Monday, October 26, 2015
1:00 - 5:00 p.m.
SPP Corporate Offices
Little Rock, AR

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of Minutes from July 27, 2015 and September 21, 2015
   c. Resolution Honoring Olan Reeves

3. UPDATES
   a. RSC Third Quarter Financial Report
   b. SPP
   c. FERC

4. BUSINESS MEETING
   a. RSC Budget for 2016 [Voting Item]
   b. Election of RSC Officers [Voting Item]

5. CAWG REPORT AND VOTING ITEMS
   a. CAWG Report………………………………………………………………………………………..Jason Chaplin
      This report provides an update on CAWG activity.
   b. Aggregate Study Waiver Criteria Evaluation Scope [Voting Item]..............................Adam McKinnie
      Consider the proposed scope for the evaluation of the Aggregate Study Waiver Criteria approved by CAWG.
   c. Incremental Long Term Congestion Rights Compliance Update [Voting Item]..............John Krajewski
      Update on and consideration of the Incremental Long Term Congestion Rights process and compliance with FERC Order in Docket No. ER14-2553-001.

6. REPORTS/PRESENTATIONS
   a. RARTF Update......................................................................................................................Steve Stoll
      Update on the activities of the Regional Allocation Review Task Force.
   b. EPA Rule 111(d) Update.......................................................................................................Lanny Nickell
      This report will update and provide for discussion from the RSC on Rule 111(d).
   c. NTC Reevaluations..............................................................................................................Antoine Lucas
      This item will provide a report on the results of NTC reevaluations to either retain, withdraw, or further study existing such NTCs.
   d. Capacity Margin Task Force...............................................................................................Tom Hestermann
      This item will provide an update on the activities of the CMTF.
   e. Seams Update.........................................................................................................................Carl Monroe
      This report will provide an update on the pending matters at FERC related to SPP’s seams.
f. Integrated Marketplace Update..............................................................................................Bruce Rew
   This report will update the RSC on the Integrated Marketplace.

g. 2017 ITP10 Scope..............................................................................................................Alan Myers
   This report will review the proposed scope for the 2017 Integrated Transmission Plan 10-Year assessment.

h. Transmission Planning Improvement Task Force Update..............................................Brian Gedrich
   This report will provide an update on the activities of the Transmission Planning Improvement Task Force

7. OTHER RSC MATTERS

8. ACTION ITEMS

9. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS
   RSC Meetings:
   January 25, 2016 – Oklahoma City, OK
   April 25, 2016 – Santa Fe, NM
   July 2016 – Date and Location TBD
   October 24, 2016 – Little Rock, AR

10. ADJOURN

* NOTE: ADDITIONAL INFORMATIONAL MATERIAL ATTACHED

Attached to the RSC’s meeting agenda and background material is additional material that is either for informational or reporting purposes.
ADMINISTRATIVE ITEMS:
The following members were in attendance:
Dana Murphy, Oklahoma Corporation Commission (OCC)
Donna Nelson, Public Utility Commission of Texas (PUCT)
Lamar Davis, Arkansas Public Service Commission (APSC)
Stephen Lichter, Nebraska Power Review Board (NPRB)
Shari Feist Albrecht, Kansas Corporation Commission (KCC)
Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)
Steve Stoll, Missouri Public Service Commission (MoPSC)

President Dana Murphy called the Regional State Committee (RSC) meeting to order at 1:06 p.m. with roll call and a quorum was declared. She then requested introductions of those in attendance. There were 132 in attendance either in person or via the phone (Attendance & Proxies – Attachment 1).

President Murphy asked for a moment of silence on behalf of Megan Nickell.

The first item of business was the approval of the April 27, 2015 and June 15, 2015 meeting minutes (RSC Minutes 14/27/15 and 6/15/15 – Attachment 2).

Commissioner Patrick Lyons moved to approve the two sets of minutes; Chairman Donna Nelson seconded. The motion passed unanimously.

UPDATES:
RSC Second Quarter Financial Report
Mr. Paul Suskie, Southwest Power Pool, Inc. (SPP) Staff provided the RSC financial report (RSC 2015 Q2 Financials – Attachment 3).

SPP Report
Mr. Nick Brown (SPP) began by discussing the redesigned SPP website which will go live on September 15, 2015. The redesigned website will feature regularly updated content, a dashboard of real-time operational data with enhanced search functionality. There will also be a new calendar and document tools, as well as an easier-to-navigate site design.

Mr. Brown reported that the Strategic Planning Committee (SPC) requested a value of transmission study. The SPP Communications Department is responsible for developing the marketing of the value of transmission study. The SPP Government Affairs and Public Relations department will provide the results of the value of transmission study with elected officials, policy makers and the general public once it is approved by the SPC.

FERC
Mr. Patrick Clarey provided the Federal Energy Regulatory Commission (FERC) report. He
began by announcing that Commissioner Cheryl LaFleur, her assistant Andrew Weinstein and Robert Ivanauskas from Commissioner Moeller’s office will be attending the Board meeting on Tuesday.

In May, FERC issued a proposed rule to approve a new reliability standard addressing the vulnerability of electric transmission systems to geomagnetic disturbances. This continues the process which began in 2013 when FERC directed NERC to develop and submit new GMD standards through a two-stage process. FERC addressed the first stage in June 2014 by approving a standard on implementation of operating plans, procedures and processes to mitigate effects of GMD. Also in May, FERC approved the sixth and final settlement related to the September 2011 outage in southern California, Arizona, and Baja California, Mexico.

In June, FERC proposed revisions to critical infrastructure protection (CIP) Reliability Standards to address risks to communication networks and related bulk electric system assets and the development of standards for supply chain management security controls to protect the bulk electric system from security vulnerabilities and malware threats.

BUSINESS MEETING:

RSC Audit Report, Related Letters and Form 990
Mr. Paul Suskie, SPP Staff provided the audit report (SPP Regional State Committee Draft – Attachment 4, SPP Regional AU-C 260 Letter Draft – Attachment 5, RSC Regional Rep Letter 2014 – Attachment 6, and SPP RSC 2014 Form 990 – Attachment 7). Commissioner Steve Stoll moved to accept the audit report and authorize the RSC President to execute the documents; Commissioner Steve Lichter seconded. The motion passed unanimously.

COST ALLOCATION WORKING GROUP (CAWG) REPORT AND VOTING ITEMS:

A. CAWG Report
President Murphy thanked the CAWG Chairman, Jason Chaplin and the CAWG for their work and ability to work well together.

Mr. Jason Chaplin provided the CAWG report (CAWG Report – Attachment 8). He began by reviewing the items the CAWG has been tasked with by the RSC:

- Develop a scoping document on how to apply cost allocation for new member integration;
- Evaluate the eligibility requirements for an aggregate study waiver request to see if the criteria is still applicable to the transmission system as it operates today; and
- Evaluate how load is forecasted for the purpose of determining the reserve margin.

The Topics covered in the CAWG Report include:

- Scoping document for Cost Allocation related to New Member Integrations
- Aggregate Study Waiver Criteria
- SPP Load Forecasting
- Revision Request RR91
- Kansas City Power & Light Company (KCPL) South Waverly Transformer Waiver Request

1. Scoping Document for Cost Allocation related to New Member Integrations
Mr. Chaplin reported that at the July CAWG meeting, the CAWG members incorporated feedback received from the RSC and unanimously adopted the New Member Cost Allocation
Review Process document with a recommendation that the RSC approve the document at the July RSC meeting. Mr. John Krajewski will present the New Member Cost Allocation Review Process Scope Document later in the meeting for consideration by the RSC.

2. **Aggregate Study Waiver Criteria**
Mr. Chaplin gave a summary of CAWG's evaluation of this issue. Mr. Adam McKinnie reviewed the Draft Proposed Scope Aggregate Study Waiver – 20% Wind Review Process (Aggregate Study Waiver – 20% Wind Review Process - Attachment 10). This Draft Process will be further developed by the CAWG and brought back to the RSC for its consideration. With respect to Item 2(c) in the Draft Process, the RSC tasked the CAWG with determining whether a consultant is needed or whether SPP Staff can provide the necessary assistance. In the event an outside consultant is needed, CAWG should prepare a scope of work for consideration by the RSC.

3. **Load Forecasting**
At the RSC’s April 27, 2015 meeting, CAWG was directed to evaluate the topic of load forecasting. Mr. Chaplin reported to the RSC that the CAWG has reviewed the load forecasting process for the SPP region including how forecasts are submitted by load serving entities to SPP and how those forecasts are used in SPP models. Mr. Chaplin reported that CAWG was presented with a member forum to discuss load forecasting. In addition, CAWG heard reports from a representative from ERCOT on ERCOT’s load forecasting methodology and SPP Staff on the processes used in other RTOs/ISOs.

4. **Revision Request 91**
Mr. John Krajewski reported on Revision Request (RR) 91 (Revision Request 91 ARR Allocation Changes – Attachment 9). The SPP Staff prepared RR91 to address TCR underfunding. The SPP Bylaws indicate that the RSC has primary responsibility for determining regional proposals in two areas that affect ARR and TCR Markets. The changes being proposed do not affect major policy issues, such as customer eligibility or broad market structure. The CAWG recommended that the RSC take no action but continue to be kept informed of Revision Requests that may affect TCR underfunding and reserve the right to take a position on future Revision Requests related to ARR and TCR allocation. The CAWG also recommended that the RSC request that the SPP staff provide to the RSC and CAWG any information related to TCR underfunding as provided to the Market Working Group (MWG) and any analyses prepared for the MWG that assesses the impact of the changes made in RR91.

5. **KCPL South Waverly Transformer Waiver Request**
Mr. Chaplin reported that SPP Staff presented this waiver request from KCPL to CAWG and that this waiver request will be presented to the RSC for a vote as Agenda Item 5(c). The CAWG voted in favor of accepting SPP Staff’s recommendation to not approve KCPL’s waiver request, with the MoPSC CAWG representative abstaining.

B. **Scoping Document for Cost Allocation Related to New Member Integration**
Mr. John Krajewski reported on the Scoping Document for Cost Allocation (Scoping Document for Cost Allocation Related to New Member Integration – Attachment 11). Item 6(f) of the draft scope was clarified to reflect that the analysis discussed in the document is technical and economic analysis and was revised to state “use of third-party technical and/or economic analysis versus in addition to SPP internal technical and/or economic analysis.”

Chairman
Donna Nelson moved to approve the scope as presented; Commissioner Patrick Lyons seconded. The motion passed unanimously.

C. KCPL South Waverly Transformer Waiver Request Assessment
Mr. Lanny Nickell reported on the KCPL South Waverly Transformer Waiver Request Assessment (KCPL South Waverly 161/69 kV Transformer Waiver Request Assessment – Attachment 12). In the Integrated Transmission Plan Near Term Assessment (ITPNT), SPP identified six unique reliability overload needs for the South Waverly transformer upgrade for two monitored elements. Of the six unique needs identified, two are located wholly within the Kansas City Power & Light – Greater Missouri Operations (GMO) zone. Because more than one zone benefits from the upgrade, KCPL is seeking waiver of the requirement for the host zone to bear the entire cost of the project. Attachment J, Section III of the Tariff states that: Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to:

(i) Whether the power flows through the transformer predominately are from the lower voltage to the higher voltage;
(ii) Whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected.

SPP studied the two factors listed in the Tariff and neither criteria requirement was met. SPP Staff’s recommendation is to not approve KCPL’s South Waverly Transformer waiver request. The CAWG adopted the SPP Staff recommendation at its July meeting with 6 votes in favor and one abstention (MoPSC). Commissioner Stoll stated that if the exact situation occurs in the future that he wants to see it treated the same way. Denise Buffington spoke on behalf of KCPL and stated that KCPL believed that the Tariff allowed an opportunity to request the waiver on the grounds other than the two that are articulated in the Tariff and that KCPL’s basis for requesting the waiver was because that more than one zone benefitted from the transformer upgrade. Chairman Donna Nelson moved to accept the SPP Staff’s recommendation to deny the waiver; President Dana Murphy seconded. A roll-call vote was taken with Commissioner Steve Stoll abstaining and all other RSC members voting in favor of accepting SPP Staff’s recommendation. The motion passed.

D. Revisions to RSC Bylaws
Chair Shari Albrecht reported on the progress of draft revisions to the RSC Bylaws. Chair Albrecht reviewed Section 7.2 of the SPP Bylaws with respect to the organization of the RSC. She also reviewed the draft amendment provisions of the current Bylaws which would require two-thirds of the majority vote of the RSC except for certain provisions requiring a unanimous vote. Chair Albrecht reviewed the amendments currently being discussed and stated that proposed amendments will be ready for consideration at the RSC’s next meeting in September.

E. SPC New Member Task Force
President Dana Murphy provided the update on the SPC New Member Task Force (New Member Task Force Report – Attachment 13). The RSC reviewed the New Member Task Force Report, which was approved by the SPC at its July meeting, along with a chart developed by SPP Staff, as directed by the SPC, to clarify when the process would apply. The RSC proposed an addition to the chart which would allow the RSC to invoke the New Member Process in any instance not otherwise identified in the chart for matters that are within the responsibilities of the RSC where the RSC finds the changes proposed by the prospective new
member are significant enough that the process should apply. Commissioner Steve Stoll
moved to support the New Member Task Force report as presented with the additional
information added; Commissioner Lamar Davis seconded. The motion passed
unanimously.

REPORTS/PRESENTATIONS:

A. RARTF Update
Commissioner Steve Stoll provided a Regional Allocation Review Task Force (RARTF) Update
(RARTF Update – Attachment 14). Commissioner Stoll reported that in response to the FERC
Order denying the SPP Remedies Filing that the RARTF recommends that SPP not re-file any
remedy tariff language at this time. Staff was directed to create a strawman Business Practice
that: lays the foundation for documenting the remedies; clarifies the process to implement a
remedy; initially focuses on remedies 1, 2, and 3; process requests for a remedy that come to
the RARTF; and any change to the remedy business practice would come to the RARTF.

To comply with the SPP Tariff the RCAR II analysis needs to be completed by October 2016,
and the RARTF recommends that: transmission topology updates to the RCAR models be
completed by October 1, 2015; ESWG and Staff have been directed to address load pocket
and trapped generation issues for the RCAR II analysis by November 18, 2015; and member
companies should commit the resources necessary to maintain this schedule.

B. EPA Rule 111(d) Update
Mr. Lanny Nickell (SPP) provided an update on the EPA Rule 111(d). SPP released a press
release today on the results of SPP’s state-by-state analysis. This is the third and final
installment of the analysis that SPP has done of the draft of the Clean Power Plan (CPP). The
objective of this analysis was to evaluate the impact of the CPP on existing resources and
resource expansion plans resulting from state-by-state compliance and provide a comparison
of the state-by-state compliance impacts with regional compliance impacts. Mr. Nickell
explained that SPP’s analysis determined that a state-by-state compliance approach potentially
would result in nearly 40 percent higher costs than a regional approach. It would also be more
disruptive than a regional approach to the significant reliability and economic value that SPP
provides to its members as a regional transmission organization. The study concluded that
coordinating individual state plans in a regional market where energy flows without respect to
state boundaries and benefits are shared regionally will be extremely challenging and risky for
states.

C. Capacity Margin Task Force
Mr. Tom Hestermann, Capacity Margin Task Force (CMTF) Chairman, provided an update on
the activities of the CMTF (CMTF Update – Attachment 15, CMTF Approved Enforcement
Policy Whitepaper – Attachment 16, and Load Responsible Entity for Reserve Margin
Obligation – Attachment 17). Mr. Hestermann reported that the CMTF approved the Load
Responsible Entity Whitepaper at the June 2 meeting, which was then approved by Markets
and Operations Policy Committee (MOPC) on July 15 and presented to the Regional Tariff
Working Group (RTWG) on July 23.

Mr. Hestermann reported that the CMTF Enforcement Policy Whitepaper was approved by the
CMTF on June 2. The SPC received an overview of the Enforcement Policy on July 16 and it
was included in the MOPC meeting materials for informational materials only. The CMTF will
discuss the feedback received from the MOPC and SPC at its July 29th meeting and will
continue to engage and solicit input from CAWG and other stakeholders.
D. Seams Update
Mr. Paul Suskie presented the Seams Update (Seams Update – Attachment 18). Mr. Suskie reported on the Interregional Planning Process required by FERC Order 1000 and reviewed the criteria for interregional projects, as approved by FERC. There are three recommended seams projects to come out of the SPP-MISO Joint Planning Committee, which must still be approved through both the SPP and MISO regional processes.

Mr. Suskie also reported that FERC has accepted the IS Integration into SPP. There are some items that are set for settlement negotiation. If these issues remain unresolved they could be sent to hearing.

SPP will soon be executing its first international joint operating agreement (JOA). There is a 230 kV line that goes into Canada and as a result SPP is working on having a JOA with SaskPower.

E. Integrated Marketplace Update
Mr. Bruce Rew (SPP) provided an update on the Integrated Marketplace (IM) (Integrated Marketplace Update – Attachment 19). There are 148 market participants, 98 of those are financial only and 50 are asset owning. The SPP Balancing Authority (BA) has successfully maintained NERC control performance standards. The system availability has exceeded expectations. Mr. Rew reviewed the Unit Commitment Improvement, Dispatch by Fuel Type, the differences in Real-Time and Day-Ahead Pricing and the Percentage Contribution of LMP Difference for Day-Ahead vs. Real-Time Pricing. Mr. Rew also informed the RSC of software upgrades and some performance improvements to the Day Ahead Market, as well as upcoming enhancements.

Other RSC Matters:
President Murphy thanked the individuals that assisted in making the meeting a success.

SCHEDULEING OF NEXT REGULAR MEETNGS, SPECIAL MEETINGS OR EVENTS:
President Murphy noted that the next meeting will be a conference call on September 21 and the meeting in Little Rock in October. She mentioned that the meeting in July 2016 will conflict with National Association of Regulatory Utility Commissioners. The RSC meeting will need to be moved to a different date. The remaining meetings for 2015 are as follows:

<table>
<thead>
<tr>
<th>Date</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>September 21, 2015</td>
<td>Conference Call</td>
</tr>
<tr>
<td>October 26, 2015</td>
<td>Little Rock, AR</td>
</tr>
</tbody>
</table>

With no further business, the meeting adjourned at 4:24 p.m.

Respectfully Submitted,

Paul Suskie
Southwest Power Pool
REGIONAL STATE COMMITTEE
Teleconference
September 21, 2015
• MINUTES •

ADMINISTRATIVE ITEMS:
The following members were in attendance:

Dana Murphy, Oklahoma Corporation Commission (OCC)
Donna Nelson, Public Utility Commission of Texas (PUCT)
Lamar Davis, Arkansas Public Service Commission (APSC)
Stephen Lichter, Nebraska Power Review Board (NPRB)
Shari Feist Albrecht, Kansas Corporation Commission (KCC)
Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)
Steve Stoll, Missouri Public Service Commission (MOPSC)

President Dana Murphy called the Regional State Committee (RSC) meeting to order at 1:03 p.m. with roll call and a quorum was declared. She then requested introductions of those in attendance. There were 132 in attendance on the conference call (Attendance & Proxies – Attachment 1).

The agenda items were taken out of order to establish a quorum.

UPDATES:

2015 RSC Goals
Mr. Jason Chaplin reported on the 2015 RSC Goals (2015 RSC Goals – Attachment 2) and the status of each:

1. Long-term Congestion Rights
2. Provide RSC Input to the SPCTF on New Members
3. Add new members to the Regional State Committee
   a. RSC Bylaws
   b. Outreach and Education for New RSC members
   c. Add New RSC Members
4. EPA Clean Power Plan
5. RSC Retreat
6. Communications

Action Items
Mr. Jason Chaplin reported on the Action Items (Action Items – Attachment 3). Item number five on the Bylaws changes is still an on-going item and will be taken up later in the meeting. The items in process at this time are the RSC’s role in cost allocation for new member Integrations, the aggregate study waiver criteria, and the Capacity Margin Task Force update.

REPORTS/PRESENTATIONS:

Incremental Long Term Congestion Rights Compliance Update
Mr. John Krajewski provided the Incremental Long Term Congestion Rights Compliance (ILTCR) presentation (ILTCR Compliance Report – Attachment 4). He began by reviewing the history and provided the overview of the order of what will need to take place. There are non-prescriptive and
Regional State Committee  
September 21, 2015

prescriptive changes that Mr. Krajewski discussed. This issue was initially presented to the Cost Allocation Working Group (CAWG) at its September 1, 2015 meeting, and was passed by the Markets Working Group at its September 15, 2015 meeting. The tariff revisions will go before the Regional Tariff Working Group at its September 24 meeting and will be presented again in October to the CAWG, as well as the Markets and Operations Policy Committee, the RSC, and the Board of Directors (BOD) for a vote in October with the compliance filing made in late October.

**OTHER RSC MATTERS:**

**Rescheduling of July 25, 2016 Meeting**

President Murphy discussed the conflict of the July 2016 RSC and the 2016 Summer NARUC meetings and possible options for rescheduling. SPP staff will look at options for having a one-day meeting on July 18, 2015 in Dallas, with no educational session, which would allow most participants to fly in and out the same day.

**Draft Topics for October 2015 Education Session and the RSC Meeting Agenda**

President Murphy reviewed the topics and meeting agenda for the October meetings (Draft Topics for October 2015 Education Session – Attachment 5). One of the topics suggested for the educational session is to review the regulatory structure and jurisdictional authorities of each commission represented on the RSC. Ms. Erin Cullum (SPP Staff) suggested this be a round-table discussion. SPP Staff will work with CAWG to develop a scope for the discussion. Other topics suggested were the 2017ITP10 draft scope and plan, the Ag Study Webinar, and an SPP 101 presentation that would include cost allocation and transmission planning.

Ms. Cullum reviewed the RSC October meeting agenda (October 2015 RSC Agenda – Attachment 6). The voting items on the agenda will be the RSC 2016 Budget, election of RSC Officers for 2016, and the modifications to incremental long-term congestion rights for a FERC compliance filing. Ms. Cullum provided the names of the new RSC and CAWG members joining in October with the integration of the Integrated System into the SPP footprint. Mr. Brian Kalk (RSC) and Mr. Victor Schock (CAWG) from the North Dakota Public Service Commission, Ms. Kristie Fiegen (RSC) and Mr. Greg Rislov (CAWG) from the South Dakota Public Utilities Commission, and Ms. Elizabeth Jacobs (RSC) and Mr. Scott Bents (CAWG) from the Iowa Utilities Board.

**REPORTS/PRESENTATIONS:**

**Revisions to the RSC Bylaws [Voting Item]**

After a quorum was confirmed, Commissioner Shari Albrecht reviewed the three Bylaws drafts (RSC Bylaws draft Majority – Attachment 7, RSC Bylaws draft Majority Plus One – Attachment 8, and RSC Bylaws draft Two-Thirds – Attachment 9).

After discussion, Commissioner Lyons moved to approve the proposed Bylaws with the Majority Plus One voting option; Commissioner Albrecht seconded. A roll-call vote was taken: Commissioners Murphy, Albrecht, Nelson, and Lyons voted yes, Commissioners Stoll, Davis, and Lichter voted no. The motion failed.

After further discussion Commissioner Stoll moved to approve the proposed Bylaws with the Majority voting option; Commissioner Lichter seconded. A roll-call vote was taken: Commissioners Murphy and Nelson voted no and Commissioners Lichter, Stoll, Davis, Albrecht, and Lyons voted yes. The motion failed.

The meeting was recessed at 3:05 p.m. to be reconvened on Tuesday, September 22, 2015 at 3:00 p.m.

The RSC reconvened at 3:03 on Tuesday, September 22, 2015. Attendance was taken and a quorum was confirmed with all RSC Members in attendance (Attendance – Attachment 10).

President Murphy thanked Commissioner Lichter for his efforts while in recess in working toward a
compromise with the Bylaws. After some discussion and clarifications, President Murphy reminded the members that a two-thirds vote is required for Bylaws changes. It would take a unanimous vote to change anything in Section 10 of the Bylaws. Commissioner Lichter suggested consideration of a two-thirds majority or a majority plus one threshold for intervention as described in Section 10.

Commissioner Lichter moved to approve the proposed Bylaw changes as circulated on September 22, 2015 (RSC Bylaws draft Majority – Attachment 11) with majority voting except for the items under paragraph 10 which would require a vote of a majority plus one. Commissioner Stoll seconded the motion. A roll-call vote was taken: Commissioners Murphy, Nelson, and Albrecht voted no and Commissioners Lyons, Stoll, Davis, and Lichter voted yes. The motion failed.

The RSC recognized that the existing Bylaws will stay in effect and nothing is required for new RSC members to join. President Murphy suggested that the Bylaws could be addressed after the new RSC members have joined. President Murphy expressed appreciation to Commissioner Albrecht and Ms. Cullum for all of their hard work with this effort.

SCHEDULEING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:

- September 22, 2015 – SPP Webinar on EPA’s Clean Power Plan
- October 26, 2015 – Little Rock, AR
- January 25, 2016 – Oklahoma City, OK
- April 25, 2016 – Santa Fe, NM
- July 25, 2016 – Rapid City, SD (to be rescheduled)
- October 24, 2016 – Little Rock, AR

The meeting was adjourned at 3:23 p.m.

Respectfully Submitted,

Paul Suskie
### Regional State Committee
For the Nine Months Ending September 30, 2015
Budget vs. Actual

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<tr>
<td>Other Income</td>
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<td>(26,067)</td>
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<tr>
<td><strong>Total Income</strong></td>
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<td>198,050</td>
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<td><strong>Net Income (Loss)</strong></td>
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### Southwest Power Pool, Inc.  
**REGIONAL STATE COMMITTEE 2015**  
**Budget and Proposed 2016 Budget**  
**October 27, 2015**

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Report to the Regional State Committee
October 26, 2015

Cost Allocation Working Group (CAWG)

Jason Chaplin
Oklahoma Corporation Commission
The Cost Allocation Working Group (CAWG) held two (2) face-to-face meetings and one (1) conference call over the past three (3) months.

New CAWG Members:

- IS Integration
  - Victor Schock, North Dakota PSC
  - Scott Bents, Iowa Utilities Board
  - Greg Rislov, South Dakota PUC

- KCC
  - Christine Aarnes, Kansas Corporation Commission
Topics:

- **New Member Cost Allocation Review Process Update**
- **Aggregate Study Waiver Criteria Evaluation Scope**
  - 5.b. – Adam McKinnie will present document developed by the CAWG as possible voting item
- **Incremental Long Term Congestion Rights**
  - 5.c. – John Krajewski to provide update and consideration of the Incremental Long Term Congestion Rights process and compliance with FERC Order in Docket No. ER14-2553-001.
At the July 2015 quarterly meeting the RSC approved the Scoping Document for Cost Allocation Related to New Member Integration.

Goal is to have complete document available for RSC review at January 2016 meeting.
Current draft of document in meeting materials with following sections drafted
  - Purpose / Goal Statement
  - Overview
  - New Member Characteristics

Additional outlining of other sections

Volunteers to provide initial draft of other sections
New Member Cost Allocation Review Process Update

- Next steps
- Feedback on already-drafted sections
- Update existing sections at November CAWG meeting
- Remaining section drafts due by November 20
- Further discussion in December
- Full document review draft to RSC for January meeting cycle
Evaluate the eligibility requirements for a waiver request to see if the criteria is still applicable to the transmission system as it operates today.

Adam McKinnie (Missouri CAWG member) presented the Draft Proposed Scope to the RSC at their July quarterly meeting. This Draft Scope was further developed by the CAWG and is being brought back to the RSC for its consideration.
The CAWG took the following action at their October 6, 2015 meeting:

- Motion: CAWG to approve the Aggregate Study Waiver Criteria Scope as amended at the October 6, 2015 CAWG meeting.

The motion was approved unanimously.

5.b. – Adam McKinnie will present document developed by the CAWG as a possible voting item.
Revision Request (RR) 119

- This revision request is in response to the FERC Order conditionally accepting the Long Term Congestion Rights (LTCR) Design, dated July 16, 2015.

John Krajewski (Nebraska CAWG member) presented this revision request to the RSC during their September 21st conference call for feedback and guidance.

- 5.c. – John Krajewski will provide the update, consideration and CAWG recommendation for RR 119
Next CAWG Meetings

- November 10, 2015: WebEx/Teleconference
- December 1, 2015: Dallas, TX (AEP Office)
Questions?

Submitted by:
Jason Chaplin
CAWG Chairman
October 26, 2015
New Member Cost Allocation Review Process

Prepared by:
COST ALLOCATION WORKING GROUP

WORKING DRAFT
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1. **HISTORY AND BACKGROUND**

2. **PURPOSE / GOAL STATEMENT**

   The purpose of this document is to provide the Regional State Committee and Cost Allocation Working Group a process to follow when considering cost allocation issues related to new transmission-owning member additions to the Southwest Power Pool. This review process is particularly important when the new member is requesting modifications to SPP’s governing documents (Open Access Transmission Tariff, Bylaws, Membership Agreement) that go beyond pro forma changes.

   ### 2.1 GOAL STATEMENT

   The goals of the New Member Cost Allocation Review Process (Review Process) are to:

   1. Ensure that the addition of new transmission-owning members does not adversely impact existing retail rate-payers in the SPP footprint
   2. Ensure that the cost allocation methodology for the new member results in transmission rates that are just and reasonable for existing members as well as the new transmission-owning member

3. **OVERVIEW OF PROCESS**

   The Review Process will consist of several steps, which will be completed over a prescribed time period as outlined in Section 8.1. The process generally includes the following steps:

   1. Collect information about proposed new member (Section 4)
   2. Review previous cost allocation and integration approaches, for purpose of determining reasonableness of proposed approach for the new member being considered (Section 5)
   3. Complete analyses (Section 6)
   4. Discuss other considerations (Section 7)
   5. Prepare recommendation for Regional State Committee action

4. **NEW MEMBER CHARACTERISTICS**

   SPP staff shall provide information to the RSC and CAWG about the new member, for purposes of completing the Review Process. The information to be collected by SPP and provided to the RSC/CAWG is as follows:

   4.1 **TRANSMISSION FACILITIES AND PLANNING INFORMATION**

   SPP staff shall provide the following information to the RSC and CAWG related to transmission facilities owned by the potential new member:
1. Line miles of transmission owned, separated by voltage class
2. List of existing interconnection points to SPP
3. List of interconnection points to neighboring RTO regions
4. List of utilities in non-RTO regions that new member is interconnected with, along with interconnection points
5. Transmission planning studies used to determine if existing facilities are adequate to meet SPP Planning Criteria
6. Current cost recovery mechanism for transmission service

4.2 GENERATION AND LOAD INFORMATION
SPP staff shall provide the following information to the RSC and CAWG related to load served by the new member, along with existing and planned resources owned by the potential new member:

1. Actual summer and winter peak demand (including capacity sales) for most recently completed calendar year (Note: Should we use ARR year or whatever period that CMTF is considering)
2. Comparison of peak demand to capacity resources by month for most recent year, including calculation of reserve margin
3. Projected peak demand for ten year period, beginning in current year.
4. Comparison of projected peak demand to resources for subsequent ten year period.
5. For planned resources, identify location and status of transmission planning to integrate resources into transmission system
6. Resource mix, including fuel type

4.3 MODIFICATIONS TO SPP GOVERNING DOCUMENTS
SPP staff shall provide, in clean and redline format, all proposed changes to the following documents related to the new member:

1. Open Access Transmission Tariff
2. Membership Agreement
3. SPP Bylaws
4. Regional State Committee Bylaws
5. SPP Criteria

Staff shall provide a summary of those changes that go beyond “pro forma” changes and provide information related to any changes that affect cost allocation. Staff shall provide the purpose for any changes beyond pro forma changes. Any changes that affect transmission cost allocation, financial transmission rights, or resource adequacy shall be identified as such so the RSC and CAWG can review and ensure that the proposed changes are consistent with the Goals listed in Section 2.1.
5. PREVIOUS COST ALLOCATION AND INTEGRATION APPROACHES

The purpose of collecting this information is to provide the RSC and CAWG examples of how new member integration has occurred in the past. These examples are intended to provide a “range” of reasonable cost allocation approaches so the RSC and CAWG can determine if the new member integration is being treated in a fashion similar to previous situations. If a new member is offered terms that differ substantially from those that have been offered in previous new member integration cases, then the RSC and CAWG may want to complete further investigation into the reasonableness of the proposed changes.

5.1 SPP INTEGRATION

- Nebraska SPP Integration
- Integrated System / SPP Integration
- Entergy / SPP Proposal

5.2 OTHER RTO REGIONS

- Entergy / MISO
- MISO Tariff
  Network Upgrades required by a generation interconnection agreement to be constructed by a Transmission Owner(s) other than the Transmission Owner that is a party to the generation interconnection agreement
- PJM Tariff

5.3 NON-RTO REGIONS

6. CRITERIA FOR COST ALLOCATION REVIEW

Introduction

6.1 RATE STANDARD
6.2 IMPACT TO EXISTING MEMBERS

6.3 EVALUATION METHODOLOGY

6.3.1 Administrative Costs

6.3.2 Production Costs

6.3.3 Transmission Costs

6.3.4 Overall Benefit / Cost Evaluation

6.4 EFFECTIVE DATE FOR COST-SHARING

6.5 FACILITIES AND ENTITIES TO WHICH COST-SHARING APPLIES

6.6 OTHER CONSIDERATIONS

6.6.1 Minimizing Administrative Burden on SPP

6.6.2 Consideration of Special Circumstances

6.6.3 Use of Third-Party vs. SPP Analyses

7. FACTORS WHICH MAY RESULT IN DEVIATION FROM APPROVED COST ALLOCATION CRITERIA

This is not an exhaustive list of circumstances that may warrant a deviation from following these criteria or strictly adhering to this process.

7.1 REMOTE SYSTEM WITHOUT AC INTERCONNECTION
7.2 SYSTEM WITH LIMITED INTERCONNECTION CAPABILITY

7.3 SYSTEM EMBEDDED IN EXISTING SPP MEMBER

8. REVIEW PROCEDURES

8.1 SCHEDULE

8.2 REPORT OF FINDINGS TO RSC

8.3 ACTION PLAN
Aggregate Study Waiver Screening Criteria
Proposed CAWG Scope of Work

Adam McKinnie
RSC Meeting
October 26, 2015
What is being requested today?
- Approval of the Aggregate Study Waiver screening criteria study scope
- If approved, the goal would be to have a finished work product by October 2016–January 2017
- Work Product would have a recommendation based on the options in slide 4
Options for Addressing the Issue

- Make no changes and retain the current process
- Eliminate the waiver process
- Modify the current process
  - 20% wind
  - 5 year minimum term of commitment
  - 125% of load
Issues to Be Developed

- Identify historical reasons for the waiver:
  - Why does the safe harbor limit exist?
  - Describe “aggregate study”
  - What does “base plan funding” apply to?

- Criteria to use to analyze use of the criteria:
  - Estimate impact if factors are changed or if the waiver process is eliminated
  - Evaluation methodology to consider (admin costs, generator costs, transmission costs, other items)
Aggregate Study Waiver Screening Criteria

The Issue
Review the Aggregate Study Waiver screening criteria and determine if any changes to the waiver process are needed.
Issues to Be Developed

- Do entities similar to SPP have limits on these criteria (wind, time, % of load)?
- Procedures for CAWG and RSC use for future reviews, if desired
  - Is there a desire for this sort of review to be done regularly? If so, how often?
Future Schedule

- October 2015 – RSC approval of scope
- January – July 2016 – RSC provided updates from CAWG (review items 1a–1d)
- Review scope items post January 2016 with RSC
- October 2016/January 2017 – RSC final consideration of CAWG recommendation(s)
CawiG Recommendation

- CAWG recommends that the RSC approve the proposed scope “Review of Aggregate Study Waiver Screening Criteria”
Proposed Scope
Review of Aggregate Study Waiver Screening Criteria- 5 year minimum commitment, 125% of load, and 20% wind

Goal – evaluating (1) whether there is still a need for any Aggregate Study Waiver screening criteria; and (2) if the need is still there, what are the appropriate Aggregate Study Waiver screening criteria?

Step Zero - Are the aggregate study safe harbor criteria still needed at all?
   a. Is the aggregate study waiver process, including the safe harbor limits, still needed?
      i. What would be the consequences of removing the safe harbor and/or waiver process for aggregate studies, either:
         1. Having all costs paid for by the requesting entity
         2. Having all costs base plan funded
         3. A different methodology for allocating costs
      ii. Essentially, how many dollars are we talking about if changes are made?

Step 1 - Identify historical elements – knowing why the “safe harbor” limit exists, what is an aggregate study, what normally gets “base plan funding”, etc.
   a. Seeing how a request to add a designated resource currently goes through the SPP process, in as simple a manner as possible, including when a waiver is requested (aggregate study process review)
   b. History of what aggregate study amounts are base plan funded versus paid for by the requesting entity
   c. History - Purpose of the “safe harbor” –Include list of documents referenced by SPP Staff in historical discussions.
      i. SPP Staff led discussion indicated one factor in the purpose of safe harbor was to provide a price signal for where generation resources were located.
   d. Purpose and background of the 20% wind requirement for a utility
      i. What was the 20% wind portion of the aggregate study waiver trying to accomplish?
      ii. Why was the 20% number chosen
   e. Previous studies involving wind limits – SPP studies in 2010 and 2015, EWITS study, EISPC, Brattle group study, others?
   f. What current ongoing studies may provide meaningful input to this review?
      Includes SPP wind study; possible Capacity Margin Task Force studies; and quarterly Generation Working Group studies.
   g. History of past waiver requests (both approved and denied) based on the three screening criteria including waiver requests that were submitted and were subsequently withdrawn by the entity requesting transmission service.
Step 2 - Identify approaches used in other similar situations
   a. Research to identify whether any other RTO / similar organization / transmission organization has a similar limit regarding all three screening criteria, and whether they have made any changes to screening criteria

Step 3 - Policy questions - criteria used to analyze the application of the three screening criteria
   a. What is the estimated impact if the three screening criteria are changed
      i. Utilities within the footprint – how close are they to the screening criteria (where applicable)?
      ii. Do we expect additional costs to be passed through the aggregate study paid for by the footprint versus the requesting member?
      iii. Essentially, how many dollars are we talking about?
   b. What are the options available regarding cost allocation related to the aggregate study process?
      i. Different values of the aggregate study waiver criteria?
         a. If the safe harbor is still needed, what is the proper screening criteria to be eligible for the safe harbor, and what should be the amount of the safe harbor?
         b. Is the amount of the safe harbor of $180000 per MW still reasonable?
         c. Is the escalation factor still reasonable?
      ii. Different aggregate study waiver components entirely?
         a. Should other renewables be included, such as solar, in the 20% wind criteria? Should the ‘wind’ criteria be changed to ‘renewable’ criteria?
   c. Evaluation methodology – an incomplete list of things to consider
      i. Administrative costs
      ii. Generator costs
      iii. Transmission costs
      iv. Appropriate benefit / cost measurements
      v. Unintended consequences
   d. Other issues of interest to the RSC?

Step 4 - Draft procedures for CAWG/RSC use in future reviews
   a. Schedule for completion
   b. Reporting findings
   c. Action plan
   d. Do we want to perform this review on a regular basis? No less than every 3-5 years? As needed?
Schedule for Completion

1. Update to the RSC in July 2015 retreat (already done)
2. Approval of scope at the October 2015 RSC meeting
3. Review update on items 1a - 1d at the January 2016 RSC educational session
4. Review remaining scope items post January 2016 with the RSC

Timeframe – finish by October 2016-January 2017
Attachments to Meeting Materials

• Proposed Revisions to Market Protocols and Tariff
• Recommendation Report
Overview of Filing

- Satisfies requirements of FERC’s compliance order, issued July 16, 2015
- Addresses prescriptive and non-prescriptive changes ordered by FERC, as outlined on RSC conference call (September 21)
Key Elements of Filing

• Clarifies that party constructing an improvement has priority for Incremental Long-Term Congestion Rights (ILTCRs) made available by their improvement

• Provide short-term TCRs to party constructing improvement, until next LTCR annual cycle

• Explains how LTCRs and Incremental LTCRs for network upgrades funded in part by direct assignment charges
  – Allocated based on each party’s funding of improvement
  – Party is not eligible to receive both Z2 and ILTCR
Key Elements of Filing

• Eliminate $5 million minimum investment to be eligible for ILTCRs

• Correct number of drafting issues
  – Use of consistent defined terms
  – Making sure parallel languages is included in all applicable sections
  – Address one compliance issue from original 10/28/2014 Order that was not addressed
Current Status

• RR 119 was approved by Market Working Group with multiple abstentions

• Approved by Regional Tariff Working Group with minor revisions

• Approved by MOPC with multiple abstentions
Timeline for Compliance

- 9/1/2015—Initial presentation to CAWG
- 9/15-16/2015—MWG *(vote)*
- 9/21/2015—Initial presentation to RSC
- 9/24/2015—RTWG *(vote)*
- 10/6/2015—CAWG recommendation to RSC *(vote)*
- 10/13-14/2015—MOPC *(vote)*
- 10/26/2015—RSC *(vote)*
- 10/27/2015—BOD *(vote)*
- Compliance filing on or before 10/30/2015
CAWG Motion

• CAWG recommends the RSC approve RR 119, Long Term Congestion Rights Compliance Filing, presented in the background materials for the October 6, 2015, CAWG meeting, as approved by the Regional Tariff Working Group on September 29, 2015. This recommendation is conditioned on there being no substantive changes by other working groups or committees prior to the SPP Regional State Committee meeting on October 26, 2015.

  – Unanimously adopted by CAWG on October 6, 2015. No substantive changes were made subsequent to CAWG action.
Attachments

- Excerpts from July 16, 2015 Order (already included in September 21, 2015 RSC Meeting Materials)
Non-Prescriptive Changes—Paragraph 54

“separate the provision of Incremental LTCRs from the proposed nomination process, and to establish a new process to provide the Incremental LTCRs when the sponsored upgrade goes into service. Additionally, the Incremental LTCRs should be immediately converted into TCRs until the next annual allocation.”
Non-Prescriptive Changes—Paragraph 54

• Candidate Incremental LTCR MW amount shall be determined on execution of service agreement.

• When the upgrade is in-service, SPP will award ILTCRs for remainder of LTCR year beginning with the next applicable month consistent with relevant processes and procedures.

• These ILTCRs will be directly converted to TCRs for the current LTCR year.

• Partial year TCRs derived from new ILTCRs will be subject to SFT in the subsequent LTCR Allocation during Round 1 (LSE Round).
“It is unclear if this change would result in changes to the initial allocation of LTCRs. In the event that a change is required, we direct SPP to treat the LTCRs allocated in the 2015 initial allocation as single year LTCRs, i.e., treat them as though they are valid for only one year, and to implement the initial allocation of LTCRs in the 2016 ARR/TCR year.”

• No changes required as no ILTCR were awarded prior to the 2015 LTCR Allocation.
Non-Prescriptive Changes—Paragraph 54

“explain how its proposed process will treat the provision of LTCRs and Incremental LTCRs for network upgrades that are funded through a combination of rolled-in transmission rates and directly assigned charges.”

• When one or more Transmission Customers request to receive Incremental LTCRs for a Service Upgrade which was funded in whole or in part through Directly Assigned cost allocations, SPP will allocate the available ILTCRs to each Transmission Service Customer in the same proportion as each customer’s pro-rata share of the total cost of the upgrade.

• If multiple customers fund a Service Upgrade through Directly Assigned cost, each customer may choose a different path for the ILTCR and each customer’s ILTCR allocation will be in proportion to the total cost of the upgrade.
Prescriptive Changes—Paragraphs 48 & 63

“…remove the minimum upgrade cost threshold for Incremental LTCRs from its Tariff.” (p48)

• Removing the minimum upgrade cost threshold of $5 million per upgrade

“include the clarification that the term “Network Integration Transmission Service Candidate LTCRs” should appear in section 7.1.3(1) instead of “Candidate LTCRs,”…” (p63)

• Correcting language to use the Tariff defined term
Prescriptive Changes—Paragraph 63

“include parallel language concerning the transfer of LTCRs to account for wholesale load shifts between transmission customers, in sections 7.1.3(2), (3), and (4).”

• Including the same language for Firm PTP, GFA NITS, and GFA Firm PTP Candidate LTCRs

“include the revision to section 7.2.1.a of Attachment AE to make it clear that only Eligible Entities that are surrendering previously awarded LTCRs are required to submit the information requested in the Tariff.”

• Including the phrase, “surrendering previously awarded LTCRs” as directed in the 10/28/2014 Order
Revision Request Recommendation Report

RR #: 119
RR Title: LTCR Compliance Filing

Date: 9/15/2015

SUBMITTER INFORMATION

Name: Nick Parker
Company: SPP
Email: nparker@spp.org
Phone: 501-303-8487

EXECUTIVE SUMMARY OF ACTION AND RECOMMENDATION

This Revision Request (RR) is in response to a recent FERC Order conditionally accepting the Long-Term Congestion Rights (LTCRs) design, dated July 16, 2015. This RR includes design changes that award Incremental Long-Term Congestion Rights (ILTCRs) at the time an upgrade goes into service instead of waiting until the next annual LTCR allocation. Awarded ILTCRs from this initial ILTCR allocation cannot be renewed. The initial ILTCRs awards will be evaluated in the next annual LTCR allocation, and the initial awards will be confirmed or denied. Market Participants with candidate ILTCRs will be eligible to nominate in the same allocation round as the Load Serving Entity (LSE) LTCRs.

MOPC recommends the BOD move to approve this Revision Request.

OBJECTIVE OF REVISION

Objectives of Revision Request:
Describe the problem/issue this revision request will resolve.

This RR is in response to the FERC Order conditionally accepting the LTCR Design, dated July 16, 2015.

FERC directives from the Order:

(p48) … we direct SPP to make a further compliance filing within 30 days of the date of issuance of this order to remove the minimum upgrade cost threshold for Incremental LTCRs from its Tariff.

(p54) … we direct SPP to make a further compliance filing within 30 days of the date of issuance of this order to separate the provision of Incremental LTCRs from the proposed nomination process, and to establish a new process to provide the Incremental LTCRs when the sponsored upgrade goes into service. Additionally, the Incremental LTCRs should be immediately converted into TCRs until the next annual allocation.

(p54) … to explain how its proposed process will treat the provision of LTCRs and Incremental LTCRs for network upgrades that are funded through a combination of rolled-in transmission rates and directly assigned charges.

(p63) … we find that SPP has failed to comply with the Commission’s directive to revise its Tariff to include the clarification that the term “Network Integration Transmission Service Candidate LTCRs” should appear in section 7.1.3(1) instead of “Candidate LTCRs,” and we will also require SPP to include parallel language concerning the transfer of LTCRs to account for wholesale load shifts between transmission customers, in sections 7.1.3(2), (3), and (4).

(p63) … We also find that SPP has failed to include the revision to section 7.2.1.a of Attachment AE to make it clear that only Eligible Entities that are surrendering previously awarded LTCRs are required to submit the information requested in the Tariff.

Describe the benefits that will be realized from this revision.

This Revision Request is in response to the July 16, 2015 FERC Order on LTCRs. MPs that have funded an upgrade and that have been granted candidate ILTCRs will now be able to receive awarded ILTCRs at the time the upgrade goes into service instead of delaying until the next annual LTCR allocation.

IMPACT ANALYSIS REQUIRED: ☐ Yes ☒ No

Estimated Cost: $n
Priority Rank for System Change: ☐ 1 – Critical ☐ 2 – High ☐ 3 – Medium ☐ 4 – Low
### SPP DOCUMENTS IMPACTED

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<th>Protocol Version:</th>
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### WORKING GROUP REVIEWS AND RECOMMENDATIONS

**List Primary and any Secondary/Impacted WG Recommendations as appropriate**

#### Primary Working Group: MWG

- **Date:** 9/15/2015
- **Action Taken:** Approved RR119 as modified by MWG
- **Abstained:** Kansas City Power & Light Company
- **Abstained:** Oklahoma Municipal Power Authority
- **Abstained:** Arkansas Electric Cooperative Corporation
- **Abstained:** Kansas Municipal Energy Agency
- **Abstained:** Empire District Electric Company
- **Abstained:** Tenaska Power Services Co.
- **Abstained:** Midwest Energy, Inc.
- **Abstained:** Omaha Public Power District
- **Abstained:** Lincoln Electric System
- **Abstained:** Golden Spread Electric Cooperative, Inc.
- **Abstained:** Westar Energy, Inc.
- **Abstained:** Exelon Generation Company, LLC
- **Abstained:** Nebraska Public Power District
- **Abstained:** Xcel Energy
- **Abstained:** Oklahoma Gas and Electric Company
- **Abstained:** The Energy Authority for City Utilities of Springfield
- **Abstained:** Basin Electric Power Cooperative

**Opposed:**

#### Secondary Working Group: RTWG

- **Date:** 9/29/2015
- **Action Taken:** Motion to approve RR 119 as modified
- **Abstained:** Empire, MJMEUC, OPPD

**Opposed:** None

#### CAWG

- **Date:** 10/6/2015
- **Action Taken:** Unanimously Approved
MOPC

Date: 10/13/2015  
Action Taken: Approved  
Opposed: None

BOD/Member Committee

Date:  
Action Taken:  
Abstained:  
Opposed:  
Reasons for Opposition:  

COMMENTS

Comment Author: MWG  
Date Comments Submitted: 9/16/2014  
Description of Comments: Minor updates to section 5.2.8 in the Market Protocols and corresponding updates to section 7.2.5 in Attachment AE of the Tariff.  
Status: Reviewed by MWG

Comment Author: RTWG  
Date Comments Submitted: 9/29/2015  
Description of Comments: Changes are being proposed to the new section 7.2.5 because the RTWG wanted the structure of the paragraph to be rephrased in a more appropriate manner without any contextual changes.  
Status: MWG will review at 10/20/2015 meeting

Comment Author: Nick Parker  
Date Comments Submitted: 10/2/2015  
Description of Comments: Revisions are being submitted to correct one instance in Section 5.2 of the Protocols that was missed when previous revisions were made that moved the nomination of candidate ILTCRs from the second step of the annual LTCR allocation to the first step.  
Status: MWG will review at 10/20/2015 meeting

PROPOSED REVISION(S) TO SPP DOCUMENTS

Market Protocols

ARR Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:
(1) For NITS Transmission Customers, the NITS ARR Nomination Cap for a particular month or season is equal to the lesser of (a) the sum of NITS Candidate ARRs and NITS Candidate LTCRs for a particular month or season as calculated under Section 5.1.1.1 or (b) one hundred and three percent (103%) of the average of that customer's three most recent annual peak Network Loads. This value will be adjusted by SPP as required to account for wholesale load shifts between Transmission Customers. In addition, NITS Candidate LTCRs and awarded NITS Candidate LTCRs associated with wholesale load shifts shall be transferred by SPP as applicable;

(2) For FPTP Transmission Customers, the FPTP ARR Nomination Cap is equal to the sum of FPTP Candidate ARRs and FPTP Candidate LTCRs as calculated under Section 5.1.1.1. In addition, FPTP Candidate LTCRs and awarded FPTP Candidate LTCRs associated with wholesale load shifts shall be transferred by SPP as applicable;

(3) For GFA customers taking the equivalent of SPP NITS, the GFA NITS ARR Nomination Cap for a particular month or season is equal to the lesser of (a) the sum of GFA NITS Candidate ARRs and GFA NITS Candidate LTCRs as calculated under Section 5.1.1.1 or (b) one hundred and three percent (103%) of the average of that GFA customer's three most recent annual peak Network Loads. This value will be adjusted by SPP as required to account for wholesale load shifts between Transmission Customers. In addition, GFA NITS Candidate LTCRs and awarded GFA NITS Candidate LTCRs associated with wholesale load shifts shall be transferred by SPP as applicable;

(4) For GFA customers taking the equivalent of SPP FPTP, the GFA FPTP ARR Nomination Cap is equal to the sum of GFA FPTP Candidate ARRs and GFA FPTP Candidate LTCRs as calculated under Section 5.1.1.1. In addition, GFA FPTP Candidate LTCRs and awarded GFA FPTP Candidate LTCRs associated with wholesale load shifts shall be transferred by SPP as applicable;

(5) An Eligible Entity’s ARR Nomination Cap is equal the sum of its NITS ARR Nomination Cap, FPTP ARR Nomination Cap, GFA NITS ARR Nomination Cap and GFA FPTP ARR Nomination Cap.

...  

5.2 Annual LTCR Allocation Process

The Annual LTCR Allocation Process addresses how candidate LTCRs and candidate ILTCRs verified in the Annual LTCR/ILTCR/ARR Verification Process may be nominated and awarded as LTCRs. The annual allocation process determines the portion of the nominated candidate LTCRs and candidate ILTCRs that are simultaneously feasible. 50% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the Annual LTCR Allocation Process. Nominated candidate LTCRs and candidate ILTCRs are evaluated on an annual basis in a two-step,
single round process. The first step evaluates nominated LSE candidate LTCRs and the second step evaluates nominated non-LSE candidate LTCRs and candidate ILTCRs. No later than five (5) Business Days prior to the start of the Annual LTCR Allocation Process, SPP will post the transmission system network topology data for the annual model, along with corresponding Parallel Flow assumptions, that SPP will use in the upcoming allocation process for use by Eligible Entities in developing their available candidate LTCR selection strategies. The following rules apply to the annual allocation of LTCRs.

5.2.1 LTCR/ILTCR Surrender

Eligible Entities and holders of ILTCRs must confirm their intent to retain previously awarded LTCRs and/or ILTCRs. Eligible Entities and holders of ILTCRs may surrender previously awarded LTCRs and/or ILTCRs in 0.1 MW increments. Prior to annual LTCR allocation, Eligible Entities and holders of ILTCRs surrendering previously awarded LTCRs and/or ILTCRs shall submit the following information:

1. Source (valid candidate LTCR and/or ILTCR source Settlement Location);
2. Sink (valid candidate LTCR and/or ILTCR sink Settlement Location);
3. Surrendered LTCR MW (cannot exceed previously awarded LTCR);
4. Surrendered ILTCR MW (cannot exceed previously awarded ILTCR).

5.2.2 LTCR/ILTCR Nomination

Eligible Entities and holders of candidate LTCRs and/or ILTCRs must submit the following information in order to nominate LTCRs and ILTCRs:

a. (1) Source (valid candidate LTCR and/or candidate ILTCR source Settlement Location);

b. (2) Sink (valid candidate LTCR and/or ILTCR sink Settlement Location);

c. (3) Nominated LTCR MW in 0.1 MW increments (total LTCR MW nominated from a source Settlement Location cannot exceed the source candidate available LTCR MW as previously determined under Section 5.1.2, less previously awarded LTCRs plus surrendered LTCRs);

d. (4) Nominated ILTCR MW in 0.1 MW increments (total ILTCR MW nominated from a source Settlement Location cannot exceed the source candidate ILTCR MW as previously determined under Section 5.1.2, less previously awarded ILTCRs plus surrendered ILTCRs).

5.2.3 LTCR Simultaneous Feasibility for LSEs and Incremental LTCRs

A simultaneous feasibility test (SFT) is performed to determine the feasibility of all nominated NITS Candidate LTCRs, FPTP Candidate LTCRs, GFA NITS Candidate LTCRs and GFA FPTP Candidate LTCRs identified as described under Section 5.1.2 for all LSEs and all nominated candidate ILTCRs. All nominated LSE candidate LTCRs and nominated candidate ILTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The feasibility analysis assures the modeling of the LSE candidate LTCRs and candidate ILTCRs does not violate any normal
transmission line thermal ratings under normal system conditions and does not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow.

1. The SPP Transmission System topology used in the SFT is the most up-to-date Network Model.
   
   (a) For withdrawals at Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. prior year peak). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

   (b) For injections at Resource Hubs, SPP will distribute the injection down to the PNode level on a pro-rata basis using the weighting factors defined for the Resource Hub.

2. Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:
   
   (a) Adjusted Monitored Transmission Line Rating (normal and Emergency) =
   
   \[(\text{Monitored Transmission Line Rating} \times \text{normal and Emergency – Parallel Flow impact})\]

   (b) Adjusted Flowgate Rating (normal and Emergency) =
   
   \[(\text{Flowgate Rating} - \text{Parallel Flow impact})\]

3. The feasibility analysis evaluates the nominated LTCR feasibility and candidate ILTCR feasibility by evaluating line flows against path limits in a single direction only without simultaneous consideration of line flows created by nominated LTCRs and candidate ILTCRs in the opposite direction (i.e. counter-flow will not act to increase the feasibility of candidate LTCRs and candidate ILTCRs).

4. The feasibility analysis models previously awarded LTCRs associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered as indicated pursuant to Section 5.2.1 and previously awarded ILTCRs issued subsequent to the initial allocation pursuant to Section 5.2.8 which were not surrendered as indicated pursuant to Section 5.2.1 as fixed injections and withdrawals. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing LSE LTCR feasibility. SPP will report back to the MWG when transmission line ratings had to be adjusted to ensure feasibility.
5.2.4 Annual LTCR Awards for LSEs

If the nominated candidate LSE LTCRs and ILTCRs are confirmed feasible, all nominated candidate LSE LTCRs and ILTCRs are awarded. If the nominated candidate LSE LTCRs and ILTCRs are not feasible, the amount of nominated candidate LSE LTCRs and nominated ILTCRs awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated candidate LSE LTCR MW and nominated candidate ILTCR MW weighted by the reciprocal of the nominated candidates resulting in a higher percentage LSE LTCR and ILTCR reduction for those candidates having the greatest impact on the constraints. LSE LTCR and ILTCR reductions associated with nominated candidates that have an equal impact on the constraints are reduced by the same percentage.

5.2.5 LTCR Simultaneous Feasibility for Non-LSEs and Incremental LTCRs

A simultaneous feasibility test (SFT) is performed to determine the feasibility of all nominated NITS Candidate LTCRs, FPTP Candidate LTCRs, GFA NITS Candidate LTCRs and GFA FPTP Candidate LTCRs identified as described under Section 5.1.2 for all non-LSEs and all nominated candidate ILTCRs. All nominated non-LSE candidate LTCRs and nominated candidate ILTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The feasibility analysis assures the modeling of the non-LSE candidate LTCRs and candidate ILTCRs does not violate any normal transmission line thermal ratings under normal system conditions and does not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part of the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow.

(1) The SPP Transmission System topology used in the SFT is the most up-to-date Network Model.

    (a) For withdrawals at Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. prior year peak). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

    (b) For injections at Resource Hubs, SPP will distribute the injection down to the PNode level on a pro-rata basis using the weighting factors defined for the Resource Hub.

(2) Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:

    (a) Adjusted Monitored Transmission Line Rating (normal and Emergency) =

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(Monitored Transmission Line Rating (normal and Emergency – Parallel Flow impact))

(b) Adjusted Flowgate Rating (normal and Emergency) =

(Flowgate Rating – Parallel Flow impact)

(3) The feasibility analysis evaluates the candidate LTCR feasibility and candidate ILTCR feasibility by evaluating line flows against path limits in a single direction only without simultaneous consideration of line flows created by candidate LTCRs and candidate ILTCRs in the opposite direction (i.e. counter-flow will not act to increase the feasibility of candidate LTCRs and candidate ILTCRs).

(4) The feasibility analysis models previously awarded LTCRs associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered as indicated pursuant to Section 5.2.1, previously awarded ILTCRs issued subsequent to the initial allocation pursuant to Section 5.2.8 which were not surrendered as indicated pursuant to Section 5.2.1, and LSE LTCRs and ILTCRs awarded under Section 5.2.4 as fixed injections and withdrawals. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing Non-LSE LTCR and ILTCR feasibility. SPP will report back to the MWG when transmission line ratings had to be adjusted to ensure feasibility.

5.2.6 Annual LTCR Awards for Non-LSEs

If the nominated candidate non-LSE LTCRs and ILTCRs are confirmed feasible, all nominated candidate non-LSE LTCRs and ILTCRs are awarded. If the nominated candidate non-LSE LTCRs and ILTCRs are not feasible, the amount of nominated candidate non-LSE LTCRs and nominated ILTCRs awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated candidate non-LSE LTCR MW and nominated candidate ILTCR-MW-weighted by the reciprocal of the nominated candidates resulting in a higher percentage non-LSE LTCR and ILTCR reduction for those nominated candidates having the greatest impact on the constraints. Non-LSE LTCR and ILTCR-reductions associated with nominated candidates that have an equal impact on the constraints are reduced by the same percentage.

5.2.7 LTCR/ILTCR Conversion to TCRs

(1) All previously awarded LTCRs associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered, as described under Section 5.2.1, are automatically awarded as LTCRs and automatically directly converted to TCRs for the current allocation year.
(2) All previously awarded ILTCRs which were not surrendered, as described under Section 5.2.1, are automatically awarded as ILTCRs and directly converted to TCRs for the current allocation year.

(3) All LSE LTCRs and ILTCRs awarded under Section 5.2.4 are directly converted to TCRs for the current allocation year.

(4) All Non-LSE LTCRs and ILTCRs awarded under Section 5.2.6 are directly converted to TCRs for the current allocation year.

5.2.8 Initial ILTCR Award Process

The initial ILTCR award process addresses how candidate ILTCRs may be nominated and awarded as ILTCRs in the remainder of the current allocation year when the upgrade is placed in-service. The Upgrade Sponsor will be required to notify SPP at least 45 days in advance of the upgrade in-service date. The Upgrade Sponsor will be required to notify SPP that the upgrade has been placed in-service; SPP will model the upgrade in the next feasible monthly TCR auction.

Nominated candidate ILTCRs will be awarded as ILTCRs during the first full month that the upgrade is included in the transmission model for a monthly TCR auction. These awarded ILTCRs will be directly converted to TCRs until they can be included in the next Annual LTCR Allocation Process, and the TCRs will only be effective for the remainder of the current allocation year. Upgrades that are placed in-service after the Annual LTCR Allocation Process but before the next allocation year starts on June 1st will receive TCRs for the remainder of the current allocation year ending by June 1 and TCRs for the next allocation year starting June 1. At the start of the next Annual LTCR Allocation Process after the upgrade has been placed in-service, Market Participants will be issued candidate ILTCRs that may be nominated in the Annual LTCR Allocation Process as described in Section 5.2.2. After initial ILTCRs are awarded, the process for ILTCRs as described in Section 5.2 will be followed.

5.3 Annual ARR Allocation Process

The Annual ARR Allocation Process addresses how candidate ARRs verified in the Annual LTCR/ILTCR/ARR Verification Process may be nominated and converted to ARRs. Eligible Entities may nominate the candidate ARRs that they wish to receive up to their Nomination Caps less any LTCRs awarded plus any LTCRs surrendered. Any candidate LTCRs not awarded in the Annual LTCR Allocation Process and surrendered LTCRs become candidate ARRs. Candidate ILTCRs which were not awarded and surrendered ILTCRs are not eligible to receive candidate ARRs.

...
Attachment Z2

IV. Incremental ILTCRs

A. For Network Upgrades with Directly Assigned Upgrade Costs greater than or equal to $5,000,000, the Upgrade Sponsor may elect to be paid for such upgrade through receipt of candidate ILTCRs. In order to be eligible to receive candidate ILTCRs, the Upgrade Sponsor must request the Transmission Provider perform an analysis for the purposes of determining available candidate ILTCRs. If so requested, the Transmission Provider shall perform the following analysis:

a) The Upgrade Sponsor may request that up to three source-to-sink paths be evaluated by the Transmission Provider to determine the amount of incremental ATC created on these paths as a result of the portion of the upgrade associated with the Directly Assigned Upgrade Cost.

b) The Transmission Provider shall determine the minimum increase in ATC on each of the requested paths over a ten-year period and communicate the MW results to the Upgrade Sponsor. The Upgrade Sponsor may then decide to select one of the requested paths on which candidate ILTCRs are desired and the increase in ATC on that selected path shall be equal to the candidate ILTCRs on that path. Such selection shall be documented in the applicable executed agreements as specified under Section V of Attachment J of this Tariff. If the Upgrade Sponsor does not confirm selection of ILTCRs in the applicable executed agreement, then the Upgrade Sponsor shall be eligible for revenue credits in accordance with Sections I and II of this Attachment Z2.

c) The Transmission Provider will consider all awarded ILTCRs in all planning studies on a going forward basis once the Upgrade Sponsor executes the applicable agreements as specified under Attachment J of this Tariff.

d) The Transmission Provider’s costs associated with studies for potential ILTCRs shall be the responsibility of the Upgrade Sponsor requesting such studies.

B. When one or more Transmission Customers request to receive candidate ILTCRs for a Service Upgrade which was funded in whole or in part through Directly Assigned...
Upgrade Costs, the Transmission Provider will allocate the available candidate ILTCRs to each Transmission Customer in the same proportion as each Transmission Customer’s pro-rata share of the total cost of the upgrade allocated in accordance with Section IV of Attachment Z1 of this Tariff.

If multiple Transmission Customers fund a Service Upgrade through Directly Assigned Upgrade Costs, each Transmission Customer may choose a different source-to-sink path for the candidate ILTCR and each Transmission Customer’s candidate ILTCR allocation will be in proportion to the total cost of the upgrade.

Attachment AE

7.1.1 Transmission Service and Incremental Long-Term Congestion Rights Verification

In order for Eligible Entities to obtain candidate LTCRs and/or ARRs, the Transmission Provider must first verify existing transmission service entitlements, including transmission service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity’s transmission service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. An Eligible Entity’s transmission service must span the entire annual period for which LTCRs are allocated and must have rollover rights to qualify for candidate LTCRs. In order to qualify for candidate ILTCRs in the current LTCR allocation year, Network Uupgrades associated with the candidate ILTCRs must be in-service prior to the start of the annual LTCR/ILTCR/ARR verification process. For transmission service with rollover rights whose deadline for providing notice of rollover occurs after the annual LTCR/ARR verification but before June 1, the Transmission Provider shall assume that the rollover will occur and shall consider the transmission service entitlement to span the entire allocation year, provided, however, that, if rollover rights for such transmission service are not exercised by the applicable deadline, any ARRs, TCRs, or LTCRs associated with such transmission service shall revert to the Transmission Provider effective on the date such transmission service terminates. The Transmission Provider will verify Eligible Entity existing transmission service entitlements as follows:

1. The following will be performed prior to each annual LTCR and ARR allocation for Eligible Entities taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff:
(a) The Transmission Provider will obtain source, sink and Reservation Capacity information from the OASIS for each monthly and seasonal period for which ARRs are allocated in which the transmission service spans the entire period, or would if or when rolled over, for the current annual allocation and for the annual period for which LTCRs are allocated in which the transmission service spans the entire year;

(i) For a transmission service reservation with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the transmission service reservation that will be utilized as the source for candidate LTCRs and/or ARRs. In the alternative, Eligible Entities may create Resource specific transmission service reservations that represent their current transmission service reservations using the process described in Section 7.1.1.1 of this Attachment AE.

(ii) For a transmission service reservation with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for candidate LTCRs and/or ARRs.

(iii) For a transmission service reservation with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for candidate LTCRs and/or ARRs.

(iv) Eligible Entities taking Network Integration Transmission Service with rollover rights under this Tariff shall be considered to have met the definition of Load Serving Entity for purposes of LTCR allocation;

(v) Eligible Entities taking Firm Point-To-Point Transmission Service with rollover rights under this Tariff shall not be considered a Load Serving Entity for LTCR allocation purposes unless the Eligible Entity provides an
attestation to the Transmission Provider confirming that the Eligible Entity is a Load Serving Entity as defined in this Attachment AE;

(b) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(c) Eligible Entities will notify the Transmission Provider within 2 weeks following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified.

(2) The following will be performed prior to each annual LTCR and ARR allocation for the Eligible Entity taking GFA service:

(a) Each Transmission Owner shall register any GFA for which candidate LTCRs and/or ARRs are to be provided to the Transmission Owner or the transmission customer under the GFA on the Transmission Provider’s OASIS. The Transmission Owner must provide the Transmission Provider with source, sink and Reservation Capacity information for each GFA on the Transmission Provider’s OASIS by registering each GFA with the Transmission Provider. The Transmission Provider will use source, sink, and Reservation Capacity information from the GFA registration for each monthly and seasonal period for which LTCRs and/or ARRs are allocated and the annual period for which the LTCRs are allocated. If both parties to the GFA are Market Participants with respect to the GFA load, then the parties may jointly inform the Transmission Provider which Market Participant will be allocated the candidate ARRs. If the parties to the GFA do not so inform the Transmission Provider, or if only the Transmission Owner that sold the GFA service is a Market Participant, then the Transmission Owner that sold the GFA service will be allocated the candidate LTCRs and/or ARRs associated with the GFA.

(i) For a GFA with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the transmission service reservation that will be utilized as the source for candidate LTCRs and/or ARRs.
(ii) For a GFA with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for the candidate LTCRs and/or ARRs.

(iii) For a GFA with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for the candidate LTCRs and/or ARRs.

(iv) An Eligible Entity under a GFA taking the equivalent of Network Integration Transmission Service with rollover rights shall be considered to have met the definition of Load Serving Entity for purposes of LTCR allocation;

(v) An Eligible Entity under a GFA taking the equivalent of Firm Point-To-Point Transmission Service with rollover rights shall not be considered a Load Serving Entity for the purposes of LTCR allocation unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is a Load Serving Entity as defined in this Attachment AE;

(b) If the transmission customer under the GFA is receiving the candidate ARRs, to the extent that the transmission service specified in the GFA is identified as the equivalent of SPP Network Integration Transmission Service, the transmission customer under the GFA must provide the historical peak loads being served under the GFA for the previous three years.

7.1.2 Candidate Long-Term Congestion Rights/Auction Revenue Rights

Following verification of an Eligible Entity transmission service, candidate LTCRs and/or ARRs associated with such transmission service, and candidate ILTCRs are assigned as follows:

(1) For each Eligible Entity with Network Integration Transmission Service, the Eligible Entity’s Network Integration Transmission Service Candidate LTCRs and/or candidate ARRs from a specific source is equal to the source Reservation Capacity.
(a) An Eligible Entity may nominate Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2.4 of this Attachment AE from a specific source to one or more sinks up to the amount of its available Network Integration Transmission Service Candidate LTCRs associated with the source such that the total of such nominations does not exceed the lesser of the sum of Network Integration Transmission Service Candidate LTCRs or the limit described under Section 7.1.3(1)(b) for that Eligible Entity.

(b) An Eligible Entity may nominate Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE from a specific source to one or more sinks up to the amount of its Network Integration Transmission Service Candidate ARRs associated with the source subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(2) For each Eligible Entity with Firm Point-To-Point Transmission Service, the Eligible Entity’s Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate Firm Point-To-Point Candidate LTCRs, as described in Section 7.2 of this Attachment AE, for this specific source and sink up to the amount of its available Firm Point-To-Point Candidate LTCRs such that the total of such nominations does not exceed the total Firm Point-To-Point Candidate LTCRs available for that Eligible Entity.

(b) Firm Point-To-Point Candidate ARRs may be nominated by an Eligible Entity, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(3) A holder of candidate ILTCRs may nominate the candidate ILTCRs up to the MW amount for the specific source and sink path documented through the process described in Section IV of Attachment Z2 of this Tariff less previously awarded ILTCRs issued subsequent to the initial allocation pursuant to Section 7.2.5 of this Attachment AE.

(4) For each Eligible Entity with equivalent Network Integration Transmission Service GFA service, the Eligible Entity’s Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs and/or ARRs from a specific source is equal to the source Reservation Capacity.
(a) An Eligible Entity may nominate Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2 of this Attachment AE, from a specific source to one or more sinks up to the amount of its available Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs such that the total of such nominations does not exceed the lesser of the sum of Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs or the limit described under Section 7.3.1(3)(b) for that Eligible Entity.

(b) An Eligible Entity may nominate Grandfathered Agreement Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, from a specific source to one or more sinks up to the amount of its Grandfathered Agreement Network Integration Transmission Service Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(5) For each Eligible Entity with equivalent Firm Point-To-Point GFA service, the Eligible Entity’s Grandfathered Agreement Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate LTCRs, as described in Section 7.2 of this Attachment AE, for this specific source and sink up to the amount of its available Grandfathered Agreement Firm Point-To-Point Candidate LTCRs such that the total of such nominations does not exceed the total Grandfathered Agreement Firm Point-To-Point Candidate LTCRs available for that Eligible Entity.

(b) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Grandfathered Agreement Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.
7.1.3 Auction Revenue Right Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:

(1) For Network Integration Transmission Customers, the Network Integration Transmission Service ARR Nomination Cap for a particular month or season is equal to the lesser of (a) the sum of Network Integration Transmission Service Candidate ARRs and Network Integration Transmission Service Candidate LTCRs for that particular month or season as calculated in Section 7.1.2 of this Attachment AE and any additional Network Integration Transmission Service Candidate ARRs for that particular month or season as calculated in Section 7.6.1 of this Attachment AE or (b) One hundred and three percent (103%) of the average of that customer’s three most recent annual peak Network Loads. This value will be adjusted by the Transmission Provider as required to account for wholesale load shifts between Transmission Customers. In addition, Network Integration Transmission Service Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(2) For Firm Point-To-Point Transmission Customers, the Firm Point-To-Point ARR Nomination Cap is equal to the sum of Firm Point-To-Point Candidate ARRs and Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Firm Point-To-Point Candidate ARRs as calculated in Section 7.6.1 of this Attachment AE. In addition, Firm Point-To-Point Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(3) For GFA customers taking the equivalent of SPP Network Integration Transmission Service, the Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap for that particular month or season is equal to the lesser of (a) the sum of Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs for that particular month or season as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement Network Integration Transmission Service Candidate ARRs for that particular month or season as calculated in Section 7.6.1 of this Attachment AE or (b) One hundred and three percent (103%) of the average of that GFA customer’s three most recent annual peak Network Loads. This
value will be adjusted by the Transmission Provider as required to account for wholesale load shifts between Transmission Customers. In addition, Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(4) For GFA customers taking the equivalent of SPP Firm Point-To-Point, the Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap is equal to the sum of Grandfathered Agreement Firm Point-To-Point Candidate ARRs and Grandfathered Agreement Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement Firm Point-To-Point Candidate ARRs as calculated in Section 7.6.1 of this Attachment AE. In addition, Grandfathered Agreement Firm Point-To-Point Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.


7.2 Annual Long-Term Congestion Right Allocation

Eligible Entities may nominate their candidate LTCRs and Market Participants may nominate their candidate ILTCRs that they wish to receive as described under Section 7.1.2 of this Attachment AE. The feasible portion of the nominated candidate LTCRs and nominated candidate ILTCRs are awarded during the LTCR annual allocation. Nominated candidate LTCRs and candidate ILTCRs are evaluated on an annual basis in a two-step, single round process; (i) nominated candidate LTCRs associated with Eligible Entities that are Load Serving Entities and nominated candidate ILTCRs associated with Load Serving Entities are evaluated in accordance with Section 7.2.2 and (ii) remaining nominated candidate LTCRs associated with Eligible Entities which are not Load Serving Entities and nominated candidate ILTCRs are then evaluated in accordance with Section 7.2.3.

The Transmission Provider shall make available fifty percent (50%) of the projected maximum Transmission System capability for the purpose of LTCR and ILTCR allocation in the
annual LTCR allocation process. No later than five (5) days prior to the start of the annual LTCR allocation process, the Transmission Provider shall post the Transmission System network topology, including the corresponding impacts from Parallel Flow, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocation.

7.2.1 **Long-Term Congestion Right and Incremental Long-Term Congestion Right Surrender and Nomination**

(a) Eligible Entities and holders of ILTCRs must confirm with the Transmission Provider their intent to retain previously awarded LTCRs and/or ILTCRs. Eligible Entities and holders of ILTCRs may surrender previously awarded LTCRs and ILTCRs in 0.1 MW increments. Prior to annual LTCR allocation, Eligible Entities and holders of ILTCRs surrendering previously awarded LTCRs and/or ILTCRs shall submit the following information:

1. Source (valid candidate LTCR source Settlement Location);
2. Sink (valid candidate LTCR sink Settlement Location);
3. Surrendered LTCR MW (cannot exceed previously awarded LTCR);
4. Surrendered ILTCR MW (cannot exceed previously awarded ILTCR).

(b) Eligible Entities and holders of candidate ILTCRs shall submit the following information in order to nominate LTCRs and ILTCRs that were not previously awarded in 0.1 MW increments:

1. Source (valid candidate LTCR and/or ILTCR source Settlement Location);
2. Sink (valid candidate LTCR and/or ILTCR sink Settlement Location);
3. LTCR MW (total LTCR MW nominated from a source Settlement Location cannot exceed the source candidate LTCR MW as previously determined under Section 7.1.2 of this Attachment AE less previously awarded LTCRs plus surrendered LTCRs);
4. ILTCR MW (total ILTCR MW nominated from a source Settlement Location cannot exceed the source candidate ILTCR MW as previously determined under Section 7.1.2 of this Attachment AE less previously awarded ILTCRs plus surrendered ILTCRs).
7.2.2 Available Long-Term Congestion Rights and Incremental Long-Term Congestion Rights for Load Serving Entities

A Simultaneous Feasibility Test is performed to determine the amount of awarded LTCRs and ILTCRs for Eligible Entities that are LSEs. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, all Load Serving Entities’ nominated candidate LTCRs and candidate ILTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition, all previously awarded LTCRs and ILTCRs issued subsequent to the initial allocation pursuant to Section 7.2.5 of this Attachment AE are modeled as fixed injections and withdrawals provided that such LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or such LTCRs and ILTCRs have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded LTCRs and ILTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution. If all Load Serving Entities’ nominated candidate LTCRs and candidate ILTCRs are feasible, then all Load Serving Entities’ nominated LTCRs are awarded. If the Load Serving Entity nominated candidate LTCRs and candidate ILTCRs are not feasible, the amount of awarded LTCRs and ILTCRs will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual LTCR and ILTCR amounts and the candidate LTCR and candidate ILTCR amounts, weighted by the reciprocal of the candidate LTCR and candidate ILTCR amounts, which results in a higher percentage LTCR and ILTCR reduction for those nominations having the greatest impact on the constraints. LTCR and ILTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

7.2.4 Long-TermCongestion Right and Incremental Long-Term Congestion Right Awards

(1) All previously awarded LTCRs and previously awarded ILTCRs are automatically awarded as LTCRs and ILTCRs for the current allocation year; provided that such LTCRs and ILTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE; or were not surrendered as described under Section 7.2.1 of this Attachment AE.
(2) All previously awarded ILTCRs awarded pursuant to Section 7.2.2 of this Attachment AE are automatically awarded as LTCRs for the current allocation year provided that such ILTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE; or were not surrendered as described under Section 7.2.1 of this Attachment AE.

(3) Additional Load Serving Entity LTCRs and/or ILTCRs are awarded as described under Section 7.2.2 of this Attachment AE.

(4) Additional non-Load Serving Entity LTCRs are awarded as described under Section 7.2.3 of this Attachment AE.

(5) Initial ILTCRs are awarded pursuant to Section 7.2.5 of this Attachment AE. ILTCRs awarded pursuant to Section 7.2.5 of this Attachment AE are not automatically awarded for the subsequent year(s). ILTCRs for subsequent years shall be awarded pursuant to Section 7.2 of this Attachment AE.

(6) All awarded LTCRs and ILTCRs as described in subsections (1) through (4) above are directly converted to TCRs prior to the annual ARR allocation for the current allocation year.

7.2.5 Initial Incremental Long-Term Congestion Right Awards

The initial ILTCR award process addresses how candidate ILTCRs will be nominated and awarded to an Upgrade Sponsor from the time when the upgrade is placed into service until the next annual LTCR allocation. The Upgrade Sponsor and/or Transmission Owner shall notify the Transmission Provider at least forty-five (45) calendar days in advance of the expected upgrade in-service date. When the upgrade is placed into service, the Upgrade Sponsor and/or Transmission Owner shall notify the Transmission Provider. Upon receipt of notification, the Transmission Provider will model the upgrade in the next feasible monthly TCR auction.

During the first full month that the upgrade is included in the transmission model for a monthly TCR auction, nominated candidate ILTCRs will be awarded as ILTCRs. These awarded ILTCRs will be directly converted to TCRs until they can be included in the next annual LTCR allocation process, and the TCRs will only be effective for the remainder of the current allocation year. Upgrades that are placed in-service after the annual LTCR/ILTCR/ARR

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verification process but before the next allocation year starts will receive TCRs for: (i) the remainder of the current allocation year, and (ii) the next allocation year.

At the start of the next annual LTCR/ILTCR/ARR verification process after the upgrade has been placed in-service, Market Participants will be issued candidate ILTCRs that may be nominated in the annual LTCR allocation process as described in Section 7.2 of this Attachment AE.

7.3 Annual Auction Revenue Right Allocation

The annual ARR allocation addresses how candidate ARRs verified in the annual LTCR/ARR verification may be nominated and awarded. Eligible Entities may nominate the candidate ARRs that they wish to receive up to their ARR nomination caps less any LTCRs awarded. Candidate ARRs are available from un-awarded candidate LTCRs and surrendered LTCRs. No candidate ARRs are available from un-awarded ILTCRs or surrendered ILTCRs. The portion of the nominated candidate ARRs that are simultaneously feasible are allocated to each Eligible Entity during the annual allocation. Candidate ARRs are nominated on a monthly and seasonal basis in a three round process.

The Transmission Provider shall make available one hundred percent (100%) of the projected maximum Transmission System capability for the purpose of ARR allocation in the annual ARR allocation process. No later than five (5) days prior to the start of the annual ARR allocation process, the Transmission Provider will post the Transmission System network topology data for each of the monthly and seasonal On-Peak and Off-Peak models, including the corresponding Parallel Flow and transmission line outage assumptions, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocations.
# RARTF Members

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steve Stoll, Chair</td>
<td>Missouri Public Service Commission</td>
</tr>
<tr>
<td>Richard Ross, Vice Chair</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>Shari Albrecht</td>
<td>Kansas Corporation Commission</td>
</tr>
<tr>
<td>Steve Lichter</td>
<td>Nebraska Power Review Board</td>
</tr>
<tr>
<td>Lamar Davis</td>
<td>Arkansas Public Service Commission</td>
</tr>
<tr>
<td>Phil Crissup</td>
<td>Oklahoma Gas and Electric</td>
</tr>
<tr>
<td>Bill Grant</td>
<td>SPS Xcel Energy</td>
</tr>
<tr>
<td>Bary Warren</td>
<td>Gridliance -SCMCN</td>
</tr>
<tr>
<td>Harry Skilton</td>
<td>SPP Board of Directors</td>
</tr>
</tbody>
</table>
SPP Tariff Requirement – Reviews.

• The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years in accordance with this Section III.D.

• The Transmission Provider and/or the Regional State Committee may initiate such review at any time.

• Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.
Highway/Byway Review Process – 4 Steps.

• **STEP 1:** RARTF

• One year prior to each three-year planning cycle (starting in 2013) the *Markets and Operations Policy Committee* and *Regional State Committee* will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the Regional State Committee and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint – *HENCE ESTABLISHMENT OF RARTF*. 
Highway/Byway Review Process – 4 Steps.

- **STEP 2: SPP Staff Review**

- For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts utilizing the analysis specified in Section III.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J [RARTF Methods].
Highway/Byway Review Process – 4 Steps.

- **STEP 3: Report: Publishing of SPP Staff Review**
- The Transmission Provider shall review the results of the cost allocation analysis with SPP’s Regional Tariff Working Group, Markets and Operations Policy Committee, and the Regional State Committee. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.
Highway/Byway Review Process – 4 Steps.

- **STEP 4: Remedies of Review**

  - The Transmission Provider shall request the Regional State Committee provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.

- In accordance with the SPP Bylaws, the SPP Board of Directors will initiate the appropriate actions, including any necessary filings with the Commission, consistent with the Regional State Committee recommendations.
RECENT MEETINGS/TOPICS
Highway/Byway Review Process – 4 Steps.

• **Potential Remedies:**
  • Solutions could include, but are not limited to, adjustments to the Highway/Byway, transfer payments, approval of projects in specific zones, etc.
July 8, 2015

- Face to Face Meeting in Dallas, TX
- Update on Potential Remedies FERC filing
  - Staff filed to have potential RCAR remedies included in the SPP OATT
  - FERC denied stating filing did not provide clarity and transparency to the RCAR process
  - RARTF agreed to draft a Business Practice to address potential remedies and implementation
- Reviewed the evolution of transmission expansion in SPP
- RCAR II planning
September 14, 2015

- Face to Face Meeting in Dallas, TX
- Update on Potential Remedy Business Practice
- ESWG Update on modeling solutions
  - Load Pockets
  - Trapped Generation
- Agreed for Rate Impact analysis to be completed in 4\textsuperscript{th} Quarter 2016 after completion off RCAR II
- Reviewed RCAR II schedule
Next Meeting

• November 2, 2015
• Face to Face Meeting in Dallas, TX
• Major Topics:
  – Potential Remedies Business Practice
  – RCAR II Schedule
  – ESWG Update
Overview

• Staff re-evaluating NTC projects in 2016 ITPNT in adherence to Business Practices 7060 and 7160
  – Suspended projects from 2015 ITPNT and ITP10 due to cost variances
  – TO-requested re-evaluation of project need
  – TO-requested modifications of project scope
## 2015 ITP Cost Variance NTC Re-evaluation Update

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Owner</th>
<th>Source Study</th>
<th>Project Type</th>
<th>Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>Martin - Pantex North - Pantex South - Highland Park 115 kV Rebuild</td>
<td>SPS</td>
<td>2015 ITP10</td>
<td>Reliability</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Labette - Neosho SES 69 kV Rebuild</td>
<td>WERE</td>
<td>2015 ITPNT</td>
<td>Reliability</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Iatan - Stranger Creek 345 kV Voltage Conversion</td>
<td>WERE/GMO/KCPL</td>
<td>2015 ITP10</td>
<td>Economic</td>
<td>Need remains; recommend <strong>NTC reinstatement</strong></td>
</tr>
<tr>
<td>Hobart - Roosevelt Tap - Snyder 69 kV Rebuild</td>
<td>AEP</td>
<td>2015 ITPNT</td>
<td>Reliability</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Mineola - Grand Saline 69 kV Rebuild</td>
<td>AEP</td>
<td>2015 ITPNT</td>
<td>Reliability</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>South Shreveport - Wallace Lake 138 kV Rebuild</td>
<td>AEP</td>
<td>2015 ITP10</td>
<td>Reliability</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Linwood - South Shreveport 138 kV Rebuild</td>
<td>AEP</td>
<td>2015 ITPNT</td>
<td>Reliability</td>
<td>Need remains; further project analysis required</td>
</tr>
</tbody>
</table>
### Iatan – Stranger Creek 345 kV Analysis

<table>
<thead>
<tr>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
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<tbody>
<tr>
<td>Reference case</td>
<td>100% of benefits for 2019 - 2022</td>
<td>100% of benefits for 2019 - 2022</td>
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<tr>
<td>40 years of benefits and costs for 2019 - 2058</td>
<td>50% of benefits for 2023 – 2030</td>
<td>0% benefits after 2022</td>
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<td></td>
<td>0% benefits after 2030</td>
<td>Costs still calculated for 40 years</td>
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<tr>
<td>40-Year Value</td>
<td>$5,212,044,211</td>
<td>$326,728,000</td>
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<td>40-Year PV APC</td>
<td>$908,676,082</td>
<td>$187,356,525</td>
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<td>Transmission Outage</td>
<td>$102,680,397</td>
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<td>40-Year PV Benefit</td>
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<td>40-Year Cost</td>
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<td>$64,492,272</td>
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<tr>
<td>NPV</td>
<td>$946,864,207</td>
<td>$144,035,540</td>
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<td>B/C</td>
<td>15.68</td>
<td>3.23</td>
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</tbody>
</table>

**Staff Conclusion:** Scenario 3 represents the most conservative approach and indicates the project to be economically beneficial.
## 2015 ITP TO-Requested NTC Re-evaluation Update

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Owner</th>
<th>Source Study</th>
<th>Purpose</th>
<th>Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>Harrisonville North - Ralph Green 69 kV Rebuild</td>
<td>GMO</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Newport 69 kV Cap Bank</td>
<td>GRDA</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Boomer 69 kV Cap Bank</td>
<td>GRDA</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Childers 69 kV Cap Bank</td>
<td>GRDA</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Four Corners 69 kV Cap Bank</td>
<td>OGE</td>
<td>2015 ITPNT</td>
<td>Modify NTC</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>CPPXF#22 69 kV Terminal Upgrades</td>
<td>GRDA</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Road Runner 115 kV Loop Rebuild (Cap Banks Only)</td>
<td>SPS</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Gracemont - Anadarko 138 kV Reconductor</td>
<td>WFEC</td>
<td>2015 ITP10</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Winchester 69 kV Cap Bank</td>
<td>WFEC</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
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<tr>
<td>Thackerville 69 kV Cap Bank</td>
<td>WFEC</td>
<td>2015 ITPNT</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
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<tr>
<td>Baldwin Creek 230/115 kV Transformer</td>
<td>WERE</td>
<td>2015 ITPNT</td>
<td>Modify NTC</td>
<td>Need remains; further project analysis required</td>
</tr>
</tbody>
</table>

**All projects in table approved as Reliability projects**
### Other TO-Requested NTC Re-evaluation Summary

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Owner</th>
<th>Source Study</th>
<th>Purpose</th>
<th>Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>Georgia Pacific – Keatchie 138 kV Rebuild</td>
<td>AEP</td>
<td>2010 STEP</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Esquandale 69 kV Cap Bank</td>
<td>WFEC</td>
<td>2008 STEP</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Elk City – Red Hills 138 kV Reconductros</td>
<td>WFEC</td>
<td>2014 ITPNT</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>White Horse 69 kV Cap Bank</td>
<td>WFEC</td>
<td>Att. AQ Study</td>
<td>Re-evaluate Need</td>
<td>No need identified; recommend <strong>NTC withdrawal</strong></td>
</tr>
<tr>
<td>Letorneau - Air Liquide Tap 69 kV New Line</td>
<td>AEP</td>
<td>2014 ITPNT</td>
<td>Modify NTC</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Harper – Bluff City – Caldwell – Milan 138 kV New Line (Viola Tap Addition)</td>
<td>MKEC</td>
<td>HPILS</td>
<td>Modify NTC</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Knobhill – Lane – Noel 138 kV New Line</td>
<td>OGE/ WFEC</td>
<td>2014 ITPNT</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
</tbody>
</table>

**All projects in table approved as Reliability projects**
## Other TO-Requested NTC Re-evaluation Summary (cont’d)

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Owner</th>
<th>Source Study</th>
<th>Purpose</th>
<th>Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meeker – Hammett 138 kV New Line</td>
<td>WFEC</td>
<td>2007 STEP</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Anadarko – Georgia Tap 138 kV Rebuild</td>
<td>WFEC</td>
<td>2007 STEP</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
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<tr>
<td>Elmore – Paoli 69 kV Rebuild</td>
<td>WFEC</td>
<td>2007 STEP</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Anadarko – Blanchard – OU SW 138 kV Rebuild</td>
<td>WFEC</td>
<td>2010 STEP</td>
<td>Modify NTC</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Mustang - Sunshine Canyon 69 kV Reconstructor</td>
<td>WFEC</td>
<td>2014 ITPNT</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Freedom 69 kV Cap Bank</td>
<td>WFEC</td>
<td>HPILS</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
<tr>
<td>Carmen – Cherokee Junction 138 kV New Line</td>
<td>WFEC</td>
<td>HPILS</td>
<td>Re-evaluate Need</td>
<td>Need remains; further project analysis required</td>
</tr>
</tbody>
</table>

**All projects in table approved as Reliability projects**
## Recommendation Summary

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Owner</th>
<th>Source Study</th>
<th>Recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Martin - Pantex North - Pantex South - Highland Park 115 kV Rebuild</td>
<td>SPS</td>
<td>2015 ITP10</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Labette - Neosho SES 69 kV Rebuild</td>
<td>WERE</td>
<td>2015 ITPN</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Iatan - Stranger Creek 345 kV Voltage Conversion</td>
<td>WERE/GMO/KCPL</td>
<td>2015 ITP10</td>
<td>Reinstate NTC</td>
</tr>
<tr>
<td>Harrisonville North - Ralph Green 69 kV Rebuild</td>
<td>GMO</td>
<td>2015 ITPN</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Newport 69 kV Cap Bank</td>
<td>GRDA</td>
<td>2015 ITPN</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Boomer 69 kV Cap Bank</td>
<td>GRDA</td>
<td>2015 ITPN</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Childers 69 kV Cap Bank</td>
<td>GRDA</td>
<td>2015 ITPN</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Four Corners 69 kV Cap Bank</td>
<td>OGE</td>
<td>2015 ITPN</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Georgia Pacific – Keatchie 138 kV Rebuild</td>
<td>AEP</td>
<td>2010 STEP</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Esquandale 69 kV Cap Bank</td>
<td>WFEC</td>
<td>2008 STEP</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>White Horse 69 kV Cap Bank</td>
<td>WFEC</td>
<td>Att. AQ Study</td>
<td>Withdraw NTC</td>
</tr>
<tr>
<td>Elk City – Red Hills 138 kV Reconstructor</td>
<td>WFEC</td>
<td>2014 ITPN</td>
<td>Withdraw NTC</td>
</tr>
</tbody>
</table>
MOPC Actions

• Approved all Staff recommendations
• Approved motions to endorse issuing modified NTCs for two projects pending completion of analysis prior to January 2016 Board meeting
  – Letorneau – Air Liquide Tap 69 kV New Line
  – Harper – Bluff City – Caldwell – Milan 138 kV New Line (Viola Tap Addition)
RSC Capacity Margin Task Force Update

Tom Hestermann
CMTF Chairman

October 26, 2015

Helping our members work together to keep the lights on... today and in the future
CMTF Efforts

• LOLE Reserve Margin Study
• Deliverability Study
• Planning Reserve Assurance Policy
• Load Responsible Entity Whitepaper
• Other Items
LOLE Reserve Margin Study

- SPP staff finalized the 2015 Reserve Margin LOLE Limbo study consistent with the study scope approved by the CMTF in July.
- Staff presented the results to the CMTF at the September 30th meeting.
- CMTF requested more clarification and justification be added to the LOLE report before a planning reserve margin could be endorsed by the CMTF.
- The CMTF will hold a joint meeting October 28th with the ORWG and GWG to review the LOLE report and discuss endorsement of a new planning reserve margin recommendation.
LOLE Study Results

Reserve Margin Loss of Load Expectation Study Results

<table>
<thead>
<tr>
<th>Reserve Margin (%)</th>
<th>2016 LOLE Results</th>
<th>2017 LOLE Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.53%</td>
<td>0.92</td>
<td>1.727</td>
</tr>
<tr>
<td>8.70%</td>
<td>0.458</td>
<td>0.454</td>
</tr>
<tr>
<td>9.89%</td>
<td>0.267</td>
<td>0.189</td>
</tr>
<tr>
<td>11.11%</td>
<td>0.184</td>
<td>0.153</td>
</tr>
</tbody>
</table>

SPP Criteria
Deliverability Study

• New language was added to the Deliverability study whitepaper by the CMTF

• Currently under review by the CMTF

  – In October, the latest version of the whitepaper will be sent to the ORWG, GWG, CAWG, RSC, and MWG for review and feedback

  – The whitepaper is currently scheduled to be presented at the October 29th CMTF meeting as an approval item
Planning Reserve Assurance Policy

- The Planning Reserve Assurance Policy whitepaper was initially approved by the CMTF at the June 2\textsuperscript{nd} meeting.
- The whitepaper was included in the July MOPC meeting materials as informational only.
- The Strategic Planning Committee (SPC) was given an overview of the policy at the July 16\textsuperscript{th} meeting.
- New language was added to the whitepaper by the CMTF.
- In October, the latest version of the whitepaper will be sent to the ORWG, GWG, CAWG, RSC, and MWG for review and feedback.
- The whitepaper is currently scheduled to be presented at the October 29\textsuperscript{th} CMTF meeting as an approval item for new language.
Load Responsible Entity

- Load Responsible Entity (LRE) Whitepaper
  - Approved by MOPC at the July MOPC meeting
  - The LRE whitepaper was presented to the Regional Tariff Working Group (RTWG) at the July 23rd meeting
    - Process Improvement Tariff Task Force (PITTF) currently discussing Tariff inclusion
    - Dennis Reed to give a progress update at the October 29th CMTF meeting
Other Items

- Demand Response Small Group
  - Comprised of CMTF members
  - Tasked with defining planning reserve requirements for Demand Response, Energy Efficiency, and Behind-the-Meter generation
Seams Update

Carl Monroe
October 26, 2015

Helping our members work together to keep the lights on... today and in the future
SPP-MISO POTENTIAL
INTERREGIONAL PROJECTS
Regional Review Objectives

- Evaluate the recommended Interregional Projects from the SPP-MISO Coordinated System Plan study (CSP)

- Determine if the Interregional Project is more cost effective than an identified regional solution

- Compare SPP benefits to SPP costs and determine if B/C ratio is greater than 1.0
1. Addition of a series reactor on the Swartz-Alto 115kV line at the Alto 115kV Substation  
   • 14% SPP funded

2. Rebuild existing 11 mile South Shreveport to Wallace Lake 138kV line  
   • 20% SPP funded

3. New 78 mile 345kV line from Elm Creek – NSUB (New substation on the Pauline – Mark Moore 345kV line)  
   • 80% SPP funded
SERIES REACTOR ON SWARTZ – ALTO 115 KV
Series Reactor on Swartz – Alto 115 kV

- SPP E&C cost: $740k
- 40-YR SPP Cost: $1.27 million
- 40-YR SPP PV Benefits: -$8 million
- MOPC recommends not approving as an Interregional Project
SOUTH SHREVEPORT – WALLACE LAKE REBUILD
S. Shreveport – Wallace Lake 138 kV

- Project details
  - Rebuild 11 mile S. Shreveport to Wallace Lake 138 kV line with 1533.3 ACSR/TW
- E&C Cost of $18.5 M
- 20% SPP funded
- E&C SPP Cost: $3.7M
South Shreveport Metrics & Total Benefit

<table>
<thead>
<tr>
<th>Categories</th>
<th>Values</th>
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</thead>
<tbody>
<tr>
<td>APC</td>
<td>$39,328,392</td>
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<tr>
<td>Wheeling</td>
<td>$-</td>
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<tr>
<td>Trans Outages</td>
<td>$4,444,108</td>
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<tr>
<td>Reliability</td>
<td>$31,898,861</td>
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<tr>
<td>40-Yr PV Benefits</td>
<td>$75,671,361</td>
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<tr>
<td>40-Yr PV Cost</td>
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<tr>
<td>NPV</td>
<td>$69,291,589</td>
</tr>
<tr>
<td>B/C Ratio</td>
<td>11.86</td>
</tr>
</tbody>
</table>
Conclusions

• Project addresses 2015 ITP10 reliability need
• APC benefit alone provides a B/C ratio greater than 6
• Total B/C ratio greater than 11
• MOPC recommends approving South Shreveport to Wallace lake rebuild as an Interregional Project
ELM CREEK – NSUB 345 KV
Elm Creek – NSUB 345kV

- Project details
  - New 78 mile 345kV from Elm Creek – NSUB (New Substation on the Pauline – Mark Moore 345kV line)
- E&C cost of $140 million
- 80% SPP Funded
- E&C SPP Cost: $112.5M
# Elm Creek Metrics & Total Benefit

<table>
<thead>
<tr>
<th>Project</th>
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</tr>
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<tbody>
<tr>
<td>APC</td>
<td>$189,646,497</td>
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<td>$8,335,167</td>
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<td>Trans Outages</td>
<td>$21,430,054</td>
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<tr>
<td>Reliability</td>
<td>-</td>
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<tr>
<td>40-Yr PV Benefits</td>
<td>$219,411,719</td>
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<tr>
<td>40-Yr PV Cost</td>
<td>$193,479,100</td>
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<tr>
<td>NPV</td>
<td>$25,932,619</td>
</tr>
<tr>
<td>B/C Ratio</td>
<td>1.13</td>
</tr>
</tbody>
</table>
40-Year Present Value

Benefits Less than Costs Until 2035
Generation Change (MWh)

- CC: -313,248
- ST Gas: -46,751
- ST Coal: 108,812
- CT Gas: -42,836
- IC Gas: -3,035
Conclusions

• Elm Creek – NSUB is significantly more cost effective without Iatan to Stranger voltage conversion
  – B/C ratio of Elm Creek – NSUB reduced to 1.13 when Iatan – Stranger is upgraded

• Costs greater than the APC benefits for approximately the first 10-years if Iatan – Stranger is upgraded

• Restrictions on ability to increase coal dispatch may result in the B/C ratio dropping below 1.0
MOPC Recommendation to the SPP Board

• MOPC does not recommend approving the Alto – Swartz series reactor as an Interregional Project
  – Could be reevaluated in a future regional or interregional study

• MOPC does not recommend approving Elm Creek – NSUB 345 kV as an Interregional Project
  – Could be reevaluated in a future regional or interregional study

• MOPC recommends the approval of the South Shreveport – Wallace Lake Rebuild as an Interregional Project
MISO SETTLEMENT UPDATE
Section 5.2 Sharing Contract Path Capacity.

If the Parties have contract paths to the same entity, the combined contract path capacity will be made available for use by both Parties. This will not create new contract paths for either Party that did not previously exist. SPP will not be able to deal directly with companies with which it does not physically or contractually interconnect and the Midwest ISO will not be able to deal directly with companies with which it does not physically or contractually interconnect.
FERC Procedural History

1/28/14
SPP filed unexecuted Service Agreement

1/28/14
SPP filed Complaint asserting JOA violations and seeking compensation

2/18/14
Entities Filing in Support of SPP: SPP TOs, Joint Parties, Basin Electric, WAPA

3/28/14
FERC accepted the SPP Service Agreement and set the matter for hearing & settlement

4/29/14
First of Seven Settlement Conferences at FERC

Feb – Oct 2015
Concentrated small group negotiations and Parties worked with docket intervenors to review draft settlement agreement

10/13/15
Settlement Agreement Filed at FERC
Settlement Terms

• Available System Capacity (ASC) and Compensation
  – ASC made available to MISO on non-firm, as-available basis
  – Compensation based on Capacity Factor of MISO flows above MISO’s Contract Path relative to amount of headroom
  – Settles prior issued invoices for $8M per year

• Operating Requirements for ASC
  – Establishes Regional Directional Transfer Limits for MISO that limit real-time flows to 3,000 MW N-S and 2,500 MW S-N
  – Parties will use normal M2M or TLR procedures for managing congestion with a couple of exceptions for AECI flowgates
Settlement Terms

• Firm Point-to-Point Transmission Service
  – MISO had previously granted firm service in excess of its Contract Path rights (almost exclusively service to NRG)
  – Compensation from NRG to SPP and Joint Parties and terms for the service previously granted by MISO to not be contested
  – Acknowledgement by MISO that it can not grant additional firm transmission service above MISO’s Contract Path

• Amendments to the SPP-MISO JOA

• Effective Date of January 29, 2014
Settlement Terms

• Term and Termination
  – Initial 7 year term for Settlement Agreement beginning January 29, 2014 (date of SPP Service Agreement) with evergreen extensions and one year prior notice from any Party to terminate
  – If no replacement agreement is reached, MISO has no transmission usage rights above its own Contract Path and will be subject to SPP Tariff rates and penalties if it does

• The Settlement includes a Compensation Manual which provides the details for determining MISO’s flows with respect to ASC usage
COMPENSATION OVERVIEW
Compensation Overview

- Compensation based on discrete bands of calculated Capacity Factor for varying amounts of MISO’s ASC Usage

0%-20%
- $1.33M per month ($16M per year)

20%-70%
- $2.25M per month ($27M per year)

70%+
- $3.17M per month ($38M per year)

- Band pricing adjusts if MISO’s Contract Path increases or decreases
- If Capacity Factor is zero in any month, no payment due for that month
Compensation Overview

1. MISO Compensation for 2014 and 2015 split **60% to SPP and 40% to Joint Parties**
2. NRG Compensation split **50% to SPP and 50% to Joint Parties**
3. MISO Compensation 2016+ split **50% to SPP and 50% to Joint Parties**
4. $16M for CF < 20%, $27M for CF between 20% and 70%, $38M for CF > 70%
5. NRG payment may be lower if NRG elects to annul some MWs
Distribution of Funds Collected

- Any funds collected under Settlement Agreement will be distributed to SPP members
- As funds are not being collected under existing OATT schedules, SPP will make a FERC filing as to the method that will be used
- SPP Board of Directors charged SPP staff and SPP TO’s who negotiated Settlement Agreement to make a recommendation as to how funds should be distributed
- Developed two principles to guide discussions of distribution method:
  - Distribution of revenue should be consistent with the basis for the charges under the Settlement Agreement
  - Revenue received by SPP Transmission Owners should flow through to the benefit of load within SPP
Distribution Options Considered

• 100% Flow-based Approach
  – MW-Mile Calculation
  – Updated allocation percentages annually

• 50% ATRR/50% Flow-based
  – ATRR portion allocated between Schedule 8 and 11
  – Flow-based portion same as 100% flow-based option

• 100% Load Ratio Share
Recommended Policy on Revenue Distribution

- Majority of SPP TO’s who were part of discussions favor 100% Flow-based Approach
  - Includes KCPL, GMO, OGE, AEP, WAPA, Westar, Basin, Heartland, Sunflower, Mid-Kansas, NPPD, OPPD, Empire, SWPA, CUS
  - LES favors 50% ATRR/50% Flow-based approach
  - SPS favors 100% Load Ratio Share approach

- All favor SPP retaining a portion of the revenue to reduce Schedule 1A for costs of administering settlement agreement
  - SPP staff recommends $250K/yr initially

- All favor portion of initial money received be used to reimburse SPP TO’s for legal expenses from litigation in docket

- General consensus is to develop a new tariff schedule specific to this settlement to address revenue distribution
  - Include requirement that revenue be treated like Point-to-Point revenue by SPP TO’s
Integrated Marketplace Update

Bruce Rew, PE
Vice President, Operations
SPP Integrated Marketplace Update

- Integrated System (IS) Integration review
- Marketplace Operational Highlights
- Marketplace Statistical Information
- Enhancements under development
EHV Transmission
(Existing and Planned with NTC)

Voltage       Project Type
230 kV       New Line
345 kV       Line Upgrade
500 kV
Integrated Marketplace with IS

- Generation and Load additions
  - Load winter peak of approximately 5000 MW
  - Generation addition of approximately 7,600 MW

- Diverse fuel mix
  - 34% hydro, 31% coal, 16% gas, 12% wind, 7% other

- Three additional DC Ties
  - Miles City, Rapid City, and Stegall

- Phase Shifter to Saskatchewan Power
  - Some energy has been scheduled across the Phase Shifter
Market “go live” with IS

- Transition into Integrated Marketplace on 10/1 went very smooth and was a non-event
- BIG Appreciation for all the hard work to make it!!
- Added 151 new tie lines on top of the existing 253 tie lines and 100 new flow gates (WAPA, MISO, MHEB)
- IS load at transition was 2400 MW and actual generation online was 3000 MW
- IS maintained self commitments for the first two days of operation
- Day-Ahead and Intra-Day Reliability Unit Commitment (RUC) for 10/3/15 solved without issue
Marketplace Over Last 12 Months

- **159 Market Participants**
  - 100 financial only and 59 asset owning
    - Added 11 new Market Participants since July report

- **SPP BA has successfully maintained NERC control performance standards (CPS1 = 151.5% and CPS2 = 94.6%)**

- **High System availability**
  - Day-Ahead Market has only been delayed from posting twice
    - Mid December 2014 (due to an importer timeout which effected MPs ability to submit offers)
    - Late September 2015 (due to MOI/Market System Issues)
  - Real-Time Balancing Market has successfully solved 99.93% of all intervals
Marketplace Operational Highlights

• 2015 Summer Peak of 45,873 MW on July 24
  – Compared to 2014 summer peak of 45,302 MW on August 21

• No major transmission or generation problems experienced

• New wind peaks
  – Peak wind output of 8,458 MW on October 18
  – Penetration level 37.8% on October 19
  – 2,800 MW of wind added to SPP in 2015 not including 826 MW of IS wind

• Winter preparedness well under way
Integrated Marketplace Capacity Overage

Average RT Daily Capacity Overage*

*Overage=Economic Max - Load - NSI - (RegUp+SPIN+SUPP)
Graph on Dispatch by Fuel Type

Real-Time

Generation (GWh)

- Jul 14
- Aug 14
- Sep 14
- Oct 14
- Nov 14
- Dec 14
- Jan 15
- Feb 15
- Mar 15
- Apr 15
- May 15
- Jun 15
- Jul 15
- Aug 15
- Sep 15

- Other
- Gas-SC
- Gas-CC
- Coal
- Hydro
- Renewable
- Wind
- Nuclear
Graph on Fuel on the Margin in RT

% Intervals on Margin

- Other
- Gas
- Coal
- Wind

Desktop Icon: SPP

10
Graph on Real-Time versus DA pricing
DA vs RT: Percent Contribution to LMP Difference

MCC: Marginal Congestion Cost
MLC: Marginal Loss Cost
MEC: Marginal Energy Cost
**Integrated Marketplace Enhancements**

**Recently Implemented:**

- Improvements to load distribution process in DA Market
- DA RUC improvements to consider current operating day commitments
  - software changes have been implemented, awaiting FERC approval before change can become effective

**On The Way (Currently Testing):**

- Current release in testing is for Internal ESB modifications only – no Member Facing or Impacting issues

**Tentative Near Term: (Target Feb 23, 2016 Implementation)**

- Real-Time Data Precision Enhancement
- Short-Term Intra-Day RUC (STRUC)
- Misc Markets UI/API Improvements
Our Mission

Helping our members work together to keep the lights on ... today and in the future.
2017 ITP10
Scope Update

Alan Myers, ESWG Chair
October 26, 2015

Southwest Power Pool
Helping our members work together to keep the lights on... today and in the future
2017 ITP10 Scope Overview

- Futures
- Modeling Parameters
- Resource Plan Phase 1
- Resource Plan Phase 2
- Siting
- Constraint/Needs Assessment
- Solution Development
- Consolidation
- Seams coordination
- Staging
- Benefit Metrics
- Sensitivities
Futures

• Future 1: Regional Clean Power Plan Solution
• Future 2: State Level Clean Power Plan Solution
• Future 3: Reference Case, no CPP implementation
Modeling

• Reference case modeling assumptions
  – Study Year 2025
  – NERC Nodal Reference Case for coal, oil, uranium and emissions prices
  – NYMEX futures and DOE growth rates for natural gas prices
  – $8/MWh VOM and curtailment price for wind
Resource Plan Phase 1

• Additional renewables will be included in the plans, as needed, to meet the renewable Mandate and Goal projections, as supplied by the Renewable Policy Survey

• Renewable generation, for the purposes of this study, includes hydro, wind, solar, and bio-fuel
Resource Plan Phase 2

• Each SPP RTO load serving member must meet the current reserve margin

• Capacity needs will be identified for each future for 2020 and 2025

• Additional renewables identified by the resource planning software may also be included

• Utilizing prototypes for new units from Lazard’s 2014 Levelized Cost of Energy Study
Siting

- Developed utilizing sites selected in the 2013 ITP20 and the 2015 ITP10 studies, and the SPP Generation Interconnection queue
Constraint/Needs Assessment

• Economic Needs
  – Up to 25 congested constraints with greater than $50,000 in annual congestion cost will be identified as economic needs

• Policy Needs
  – Shortfall of deliverable energy mandates or goals by utility, by state, will be identified

• Reliability Needs
  – An N-1 contingency analysis will be conducted on each future for the peak and off peak cases, to determine thermal and voltage needs
Solution Development

- Solutions will come from:
  - Detailed Project Proposals
  - Transmission Service Studies
  - Generation Interconnection Studies
  - Previous ITP studies
  - Other Solutions Proposed by Stakeholders and SPP Staff
Consolidation

- Reliability, policy, and economic solutions will be grouped together and refined to create a portfolio for each future
- The final portfolio for each future will be consolidated into a single portfolio
- The consolidation of reliability, policy and economic projects will be based upon criteria approved by the ESWG, TWG, and the MOPC
Seams Coordination

• Seams projects will be considered as part of the study
• SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs
• If JOA is in place, joint coordination will be done in accordance with the agreement
• Seams projects will be evaluated based on the assumption that the project would be cost shared with an SPP neighbor
Staging

• Economic Projects
  – based on linear interpolation of B/C ratios from 2020 to 2025 with consideration of lead times

• Policy Projects
  – staged in order to meet the renewable requirements

• Reliability Projects
  – based on linear interpolation of thermal loadings and voltage violations from 2020 to 2025

• Multiple Project Classification
  – staged to meet the earliest need date established through the Single Project Classification
## Benefit Metrics

### Metric Description

<table>
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<tr>
<th>Metric Description</th>
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<tbody>
<tr>
<td>APC Savings</td>
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<tr>
<td>Savings Due to Lower Ancillary Service Needs and Production Costs</td>
</tr>
<tr>
<td>Avoided or Delayed Reliability Projects</td>
</tr>
<tr>
<td>Marginal Energy Losses</td>
</tr>
<tr>
<td>Capacity Cost Savings Due to Reduced On-Peak Transmission Losses</td>
</tr>
<tr>
<td>Reduction of Emissions Rates and Values</td>
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<tr>
<td>Public Policy Benefits</td>
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<tr>
<td>Assumed Benefit of Mandated Reliability Projects</td>
</tr>
<tr>
<td>Mitigation of Transmission Outage Costs</td>
</tr>
<tr>
<td>Increased Wheeling Through and Out Revenues</td>
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Sensitivities

• Some or all of the following sensitivities will be performed
  – Natural Gas Price
  – Demand levels
  – Others as determined
• Final Reliability Assessment
• Final Stability Assessment
Stakeholder Feedback

- The TWG and ESWG approved the 2017 ITP10 Scope.
  - ESWG unopposed, September 23rd
  - TWG unopposed, September 29th
Recommendation

- The TWG and ESWG approved the 2017 ITP10 Scope in September 2015
- MOPC approved the 2017 ITP10 Scope on October 13th with the following change to the reliability assessment:
  - All SPP BES facilities will be monitored for the NERC TPL-001-4 standard Table 1 planning events that do not allow for non-consequential load loss or curtailment of firm transmission service in development of 100 kV and above solutions
Transmission Planning Improvement Task Force (TPITF)

Brian Gedrich - Chair

RSC
October 26, 2015
TPITF Scope

- Evaluate and propose recommendations on:
  - The methodologies and modeling practices used in the studies
  - Utilization of data to ensure consistency in the planning process
  - The appropriateness of the planning cycle and assessments

- Recommendations will be presented to MOPC, SPC, and Board in January 2016

- Face-to-face and Webex meetings

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<th>Location</th>
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<th>Location</th>
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<td>4/7</td>
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TPITF Members

- Brian Gedrich – Chair
- Jason Atwood – Vice Chair
- Antoine Lucas – Secretary
- Mohammad Awad
- Bruce Cude
- Katy Onnen
- John Krajewski
- Adam McKinnie
- Alan Myers
- Steve Sanders
- Wayman Smith
- Lloyd Kolb
Key Issues Identified

• A three-year planning cycle is not timely
• Stakeholder process approvals and model development are bottlenecks and can limit the frequency of the planning process
• Duplication and variance of modeling in planning processes and studies create inefficiencies and add additional time
• Real-time operations data not always considered in the planning process
• The ITP20 is resource intensive and provides primarily strategic value and not actionable results
TPITF Consensus Items

- 18-month planning cycle
- Common planning model
- Holistic planning process
- Standardized scope
18-Month Planning Cycle

• Reduce the ITP planning cycle from 36 to 18 months
  – Perform ITP20 study separate from planning cycle
  – Overlap to produce an annual ITP report

Common Planning Model

• Build a common base model for all planning processes
  – Region-wide economic commitment and dispatch that more appropriately accounts for renewables and firm transmission rights
  – Leverage Model Development Working Group (MDWG) model build process for data submission
Holistic Planning Process

• Combine the ITPNT, ITP10, and TPL processes into one 10-year study
  – Reliability, economic, policy, and compliance assessments
  – Evaluate feasibility of including compliance assessments in planning cycle

Standardized Scope

• Standardize traditional scope items
  – Leverage ITP Manual for established planning approaches
  – Utilize assumptions document for approval of items that typically change per study (i.e., futures, fuel prices, etc.)
Questions?
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<th>Action Item</th>
<th>Date Originated</th>
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<th>Comments</th>
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<td>5</td>
<td>Consideration of RSC Bylaws changes related to membership eligibility</td>
<td>Ongoing</td>
<td>Ongoing</td>
<td>Discussed at December 1, 2014 meeting, January 2015 Educational Session and March 9, 2015 Meeting. Action is needed by July 2015 meeting. A small group of RSC Commissioners (Albrecht, Davis and Nelson, along with Commissioner Kalk from North Dakota) will review the bylaws and report back to the RSC for further consideration. This was discussed at the RSC retreat and meeting on July 27, 2015. Bylaws changes were considered at the September 21, 2015 meetings but were not approved. Changes to the Bylaws may be considered again at a later time.</td>
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<td>9</td>
<td>Goals and Objectives for 2015 RSC Year</td>
<td>12/1/2014</td>
<td>Ongoing</td>
<td>Discussed at December 1, 2014 meeting and draft goals were reviewed on January 26, 2015, March 9, 2015, April 27, 2015 and September 21, 2015.</td>
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<td>12</td>
<td>RSC Role in Cost Allocation for New Member Integrations</td>
<td>4/27/2015</td>
<td>In Process.</td>
<td>In January 2015, the RSC tasked the CAWG with looking at what role the RSC should have in regards to Cost Allocation methodology for new members joining SPP. At the April RSC educational session the RSC heard a presentation from Carl Monroe on the history of integrating new members in SPP and had a discussion with CAWG members regarding the Nebraska integration, IS integration, and areas of interest from RSC &amp; CAWG members. After discussion on the topic, the RSC tasked the CAWG to develop a scoping document on how to apply cost allocation for new members joining SPP. The Scope Document developed by CAWG was approved by the RSC on July 27, 2015 and CAWG is moving forward with its analysis of this issue.</td>
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<tr>
<td>No.</td>
<td>Action Item</td>
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<td>Comments</td>
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<tr>
<td>13</td>
<td>Aggregate Study Waiver Criteria</td>
<td>4/27/2015</td>
<td>In Process</td>
<td>While discussing a request for waiver of the eligibility requirements of Section III.B.1 of Attachment J for a request for a new Designated Wind Resource, the RSC determined it should review the eligibility requirements set out in Section III.B.1 (specifically the 20% threshold), and whether the requirements are applicable today in light of the changes to the transmission system since the requirements were approved. The RSC asked CAWG to evaluate the eligibility requirements for a waiver request to see if the requirements are still applicable to the transmission system as it operates now. CAWG presented a draft scoping document to the RSC on July 27, 2015. The RSC asked CAWG to evaluate whether the RSC consultant was needed, and if so to develop a scope of work, or whether SPP staff could provide the necessary background and analysis. The draft scope document was approved by CAWG on October 6, 2015 and will be presented to the RSC for its consideration at the October 2015 meeting.</td>
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<td>14</td>
<td>Capacity Margin Task Force Update</td>
<td>4/27/2015</td>
<td>In Process</td>
<td>After a presentation at the April 2015 RSC meeting, and discussion on the Capacity Margin Task Force, the RSC tasked the CAWG to evaluate how load is forecasted for the purpose of determining the reserve margin. CAWG reported back to the RSC on load forecasting at their July meeting and the RSC provided no further action to the CAWG on this item. Updates on the CMTF activities were provided to the MOPC, RSC and BOD at the July 2015 meetings. This item remains ongoing and an update will be provided at the October 2015 RSC meeting.</td>
</tr>
<tr>
<td>No.</td>
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<td>Comments</td>
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<td>EPA 111(d) : (1) Lanny Nickell to provide scope document on compliance analysis and an update on when SPP reliability analysis will be completed (2) Commissioner Reeves to provide update on possibility of studies to be performed by BPC and GPI, what services those entities are providing</td>
<td>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
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<tr>
<td>2</td>
<td>RARTF: Update on RARTF and New Metrics</td>
<td>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
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<tr>
<td>3</td>
<td>Seams Project Task Force: CAWG will consider the issue at next meeting and bring back to RSC for discussion</td>
<td>8/25/2014</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting; On 10/27/14 Meeting as a voting item</td>
</tr>
<tr>
<td>4</td>
<td>SPC Task Force on New Members: RSC should email Commissioner Murphy with any concerns or topics. Update to be provided at next RSC meeting</td>
<td>8/25/14</td>
<td>Completed</td>
<td>Addressed at 9/29/14 Meeting</td>
</tr>
<tr>
<td>No.</td>
<td>Action Item</td>
<td>Date Originated</td>
<td>Status</td>
<td>Comments</td>
</tr>
<tr>
<td>-----</td>
<td>------------------------------------------------------------------------------</td>
<td>-----------------</td>
<td>--------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>7</td>
<td>SPC Task Force on New Members – Discuss 3 RSC Action Items</td>
<td>9/29/2014</td>
<td>Complete</td>
<td>Discussed at October 27, 2014 Meeting and December 1, 2014 Meeting. On January 2015 Educational Session for discussion and January 2015 Meeting Agenda as a voting item. Feedback was provided to SPC TF on NM on items 1 and 2 on January 26, 2015 and subsequent to the March 9, 2015 RSC teleconference. The RSC will continue to discuss item 3 on cost allocation and has delegated this item to the CAWG (Action Item 12). On July 27, 2015, the RSC approved a scoping document developed by CAWG. The SPC TF on New Members finalized its report, which was approved by the SPC in July 2015. The RSC approved the New Member Process document with the addition of catch-al language permitting the RSC to invoke the new member process for matters within the RSC’s responsibility.</td>
</tr>
<tr>
<td>10</td>
<td>RSC Retreat</td>
<td>1/25/2015</td>
<td>Complete</td>
<td>Consensus on holding retreat in Kansas City in connection with the July RSC meeting. SPP staff is making arrangements.</td>
</tr>
<tr>
<td>11</td>
<td>Educational Session on SPP “Building Blocks”</td>
<td>1/25/2015</td>
<td>Removed</td>
<td>Educational Session on the SPP “Building Blocks” – possible topic for July retreat. Unclear what this was intended to cover. Removed when list of retreat topics was updated.</td>
</tr>
</tbody>
</table>
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Executive Summary

SPP actively monitors and supports the progress of transmission expansion projects, emphasizing the importance of maintaining accountability for areas such as grid regional reliability standards, firm transmission commitments and Tariff cost recovery.

Each quarter SPP staff solicits feedback from the project owners to determine the progress of each approved transmission project. This quarterly report charts the progress of all SPP Transmission Expansion Plan (STEP) projects approved either directly by the SPP Board of Directors (Board) or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

The reporting period for this report is May 1, 2015 through July 31, 2015. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades in which construction activities are ongoing, or construction has completed but not all the close-out requirements have been fulfilled in accordance to Section 13 of Business Practice 7060. The PTP includes all active Network Upgrades including transmission lines, transformers, substations, and devices.

Table 1 below summarizes the PTP for this quarter. Figures 1 reflects the percentage cost of each upgrade type in the PTP. Figure 2 shows the percentage cost of each project status in the PTP.

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>No. of Upgrades</th>
<th>Estimated Cost</th>
<th>Miles of New</th>
<th>Miles of Rebuild</th>
<th>Miles of Voltage Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balanced Portfolio</td>
<td>4</td>
<td>$267,296,361</td>
<td>226.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Economic</td>
<td>4</td>
<td>$37,914,101</td>
<td>0.0</td>
<td>0.0</td>
<td>28.8</td>
</tr>
<tr>
<td>High Priority</td>
<td>102</td>
<td>$2,136,607,045</td>
<td>1761.4</td>
<td>11.5</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>331</td>
<td>$3,132,161,220</td>
<td>1551.6</td>
<td>591.8</td>
<td>588.4</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>22</td>
<td>$91,383,341</td>
<td>12.7</td>
<td>15.3</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$109,022,970</td>
<td>34.7</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td>NTC Projects Subtotal</td>
<td>472</td>
<td>$5,774,385,039</td>
<td>3586.9</td>
<td>647.1</td>
<td>617.3</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>39</td>
<td>$147,381,777</td>
<td>39.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>2</td>
<td>$11,907,090</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>TO - Sponsored</td>
<td>11</td>
<td>$66,024,411</td>
<td>22.7</td>
<td>0.0</td>
<td>1.6</td>
</tr>
<tr>
<td>Non-NTC Projects Subtotal</td>
<td>52</td>
<td>$225,313,278</td>
<td>62.2</td>
<td>0.0</td>
<td>1.6</td>
</tr>
<tr>
<td>Total</td>
<td>524</td>
<td>$5,999,698,317</td>
<td>3649.1</td>
<td>647.1</td>
<td>618.9</td>
</tr>
</tbody>
</table>

*Table 1: Q3 2015 Portfolio Summary*
Figure 1: Percentage of Project Type on Cost Basis

- Balanced Portfolio: 36%
- Economic: 53%
- Generation Interconnection: 2%
- High Priority: 2%
- Regional Reliability: 2%
- Transmission Service: 0.6%
- Zonal Reliability: 0.6%

Figure 2: Percentage of Project Status on Cost Basis

- Closed Out: 12%
- Complete: 18%
- On Schedule < 4: 27%
- On Schedule > 4: 18%
- Delay - Mitigation: 6%
- NTC Suspension: 3%
- NTC - Commitment Window: 0.3%
- NTC-C Project Estimate Window: 0.4%
- RFP Response Window: 0.3%
- Re-evaluation: 0.6%
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to commence the construction of Network Upgrades that have been approved or endorsed by the Board intended to meet the construction needs of the STEP, OATT, or Regional Transmission Organization (RTO).

Figure 3 reflects project status within each source study, and Table 2 provides the supporting data. Figure 4 shows the amount of estimated cost by in-service year for all Network Upgrades that have been issued an NTC or NTC-C. Figure 5 shows the cost trend of all the Board-approved studies that have resulted in NTCs. **Note: Figures 3, 4, and 5, and Table 2 provide data for all projects for which SPP has issued an NTC or NTC-C, regardless of completion date, and therefore include data from Network Upgrades no longer included in PTP.**
Southwest Power Pool, Inc.

Table 2: Project Status by NTC Source Study

<table>
<thead>
<tr>
<th>Source Study</th>
<th>Complete</th>
<th>Delayed</th>
<th>Suspended</th>
<th>On Schedule</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006 STEP</td>
<td>$190,913,983</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$190,913,983</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$419,115,229</td>
<td>$21,413,000</td>
<td>$0</td>
<td>$0</td>
<td>$440,528,229</td>
</tr>
<tr>
<td>2008 STEP</td>
<td>$236,295,895</td>
<td>$3,543,000</td>
<td>$0</td>
<td>$0</td>
<td>$239,838,895</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$826,858,642</td>
<td>$7,900,000</td>
<td>$0</td>
<td>$0</td>
<td>$826,858,642</td>
</tr>
<tr>
<td>2009 STEP</td>
<td>$563,523,628</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$571,423,628</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$844,787,522</td>
<td>$127,995,000</td>
<td>$0</td>
<td>$336,433,874</td>
<td>$1,309,216,396</td>
</tr>
<tr>
<td>2010 STEP</td>
<td>$108,424,323</td>
<td>$33,304,460</td>
<td>$0</td>
<td>$168,322,800</td>
<td>$158,560,583</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$141,645,332</td>
<td>$46,609,056</td>
<td>$0</td>
<td>$0</td>
<td>$188,254,388</td>
</tr>
<tr>
<td>2012 ITP10</td>
<td>$0</td>
<td>$313,766,232</td>
<td>$0</td>
<td>$459,087,099</td>
<td>$772,463,722</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$166,895,766</td>
<td>$267,007,825</td>
<td>$0</td>
<td>$71,914,632</td>
<td>$505,818,223</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$12,054,467</td>
<td>$396,135,210</td>
<td>$0</td>
<td>$237,595,667</td>
<td>$645,785,344</td>
</tr>
<tr>
<td>HPILS</td>
<td>$70,381,595</td>
<td>$204,848,150</td>
<td>$0</td>
<td>$553,313,728</td>
<td>$828,543,473</td>
</tr>
<tr>
<td>2015 ITPNT</td>
<td>$0</td>
<td>$144,186,383</td>
<td>$72,135,858</td>
<td>$86,013,169</td>
<td>$302,335,410</td>
</tr>
<tr>
<td>2015 ITP10</td>
<td>$0</td>
<td>$404,101</td>
<td>$75,597,284</td>
<td>$32,322,911</td>
<td>$108,324,295</td>
</tr>
<tr>
<td>IS Integration Study</td>
<td>$0</td>
<td>$38,000,000</td>
<td>$0</td>
<td>$345,400,000</td>
<td>$383,400,000</td>
</tr>
<tr>
<td>Ag Studies</td>
<td>$679,111,530</td>
<td>$79,128,111</td>
<td>$0</td>
<td>$44,188,240</td>
<td>$802,427,881</td>
</tr>
<tr>
<td>DPA Studies</td>
<td>$119,237,386</td>
<td>$70,865,077</td>
<td>$0</td>
<td>$7,652,131</td>
<td>$197,754,594</td>
</tr>
<tr>
<td>GI Studies</td>
<td>$395,822,060</td>
<td>$31,190,335</td>
<td>$10,588,285</td>
<td>$24,460,603</td>
<td>$462,061,283</td>
</tr>
<tr>
<td>Total</td>
<td>$4,775,067,358</td>
<td>$1,785,905,332</td>
<td>$158,321,427</td>
<td>$2,215,214,853</td>
<td>$8,934,508,969</td>
</tr>
</tbody>
</table>

Figure 4: Estimated Cost for NTC Projects per In-Service Year
Figure 5: Cost Trend per Board-Approved Study
NTC Issuance
No new or modified NTCs were issued since the last quarterly report was published.

NTC Withdraw
Three previously issued NTCs were withdrawn since the last quarterly report. The NTCs included four Network Upgrades estimated to cost $26.8 million.

One NTC previously issued to Westar Energy (WR) included Network Upgrades that were requested to be restudied by the DTO, and were determined to be no longer needed through the Aggregate Study process.

One NTC previously issued to Sunflower Electric as a part of the 2014 Integrated Transmission Planning Near-Term Assessment (ITPNT) was withdrawn when further analysis in the 2015 ITPNT revealed that the two Network Upgrades were no longer needed.

One NTC previously issued to Southwestern Public Service Company (SPS) as part of the 2015 ITPNT was withdrawn when it was determined that the facilities that necessitated the Network Upgrade were not under the jurisdiction of the OATT.

Table 3 lists the NTC Withdraw activity from July 1, 2015 through September 30, 2015. NTC ID values in **bold** font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>DTO</th>
<th>NTC Withdraw Date</th>
<th>Upgrade Type</th>
<th>Original Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of Withdrawn Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200346</td>
<td>WR</td>
<td>7/23/2015</td>
<td>Transmission Service</td>
<td>SPP-2012-AG1-AFS-7</td>
<td>1</td>
<td>$18,396,464</td>
</tr>
<tr>
<td>200347</td>
<td>SPS</td>
<td>8/24/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>1</td>
<td>$822,140</td>
</tr>
<tr>
<td>200350</td>
<td>SEPC</td>
<td>8/26/2015</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>2</td>
<td>$7,603,530</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>4</strong></td>
<td><strong>$26,822,134</strong></td>
</tr>
</tbody>
</table>

*Table 3: Q3 2015 NTC Withdraw Summary*
Completed Projects

Twenty-two Network Upgrades with NTCs and five Generation Interconnection Network Upgrades were completed during the reporting period, totaling an estimated $200.1 million.

Table 4 lists the Network Upgrades completed during the reporting period. Table 5 summarizes the completed projects over the previous year. Figure 6 reflects the completed projects by upgrade type on a cost basis for the current year and the following year based on current projected in-service dates. Tables 6 and 7 summarize all Network Upgrades that include construction of transmission lines, both for the current year and the following year. Note: Previous quarter’s updated results are listed as the Transmission Owners may make adjustments to final costs and status of projects completed during the year.

<table>
<thead>
<tr>
<th>UID</th>
<th>Network Upgrade Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>10413</td>
<td>Cowskin - Westlink 69 kV Ckt 1 Rebuild</td>
<td>WR</td>
<td>Ag Studies</td>
<td>$4,151,903</td>
</tr>
<tr>
<td>10538</td>
<td>Eastborough - Sixty-Fourth (64th) 69 kV Ckt 1</td>
<td>WR</td>
<td>2013 ITPNT</td>
<td>$4,915,569</td>
</tr>
<tr>
<td>11082</td>
<td>GILL ENERGY CENTER EAST - MACARTHUR 69KV CKT 1 #2</td>
<td>WR</td>
<td>2009 STEP</td>
<td>$7,149,555</td>
</tr>
<tr>
<td>11158</td>
<td>Bluebell - Prattville 138 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$10,241,314</td>
</tr>
<tr>
<td>11496</td>
<td>NORTHWEST 345/138KV TRANSFORMER CKT 3</td>
<td>OGE</td>
<td>Ag Studies</td>
<td>$15,760,299</td>
</tr>
<tr>
<td>50367</td>
<td>TALOGA (TALOGA) 138/69/13.8KV TRANSFORMER CKT 1</td>
<td>WFEC</td>
<td>Ag Studies</td>
<td>$837,746</td>
</tr>
<tr>
<td>50379</td>
<td>Drinkard Sub 115 kV</td>
<td>SPS</td>
<td>2012 ITPNT</td>
<td>$1,320,000</td>
</tr>
<tr>
<td>50409</td>
<td>Bushton - Ellsworth 115 kV (MKEC)</td>
<td>MKEC</td>
<td>2012 ITPNT</td>
<td>$11,880,984</td>
</tr>
<tr>
<td>50410</td>
<td>Ellsworth Tap 115 kV ring bus</td>
<td>MKEC</td>
<td>2012 ITPNT</td>
<td>$6,713,869</td>
</tr>
<tr>
<td>50449</td>
<td>Ellsworth Substation 115 kV</td>
<td>MKEC</td>
<td>2012 ITPNT</td>
<td>$3,193,453</td>
</tr>
<tr>
<td>50509</td>
<td>North Ft. Dodge - Spearville 115kV Ckt 2</td>
<td>MKEC</td>
<td>GI Studies</td>
<td>$12,042,751</td>
</tr>
<tr>
<td>50510</td>
<td>Spearville 345/115 kV Transformer CKT 1</td>
<td>MKEC</td>
<td>GI Studies</td>
<td>$18,276,977</td>
</tr>
<tr>
<td>50549</td>
<td>Bushton 115 kV</td>
<td>MIDW</td>
<td>2012 ITPNT</td>
<td>$1,459,629</td>
</tr>
<tr>
<td>50567</td>
<td>Dekalb - New Boston 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$16,548,317</td>
</tr>
<tr>
<td>50568</td>
<td>Hardy Street - Waterworks 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$7,519,658</td>
</tr>
<tr>
<td>50569</td>
<td>Midland REC - North Huntington 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$1,829,026</td>
</tr>
<tr>
<td>50570</td>
<td>Midland - Midland REC 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$5,653,353</td>
</tr>
<tr>
<td>50571</td>
<td>Howe Interchange - Midland 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$9,145,130</td>
</tr>
<tr>
<td>50572</td>
<td>Chelsea - Childers 69 kV Ckt 1</td>
<td>GRDA</td>
<td>2013 ITPNT</td>
<td>$355,000</td>
</tr>
<tr>
<td>50693</td>
<td>Quahada Switching Station 115 kV</td>
<td>SPS</td>
<td>2014 ITPNT</td>
<td>$8,250,000</td>
</tr>
<tr>
<td>50752</td>
<td>Eddy County - Tolk 345kV Ckt 1</td>
<td>SPS</td>
<td>GI Studies</td>
<td>$12,525,622</td>
</tr>
<tr>
<td>50809</td>
<td>Alva OGE 69 kV Terminal Upgrades</td>
<td>OGE</td>
<td>HPILS</td>
<td>$72,851</td>
</tr>
<tr>
<td>50817</td>
<td>Eagle Chief 69 kV Cap Bank</td>
<td>WFEC</td>
<td>HPILS</td>
<td>$237,000</td>
</tr>
<tr>
<td>50870</td>
<td>Hopi Sub - North Loving 115 kV Ckt 1</td>
<td>SPS</td>
<td>HPILS</td>
<td>$10,211,678</td>
</tr>
<tr>
<td>50883</td>
<td>China Draw - North Loving 115 kV Ckt 1</td>
<td>SPS</td>
<td>HPILS</td>
<td>$9,983,589</td>
</tr>
<tr>
<td>51007</td>
<td>Ft. Dodge - North Ft. Dodge 115 kV Ckt 2</td>
<td>MKEC</td>
<td>GI Studies</td>
<td>$18,453,994</td>
</tr>
<tr>
<td>51058</td>
<td>Beaver County 345kV Substation GEN-2010-001 Addition</td>
<td>OGE</td>
<td>GI Studies</td>
<td>$1,326,900</td>
</tr>
</tbody>
</table>

Table 4: Q3 2015 Completed Network Upgrades

Total $200,056,169
<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Q4 2014</th>
<th>Q1 2015</th>
<th>Q2 2015</th>
<th>Q3 2015</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>5</td>
<td>23</td>
<td>17</td>
<td>15</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>$16,466,753</td>
<td>$178,283,263</td>
<td>$61,021,577</td>
<td>$99,971,761</td>
<td>$355,743,354</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>3</td>
<td>5</td>
</tr>
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<td>$0</td>
<td>$314,144</td>
<td>$0</td>
<td>$16,598,045</td>
<td>$16,912,189</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
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<td>0</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>$201,954,301</td>
<td>$0</td>
<td>$65,342,060</td>
<td>$0</td>
<td>$267,296,361</td>
</tr>
<tr>
<td>High Priority</td>
<td>2</td>
<td>16</td>
<td>1</td>
<td>4</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td>$2,248,743</td>
<td>$509,541,652</td>
<td>$327,861</td>
<td>$20,505,118</td>
<td>$532,623,374</td>
</tr>
<tr>
<td>Economic</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
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<td>$0</td>
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<td>$0</td>
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</tr>
<tr>
<td>Zonal Reliability</td>
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<td>0</td>
<td>1</td>
<td>1</td>
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<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$355,000</td>
<td>$355,000</td>
</tr>
<tr>
<td>Generation</td>
<td>5</td>
<td>5</td>
<td>2</td>
<td>6</td>
<td>18</td>
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<tr>
<td>Interconnection</td>
<td>$32,687,367</td>
<td>$11,417,274</td>
<td>$2,418,473</td>
<td>$63,884,665</td>
<td>$110,407,778</td>
</tr>
</tbody>
</table>

Table 5: Completed Project Summary through 3rd Quarter 2015
Table 6: Line Upgrade Summary for Previous 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>13</td>
<td>29.6</td>
<td>20.6</td>
<td>0.0</td>
<td>$71,489,610</td>
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<tr>
<td>115</td>
<td>9</td>
<td>109.9</td>
<td>0.0</td>
<td>0.0</td>
<td>$103,650,615</td>
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<tr>
<td>138</td>
<td>14</td>
<td>62.9</td>
<td>30.9</td>
<td>32.3</td>
<td>$101,504,878</td>
</tr>
<tr>
<td>161</td>
<td>1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$4,410,087</td>
</tr>
<tr>
<td>230</td>
<td>3</td>
<td>61.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$47,777,550</td>
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<td>12</td>
<td>684.7</td>
<td>0.0</td>
<td>0.0</td>
<td>$687,652,957</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>52</strong></td>
<td><strong>948.0</strong></td>
<td><strong>51.5</strong></td>
<td><strong>32.3</strong></td>
<td><strong>$1,016,485,697</strong></td>
</tr>
</tbody>
</table>

Figure 6: Completed Projects by Upgrade Type

Table 6: Line Upgrade Summary for Previous 12 Months
<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
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</thead>
<tbody>
<tr>
<td>69</td>
<td>14</td>
<td>44.0</td>
<td>90.7</td>
<td>0.0</td>
<td>$89,187,245</td>
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<td>115</td>
<td>11</td>
<td>104.9</td>
<td>10.3</td>
<td>4.5</td>
<td>$110,526,236</td>
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<tr>
<td>138</td>
<td>10</td>
<td>32.0</td>
<td>44.6</td>
<td>19.5</td>
<td>$88,944,715</td>
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<tr>
<td>161</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$0</td>
</tr>
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<td>230</td>
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<td>42.4</td>
<td>0.0</td>
<td>122.0</td>
<td>$63,103,827</td>
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<tr>
<td>345</td>
<td>4</td>
<td>244.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$353,774,278</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>43</strong></td>
<td><strong>467.3</strong></td>
<td><strong>145.55</strong></td>
<td><strong>146.01</strong></td>
<td><strong>$705,536,301</strong></td>
</tr>
</tbody>
</table>

*Table 7: Line Upgrade Projections for Next 12 Months*
Project Status Summary

SPP assigns a project status to all Network Upgrades based on the projected in-service dates provided by the DTOs relative to the Need Date determined for the project. Project status definitions are provided below:

- **Complete**: Construction complete and in-service
- **Closed Out**: Construction complete and in-service; all close-out requirements fulfilled
- **On Schedule < 4**: On Schedule within 4-year horizon
- **On Schedule > 4**: On Schedule beyond 4-year horizon
- **Delayed**: Projected In-Service Date beyond Need Date; interim mitigation provided or project may change but time permits the implementation of project
- **Within NTC Commitment Window**: NTC/NTC-C issued, still within the 90-day written commitment to construct window and no commitment received
- **Within NTC-C Project Estimate Window**: Within the NTC-C Project Estimate (CPE) window
- **Within RFP Response Window**: RFP issued for the project
- **Re-evaluation**: NTC/NTC-C active; pending re-evaluation
- **NTC Suspension**: NTC/NTC-C suspended; pending re-evaluation

Figure 7 reflects a summary of project status by upgrade type on a cost basis.
Figure 7: Project Status Summary on a Cost Basis
Balanced Portfolio

Approved in April 2009, the Balanced Portfolio was an initiative to develop a group of economic transmission upgrades that benefit the entire SPP region, and to allocate those project costs regionally. The projects that were issued NTCs as a result of the study include a diverse group of projects, estimated to add approximately 702 miles of new 345 kV transmission line to the SPP system.

The total cost estimate for the projects making up the Balanced Portfolio increased 0.6% from the previous quarter to $826.9 million. Changes in the project costs this quarter are due to incorporating the latest information provided by the DTOs in their respective Formula Rate updates.

All the projects making up the Balanced Portfolio have been completed and placed into service. A final reallocation of Revenue Requirements for deficient Zone(s) will be performed once all actual costs have been reported.

Figure 8 below depicts a historical view of the total estimated cost of the Balanced Portfolio. Table 8 provides a project summary of the projects making up the Balanced Portfolio.
<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>705/709</td>
<td>WFEC/OGE</td>
<td>Gracemont Substation 345 kV</td>
<td>N/A</td>
<td>$8,000,000</td>
<td>$15,091,100</td>
<td>$14,486,622</td>
<td>-4.0%</td>
</tr>
<tr>
<td>707/708</td>
<td>ITCGP/NPPD</td>
<td>Spearville - Post Rock - Axtell 345 kV</td>
<td>226.9</td>
<td>$236,557,015</td>
<td>$203,776,145</td>
<td>$203,702,073</td>
<td>-0.0%</td>
</tr>
<tr>
<td>698/699</td>
<td>OGE/GRDA</td>
<td>Sooner - Cleveland 345 kV</td>
<td>36.0</td>
<td>$33,530,000</td>
<td>$49,718,139</td>
<td>$50,018,622</td>
<td>0.6%</td>
</tr>
<tr>
<td>702</td>
<td>KCPL</td>
<td>Swissvale - Stilwell Tap 345 kV</td>
<td>N/A</td>
<td>$2,000,000</td>
<td>$2,866,604</td>
<td>$2,875,727</td>
<td>0.3%</td>
</tr>
<tr>
<td>700</td>
<td>OGE</td>
<td>Seminole - Muskogee 345 kV</td>
<td>118.0</td>
<td>$129,000,000</td>
<td>$165,000,000</td>
<td>$163,184,524</td>
<td>-1.1%</td>
</tr>
<tr>
<td>701/704</td>
<td>SPS/OGE</td>
<td>Tuco – Woodward 345 kV</td>
<td>290.1</td>
<td>$227,727,500</td>
<td>$320,426,576</td>
<td>$327,249,015</td>
<td>2.1%</td>
</tr>
<tr>
<td>703</td>
<td>TSMO</td>
<td>Iatan – Nashua 345 kV</td>
<td>30.9</td>
<td>$54,444,000</td>
<td>$65,342,060</td>
<td>$65,342,060</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

| Total        |                  |                  |                  | $691,258,515              | $822,220,624           | $826,858,642           | 0.6%       |

*Table 8: Balanced Portfolio Summary*
Priority Projects

In April 2010 the SPP Board of Directors and Members Committee approved for construction a group of "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects issued NTCs as a result of the study are estimated to add 291 miles of new single circuit 345 kV transmission line and 435 miles of double circuit 345 kV transmission to the SPP region.

In October 2010 the SPP Board of Directors approved an overall cost increase for the Priority Projects due to line rerouting and addition costs for reactive compensation. The total cost estimate for the Priority Projects after the variances were approved was $1.42 billion.

The current total cost estimate of $1.31 billion for the projects making up the Priority Projects indicates a decrease of 5.7% from the previous quarter’s total amount. The decrease is attributed primarily to a 17.5% reduction in the cost of the Nebraska City – Mullin Creek – Sibley 345 kV project owned by Transource Missouri and Omaha Public Power District. The DTOs reported that a reduction of risk has been recognized as the project schedule has progressed, allowing the removal of contingency from the estimates.

Figure 9 below depicts a historical view of the total estimated cost of the Priority Projects. Table 9 provides a project summary of the projects making up the Priority Projects.
Table 9: Priority Projects Summary

<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project Name</th>
<th>Project</th>
<th>Estimated Line Length</th>
<th>Board Approved Estimates (10/2010)</th>
<th>Q2 2015 Cost Estimates</th>
<th>Q3 2015 Cost Estimates</th>
<th>Var. %</th>
</tr>
</thead>
<tbody>
<tr>
<td>937</td>
<td>AEP</td>
<td>Tulsa Power Station 138 kV Reactor</td>
<td>N/A</td>
<td>$842,847</td>
<td>$960,895</td>
<td>$614,753</td>
<td>-36.0%</td>
<td></td>
</tr>
<tr>
<td>940/941</td>
<td>SPS/OGE</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt</td>
<td>128.8</td>
<td>$221,572,283</td>
<td>$231,203,065</td>
<td>$229,382,512</td>
<td>-0.8%</td>
<td></td>
</tr>
<tr>
<td>942/943</td>
<td>PW/OGE</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt</td>
<td>106.6</td>
<td>$201,940,759</td>
<td>$190,471,326</td>
<td>$185,264,405</td>
<td>-2.7%</td>
<td></td>
</tr>
<tr>
<td>945</td>
<td>ITCGP</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td>122.5</td>
<td>$293,235,000</td>
<td>$309,000,001</td>
<td>$309,000,001</td>
<td>0.0%</td>
<td></td>
</tr>
<tr>
<td>946</td>
<td>PW/WR</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td>77.5</td>
<td>$163,488,000</td>
<td>$120,440,612</td>
<td>$120,525,851</td>
<td>0.1%</td>
<td></td>
</tr>
<tr>
<td>936</td>
<td>AEP</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>76.3</td>
<td>$131,451,250</td>
<td>$127,995,000</td>
<td>$127,995,000</td>
<td>0.0%</td>
<td></td>
</tr>
<tr>
<td>938/939</td>
<td>OPPD/TSMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV</td>
<td>215.0</td>
<td>$403,740,000</td>
<td>$407,791,450</td>
<td>$336,433,874</td>
<td>-17.5%</td>
<td></td>
</tr>
</tbody>
</table>

**Total** 726.7 $1,416,270,139 $1,387,862,349 $1,309,216,396 -5.7%

Table 10: Priority Projects Construction Status

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Projected In-Service Date</th>
<th>Engineering</th>
<th>Siting and Routing</th>
<th>Environmental Studies</th>
<th>Permits</th>
<th>Material Procurement</th>
<th>Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>936</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>10/1/2016</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
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<tr>
<td>938</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (TSMO)</td>
<td>12/31/2016</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>N/A</td>
</tr>
<tr>
<td>939</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
<td>12/31/2016</td>
<td>IP</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
</tr>
</tbody>
</table>

Table 10 lists construction status updates for the Priority Projects not yet completed.
Out-of-Bandwidth Projects

In adherence to the Business Practice 7060, SPP reports projects that have updated cost values that exceed their established baseline values based upon a ±20% bandwidth. Variances are determined by total project cost.

Three projects with a cost estimate greater than $5 million were identified as having exceeded the ±20% bandwidth requirement during the reporting period.

Table 12 provides summary information and Table 13 lists the cost detail for the out-of-bandwidth projects for Q3 2015.

<table>
<thead>
<tr>
<th>PID</th>
<th>Project Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Upgrade Type</th>
<th>In-Service Date</th>
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</thead>
<tbody>
<tr>
<td>30483</td>
<td>Gill 138/69 kV Transformer Ckt 3</td>
<td>Westar</td>
<td>2013 ITPNT</td>
<td>Regional Reliability</td>
<td>12/1/2015</td>
</tr>
<tr>
<td>30579</td>
<td>Wellington - Creswell 69 kV Ckt 1 Rebuild</td>
<td>Westar</td>
<td>2014 ITPNT</td>
<td>Regional Reliability</td>
<td>12/1/2015</td>
</tr>
<tr>
<td>30731</td>
<td>Mt. Pleasant - West Mt. Pleasant 69 kV Ckt 1 Rebuild</td>
<td>AEP</td>
<td>DPA Study</td>
<td>Regional Reliability</td>
<td>4/20/2015</td>
</tr>
</tbody>
</table>

Table 11: Out-of-Bandwidth Project Summary

<table>
<thead>
<tr>
<th>PID</th>
<th>Baseline Cost Estimate</th>
<th>Baseline Cost Estimate Year</th>
<th>Baseline Cost Estimate with Escalation</th>
<th>Latest Estimate or Final Cost</th>
<th>Variance</th>
<th>Variance %</th>
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<tbody>
<tr>
<td>30483</td>
<td>$7,122,480</td>
<td>2013</td>
<td>$7,483,056</td>
<td>$5,803,853</td>
<td>($1,679,203)</td>
<td>-22.44%</td>
</tr>
<tr>
<td>30579</td>
<td>$15,537,353</td>
<td>2014</td>
<td>$15,925,787</td>
<td>$9,486,051</td>
<td>($6,439,736)</td>
<td>-40.44%</td>
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<tr>
<td>30731</td>
<td>$4,715,419</td>
<td>2015</td>
<td>$4,715,419</td>
<td>$7,381,799</td>
<td>$2,666,380</td>
<td>56.55%</td>
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</table>
Responsiveness Report

Table 13 and Figures 10 and 11 provide insight into the responsiveness of DTOs constructing Network Upgrades within SPP in the Quarterly Project Tracking Report for Q3 2015. **Note:** Network Upgrades with statuses of “NTC Suspension”, “Re-evaluation”, “Within NTC Commitment Window”, “Within NTC-C Project Estimate Window”, and “Within RFP Response Window” were excluded from this analysis.

![Table 13: Responsiveness Summary by Project Owner](image)
Figure 10: In-Service Date Changes by Project Owner

Figure 11: Cost Changes by Project Owner
Appendix I

See accompanying list of Network Upgrades
| PID | NTC - COMMITMENT WINDOW | State(s) | NTC/NTC-C active; pending re-evaluation | NTC/NTC-C suspended; pending re-evaluation | Project Status | Quarter 4 2015 Project Tracking Portfolio | Indicated In-Service | Quarter 4 2015 Project Tracking Portfolio | Number of New System Bases | Number of Voltage Bases | Number of Edge Construction | Estimate | Estimate with Delay - MITIGATION | In-service and all required project close-out documentation supplied by TO | Complete and in-service | Project Status | Number of New System Bases | Number of Voltage Bases | Number of Edge Construction | Estimate | Delay Margin
<table>
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<tbody>
<tr>
<td>#</td>
<td>State</td>
<td>Utility</td>
<td>Project Description</td>
<td>Start Date</td>
<td>Completion Date</td>
<td>Actual Cost 2013</td>
<td>Actual Cost 2014</td>
<td>Actual Cost 2015</td>
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</tr>
<tr>
<td>191</td>
<td>KS</td>
<td>Franklin</td>
<td>Sheffield 69KV CKT 1</td>
<td>7/25/2014</td>
<td>6/1/2013</td>
<td>1,695,722</td>
<td>1,738,115</td>
<td>1,320,792</td>
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</tr>
<tr>
<td>192</td>
<td>KS</td>
<td>Franklin</td>
<td>Sheffield 69KV CKT 1</td>
<td>7/25/2014</td>
<td>6/1/2013</td>
<td>1,695,722</td>
<td>1,738,115</td>
<td>1,320,792</td>
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</tr>
<tr>
<td>193</td>
<td>NE</td>
<td>NPPD</td>
<td>NE CLARKS 115KV Regional Reliability</td>
<td>11/1/2012</td>
<td>2/8/2010</td>
<td>700,000</td>
<td>717,500</td>
<td>700,000</td>
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</tr>
<tr>
<td>194</td>
<td>TX</td>
<td>AEP</td>
<td>WINNSBORO 138KV Regional Reliability</td>
<td>6/1/2016</td>
<td>6/1/2016</td>
<td>1,166,400</td>
<td>1,195,560</td>
<td>1,166,400</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>195</td>
<td>TX</td>
<td>SPS</td>
<td>Channing - XIT 230 kV Ckt 1 Regional Reliability</td>
<td>12/31/2015</td>
<td>6/1/2013</td>
<td>9,166,904</td>
<td>9,630,979</td>
<td>9,171,505</td>
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<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>196</td>
<td>KS</td>
<td>WR</td>
<td>Moundridge 138/115 kV Transformer Ckt 2</td>
<td>4/7/2015</td>
<td>6/1/2013</td>
<td>19,770,066</td>
<td>20,770,926</td>
<td>13,540,579</td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>197</td>
<td>OK</td>
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### Notes
- Transmission Service: 6/1/2016 - 3/1/2018
- ITPNT: 2013

- **COMPLETE ON SCHEDULE**
- **DELAY - MITIGATION**
- **CLOSED OUT**

- **ON SCHEDULE < 4**
- **ON SCHEDULE > 4**

- **$** costs only
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**Funding**

- **OPPD NE**
  - S907 - S919 69 kV Ckt 1 Rebuild: $3,141,600
  - S924 - S912 69 kV Ckt 1 Terminal Upgrades: $69,679

- **WFEC OK**
  - Cherokee Junction Tap 138/69 kV Ckt 1 Transformer: $2,680,000
  - Knobhill - Noel 138 kV Ckt 1 Terminal Upgrades: $450,000

**Other Projects**

- **MKEC KS**
  - Garden City - Kansas Avenue 115 kV Ckt 1 Terminal Upgrades: $112,722
  - Anthony - Harper 138 kV Ckt 1 High Priority: $13,253,238
  - Anthony - Harper 138 kV Ckt 1 High Priority: $12,838,896

- **OGE OK**
  - SW Station - Warwick Tap 138 kV Ckt 1 High Priority: $12,767,120
  - SW Station - Warwick Tap 138 kV Ckt 1 High Priority: $12,767,120

- **OPPD NE**
  - S1366 161/69 kV Ckt 1 Transformer: $4,426,730
  - S1366 161/69 kV Ckt 1 Transformer: $4,426,730

- **SPS NM**
  - Eddy County - Tolk 345kV Ckt 1 Generation Interconnection: $12,525,622
  - Eddy County - Tolk 345kV Ckt 1 Generation Interconnection: $12,525,622

- **OGE OK**
  - SW Station - Warwick Tap 138 kV Ckt 1 High Priority: $12,767,120
  - SW Station - Warwick Tap 138 kV Ckt 1 High Priority: $12,767,120
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