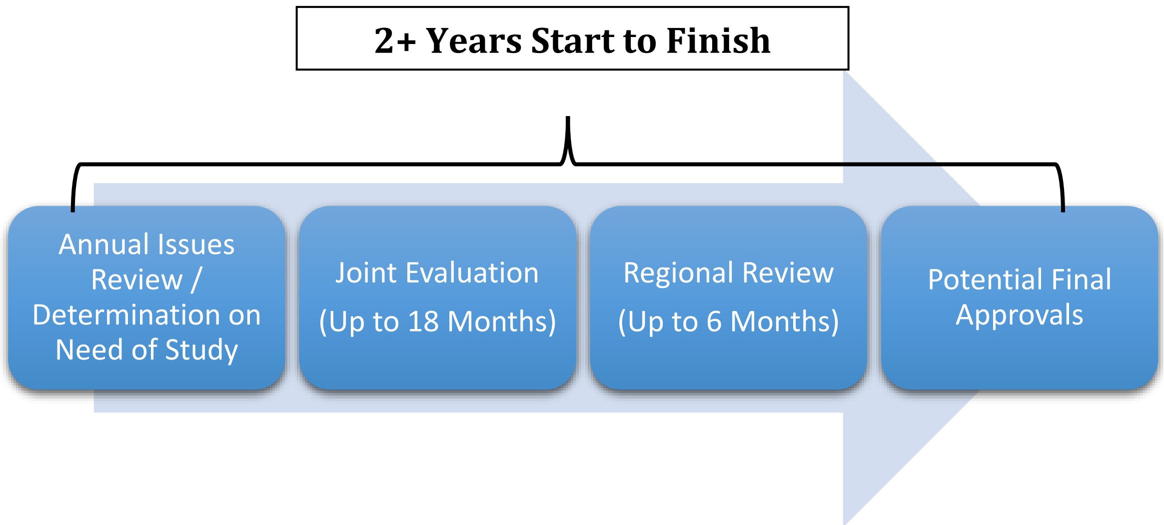
*Table 6: Benefit Metric by Project Driver*

| Project Driver | Benefit Metric Calculated |
|---|---|
| Economic Projects | Adjusted Production Cost (APC) Only |
| Reliability Projects | APC and Avoided Cost |
| Public Policy Cost | Avoided Cost Only |

If a proposed interregional project satisfies all of the aforementioned criteria, its costs are shared between SPP and MISO based on the percentage of benefits each party receives over a 20 year net present value. The interregional cost allocation of any project is determined exclusively by using the benefit metrics calculated for each project type.

Visualized below in Figure 8 is a representative timeline for the CSP process.

*Figure 8: CSP Process Timeline*




***2014 SPP-MISO CSP***

SPP and MISO performed the first SPP-MISO CSP beginning in 2014. The 2014 SPP-MISO CSP evaluated the combined MISO and SPP transmission systems in an effort to identify mutually beneficial transmission improvements. The study was an 18-month effort that began in January 2014. MISO and SPP staff focused efforts on two primary sets of analyses - an economic evaluation and a reliability assessment.

For the economic assessment, a 2024 joint model was built specifically for this study. SPP and MISO staff evaluated the congestion resulting from the 2024 joint model to identify a list of economic needs. Based on those economic needs identified, both staff and stakeholders collaborated to propose potential projects to solve the identified issues, which were tested for APC and other benefits. Based on those results, SPP and MISO identified three projects for consideration as an Interregional Project:

- Elm Creek to NSUB 345 kV;
- Alto Series Reactor; and
- South Shreveport – Wallace Lake 138 kV Rebuild

The results of the 2014 SPP-MISO CSP, utilizing the joint model, showed that each of these projects individually were estimated to provide benefit to both SPP and MISO, as well as APC benefits that was estimated to exceed the cost of the project over the initial 20 years of each project's life. These projects were then recommended by the JPC to the IPSAC for endorsement to move from the interregional portion of the study to both of the SPP and MISO's respective regional review processes. Both the MISO and SPP portion of the IPSAC endorsed the projects with no opposition. Based on that recommendation, the JPC voted in favor for approving all three projects for further review in both MISO's and SPP's respective regional processes.

To accomplish the reliability assessment, a 2024 joint power flow model reflecting generation dispatch utilized in MISO and SPP's respective regional planning processes was built specifically for this study. MISO and SPP staff also performed assessment contingency analysis on the joint power flow model to determine a list of potential reliability needs. Similar to the economic assessment, those needs were reviewed by staff and stakeholders to develop potential projects addressing the issues. The projects that were tested were compared to MISO and SPP regional projects that also mitigated the corresponding needs to determine if the potential Interregional Projects were more cost effective than the regional solutions. Based on the results of the study, SPP and MISO did not identify any interregional projects for the sole purpose of resolving reliability issues more cost effectively than MISO and SPP regional solutions.

The interregional projects recommended by the JPC were then subject to a regional review and required approval of both SPP and MISO Board of Directors (BOD). The MISO regional review found only the Alto-Series Reactor project exceeded MISO's benefit to cost threshold, however, with additional alternatives also being evaluated, it was concluded that a more comprehensive solution was required in that area. MISO's BOD did not approve any of the three recommended interregional projects.

The SPP regional review found that both the Southwest Shreveport – Wallace Lake and Elm Creek – NSUB projects provided benefits to SPP greater than their respective costs. However, based on SPP's analysis of the benefit drivers of the Elm Creek – NSUB project, it was determined that the project should be evaluated in later SPP regional studies before being considered for approval. The SPP BOD approved South Shreveport to Wallace Lake as an interregional project at its October 2015 Board meeting. However, since the MISO Board of Directors did not also approve the project, it ultimately was not approved because there was not unanimous support from both SPP and MISO. The study analysis and results are captured in detail in the 2014 SPP-MISO CSP Report.[18]

***2016 SPP-MISO CSP***

The second iteration of the SPP-MISO CSP process was the 2016 SPP-MISO CSP. The study was performed to evaluate the combined SPP and MISO transmission systems in an effort to identify mutually beneficial transmission improvements. The study began on May 31, 2016 and lasted for more than a year. SPP and MISO staff focused efforts on an economic analysis of a targeted set of transmission needs identified by SPP's and MISO's respective regional planning processes along the SPP and MISO seam.

SPP and MISO evaluated seven unique transmission needs in the 2016 CSP that had been identified in the 2017 SPP Integrated Transmission Planning study (ITP10) or the 2016 MISO Transmission Expansion Planning (MTEP) process. This approach of targeting transmission needs identified by the regional planning processes was chosen in response to stakeholder feedback and to make the joint study process more efficient by leveraging the regional studies that were already complete. The parties believed this approach better facilitated a determination of whether interregional transmission solutions exist that are more efficient or cost effective as compared to the regional solutions already identified in the SPP 2017 ITP10 and MISO 2016 MTEP. This approach

[18] *2014 MISO-SPP Coordinated System Plan Study Report*, https://www.spp.org/documents/34199/miso-spp%20coordinated%20system%20plan%20report_final.pdf (December 21, 2015).

was pursued based on the lessons learned effort at the conclusion of the 2014 CSP, which will be discussed later in the paper.

Beginning with the list of seven targeted needs, staff and stakeholders collaborated to propose potential Interregional Projects to address the identified transmission issues. The proposed interregional projects were then tested for APC benefits. Based on those results, SPP and MISO identified one transmission project for consideration as an interregional project:

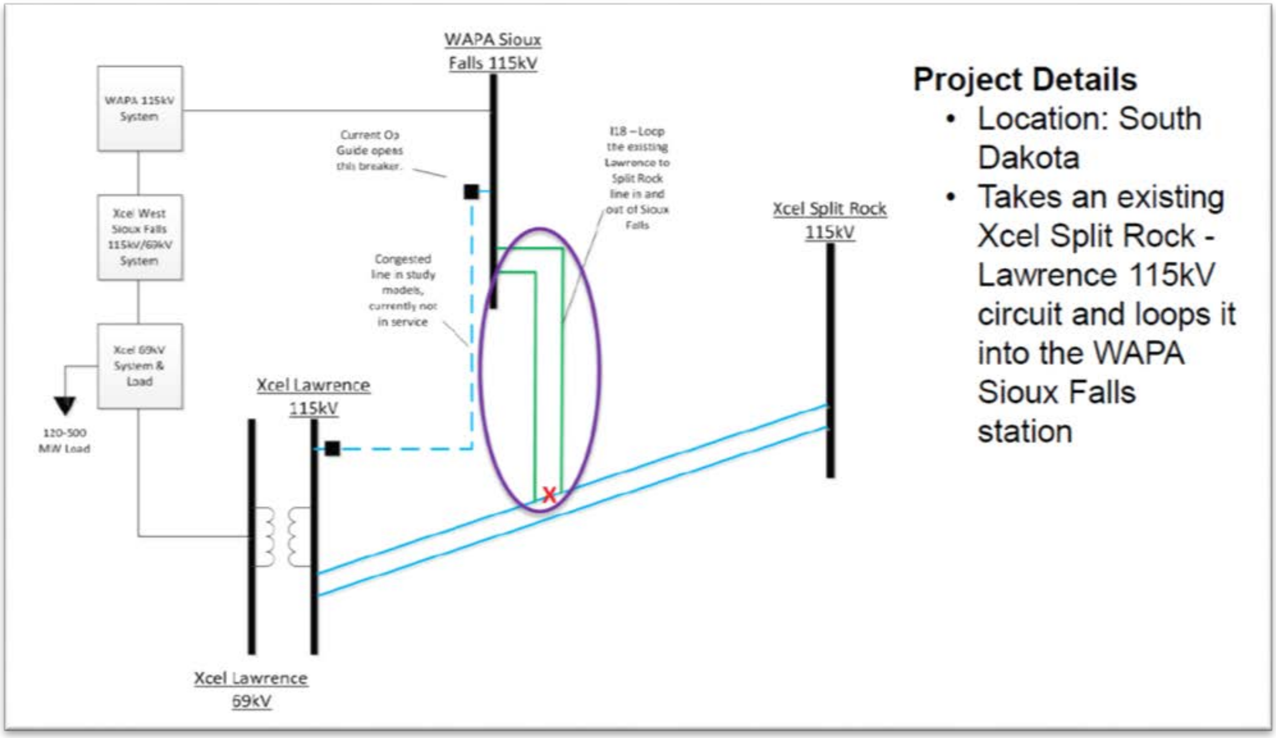
- Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls

The 2016 CSP study demonstrated this project was estimated to provide benefits to both MISO and SPP as well as APC benefits that exceeded the cost of the project over the initial 20 years of the project's life. The joint model resulted in expected benefit to cost ratio of more than 4 to 1. As a result, the Loop One Split Rock to Lawrence 115kV circuit into Sioux Falls project was recommended by SPP and MISO to the IPSAC for endorsement to move from the interregional portion of the study into both SPP and MISO's respective regional review processes. Both the SPP and MISO portion of the IPSAC endorsed this recommendation with no opposition. Based on that recommendation, the JPC voted in favor of approving this project for review in both the MISO and SPP regional review processes. The interregional project recommended by the JPC was then subject to a regional review and required approval of both SPP and MISO Board of Directors to proceed with final approval. SPP and MISO each reviewed the 'Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls' Interregional Project in their respective regional reviews, which yielded different results.

The analysis performed as part of MISO's Regional Review demonstrated there were two alternatives that were more cost-effective and efficient than the proposed 'Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls' interregional project. Therefore, MISO did not recommend the more costly 'Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls' as an Interregional Project.

MISO's regional review of the project also brought to light the potential for the project to create a situation where MISO Transmission Customers could face potential unreserved use penalties from SPP in certain situations. The nature of the 'Loop One Split Rock to Lawrence 115 kV into Sioux Falls' project would result in tapping an existing line and potentially isolating an existing MISO load being served from the SPP transmission system under certain contingencies. SPP and MISO had begun discussing ways to mitigate this concern when it was determined by MISO and MISO stakeholders that there were lower cost alternatives that were preferable over the 'Loop One Split Rock to Lawrence 115kV into Sioux Falls' project.

*Figure 9: Loop One Split Rock to Lawrence 115kV into Sioux Falls Project*




SPP's regional review analyses evaluated the 'Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls' interregional project as well as one alternative project. SPP's analyses determined both solutions evaluated were potentially beneficial to the SPP transmission system, with the 'Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls' being the better long-term solution. However, the project ultimately was not approved because there was not unanimous support from both SPP and MISO. The study analysis and results are captured in detail in the 2016 SPP-MISO CSP Report.[19]

## SPP-MISO COORDINATED SYSTEM PLAN ISSUES

Joint projects being pursued by more than one entity inherently face obstacles that regional projects do not encounter. When two separate regions coordinate to jointly evaluate potential transmission projects, several barriers must be overcome to achieve the desired result of finding projects that are mutually beneficial. These barriers arise because different regions prefer to plan their systems differently and have differing opinions on the regional value of transmission. Competing cost allocations and a lack of experience dealing with joint projects also play a role in the

[19] 2016 *MISO-SPP Coordinated System Plan Study Report*, https://www.spp.org/documents/56233/2016%20miso-spp%20coordinated%20system%20plan%20final%20study%20report%20(includes%20regional%20review%20results).pdf (December 21, 2017).

difficulty of approving joint projects. SPP and MISO's joint planning efforts are not immune to these overarching barriers to finding mutually beneficial interregional projects.

***CSP Lessons Learned Efforts***

SPP and MISO staff were committed to performing extensive lessons learned efforts at the conclusion of each CSP. The 2014 and 2016 CSPs both encountered many of the above discussed barriers to finding mutually beneficial joint interregional projects as well as hurdles specific to the SPP-MISO CSP process.

The 2014 CSP lessons learned efforts consisted of discussions at several stakeholder meetings including the MISO-SPP IPSAC, SPP SSC, and MISO PAC. The IPSAC was also asked to provide written feedback on enhancements needed to the CSP process after the study was concluded. This review of the process resulted in several takeaways for SPP and MISO staff to consider moving forward, which are outlined in Figure 10.

*Figure 10: 2014 SPP-MISO CSP Lessons Learned*

| | |
|---|---|
| Joint Model Build | • Very complex<br>• Time consuming |
| Modeling Inconsistencies | • Joint model inputs must be agreed upon and can divert from the inputs in the RTO's regional models<br>• Due to challenges in building joint models only one future was studied and regional reviews could study multiple futures |
| Regional APC Calculation Differences | • SPP calculates APC comparable to how the JOA prescribes<br>• MISO's regional calculation of APC is different than how the JOA states it will be calculated in joint studies and SPP's regional calculation |
| Limited Benefit Metrics | • South Shreveport project also provided SPP reliability benefit but could not be accounted for in cost allocation between SPP and MISO due to the limitations of the JOA |
| Lack of Flexibility | • JOA does not allow for further negotiation of cost allocation after the regional reviews |
| Timing of Regional and Interregional Studies | • Creates problems in weighing regional projects vs. Interregional Projects |
| Lack of Clarity of Approval Process | • No requirement projects under regional review go to each RTO's Board of Directors for an up or down vote |

The 2016 CSP implemented several process improvements identified in the 2014 CSP lessons learned effort. One primary improvement was to leverage the results of each party's respective regional planning processes (ITP and MTEP) to help focus the CSP study in lieu of relying on the joint model to produce previously unidentified needs. However, the 2016 CSP still encountered several of the same issues that were encountered in 2014. Similar to the lessons learned from the 2014 CSP effort, SPP and MISO utilized the IPSAC, regional stakeholder meetings, and written feedback to gather input for the 2016 CSP lessons learned. The 2016 CSP lessons learned are listed below in Figure 11.

*Figure 11: 2016 SPP-MISO CSP Takeaways*

| | |
|---|---|
| Joint Model Build | •Joint model building issues were still encountered in 2016<br>•Modeling inconsistencies which led to differing results were still seen |
| Regional APC Calculation Differences | •Differences in 2014 are still prevalent in 2016 CSP and created differing results in the CSP and regional review prices |
| Lacked consistency between regional review analysis and joint study | • SPP and MISO evaluated different sets of alternative solutions in the regional review analysis |
| JOA Interregional Project Criteria | •JOA Interregional Process Criteria limited potentially beneficial projects from moving forward due to the cost threshold |

### *SPP and MISO CSP Process Short Falls*

Through two iterations of performing the SPP-MISO CSP and two lessons learned efforts, the parties identified several short falls in the SPP-MISO CSP process.

#### Modeling:

Modeling issues were one of the main complications that arose when performing the CSP. The first modeling issue of the CSP is created due to the differences is SPP and MISO's respective regional models. During the joint model development effort, required by the JOA, SPP and MISO are more or less merging their two respective regional models. SPP and MISO both spend a great deal of staff and stakeholder time determining the joint modeling assumptions and how those differ from the assumptions being used in SPP and MISO's respective regional models. This poses a challenge when merging regional models to develop a joint model. SPP and MISO staff must decide whether to use SPP's assumption, MISO's assumption or a new negotiated assumption. This complication and the need to be transparent with stakeholders about the decisions being made is what creates the complexity and a large time commitment to build a joint model.

The second modeling issue experienced was the differences in the joint model and SPP and MISO's respective regional models led to inconsistent results between the CSP and regional review processes. As detailed earlier, SPP and MISO must divert from the regional modeling assumptions that each RTO prefers when creating a joint model. This results in evaluating potential interregional projects under a different set of assumptions than each RTO would perform regionally. This understandably yields different results when evaluating a potential interregional project in a joint model versus in regional models. This issue of differing results is amplified by the CSP process design requiring projects be studied in a joint model within the CSP and regional models within the regional review process. This modeling issue is one of the reasons SPP and MISO have initially identified mutually beneficial projects based on analysis in the joint model but those same projects not being identified in the regional review process.

### Benefit Metrics and Project Criteria:

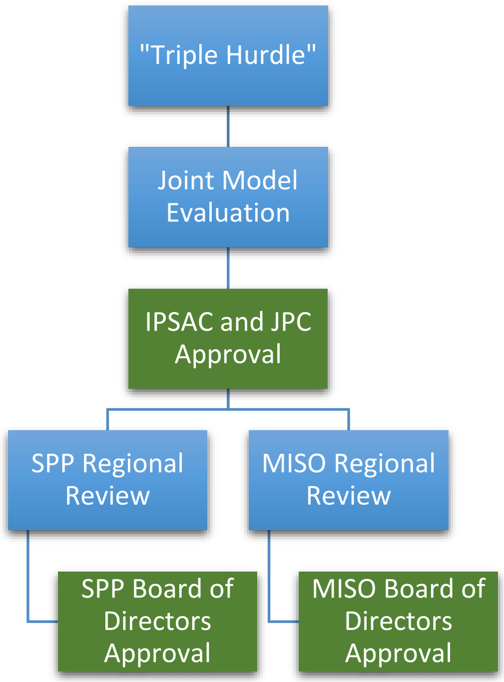
Limited benefit metrics and project criteria are another short fall of the CSP process that was identified through the lessons learned efforts. The JOA language is prescriptive on which benefit metrics can be evaluated and considered in the calculation of interregional cost allocation by project driver, as shown in Table 6 above. For example, even if a project that is primarily driven by economics provided avoided cost benefit, the avoided cost benefit could not be included in the benefit that goes into determining the interregional cost allocation. This limitation excluded potential benefits and resulted in interregional cost allocation that did not include an accurate representation of the benefits received by each RTO.

The JOA also limited what projects could be considered as interregional projects within a CSP. The interregional project criteria required a project have a minimum cost estimate of $5,000,000. This project criteria is possibly too restrictive and potentially eliminated mutually beneficial projects from the CSP process. It is possible that projects under $5,000,000 could also be appropriate for the CSP by providing both regions with significant benefits.

### *"Triple Hurdle"*:

The "triple hurdle" of approvals interregional projects must undergo was also identified as a shortfall of the SPP-MISO CSP process. Both SPP and MISO separately have approved billions of dollars' worth of regional projects, but those projects must only receive approval from one regional planning process and one board of directors. Interregional projects must be studied and approved by three separate planning processes and three separate staff and stakeholder groups. This obstacle was identified by stakeholders in the 2014 and 2016 CSPs as an overly burdensome requirement.

*Figure 12: "Triple Hurdle" of Approvals*




SPP views MISO's 300+ kV regional voltage threshold for Market Efficiency Projects (MEPs) as complicating the ability of the SPP-MISO CSP to approve sub-300 kV projects. MISO and their stakeholders are currently targeting filing by the end of 2018 changes to the MISO Tariff that would lower the voltage threshold for MISO-SPP interregional market efficiency projects to 100 kV.

The length of the study process, which can run up to 30 months from the determination to conduct a study to the end of the regional review processes, can lead to a lack of stakeholder confidence in the results. This length of the interregional study process results in a misalignment of regional and interregional study timelines, making it difficult to have all the information necessary to make informed decisions.

### Unreserved Usage Penalties:

MISO has identified an additional complication to the SPP-MISO CSP process with the potential exposure to MISO Transmission Customers of unreserved usage penalties that MISO views is inconsistent with the contract path capacity sharing provisions in Section 5.2 of the MISO-SPP JOA, while SPP views it as a transmission provider obligation under SPP's open access transmission tariff. These charges and penalties could be a deterrent to interregional planning as, under certain circumstances, MISO Transmission Customers could potentially be charged for the interregional project as well as charged for SPP transmission service and associated penalties by SPP for unreserved use of the SPP transmission system. SPP has indicated there could be a way to address this by conferring certain transmission capacity and usage rights associated with the interregional project, which could require changes to the MISO-SPP JOA.

### SPP-MISO Coordinated System Plan Improvement Effort:

In February of 2018, SPP and MISO held the required annual issues review meeting with the IPSAC to determine if there was a need to initiate a new CSP study. At the meeting, the IPSAC recommended that SPP and MISO staff forgo initiating a new study in 2018 and instead focus interregional planning efforts on identifying and implementing CSP process improvements. Throughout the first three quarters of the year, SPP and MISO have met with the IPSAC several times to develop the current CSP enhancements proposal that is currently being drafted into modifications to the existing JOA language. SPP and MISO considered all recommendations by stakeholders and proceeded with a sub-set of options. The recommendations highlighted three main improvements that SPP and MISO both agree should be made with the goal to file the amendments to the CSP process at FERC by the first quarter of 2019.

The removal of the joint model requirement is the largest proposed change to the current CSP process. As discussed above, the current CSP process requires the use of a joint and common model for the evaluation of interregional projects. The joint model requirement was identified as the origin of many of the CSP shortfalls. Eliminating the joint model requirement will allow SPP and MISO to leverage the robust regional planning models and processes that each RTO is already using. SPP will use the most current SPP ITP models and MISO will use the most current MTEP models for the evaluation of interregional projects. It is expected this change will result in the removal of several previously identified barriers as well as other improvements to the process. One expected benefit is the removal of the inconsistencies between the joint model and the regional model. Another expected benefit is that this removes the triple hurdle of approvals because, while the CSP process will still be overseen by the IPSAC, there will not be an interregional evaluation required before projects are considered by the SPP and MISO regional processes. The projects will now only be required to be approved by each RTO's respective Board of Directors. The other expected benefits are the ability to test more potential projects, the ability to perform interregional planning on an annual basis, and shortening the lengthy CSP process.

The second CSP process improvement that is being pursued by SPP and MISO is the inclusion of both APC and avoided cost as benefit metrics for determining cost allocation of all potential interregional projects regardless of primary project driver (economic, reliability, or public policy). SPP and MISO both support allowing each RTO to calculate these benefit metrics based on each RTO's regional benefit metric calculations. As stated earlier, the current JOA language restricts which benefit metrics can be calculated and accounted for in interregional cost allocation based on the primary driver of the project. By allowing the use of APC and avoided cost for all potential interregional projects, it will broaden the current JOA prescribed benefit metrics used for economic and public policy projects. This will also ensure that if a project provides benefit to either RTO that those benefits can be accounted for when determining interregional cost allocation. While it is not currently a part of the CSP enhancements proposal, SPP and MISO support continuing to explore additional benefit metrics used for selection of possible interregional projects, specifically potential benefit metrics or processes that account for real-time congestion and market-to-market activities.

The third CSP process improvement being proposed by SPP and MISO will address the minimum $5,000,000 cost threshold required by the JOA. SPP and MISO propose removing the minimum cost threshold from the JOA altogether. This will expand the number of solution options that can be pursued in future CSPs. This process improvement will not require SPP or MISO to approve any low cost projects that either RTO might perceive as a regional project not appropriate for a CSP, rather just allows it as a possibility. This would allow SPP and MISO the ability to pursue a lower cost project that is identified as mutually beneficial to each RTO without the need for a FERC filing.

The three CSP process improvements result in the need for a new interregional cost allocation methodology. Currently, the interregional cost allocation is a product of the joint model, which is being proposed to be removed. The new proposal for interregional cost allocation will not deviate from the policy that each RTO is allocated costs based on the proportion of benefits that each party receives, rather it will change how the benefit is determined. Under the new process, benefits a proposed interregional project will bring to SPP and MISO will be determined by utilizing SPP and MISO's regional models. As previously discussed, SPP and MISO will calculate APC and avoided cost based on each RTO's regional benefit metric calculations using each regions respective regional models. SPP and MISO will only calculate their own benefit and will not evaluate a potential projects benefit to the other region. The cost will be shared between the RTO's based upon each RTO's percentage of the project's total benefit as determined by adding the benefit calculated out of each RTO's regional model. SPP and MISO's percentage of the cost will be equal to their percentage of the total project benefit. Below is the formulas and an example that illustrates the interregional cost allocation calculation that is being proposed as CSP process improvement.

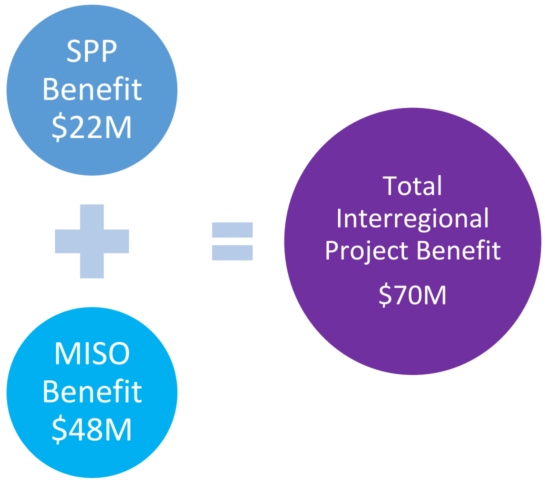
Proposed Interregional Cost Allocation Formula:

- *MISO Cost = (MISO Benefit)/(MISO Benefit + SPP Benefit) * Total Cost*
    - *MISO Benefit = NPV of MISO's benefits as calculated in MISO's MTEP process*
- *SPP Cost = (SPP Benefit)/(MISO Benefit + SPP Benefit) * Total Cost*
    - *SPP Benefit = NPV of SPP's benefits as calculated in SPP's ITP process.*

Proposed Interregional Cost Allocation Example: Hypothetical Interregional Project X

- Project X Total Benefit - $70M
    - SPP Benefit - $22M (31.4%)
        - Calculated by SPP in SPP's ITP Process
            - Avoided Cost - $15M
            - APC - $7M
    - MISO Benefit - $48M (68.6%)
        - Calculated by MISO in MISO's MTEP Process
            - Avoided Cost - $0
            - APC - $48M
- Project X Total Cost - $19M
    - SPP Cost Responsibility - $5.97M
    - MISO Cost Responsibility - $13.03M

*Figure 13: Proposed Interregional Cost Allocation*




In addition to the three proposed CSP process improvements and the resulting new interregional cost allocation proposal, SPP and MISO are committed to continuing to consider other ways to improve the SPP-MISO CSP process. Just as there was a priority placed on lessons learned efforts after the 2014 and 2016 CSPs, SPP and MISO will continue to review and learn from past experiences once these new process improvements are approved by FERC and implemented into the JOA

## ADDITIONAL TRANSMISSION PLANNING ISSUES AND EFFORTS

SPP and MISO are involved in several transmission planning efforts outside of the SPP-MISO CSP. A few of those planning efforts are exploring new processes to address gaps in interregional planning, coordinating regional studies, and assessing transmission impacts.

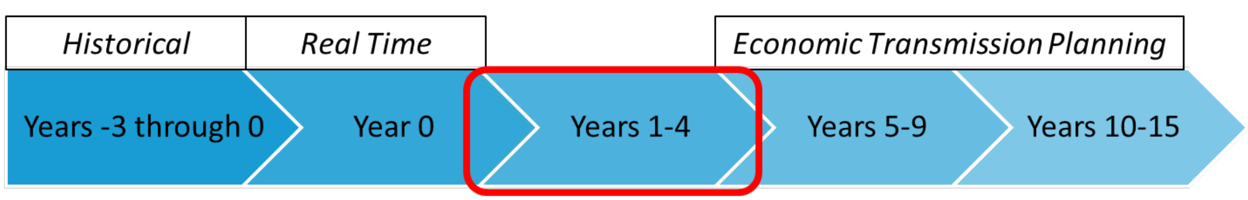
### *Project Drivers Not (Always) Captured in Traditional Joint Planning*

While the SPP-MISO CSP and the process enhancements that are being pursued are improved approaches for achieving effective interregional planning, it often does not capture all of the issues actually experienced on each RTO's transmission system. Real-time or operational issues are often not captured in traditional transmission planning efforts. Regional and interregional studies alike do not always capture the persistent operational issues that system operators routinely experience. Because these long-term transmission planning processes currently do not always identify these persistent operational needs, a transmission solution may still be warranted to enhance reliability and to reduce costs to ratepayers.

To fill this gap in SPP's planning processes, SPP plans to start assessing "persistent operational needs" through the ITP process. Persistent operational needs may be either economic or reliability related. The criteria for identifying these needs is described in SPP ITP Manual.[20] SPP also has the ability to propose additional needs to account for other problematic operational issues observed in operating the transmission system not fitting the given criteria. With the CSP, process enhancements that are being pursued, specifically with the leveraging of the SPP ITP models and the ability of SPP to propose additional corrections to problematic operational issues, these persistent operational needs that are identified will filter their way into the SPP-MISO CSP.

Another potential gap of the SPP-MISO CSP process is that it does not target congestion on reciprocally coordinated flowgates[21] that are identified in the Market-to-Market process between SPP and MISO. Traditional economic planning typically focuses on addressing congestion on the system five years out and beyond. Economic models also do not always depict the actual congestion showing up repeatedly in real-time markets.

*Figure 14: Gap in SPP-MISO CSP.*




[20] *Integrated Transmission Planning Manual,* p. 31, Section 4.4. (Oct. 17, 2008)

[21] A Flowgate is a representative modeling of facilities or groups of facilities that may act as significant constraint points on the regional system. A Reciprocal Coordinated Flowgate is a Flowgate that is subject to reciprocal coordination by Operating Entities, under the JOA.

SPP and MISO have developed a framework for an initial study design specifically to address this gap between real-time operations and long-term planning that will consider historical Market-to-Market congestion where potential projects are needed within three years. This framework is modeled on the Targeted Market Efficiency Project (TMEP) study process implemented by MISO and PJM.[22] The study framework is still undergoing discussions between the parties and with stakeholders; however, some of the criteria being considered for these projects include:

- Minimum total project cost of less than $20 million in study year dollars
- In-service date within 4 years
- Determined through congestion savings to pay for itself within 4 years
    - Annual congestion is the estimated average historical congestion based on the two historical years prior to the study year
    - Future congestion relief benefit is adjusted by historical Market-to-Market settlements to account for accurate impact of implementing the Project

The cost allocation between SPP and MISO of these types of projects would be determined based upon the percentage of congestion relief each RTO is expected to receive offset by any expected Market-to-Market payments. SPP and MISO both support continuing to explore this potential process to address chronic constraints and expect to devote efforts in early 2019 to finalize the process design with stakeholders.

***Regional Planning Coordination***

SPP and MISO actively participate in coordinating each other's respective regional processes. This coordination is not only performed to meet the data and information sharing requirements of the JOA, but serves as an avenue for SPP and MISO to learn from each other. By learning about the different ways each RTO performs planning, to the parties can explore new ideas and improve each RTO's regional planning processes. Because of the desire for continuous improvement in the planning coordination, both RTOs have taken advantage of having an open line of communication between each other's planning staffs.

Another aspect of regional planning that has benefited from SPP and MISO coordination is modeling accuracy. SPP and MISO have always attempted to model each other's transmission system as close to how the other RTO actually models its own transmission system. However, in the past those attempts often fell short due to the lack of transparency or coordination. Currently SPP and MISO have regular modeling discussions to ensure each RTO is modeling the other's transmission system as accurately as possible. The data and information sharing between SPP and MISO has significantly improved regional planning models depiction of neighboring systems.

SPP and MISO are also currently undergoing an effort to improve coordination when transmission impacts are observed on the other RTO's system due to recently approved projects or changes to the transmission system. The current JOA language and coordination requirements are

[22] Targeted Market Efficiency Projects are intended to address historical congestion along the MISO-PJM seam that MISO's or PJM's regional transmission planning process or their joint interregional transmission coordination process would not otherwise address.

very broad and lack specificity. SPP and MISO both see the value in clear coordination expectations between the each RTO when transmission impacts are identified. The RTOs are continuing to work to provide clarity to the JOA through developing a separate coordination document. The document can be found on SPP and MISO's websites on the interregional coordination page.[23]

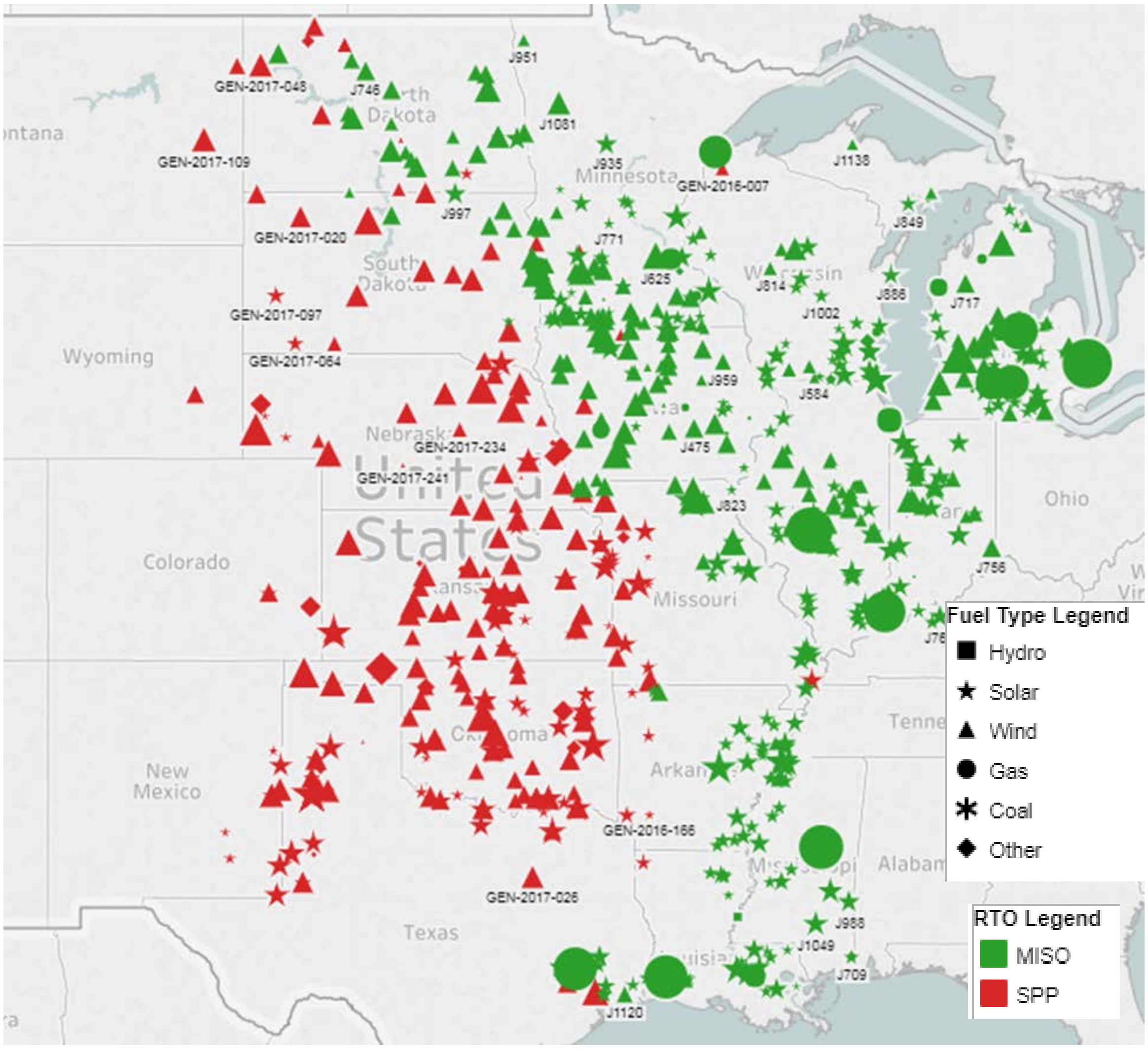
# RESOURCE INTEGRATION

### SPP AND MISO GENERATOR INTERCONNECTION HISTORY

Both SPP and MISO currently have substantial Generator Interconnection ("GI") queues (sometimes simply referred to as the "Queue") currently under study. SPP and MISO's respective GI processes provide a means for generation planners and developers to submit new GI projects into the Queue for validation, study, analysis and, ultimately, execution of a Generator Interconnection Agreement with the applicable RTO. These GI studies ensure that when new generation is added each RTO's transmission system remains reliable. SPP currently has a coincident peak load of 50.6 GW and has 85 GW of generation in the Queue. MISO has a peak load of 131 GW and 82 GW in the Queue, as of Oct 29, 2018, with 43 GW of that amount in Queue located in the West and South Regions of MISO, which interface with SPP. The map below in Figure 15 shows the location of the generation in the GI Queue in both MISO and SPP.

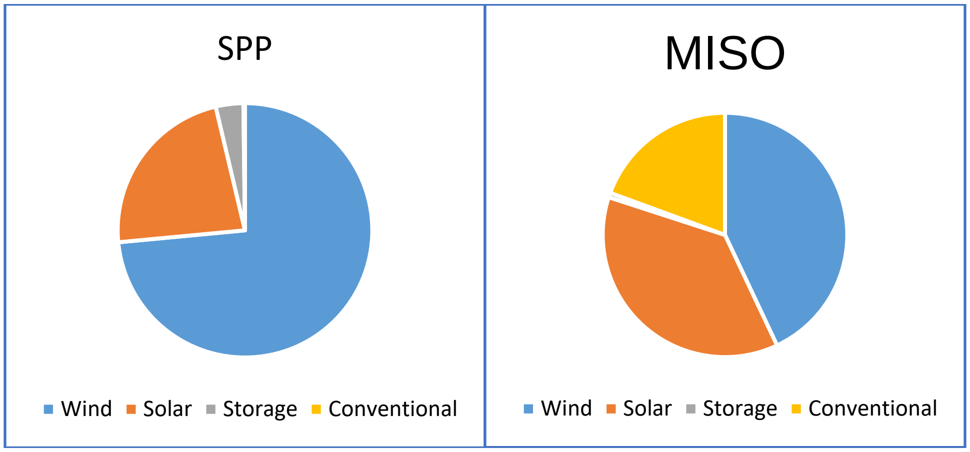
[23] https://www.spp.org/engineering/interregional-relations/

*Figure 15: GI Queue Generation in MISO and SPP*




The SPP Queue is comprised primarily of non-conventional generation resources with 73.5% wind, 22.8% solar, and 3.5% battery storage. Conventional generation resources represent only 0.2% of the SPP Queue. The MISO Queue is also comprised primarily of non-conventional generation resources with 50% wind, 42.8% solar, and less than 0.1% battery storage. Conventional generation represents 11.3% of MISO's Queue.

*Figure 16: Generation Mix of GI Queue in MISO and SPP*




SPP currently has two 6-month application windows annually for GI requests for inclusion in the required system impact study. SPP's second 2016 system impact study, DISIS-2016-002, was completed in August 2018, but a restudy is anticipated to re-evaluate the identified upgrades due to significant withdrawals of a number of GI requests. Subsequent studies will be conducted in sequential order. MISO is transitioning from 6-month study cycle application window to a 9-month to 12-month window for GI requests for inclusion in their three-stage system impact study. The three-stage process allows for simultaneous evaluation of study windows, coupled with distinct regions where there are multiple study cycles being evaluated. SPP is in the process of reforming the GI study process to a similar three-stage system impact study. Both RTOs are working to create a more streamlined GI study process to alleviate the current backlog. SPP and MISO each perform affected system impact studies to evaluate reliability impacts from GI requests in the neighboring system.

***Current SPP-MISO JOA GI Process and Requirements***

Section 9.4 of the SPP-MISO JOA outlines the coordination and study requirements of the analysis of interconnection requests. The coordination requirements cover several different aspects of data and information sharing between SPP and MISO as it relates to each RTO's GI studies. The JOA also requires that each RTO will notify the other if a study shows potential reliability concerns on the other party's system. Staff from SPP and MISO's GI departments have a good working relationship on how each party notifies and studies these requests. However, the coordination requirements, as established in the JOA, for sharing and analyzing these third party impacts could be revised to provide both parties benefits of providing clarity and specificity to the affected system coordination requirements.

In addition to the ambiguity of the JOA language, the JOA was also developed when both SPP and MISO had similar 6-month study cycle application windows and a similar timeframe when the application windows closed. With reforms that have occurred in SPP and MISO's GI procedures and studies, there is no longer similarity in the commencement and closure dates of the application windows. An update is necessary to align with current and future processes to provide greater transparency.

## SPP-MISO GENERATOR INTERCONNECTION COORDINATION ISSUES

***SPP Concerns with MISO Deliverability Analysis***

As discussed in the earlier section on the historical flowgate allocation calculation, the CMP members have been working on revising the CMP to transition away from the concept known as "Freeze Date." The Freeze Date, which is currently set as April 1, 2004, is used when determining the firm rights that reciprocal entities have for flows across their own system as well as the systems of other Operating Entities. The highest priority rights are given to Network Resources, as that term is defined in each Operating Entity's open access transmission tariff, and transmission service rights that existed prior to the Freeze Date. To fully appreciate the potential impacts to updating the CMP, it is important that each Operating Entity understands the processes that neighboring Operating Entities use to determine which resources qualify as Network Resources under their respective open access transmission tariff because the qualification as a Network Resource could result in the allocation of certain rights to a neighboring Network Resource to flow across its system, sometimes referred to as "parallel flows."

During the review by SPP of the qualification process of a Network Resource under the MISO tariff, SPP staff requested discussions with MISO staff to better understand the Deliverability Analysis that is performed. Following several discussions, SPP staff raised concerns to MISO staff about the robustness of the Network Resource Interconnection Service (NRIS) Deliverability Analysis that is performed by MISO. Under the MISO tariff, a resource can be qualified as a Network Resource and designated to serve any MISO Network Load under the MISO process once it has been evaluated through MISO's Deliverability Analysis and does not require completion of a transmission service capability analysis (transaction analysis) from specific resource to specific load. Under the SPP process, a resource must be studied through the generator interconnection process as well as through the transmission service request process before it can be designated as a Network Resource to serve Network Load under the SPP tariff. There is an opportunity to converge the gap that exists between the two RTOs' handling of NRIS through the coordination improvements effort of the GI staffs and revising Section 9.4 of the MISO-SPP Joint Operating Agreement. Additionally, both RTOs should include any applicable conditions or requirements in the interconnection agreements they execute with their respective interconnection customer if any interconnection request had been identified as potentially impacting and requiring mitigation on the neighboring system.

***Affected Systems Coordination Procedure –EDF Renewable Energy Inc.'s Complaint and FERC's Notice of Proposed Rulemaking***

On February 2, 2018, FERC issued a Notice of Technical Conference, which scheduled a staff-led technical conference that was held at FERC headquarters on April 3-4, 2018.[24] The purpose of the conference was to explore issues raised in the EDF Renewable Energy, Inc.'s (EDF) Complaint[25]

[24] *Reform of Affected System Coordination in the Generator Interconnection Process,* Notice of Conference, Docket Nos. AD18-8-000 and ELI8-26-000 (Feb. 2, 2018).

[25] *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, Docket No. EL18-26 (Oct. 30, 2016) (the "EDF Complaint").

related to affected systems[26] coordination procedures contained in the SPP, MISO, and PJM Interconnection, LLC (PJM) open access tariffs, the SPP-MISO JOA, and the MISO-PJM JOA, as well as the affected systems coordination issues raised in the Commission's Notice of Proposed Rulemaking issued in Docket No. RM17-8-000. The Commission found that "holding a joint technical conference on Affected Systems issues identified both in [the EDF Complaint] and in the Generator Interconnection NOPR will offer the Commission and interested parties the opportunity to consider specific reforms in MISO, SPP, and PJM at the same time as more generic reforms."

In the EDF Complaint, EDF alleged that there is no clear process by which MISO, SPP, and PJM determine cost responsibility for network upgrades on an affected system stemming from an interconnection request made in a host RTO, particularly for generation projects located near RTO seams. In addition, EDF alleges in the Complaint that the RTOs informally apply a “higher-queued” principle for affected system analyses, whereby network upgrade costs are assigned to higher-queued projects (earlier in time) rather than to lower-queued projects (later in time). EDF contends that the RTOs have not demonstrated that the use of such a standard is just and reasonable.

Both SPP and MISO attended and presented at the technical conference on April 3-4, 2018. On April 19, 2018, FERC issued a Notice Inviting Post-Technical Conference Comments inviting all interested persons to file comments in response to questions identified by the Commission.[27] On May 21, 2018, SPP filed its Post-Technical Conference Comments.[28] On May 22, 2018, MISO filed its Post-Technical Conference Comments.[29] On June 18, 2018, both SPP and MISO filed Post-Technical Conference Reply Comments.[30] This docket is still pending before FERC, and all parties in this docket are awaiting a final order from FERC.

## SPP-MISO GENERATOR INTERCONNECTION COORDINATION IMPROVEMENT EFFORTS

In 2015, SPP and MISO developed an SPP-MISO Generator Interconnection Coordination Document.[31] The document was created to address some of the vague language in the JOA. The coordination document provided more clarity and specificity to the high-level JOA requirements.

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[26] An affected system is an electric system other than the transmission provider’s transmission system that may be affected by the proposed interconnection. *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 29 n.32 (2003), *order on reh’g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh’g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh’g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff’d sub nom. Nat’l Ass’n of Regulatory Util. Comm’rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[27] *Reform of Affected System Coordination in the Generator Interconnection Process,* Notice Inviting Post-Technical Conference Comments, Docket Nos. AD18-8-000 and ELI8-26-000 (Apr. 19, 2018) ("April 19 Notice").

[28] *Id.*, Comments of the Southwest Power Pool, Inc., (May 21, 2018).

[29] *Id.*, Comments of Midcontinent Independent System Operator, Inc., (May 22, 2018).

[30] *Id.*, Reply Comments of Southwest Power Pool, Inc. and Midcontinent Independent System Operator, Inc. (June 18, 2018).

[31] https://www.spp.org/engineering/interregional-relations/

Specific dates throughout each year were agreed upon by the RTOs as to when each party would provide study results. Additionally, MISO included language from the coordination document in its Generator Interconnection Business Practices Manual.

The coordination document outlines the treatment of the following GI related topics:

- Study of SPP Interconnection Request impacts on MISO transmission;
- Study of MISO Interconnection Request impact on SPP Transmission; and
- Coordination of Projects with Provisional/Conditional GIAs

Many of the improvements accomplished by the coordination document are now being developed by SPP and MISO as amendments to the JOA. Both RTOs agree the JOA needs to be restructured in an effort to reflect what is captured in the coordination document and updated to reflect the recent changes in SPP and MISO's regional GI study processes. SPP and MISO have begun negotiations related to significant revisions of section 9.4 of the JOA. The revisions will more clearly outline the requirements of the coordination and include specific timelines for which affected system studies must be completed.

In addition to working on JOA changes, the GI departments from each entity have been holding bi-annual face-to-face meetings and monthly teleconferences for over two years now. SPP and MISO have been educating each other on their specific GI processes. This education has improved coordination and provided a better understanding of the milestones and timelines that each entity must meet to facilitate efficient and effective conveyance of interconnection service.

## SUMMARY

As outlined in this paper there are a number of seams enhancements that MISO and SPP have identified. MISO and SPP look forward to the input of the OMS and RSC on how to enhance seams coordination between the two RTOs.