CURRENT ISSUES
AGENDA

• Interregional Planning Update

• HITT

• Review of the regional transfer and impacts of January 17, 2018
OVERVIEW

- SPP-AECI Joint and Coordinated System Planning
  - 2018 SPP-AECI JCSP
  - SPP-AECI Joint Projects Update

- SPP-MISO Joint Planning
  - SPP-MISO Coordinated System Plan (CSP) Process Improvements
NORTH AMERICAN INDEPENDENT SYSTEM OPERATORS (ISO) AND REGIONAL TRANSMISSION ORGANIZATIONS (RTO)

AECI
SPP-AECI JOINT & COORDINATED SYSTEM PLAN (JCSP)

• SPP and AECI initiated a new joint study in 2018

• 2018 SPP-AECI JCSP Scope was endorsed by the SPP-AECI IPSAC on April 4th
  • Study was to use the SPP 2018 ITPNT models and needs assessment
    • Scenario 0 – 2019 Summer/Winter & 2022 Summer/Winter/Light Load
    • Scenario 5 – 2022 Light Load
  • SPP and AECI needs along the seam were to be evaluated for beneficial joint solutions
2018 SPP-AECI JCSP CONT.

- Due to various reasons no joint needs were identified in the study
  - Model Corrections
  - Operational Guides
  - Invalid Contingencies

- SPP and AECI held an IPSAC Meeting in June to discuss the study results with stakeholders

- A final report will be circulated with stakeholders once completed

- SPP will now focus on improvements to the process before the next SPP-AECI study which is scheduled for 2020
SPP-AECI JOINT PROJECTS UPDATE

• Joint projects approved out of the 2016 SPP-AECI JCSP
  • Morgan Transformer Project
    • SPP Staff is working with FERC staff and targeting a new filing in July 2018
    • Filing will pursue regional funding
  • Brookline Reactor Project
    • Currently being studied in the SPP 2018 ITPNT
    • Potential approval of the project out of the ITPNT in July 2018
MORGAN TRANSFORMER PROJECT

- Addition of a new 400 MVA 345/161 kV Transformer at AECI’s Morgan substation and an uprate of the 161 kV line between Morgan and Brookline
  - Located in southwest Missouri
  - Wholly on AECI’s transmission system
  - $13.75M Cost Estimate
    - SPP Responsible for $12.25M (89%)
SPP-MISO JOINT PLANNING
SPP-MISO CSP IMPROVEMENTS – FEEDBACK REQUEST

- SPP and MISO held an Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting on Feb. 27th

- Based on feedback from the IPSAC, SPP and MISO staff have opted not to perform a Coordinated System Plan (CSP) in 2018

- Staff will focus on developing a new CSP process to implement process improvements identified through the lessons learned of the previous joint studies
SPP-MISO STAKEHOLDER FEEDBACK REQUEST

• SPP and MISO requested feedback from stakeholders on CSP enhancements on March 5, 2018
  • Requested by March 30, 2018

• SPP-MISO Coordinated System Plan Process Improvements
  • Which of the process improvements do you support?
  • Are there additional process improvements you would like to see that weren’t discussed?
  • Ideas on a study structure that will support all of the enhancements?
  • Other thoughts or questions?
RESULTING CSP CHANGES

• Removal of Joint Model Requirement
  • Utilize SPP and MISO Regional Planning Processes

• Expand Interregional Benefit Metrics
  • Include APC and Avoided Cost for all project drivers
  • Explore Potential Market to Market Metric

• Amend JOA stated Interregional Project Criteria
  • Remove $5M Cost Threshold

• Other items being considered
  • Review of Approval Process and Flexibility
  • Increase coordination between Operations and Joint Studies
  • MISO Voltage Threshold for Interregional Projects with SPP (MISO Regional Issue)
  • Reducing the length of the study
  • Market-to-Market Impacts
HOLISTIC INTEGRATED TARIFF TEAM (HITT)
In January 2009, the SPP Board of Directors established the Synergistic Planning Project Team (SPPT) to recommend improvements to SPP’s regional transmission planning process and cost allocation methodology.

Based on its findings, the SPPT issued a report in April 2009 and recommendations for reforming SPP’s transmission planning and cost allocation processes.

- The SPPT Report was endorsed by the RSC in April 2009.
- The SPPT Report was adopted by the Board of Directors in April 2009.
SPPT SCOPE

Planning Processes

Cost Allocation Principles
OVERVIEW – SPPT HISTORY

The SPPT produced a report that recommended among other things:

• Adoption and implementation of five new transmission planning principles;

• Adoption and implementation of a new planning process to create a robust, flexible, and cost-effective transmission network for the SPP region and;

• SPP RSC development and approval of a simplified “Highway/Byway” cost allocation methodology for new transmission upgrades in the SPP region.
HITT MEMBERSHIP

• SPP Board - 2 Representatives
  Jim Eckelberger (Director)
  Graham Edwards (Director)

• RSC - 2 Representatives/ 1 Liaison
  Shari Feist Albrecht (Commissioner Kansas Corporation Commission and RSC)
  Dennis Grennan (Commissioner Nebraska Power Review Board and RSC)
  Cindy Ireland (CAWG Liaison to the HITT, Arkansas Public Service Commission)

• Investor Owned Utilities – 4 Representatives
  Richard Ross (AEP)
  Denise Buffington (KCPL)
  Greg McCauley (OG&E)
  Bill Grant (SPS)

• Cooperatives - 3 Representatives
  Mike Wise (Golden Spread)
  Mike Risan (Basin)
  Al Tamimi (Sunflower)

• Independent Power Producers - 2 Representatives
  Rob Janssen (Dogwood Energy) – Vice-Chair
  Holly Carias (NexEra)

• Municipals - 1 Representative
  Dennis Florom (LES)

• State Agencies - 1 Representative
  Tom Kent (Nebraska Public Power District) - Chair

• Independent Transmission Companies - 1 Representative
  Brett Leopold (ITC Great Plains)

• Senior SPP Staff (to Serve as Staff Secretary) - 1 Representative
  Paul Suskie (SPP Staff)
HITT SCOPE

- Cost Allocation Principles
- Market Services
- Planning Processes
OVERVIEW OF HITT TASKS (5 AREAS)

- SPP’s transmission planning and study processes;

- Transmission cost allocation issues;

- Integrated Marketplace impacts related to, among others, a changing resource mix, potential changes in production tax credits, approach of using market-based compensation for varying attributes of different types of generators, etc.;

- Disconnects or potential synergies between transmission planning and real-time reliability and economic operations; and

- The Team is to issue a report to the SPP Board of Directors and Members Committee containing a set of high-level recommendations that address these areas for the region by April 2019.
## DATES FOR FACE TO FACE MEETINGS

<table>
<thead>
<tr>
<th>Dates</th>
<th>Times</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tues/Wed, 24-25 April</td>
<td>Following BOD/MC-3pm</td>
<td>Kansas City</td>
</tr>
<tr>
<td>Wednesday, 16 May</td>
<td>9am-3pm</td>
<td>Dallas</td>
</tr>
<tr>
<td>Friday, 8 June</td>
<td>9am-3pm</td>
<td>Dallas</td>
</tr>
<tr>
<td>Monday, 9 July</td>
<td>9am-3pm</td>
<td>Dallas</td>
</tr>
<tr>
<td>Tues/Wed, 31 July – 1 Aug</td>
<td>Following BOD/MC-3pm</td>
<td>Omaha</td>
</tr>
<tr>
<td>Tues/Wed, 21-22 Aug</td>
<td>9am-3pm (Both Days)</td>
<td>Dallas</td>
</tr>
<tr>
<td>Wednesday, 22 August</td>
<td>9am-3pm</td>
<td>Dallas</td>
</tr>
<tr>
<td>Wednesday, 5 September</td>
<td>9am-3pm</td>
<td>Dallas</td>
</tr>
<tr>
<td>Tuesday, 6 November</td>
<td>9am-3pm</td>
<td>Dallas</td>
</tr>
<tr>
<td>Wednesday, 5 December</td>
<td>9am-3pm</td>
<td>Little Rock or Dallas</td>
</tr>
</tbody>
</table>
SPP AND JOINT PARTY REVIEW OF THE REGIONAL TRANSFER AND IMPACTS OF JANUARY 17, 2018
The Joint Parties (AECI, LGE/KU, PowerSouth, Southern, TVA), SPP and MISO were able to manage operations in the mid and south central U.S. during the very challenging week of January 15.

High loads caused by extreme cold temperatures, coupled with heavy flows from MISO Midwest to MISO South, created significant challenges throughout the event.

The Joint Parties, SPP and MISO have been reviewing the event and associated operational impacts.

The Joint Parties, SPP and MISO are striving to reach a common expectation of reliable operations on the SPP and Joint Parties’ systems, consistent with the Regional Directional Transfer Limits established in their 2015 Settlement Agreement and accepted system operating practices.
BACKGROUND
In December 2013, Entergy and other companies in the Southern US joined MISO.

Reliability concerns raised by SPP and the Joint Parties related to the integration of these companies into the MISO BA resulted in a Settlement Agreement approved by FERC in Docket Nos. EL14-21-000 et. al., effective February 2016.
<table>
<thead>
<tr>
<th>April 2012</th>
<th>December 2013</th>
<th>January 2014</th>
<th>October 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>MISO filed Petition for Declaratory Order seeking to use JOA to integrate Entergy using SPP’s transmission system</td>
<td>SPP presented MISO with proposals in an unsuccessful attempt to resolve the dispute</td>
<td>SPP unsuccessfully sought assurance from MISO that it would not exceed its firm transmission rights</td>
<td>SPP, Joint Parties and MISO filed Settlement Agreement addressing reliability limits and compensation</td>
</tr>
<tr>
<td>SPP presented MISO with proposals in an unsuccessful attempt to resolve the dispute</td>
<td>D.C. Circuit Court of Appeals Vacated FERC’s Declaratory Order and Remanded</td>
<td>SPP began invoicing MISO for unreserved transmission service under the SPP Tariff</td>
<td>SPP, Joint Parties and MISO filed Settlement Agreement addressing reliability limits and compensation</td>
</tr>
<tr>
<td>SPP unsuccessfully sought assurance from MISO that it would not exceed its firm transmission rights</td>
<td>SPP filed unexecuted Non-Firm Point-to-Point Transmission Service Agreement and also a Complaint against MISO</td>
<td>Joint Parties intervened in both proceedings</td>
<td></td>
</tr>
</tbody>
</table>

**HISTORICAL TIMELINE**
Allows MISO some use of the SPP and Joint Parties’ systems (above MISO’s firm capability) on a non-firm, as-available basis

- MISO currently has 1,000 MW of firm transmission transfer capability between its Midwest and South regions
- MISO, SPP and the Joint Parties agreed to the following total Regional Directional Transfer Limits:
  - Midwest to South Limit: 3,000 MW (2,000 MW being non-firm, as available)
  - South to Midwest Limit: 2,500 MW (1,500 MW being non-firm, as available)

Definitions in NERC glossary of terms

- Non-firm transmission service is defined as transmission service that is reserved on an as-available basis and is subject to curtailment or interruption
- Firm transmission service is defined as the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption
TEMPERATURE DEVIATION FROM NORMAL
MINIMUM SURFACE TEMPERATURE

![Temperature Deviation Map]
The Real Time data values Midwest-South on January 17 and 18 were in excess of 3,000 MW for many hours of both days with a maximum value of 4,331 MW on the morning of January 17.

The Midwest-South Regional Directional Transfer Limit (RDTL), as defined in the Settlement Agreement, was exceeded on January 17 from 0635-0745 EST, with a maximum exceedance during this timeframe of 936 MW (as measured by the Settlement Transfer Flow, which uses UDS as a proxy for real time flows).
REGIONAL OPERATIONS ON 1/17

3,000 MW Transfer Limit, per the Settlement Agreement

1,000 MW Firm Limit

Real Time Transfer Flow (Midwest-South)
Settlement Transfer Flow (UDS proxy for real time flows)
SPP AND JOINT PARTIES FLOWGATE LOADING ISSUES ON 1/17

3,000 MW Transfer Limit, per the Settlement Agreement

1,000 MW Firm Limit

Real Time Transfer Flow (Midwest-South)

01:00 6 FGs > 100%

03:30 19 FGs > 100%

05:50 26 FGs > 100%

06:30 28 FGs > 100%

11:00 8 FGs > 100%
SPP and JPs together had 28 flowgates > 100% post-contingent during peak regional transfer
- Post-contingent load shed plans were the only remaining mitigation measures for several of these flowgates
- Some elements were approaching overload conditions with no contingency

Non-firm transactions in the TVA BA, sourced from PJM, were cut due to a MISO TLR, causing TVA to call EEA 1
- This TLR lasted many hours without any reductions, and was held active to allow for more flow from MISO Midwest to MISO South

SPP experienced voltage decay in the Southwest Missouri and Northeast Oklahoma region, with voltage as low as 0.89 per unit in real-time

SPP committed 45 resources from intra-day/short term reliability unit commitment (RUC), or manually committed per RC request, due to transmission congestion

PowerSouth declared EEA1 due to all resources being deployed

SPP and the JPs communicated their system reliability issues to MISO several times during this event

Cold weather ratings were employed during this event. If this event occurred in the summer, loading conditions would be much more severe

The JPs provided 1,150 MW of Emergency Energy to MISO South, without which the RDTL exceedances may have persisted or worsened
Due to large correlation of the RDTL on particular flowgates, both AECI and LGE/KU internally re-dispatched firm generation to maintain real-time and N-1 System Operating Limits.

*Absolute value of MISO transfers shown in this graph.*
SPP REAL TIME VOLTAGE ISSUES ON 1/17
LESSONS LEARNED FROM 1/17

- More clarity and mutual understanding of the non-firm, as-available nature of MISO’s Regional Transfer flows and of the expectations for congestion management processes, use of TLR, redispatch, reconfiguration, or manual load shed (if necessary)

- 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 Regional Transfer flows

- Operational control of Regional Transfers using real-time data rather than controlling to UDS flows
On January 17, 2018, MISO exceeded the “non-firm, as-available” transfer limits established under the Settlement Agreement.

This failure to comply with the agreed transfer limits put firm load at risk in adjacent Reliability Coordination Areas.

SPP and the Joint Parties have raised their concerns with MISO and the parties are discussing meaningful improvements to ensure reliable operations and protect firm load.
QUESTIONS