1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Roll Call and Declaration of a Quorum
   b. Adoption of April 17, 2017 Meeting Minutes
   c. Review of Past Action Items

3. UPDATES
   a. RSC Second Quarter 2017 Financial Report
   b. SPP
   c. FERC
   d. SPC Retreat

4. BUSINESS MEETING

5. CAWG REPORT AND VOTING ITEMS
   a. CAWG Report......................................................................................................................Adam Mckinnie
      This report provides an update on CAWG activity.
      i. Aggregate Study Safe Harbor Criteria Update...........................................................................
         [Voting Item]
         This report will update the RSC on the revised calculation and process.
      ii. Annual Review of Safe Harbor Criteria Update...........................................................................
          [Voting Item]
          This report will update the RSC on the frequency and depth of reviews.
      iii. Reviewing Revision Requests...................................................................................................
           [Possible Voting Item]
           This report will update the RSC on reviewing revision requests.
      iv. Derating Facilities and Cost Allocation .................................................................Adam Mckinnie, Lanny Nickell
           This report will update the RSC on derating facilities and cost allocation.

6. REPORTS/PRESENTATIONS
   a. Integrated Transmission Planning (ITP) and Transmission Planning Improvement Update...........
      ......................................................................................................................................................Lanny Nickell
      This report will update the RSC on the 2017 ITP Assessment and Report.
      i. Potential High Priority Study Update...........................................................................................
         This report will update the RSC on the potential High Priority Study.
b. Z2 Task Force Update........................................................................................................................................ Denise Buffington
This report will update the RSC on the activities of the Z2 Task Force.

c. Integrated Marketplace and Operations Update................................................................................................ Bruce Rew
This report will update the RSC on the Integrated Marketplace.

d. Export Pricing Task Force.................................................................................................................................... Mike Wise
This report will update the RSC on the activities of the Export Pricing Task Force.

e. Seams Update .................................................................................................................................................. Carl Monroe
This report will update the RSC on Seams issues.

7. OTHER RSC MATTERS
   a. ACTION ITEMS

8. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS
   a. RSC Meetings:
      October 30, 2017 – Little Rock, AR
      January 29, 2018 – Oklahoma City, OK
      April 23, 2018 – Kansas City, MO
      July 30, 2018 – Omaha, NE
      October 29, 2018 – Little Rock, AR

9. 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 participated:

- Steve Stoll, Missouri Public Service Commission (MOPSC)
- Shari Feist Albrecht, Kansas Corporation Commission (KCC)
- Kristie Fiegen, South Dakota Public Utilities Commission (SDPUC)
- Randy Christmann, North Dakota Public Service Commission (NDPSC) via phone
- Dennis Grennan, Nebraska Power Review Board (NPRB)
- Libby Jacobs, Iowa Utilities Board (IUB)
- Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)
- Dana Murphy, Oklahoma Corporation Commission (OCC)
- Donna Nelson, Public Utility Commission of Texas (PUCT)
- Kim O’Guinn, Arkansas Public Service Commission (APSC)

President Steve Stoll called the Regional State Committee (RSC) meeting to order at 1:01 p.m. with roll call and a quorum was declared. He requested introductions of those in attendance. There were 68 people in attendance, either in person or via the phone (Attendance & Proxies – Attachment 1).

The first item of business was the approval of the 1/30/17 meeting minutes (RSC Minutes 10/24/17 – Attachment 2).

Commissioner Patrick Lyons moved to approve the minutes; Commissioner Dennis Grennan seconded. The motion was approved unanimously.

Commissioner Kristie Fiegen moved to approve the minutes from the special meeting on 2/10/17 (RSC Minutes 2/10/17 – Attachment 3); Commissioner Patrick Lyons seconded. The motion was approved unanimously.

UPDATES

RSC Fourth Quarter Financial Report
Mr. Paul Suskie (SPP Staff) provided the financial report for the fourth quarter and end of year (RSC 2017 Q1 Financials – Attachment 4). He noted that the RSC was under budget for the first quarter.

SPP Report
Mr. Paul Suskie provided the SPP report. He began by welcoming Commissioner Randy Christmann from the North Dakota Public Service Commission. Commissioner Steve Lichter, Nebraska Power Review Board, was recognized for his service on the RSC. This included his work on the Regional Allocation Review Task Force (RARTF). SPP continues to talk with Mountain West members about potential membership. Commissioners Patrick Lyons and Steve Stoll were thanked for their participation in a forum and educational session for
Commissioners from some of the western states at the Colorado Public Utilities Commission several weeks ago. Commissioners Libby Jacobs and Donna Nelson were thanked for their service on the RSC.

Commissioner Jacobs noted that she appreciated the time she has been able to serve on the RSC representing the Iowa Utilities Board. Commissioner Stoll thanked both Commissioners Jacobs and Nelson for their work on the RSC.

**Federal Energy Regulatory Commission (FERC) Report**

Mr. Patrick Clarey, FERC staff, provided the FERC report. The FERC is still operating without a quorum. There are two technical conferences scheduled, the first on May 1 and 2. The focus will be to discuss certain matters effecting whole-sale energy and capacity markets with Eastern RTOs. A second technical conference will be held in June. The focus will be to discuss opportunities for increasing real-time and day-ahead market efficiencies through the use of improved software.

**Cost Allocation Working Group (CAWG) REPORT AND VOTING ITEMS**

**CAWG Report**

Mr. Adam Mckinnie (MOPSC) provided the Cost Allocation Working Group (CAWG) report (CAWG Report – Attachment 5). He reviewed CAWG activities since the last RSC meeting and reported on the ongoing and expected future issues before CAWG.

**Seams Project Policy Paper**

The Seams Projects Policy Paper will set guidelines for SPP approval and cost allocation processes for non-Order 1000 interregional transmission projects on a project-by-project basis.

Commissioner Libby Jacobs moved to accept the Seams Policy White Paper as revised as consistent with previous RSC actions; Commissioner Danna Murphy seconded the motion. The motion was approved unanimously.

**ITP10 Morgan Project Cost Allocation**

The Morgan Transformer Project is an addition of a new 345/161 kV Transformer at AECI's Morgan substation and an uprate of the 161 kV line between Morgan and Brookline. Regional funding applies a load-ratio based proportion of the SPP share of the project cost to all SPP transmission owners. The Markets and Operations Policy Committee (MOPC) approved this motion at the April 11, 2017 meeting.

For the record, Mr. Bill Grant (Xcel/SPS) expressed concerns on behalf of his company for this particular project. In the ITP10 one of these studies had 60% of the benefits going to one zone. Mr. Grant noted that his company is against automatic highway funding of Seams Projects.

Commissioner Kristie Fiegen moved to Regional Funding for the SPP portion of the cost of the Morgan Transformer Project; Commissioner Patrick Lyons seconded the motion. The motion was approved unanimously.

**RR208 Transmission Planning Improvement Task Force (TPITF) Tariff Revisions**

Revision Request (RR) 208 changes the Integrated Transmission Planning cycle from a 3-year process that produces a 20-year, 10-year and three one-year forward looking plans to an annual process that produces a 10-year forward looking plan. The one-year forward looking plans will be combined into the 10-year forward looking plan. The 20-year forward looking planning process will be conducted every five years.

Commissioner Shari Feist Albrecht moved to support RR208 with respect to the RSC authority for planning for remote resources; Commissioner Dennis Grennan seconded the motion. The motion was approved unanimously.

**RR203 Monthly ARR Allocation Process**

The CAWG determined that the RR203 is consistent with past policy decisions of the RSC with respect to the allocation of Annual Revenue Rights (ARRs) pursuant to its authority under Section 7.2 of the SPP Bylaws. The
Regional State Committee  
April 17, 2017

CAWG agrees there are no significant changes in ARR allocation policy associated with RR203. (RR203 Recommendation Report – Attachment 6)

Commissioner Murphy commented that the comments from the MOPC meeting should be reviewed where the MOPC thinks the ARR process is sufficient. There was discussion at MOPC questioning the cost of this effort.

Commissioner Patrick Lyons moved that the RSC does not object to RR203 per the RSC’s authority for FTRs under Section 7.2 of the SPP Bylaws with RR 203 being consistent with and no significant changes to prior approved RSC FTR policies; Commissioner Kim O’Guinn seconded the motion. The motion was approved unanimously.

RR202 Network Customers Obligation for Redispatch Costs
FERC is concerned that Point-to-Point transmission service customers are being treated differently than Network Integration Transmission Customers. FERC is allowing SPP to revise its redispatch process through the stakeholder process. (RR202 Recommendation Report – Attachment 7)

Commissioner Patrick Lyons moved that the approved RR202 or staff’s original proposed RR202 is consistent with past policy decisions of the RSC with respect to the allocation of financial transmission rights pursuant to its authority under Section 7.2 of the SPP Bylaws; Commissioner Kristie Fiegen seconded the motion. The motion was passed.

Annual Review of Aggregate Study Criteria Review
This topic is focused on the type of review the CAWG is going to do with the RSC’s request for an annual review of the Safe Harbor Criteria. This issue will be discussed at the May CAWG meeting. The goal is to come up with a review process that the CAWG can perform and the timing of such a review. The CAWG is looking for guidance on how often the RSC would like the CAWG to review the 20% rule.

Commissioner Stoll asked that the CAWG come to the next meeting with a recommendation.

Review of RSC Action Items
The CAWG recommended one change to the RSC action items.

Commissioner Albrecht volunteered to draft nominating committee language to insert into the Bylaws that could be discussed at the RSC retreat in July.

Mr. McKinnie thanked Ms. Tamika Barker for her service working with the CAWG. She has recently left the position as the CAWG staff secretary for another job at SPP. Mr. McKinnie commented that she was very helpful and professional.

REPORTS/PRESENTATIONS

RARTF Update
Commissioner Stoll presented the Regional Allocation Review Task Force (RARTF) update and recommendation (RARTF Presentation – Attachment 8 and RR223 Recommendation – Attachment 9). There are two new members on the task force, Commissioners Kim O’Guinn from Arkansas and Dennis Grennan from Nebraska. At its last meeting the task force discussed options for future RCARs. This topic will continue at the next RARTF meeting. Lessons learned from RCAR II were reviewed and the topic of RCAR III was discussed. A change in the planning cycle from a three-year to a one-year cycle was also discussed. With the change to the planning cycle the RARTF reviewed the frequency of performing the RCAR and recommended changing the frequency from every three years to at least once every six years.

Commissioner Donna Nelson moved the RSC approve the RARTF recommendation and RR223 to change the frequency of required RCAR review to at least once every six years; Commissioner Dana Murphy seconded the motion. Commissioners Patrick Lyons and Kristie Fiegen voted no. The motion passed.
Commissioner Stoll updated the group on RR155, which addresses potential RCAR remedies. At its February 2017 meeting, the RARTF voted to maintain RR155 as a process document for SPP staff and the RARTF to use in future RCARs.

Integration Transmission Planning (ITP) and Transmission Planning Improvement Update
Mr. Lanny Nickell (SPP Staff) provided the update on the 2017ITPNT (2017 ITPNT – Attachment 10). The ITPNT is an annual reliability assessment. The reliability needs are defined per SPP criteria, NERC criteria, and company-specific planning criteria such as transmission overloads and voltage violations. Economic needs or solutions are not evaluated in the ITPNT. The 2017 ITPNT has been presented to MOPC and it will be presented to the Board next week. Mr. Nickell provided an update on Kummer Ridge – Roundup 345 kV Line (Roundup-Kummer Ridge Update – Attachment 11) and an update on the Potter-Tolk 345 kV line (Potter-Tolk 345 kV Additional Analysis – Attachment 12)

Z2 Task Force Update
Ms. Denise Buffington (KCPL) provided an update on the Z2 Task Force (Z2 Task Force Update – Attachment 13). The task force is currently evaluating potential improvements to the crediting for sponsored upgrades provided for in Attachment Z2. The primary objective is to try to simplify the process.

Integrated Marketplace Update
Mr. Bruce Rew (SPP Staff) provided an update on the Integrated Marketplace (Integrated Marketplace Update – Attachment 14). SPP has continued to successfully maintained NERC control performance standards. All new wind records occurred while maintaining reliability and optimizing economics, within all NERC requirements.

Export Pricing Task Force (EPTF) Update
Mr. Mike Wise (Golden Spread Electric Cooperative) provided the report on the Export Pricing Task Force (Export Pricing Task Force Update – Attachment 15). The EPTF was formed in response to the SPP strategic plan that recognized that variable energy resources within the region provide a possible strategic opportunity for members and ratepayers. The meetings have focused on educating task force members about opportunities presented by the abundance of wind within the region. The task force has developed and prioritized several recommendations.

Seams Update
Mr. Lanny Nickell provided the Seams update (Seams Update – Attachment 16). There are three studies being considered that were the result of the 2016 SPP-MISO Coordinated System Planning Study.

ACTION ITEMS:
A list is attached here to. (Action Items – Attachment 17).

SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:

- July 23-24, 2017 – RSC Retreat
- July 24, 2017 – Denver (Regular Meeting)
- October 30, 2017 – Little Rock

With no further business, the meeting adjourned at 4:47 p.m.

Respectfully Submitted,

Paul Suskie
<table>
<thead>
<tr>
<th>No.</th>
<th>Action Item</th>
<th>Date Originated</th>
<th>Status</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<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. The bylaws draft modifications were 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. January 25, 2016 – RSC Goal for 2016 to consider adopting the clean-up of the Bylaws discussed in 2015. Prior to the January 30, 2017 RSC meeting, the current draft of the bylaws was distributed to the RSC.</td>
</tr>
<tr>
<td>17</td>
<td>Educational Session Topic Request – Role of RSC in SPP FERC Filings</td>
<td>1/25/2016</td>
<td>Ongoing</td>
<td>Request for SPP Staff to provide educational update on the FERC filings process and the role of the RSC.</td>
</tr>
<tr>
<td>19</td>
<td>Circulation of RSC Agendas</td>
<td>4/25/2016</td>
<td>Ongoing</td>
<td>SPP to circulate draft agendas to RSC members and CAWG earlier for comment</td>
</tr>
<tr>
<td>21</td>
<td>Establish a Nominating Committee per the RSC Bylaws</td>
<td>01/30/2017</td>
<td>Ongoing</td>
<td>Established for providing a slate of officers for RSC. Commissioner Albrecht to draft sample bylaw language in establishing a Nominating Committee for review at July RSC Meeting (April 2017 RSC Meeting).</td>
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<tr>
<td>No.</td>
<td>Action Item</td>
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<tr>
<td>22</td>
<td>Aggregate Study Waiver Criteria Review</td>
<td>01/30/2017</td>
<td>Ongoing</td>
<td>Annual CAWG review for limited time period (i.e. not in perpetuity). CAWG to present recommendation(s) to the RSC in July 2017 on how the RSC should proceed in reviewing the Aggregate Study Criteria (April 2017 RSC Meeting).</td>
</tr>
<tr>
<td>23</td>
<td>RSC Retreat Information</td>
<td>04/17/2017</td>
<td>Ongoing</td>
<td>Paul Suskie to send RSC Retreat information to Commissioners. (April 2017 RSC Meeting)</td>
</tr>
<tr>
<td>1</td>
<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>
</tr>
<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>
</tr>
<tr>
<td>No.</td>
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<td>Date Originated</td>
<td>Status</td>
<td>Comments</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>7</td>
<td>SPC Task Force on New Members – Discuss 3 RSC Action Items</td>
<td>9/29/2014</td>
<td>Completed</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>
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</table>

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.
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</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>Goals and Objectives for 2015 RSC Year</td>
<td>12/1/2014</td>
<td>Completed</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>
</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>
<tr>
<td>12</td>
<td>RSC Role in Cost Allocation for New Member Integrations</td>
<td>4/27/2015</td>
<td>Completed</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. 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. At its October 2016 meeting, the RSC approved the process document developed by the CAWG.</td>
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<td>No.</td>
<td>Action Item</td>
<td>Date Originated</td>
<td>Status</td>
<td>Comments</td>
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<tr>
<td>13</td>
<td>Aggregate Study Waiver Criteria</td>
<td>4/27/2015</td>
<td>Completed</td>
<td>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 tasked the 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. A recommendation by the CAWG to retain the study waiver criteria was approved by the RSC on January 30, 2017.</td>
</tr>
<tr>
<td>14</td>
<td>Capacity Margin Task Force Update</td>
<td>4/27/2015</td>
<td>Completed</td>
<td>After a presentation at the April 2015 RSC meeting, and discussion of 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 at their July 2015 meeting. Voted and approved at April 2016 meeting.</td>
</tr>
<tr>
<td>15</td>
<td>RSC Goals for 2016</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>RSC discussed goals for 2016 at the January 2016 Educational Session. Any additional goals should be submitted to Erin Cullum for distribution in advance of the April 2016 RSC meeting.</td>
</tr>
<tr>
<td>16</td>
<td>Engagement Term of RSC Auditor</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>Determine the initial arrangement with the RSC auditor and the number of years for reengagement. Erin Cullum will review the agreement and inform the RSC</td>
</tr>
<tr>
<td>No.</td>
<td>Action Item</td>
<td>Date Originated</td>
<td>Status</td>
<td>Comments</td>
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<td>--------------------------------------------------------------------------</td>
</tr>
<tr>
<td>18</td>
<td>Talking Points on CPP</td>
<td>1/25/2016</td>
<td>Completed</td>
<td>Request for SPP’s talking points on the CPP. Erin Cullum will distribute the link to posted comments.</td>
</tr>
<tr>
<td>20</td>
<td>Z2 Crediting Overview</td>
<td>4/25/2016</td>
<td>Completed</td>
<td>SPP to provide higher level overview of Z2 key points, significance, and state specific information (if possible). This will be provided in advance of the next RSC Meeting.</td>
</tr>
<tr>
<td>21</td>
<td>Form Commissioner Forum for Mountain West proposal.</td>
<td>01/30/2017</td>
<td>Completed</td>
<td>Phone call scheduled for February 10, 2017 to discuss further.</td>
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</table>
Regional State Committee  
**For the Six Months Ending June 30, 2017**  
**Budget vs. Actual**

<table>
<thead>
<tr>
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<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>121,141</td>
<td>159,700</td>
<td>(38,559)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>121,141</td>
<td>159,700</td>
<td>(38,559)</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Travel/Meeting</td>
<td>121,141</td>
<td>134,200</td>
<td>(13,059)</td>
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<tr>
<td>Audit</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Administrative Costs</td>
<td>-</td>
<td>500</td>
<td>(500)</td>
</tr>
<tr>
<td>RSC Consultant</td>
<td>-</td>
<td>25,000</td>
<td>(25,000)</td>
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<tr>
<td>Technical Conference</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td>121,141</td>
<td>159,700</td>
<td>(38,559)</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
CAWG Update for July 2017 RSC Meeting

Adam McKinnie
RSC Meeting
July 24, 2017
Goal of Presentation

• Discuss CAWG activities since last RSC meeting
  – May 9, 2017 CAWG call
  – June 6, 2017 CAWG meeting
  – July 6, 2017 CAWG meeting
• Discuss CAWG recommendations on RSC voting items
• Discuss ongoing and expected future CAWG issues
May CAWG Call Topics

• Derating Facilities Discussion
• Aggregate Study Safe Harbor Waiver Criteria Discussion
• Export Pricing Task Force
June CAWG Meeting Topics

• Z2 Task Force – change options
• Derating Facilities Discussion
• Aggregate Study Safe Harbor Waiver Criteria Discussion
• Revision Request Process Education and SPP Staff Proposal
July CAWG meeting

- Z2 Task Force – change options
- Derating Facilities Discussion
- Aggregate Study Safe Harbor Waiver Criteria Discussion
- Revision Request Process – adopted SPP Staff proposal
- Zonal Placement
Expected future issues

- CAWG has been and will continue working on the Derating Facilities Discussion
  – see separate presentation
- CAWG will continue work on the SPP-AECI interregional projects as they go through the SPP regional process
Upcoming CAWG Meetings

• August 8, 2017 CAWG Call
• September 7, 2017 CAWG meeting
• October 3, 2017 CAWG meeting
Topic Specific Presentations

1) Aggregate Study Safe Harbor Amount
   – RSC Voting Item

2) Aggregate Study Safe Harbor Waiver Criteria – How Often and How In Depth to Review
   – RSC Voting Item

3) Reviewing Revision Requests

4) Derated Facilities
Aggregate Study Safe Harbor Amount (RSC Voting Item)

Adam McKinnie
RSC Meeting
Goals of Presentation

• Present CAWG’s recommendation to not alter the current $180k / MW Aggregate Study Safe Harbor Amount

• Report how future reviews occur
  – SPP filing annual letter with FERC on this issue
  – CAWG future review
Refresher – Why do we care?

• Essentially, this is a COST ALLOCATION issue
• The decisions made by the RSC / CAWG on this issue will determine: What transmission project costs are paid for by companies purchasing transmission service to designate a resource versus the SPP footprint?
Refresher – Aggregate Study

Safe Harbor

• The “Safe Harbor” is applied if the applicable Aggregate Study waiver criteria are met:
  – If the TSR is granted, the utility will not have over 20% of their designated resources from wind (only applies to a TSR related to designating wind as a Designated Resource*) [<20% wind]
  – 5 year minimum term of commitment for the TSR
  – If the TSR is granted, the utility will not have Designated Resources greater than 125% of their forecasted load [<125% of load]

• A utility may apply for a waiver if the TSR does not meet the applicable “Safe Harbor” criteria or for an increase in the “Safe Harbor” amount.

* A Designated Resource is used to meet the capacity margin requirement of a Load Serving Entity
Refresher – Aggregate Study

Safe Harbor

• The Safe Harbor amount is $180 / MW, and was originally set in FERC Docket ER05-652.

• The cost of Transmission Upgrades under the Safe Harbor amount are “base plan funded” – currently, Highway / Byway
CAWG Review

• In its review of the Safe Harbor amount of $180k/MW, CAWG:
  – Solicited written comments from and had discussions with SPP Stakeholders
  – Asked SPP Staff to attempt to replicate the original calculation that created the Safe Harbor amount in 2005
  – Asked SPP for different ways to assess the proper Safe Harbor amount
  – Reviewed the number of waivers to the Safe Harbor amount
CAWG Review

• Since the establishment of the Safe Harbor amount, SPP files an annual letter at FERC in docket ER05-652 on whether the $180k/MW is correct.

• SPP has never recommended a change to the Safe Harbor amount.

• An annual limited review of the Safe Harbor amount could include a discussion of this annual letter, including the methodology behind SPP’s recommendation of whether to change the $180k/MW Safe Harbor Amount.
CAWG Review

- CAWG members, SPP Staff, and stakeholders had discussions on what the correct methodology is for calculating the Safe Harbor limit.
- No consensus was reached on what the correct methodology is.
  - That discussion is ongoing.
- CAWG, based on the material it reviewed, unanimously approved a motion to not recommend changes to the $180k/MW.
CAWG Approved Motion

• As to the Aggregate Study Safe Harbor Cost Limit, the CAWG recommends the RSC not take action to modify the $180K per MW Safe Harbor Cost Limit
Proposed RSC Motion

• As to the Aggregate Study Safe Harbor Cost Limit, the RSC takes no action to modify the $180K per MW Safe Harbor Cost Limit
Aggregate Study Safe Harbor Review Frequency (RSC Voting Item)

Adam McKinnie
RSC Meeting
July 24, 2017
Goals of Presentation

• Present CAWG’s recommendation on how often and how deeply to review issues related to the Aggregate Study Safe Harbor Amount and Waiver Criteria

• Present estimates of how long it would take CAWG to do various levels of review
Refresher – Why do we care?

• Essentially, this is a COST ALLOCATION issue
• The decisions made by the RSC / CAWG on this issue will determine: What transmission project costs are paid for by companies purchasing transmission service to designate a resource versus the SPP footprint?
Refresher – Aggregate Study
Safe Harbor

• The “Safe Harbor” is applied if the applicable Aggregate Study waiver criteria are met:
  – If the TSR is granted, the utility will not have over 20% of their designated resources from wind (only applies to a TSR related to designating wind as a Designated Resource*) [<20% wind]
  – 5 year minimum term of commitment for the TSR
  – If the TSR is granted, the utility will not have Designated Resources greater than 125% of their forecasted load [<125% of load]

• A utility may apply for a waiver if the TSR does not meet the applicable “Safe Harbor” criteria or for an increase in the “Safe Harbor” amount.

* A Designated Resource is used to meet the capacity margin requirement of a Load Serving Entity
Refresher – Aggregate Study
Safe Harbor

• The 5 year and 125% of load criteria were created in FERC Docket ER05-652
• The 20% wind criterion was created in FERC Docket ER09-1039
Previous RSC Actions

• When the RSC voted to not change the three Aggregate Study Safe Harbor Waiver Criteria in January 2017, the RSC requested an annual review of issues related to the criteria.

• RSC Minutes from January 2017 meeting state: Commissioner Patrick Lyons moved to adopt the resolution proposed by CAWG regarding the waiver criteria and adding an annual review of the criteria; Commissioner Libby Jacobs seconded the motion. Commissioners Kristie Fiegen and Dana Murphy abstained. The motion passed.
Previous RSC Actions

• In April, the issue of how to review the Waiver Criteria continued.
• The minutes of the April RSC meeting describe the discussion on this topic as follows:

Annual Review of Aggregate Study Criteria Review
This topic is focused on the type of review the CAWG is going to do with the RSC’s request for an annual review of the Safe Harbor Criteria. This issue will be discussed at the May CAWG meeting. The goal is to come up with a review process that the CAWG can perform and the timing of such a review. The CAWG is looking for guidance on how often the RSC would like the CAWG to review the 20% rule. Commissioner Stoll asked that the CAWG come to the next meeting with a recommendation. [emphasis added]
CAWG Work

• In the meetings since the RSC’s January motion, CAWG has had many discussions at meetings on how in depth and how often to review issues related to both the Safe Harbor amount and the Safe Harbor Waiver Criteria
CAWG Work

• Issues discussed by RSC and CAWG include:
  – Not wanting the Safe Harbor reviews to become CAWG’s “full time job”
  – How to not go another 8-10 years without reviewing Safe Harbor issues
  – Wanting to make sure nothing would prevent RSC / CAWG from doing a review at any time
How long would a review take

• It took CAWG approximately two years to perform the intensive review of the Safe Harbor Waiver Criteria
  – First review ever of the criteria
  – Required a lot of digging through previous material
  – Lots of education for SPP Staff, CAWG and RSC members

• I estimate it would take 9 months-1 year for future intense reviews of all Safe Harbor issues
How long would a review take

• Limited review would take approximately one quarter
  – Have sufficient time to seek out stakeholder written and verbal comments
  – Could focus on issues of interest to RSC and / or stakeholders, if any
  – Could focus on what has changed since the most recent limited / intense review
CAWG Discussion

- CAWG members and stakeholders discussed many options of how often and how intensely to study the Safe Harbor issues.
- The group also discussed whether to study the 20% wind criterion more often than the other Safe Harbor Waiver Criteria.
- CAWG members unanimously voted to do a limited annual review of all the issues and an in-depth review of all the issues no less than every five years.
CAWG Approved Motion

• The CAWG recommends the RSC direct CAWG to conduct a limited review of the three base plan funding eligibility criteria and the $180k/MW Safe Harbor limit on an annual basis and a more in-depth review at least once every 5 years.
Proposed RSC Motion

• The RSC directs CAWG to conduct a limited review of the three base plan funding eligibility criteria and the $180k/MW Safe Harbor limit on an annual basis and a more in-depth review at least once every 5 years.
Reviewing Revision Requests

Adam McKinnie
RSC Meeting
Goals of Presentation

• Present CAWG’s motion on how to address future reviews of Revision Requests under the RSC’s purview
• Discuss on CAWG will present reviewed items to the RSC
Refresher – Why do we care?

- The RSC has specific items of SPP policy under RSC purview per the RSC bylaws
- Historically, the RSC, with the assistance of CAWG, has reviewed and taken votes on all Revision Requests (RR) as to whether the RR is consistent with established RSC policy
What is a Revision Request

• In short, a Revision Request revises an existing SPP tariff or other organizational document.

• Per the SPP website:

  A request to make additions, edits, deletions, revisions, or clarifications to the SPP Business Practices, SPP Operating Criteria, SPP Planning Criteria, SPP Market Protocols, and SPP Open Access Transmission Tariff including any attachments and exhibits to these documents, except for Appendix F of the Market Protocols, is called a "Revision Request" (RR).
April RSC Meeting – lots of Revision Requests

• The April RSC meeting had 4 separate Revision Requests scheduled for an RSC vote

• There were questions raised about whether there was a better way to handle these Revision Requests, especially those that are technical or administrative
SPP Staff Proposal and CAWG Discussion

• Over the last quarter, SPP Staff brought forth a proposal to handle these technical and/or administrative Revision Requests

• CAWG members and stakeholders discussed the proposal to make sure that no significant Revision Requests would get lost in the shuffle as well as ensuring the RSC would be notified of all Revision Requests in their purview
SPP Staff Proposal and CAWG Discussion

• The proposal, as voted on by CAWG, would:
  – Place all technical/administrative Revision Requests under the RSC purview on a newly created CAWG “Consent Agenda”
  – Any CAWG member could request that a Revision Request be removed from the CAWG “Consent Agenda” for questions and/or discussion
  – CAWG Stakeholders could also request a Revision Request receive full discussion
  – If there is no request to remove the Revision Request, it will be deemed consistent with past RSC policy
Notifying the RSC

- The RSC will be notified of Revision Requests that passed via the CAWG “Consent Agenda” through the CAWG Report
  - This will allow any RSC Commissioner or stakeholder an opportunity to discuss the Revision Request
  - Under the proposal, the RSC would not be asked to vote on Revision Requests approved under the CAWG “Consent Agenda”
Significant Revision Requests

• If any Revision Request changes past RSC policy or establishes new RSC policy, it will not be placed on the CAWG “Consent Agenda”

• Instead, this Revision Request will receive full discussion at CAWG and CAWG will vote on a recommendation for the RSC
Significant Revisions Requests – RSC Action

• Any Revision Request that was seen as changing current RSC policy or establishing new RSC policy would be brought as a separate item to the RSC and listed as an RSC “Voting Item”

• This will help ensure that no significant Revision Requests get “lost in the shuffle” before the RSC
CAWG Approved Motion

• Subject to RSC agreement, CAWG accepts the following SPP Staff recommendation for the review of Revision Requests:

• If the modifications in any Revision Requests (RR) are minor technical and/or language issues, and are consistent with past RSC policy decisions, those RRs will be presented to the CAWG for information and review purposes on a CAWG consent agenda and will not be forwarded to the RSC for consideration and possible action.

• If the modifications in any RR alter or change past RSC policy decisions or create a new policy for issues within the purview of the RSC, they will be presented to the CAWG for review and recommendation. Those RRs will be forwarded to the RSC for consideration and possible action.
Questions?
Derated Facilities

Adam McKinnie
RSC Meeting
Goals of Presentation

• Information only – not asking for an RSC vote
• Discuss CAWG work in the previous quarter on derated facilities and projects to restore capacity
• Discuss future CAWG work on the topic
What is a Derated Facility?

• Lanny Nickel of SPP has been working with CAWG to provide an explanation of a derated facility as well as how different transmission owners act to restore the capacity of a derated facility

• Simply, a derated facility is operating at a lower capacity than is in the current SPP planning model
Why is CAWG looking into this?

• It came to CAWG’s attention earlier this year that different Transmission Owners (TOs) were utilizing different cost allocation methodologies to restore the lost capacity of a derated facility
  – Some TOs were sponsoring the project to restore lost capacity, paying for it themselves
  – Some TOs were using the SPP planning process, and transmission projects restoring the lost capacity were receiving base plan funding (Highway/Byway)
Where has CAWG been – Education

• CAWG has received information on the projects that have received base plan funding to restoring the lost capacity from a derated facility

• CAWG has received information about the wide variety of reasons a facility may be derated

• CAWG has had initial discussions with the Chair of the Transmission Working Group (TWG), Travis Hyde, to help form questions CAWG could ask of the TWG
  – TWG has technical expertise about why and how transmission facilities are derated
Where is CAWG going

• Over the next quarter:
  – CAWG will work towards finalizing questions for the Transmission Working Group
  – CAWG will continue discussions with SPP Staff and stakeholders on this topic
  – Some Stakeholders have indicated that if CAWG is looking at restoring capacity from derated facilities, CAWG should perhaps also look at uprated facilities where Transmission Owners have increased the capacity of a transmission facility
    • No CAWG decision has been made on that yet
Looking for a volunteer

• The CAWG Chair is looking for a CAWG member to volunteer to lead this effort
• Hopefully, that CAWG member could update the RSC about this topic next month
Questions?
Overview

• Background

• Proposed analysis approaches
  • Market congestion analysis
  • Auction revenue right (ARR) analysis

• Stakeholder feedback

• Next steps
Background
Study Background

- 2017 ITP10 Additional Analysis
  - Objective: Demonstrate the range of potential benefits of Potter – Tolk 345 kV under different future uncertainties
  - Conclusions: the Potter – Tolk 345 kV solution may not be the best comprehensive solution due to uncertainty of scenario assumptions and transmission needs in other areas that could arise under the studied scenarios

- The SPP Board accepted SPP staff’s recommendation to remove the Potter – Tolk 345 kV line from the 2017 ITP10 portfolio and directed the development of a High Priority Study scope to address needs in the Texas panhandle for consideration in July 2017
# Historical Congestion

<table>
<thead>
<tr>
<th>Flowgate Element</th>
<th>Region</th>
<th>Rank*</th>
<th>Projects that may provide mitigation</th>
</tr>
</thead>
</table>
| Woodward-FPL Switch (138)    | Western Oklahoma        | 1     | 1. Woodward EHV Phase Shifting Transformer (June 2017, Generator Interconnection)  
2. Matthewson - Tatonga 345 kV Ckt 2 (July 2018, ITP10) |
| Osage Switch-Canyon East (115)| Texas Panhandle         | 2     | Canyon East Sub – Randall County Interchange 115 kV line (March 2018, Aggregate Studies)             |
| Neosho-Riverton (161)        | SE Kansas               | 4     | Neosho – Riverton 161kV Terminal Upgrades (June 2018, 2017 ITP10)                                    |
| Brookline Xfmr (345/161)     | SW Missouri             | 7     | Morgan 345/161 kV transformer and Morgan – Brookline 161 kV line uprate (December 2019, 2017 ITP10) |
| Stanton-Indiana (115)**      | West Texas (Lubbock Area)| -     | 1. Tuco – Yoakum 345 kV Ckt 1 (June 2020, ITPNT)  
2. Tuco – Stanton – Indiana – Erskine 115 kV Terminal Upgrades (June 2018, 2017 ITP10) |

*As shown in the 2015 SPP Annual State of the Market Report

**Tuco-Stanton or Stanton-Indiana ranked between 1 and 7 in subsequent Quarterly State of the Market Reports
Wind Planning vs Wind Development

*Business as Usual/Reference Case for Economic Studies Only. Sensitivity case wind levels not included.*
Market Congestion Analysis Approach
Study Approach

• Objective is to analyze areas of the footprint where historical market congestion may persist or increase over time

• Study business as usual future considering;
  • Updated load forecasts – with sensitivities
  • Latest natural gas price forecast – with sensitivities
  • Updated generation forecasts – leverage the SPP GI queue

• Develop generation forecast considering;
  • Generator interconnection network upgrade cost considerations
    • Last 7.6GW of wind placed in service at average cost of $32,500/MW
    • Interconnection costs under a $100,000/MW threshold are low to mid range and have an average cost of $34,500/MW
  • Market saturation analysis
Installed Renewable Capacity at Interconnection Cost* Thresholds

- **Capacity at $0/MW**
- **Capacity Incremental to $0/MW**

### Installed Renewable Capacity at Interconnection Cost Thresholds ($/MW)

- **$0/MW**: 18,478 MW, $4,821
- **$10,000/MW**: 21,287 MW, $12,938
- **$30,000/MW**: 26,870 MW, $29,556
- **$50,000/MW**: 34,498 MW, $34,313
- **$100,000/MW**: 36,965 MW, $34,498
- **$200,000/MW**: 49,315 MW, $34,498

* Remaining actual and projected Network Upgrade costs per MW requested reported for capacity incremental to $0/MW threshold.
Saturation Analysis

• Analyze installed renewable capacity by GI cost threshold to indicate the potential point of diminishing economic returns

• Analysis
  • Perform production cost simulations
  • Disable all interchange between SPP and Tier 1 to ensure no renewable energy exports
  • Disable transmission thermal limitations and losses to determine optimal unit commitment and dispatch considering only ancillary service needs and resource specific constraints
  • Analyze increases in renewable energy curtailments
## Renewable Saturation Analysis

<table>
<thead>
<tr>
<th>Interconnection Cost Ceiling</th>
<th>Installed Renewable Capacity* (GW)</th>
<th>Annual Energy Delivered (TWh)</th>
<th>Minimum Conventional Dispatch (MW)</th>
<th>Maximum Renewable Penetration</th>
<th>Annual Curtailment %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base (2017ITP10 F3)</td>
<td>17.1</td>
<td>70</td>
<td>10,755</td>
<td>54.2%</td>
<td>0.0%</td>
</tr>
<tr>
<td>$10K/MW</td>
<td>21.1</td>
<td>86</td>
<td>8,430</td>
<td>65.2%</td>
<td>0.3%</td>
</tr>
<tr>
<td>$30K/MW</td>
<td>26.4</td>
<td>105</td>
<td>7,523</td>
<td>72.1%</td>
<td>2.8%</td>
</tr>
<tr>
<td>$50K/MW</td>
<td>29.1</td>
<td>114</td>
<td>6,360</td>
<td>76.6%</td>
<td>4.5%</td>
</tr>
<tr>
<td>$100K/MW</td>
<td>33.6</td>
<td>127</td>
<td>3,621</td>
<td>87.4%</td>
<td>8.0%</td>
</tr>
</tbody>
</table>

* Scenario also contains ~2.7GW of proxy solar by 2025, not included in totals
ARR Analysis
Approach
ARR Analysis Approach

- Evaluate the system in terms of transmission service already confirmed and congestion hedges (ARRs/LTCRs)
  - Evaluate the last cycle of hedge requests
  - Identify the requests left unfulfilled
  - Determine upgrades necessary to allow awarding of those unfulfilled requests

- Evaluate varying solution sets required to grant portions of unfulfilled requests
Stakeholder Feedback
Stakeholder Feedback

• Study cost and value
  • Reduce scope to manage cost while still gaining information
    • Model one production cost scenario with only renewables that are expected to go in-service (i.e. have a signed Interconnection Agreement)
  • Make recommendation on what can be learned from this type of study
  • Provide information that may inform the 2019 ITP

• Solution efficiency and benefit
  • Determine transmission needed to allow a reasonable level of ARRs to be allocated, comparing against cost of market uplift
  • Coordinate results with ARR impacts

• Transmission expansion
  • Consider performing outside the High Priority Study process
  • Consider options to recommend NTCs after review of study results

• Complete by April 2018
Z2 Task Force Update

Denise Buffington

July 24, 2017
Process Improvement Review

• Reviewed Z2 Regulatory and Legal requirements from FERC Orders and historical process from inception to present Tariff.

• Reviewed cost recovery mechanisms from MISO and PJM and other regions

• Task Force members provided process improvement alternatives for consideration.
Alternatives reviewed

- Converting Z2 to an Incremental Long-Term Congestion Right (ILTCR) only process
  - There would be no revenue crediting for future upgrades
- Roll-in and partial roll-in of facilities
- Modifications to existing Z2 process
  - Elimination of short-term transmission service credits
  - Fixed Credit Payment Obligation (CPO)
  - Removal of non-capacity upgrades
  - Elimination of credit stacking of subsequent users
  - Combinations of listed options
ILTCRs

- Current Z2 process includes a provision for Upgrade Sponsors to elect to receive ILTCRs
- Converting Z2 to an ILTCR-only process garnered a significant amount of discussion and review.
- Several members expressed concern about existing process and that work was underway to improve it
- Motion was made and voted on for ILTCRs-only but failed by a vote of 6 in favor, 9 opposed and 1 abstention
Roll-in or Partial Roll-in

- The Z2TF discussed how upgrades may eventually get rolled-in to rates under the SPP Tariff
- There were at least three different proposals submitted looking at variations of roll-in of upgrade costs
- Concern was expressed by different members regarding the potential to increase transmission service rates with additional facilities included
- Ultimately no vote was taken to change Z2 to provide for additional facilities being rolled-in
Simplification of existing Z2 process

• SPP Staff spent some time evaluating alternatives to simplify the process.

• Several proposals were reviewed with the Task Force

• Some members preferred a simplification approach over a more dramatic change to reduce risk and potential cost to convert.

• Options and combinations thereof consisted of:
  • Fixed CPO
  • Elimination of short-term transmission service credits
  • Elimination of credit stacking
  • Non-capacity upgrade removal
Recommendation 1

Eliminate credits from new upgrades that do not add transfer capability under Tariff Attachment Z2.

- Non-capacity upgrades are those upgrades which do not add transfer capability such as tapping into an existing line to place a generator interconnection substation.
- Associated upgrades are primarily generator interconnection.
- Non-capacity upgrades are the majority of the Z2 costs for generator interconnections.
Eliminate Credits for New Upgrades that Do Not Add Transfer Capability

• Pros:
  • Reduced staff time to administer
  • Reduced shadow settlement burden for sponsors, customers, and TOs
  • Less Base Plan funding and less direct assignment of credit payment obligations

• Cons:
  • Upgrade sponsors would have to recover their costs through another means
Recommendation 2

Eliminate credits from short-term service under Tariff Attachment Z2.

• Short-term service under the pro-forma is primarily for use of the existing transmission system and doesn’t consider transmission expansion costs.

• Cost recovery from short-term service was on average about 2.5% of the total credit revenue

• Sponsor impacts will vary depending on use of each upgrade
Eliminate Credit Payments by Short-Term Service

• Pros:
  • Reduced staff time to administer
  • Improved auditability
  • Reduced shadow settlement burden for sponsors, customers, and TOs
  • Lower transmission rates

• Cons:
  • Slower rate of reimbursement for upgrade sponsors
Recommendations

Approved by MOPC with 10 no’s, 3 abstentions

1. Eliminate credits from new upgrades that do not add transfer capability under Tariff Attachment Z2.
   - Z2TF Passed with 12 in favor, NextEra and Enel opposed, Westar and AECC abstaining

2. Eliminate credits from short-term service under Tariff Attachment Z2.
   - Z2TF Passed with 12 in favor, NextEra opposed, and AECC, CU, and Enel abstaining

3. Recommend concluding the work of the Task Force and allowing the Task Force to expire.
   - Z2TF Passed with AEP and SPS opposed, abstaining were KPP, SPS, and CUS
Integrated Marketplace Update

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

- Marketplace Highlights Over Last 12 Months
- Marketplace Statistical Information
- Marketplace Wind Highlights and Records
- Enhancements under development
- TCR Funding Update
Marketplace Over Last 12 Months

• 191 Market Participants
  • 125 financial only and 66 asset owning
  • One less MP over the last quarter (financial only entity)

• SPP BA has successfully maintained NERC control performance standards (BAAL & CPS)

• High System availability
  • Day-Ahead Market has not been delayed from posting in the last 12 months
  • Real-Time Balancing Market has successfully solved 99.95% of all intervals
Dispatch by Fuel Type

Real-Time

Generation (TWh)

Apr 16 May 16 Jun 16 Jul 16 Aug 16 Sep 16 Oct 16 Nov 16 Dec 16 Jan 17 Feb 17 Mar 17 Apr 17 May 17 Jun 17

- Other Gas-SC Gas-CC Coal Hydro Renewable Wind Nuclear
Fuel on the Margin in Real-Time
Real-Time versus Day-Ahead Pricing
Marketplace Operational Highlights

- Total of 16,280 MW of installed and operational wind capacity to date
  - As of July 10th, there is a approximately 100 MW of wind registered, but not yet operational

- Slightly expanded wind penetration record to 54.47% on 4/24 (from previous record 54.45% on 3/19)
  - Before 12/25/16, SPP had not averaged 40% wind penetration for an entire day
    - 1st Quarter of 2017 SPP averaged >40% wind penetration for seven different days
    - SPP averaged >40% wind penetration for seven days in April 2017 alone
Wind Output: April - June 2017

• Wind output represents the total real-time output of all wind generators in the SPP market at a point in time.

• Max wind output: 13,099 MW 6/12 @22:52
  • Approximate generation mix at time:
    • Coal - 39% (34% Self)  Hydro – 4%  Nuclear – 5%  Nat. Gas - 16%  Wind – 36%
  • SPP load @35,600 MW at the time

• Min wind output: 317MW 6/4 @01:38
  • Approximate generation mix at time:
    • Coal - 66% (53% Self)  Hydro – 4%  Nuclear – 8%  Nat. Gas - 21%  Wind – 1%
  • SPP load @24,700 MW at the time

• Q2 Average daily wind output: 6,917 MW
  • 2017 Q1 Average daily wind output: 7,199 MW

• All-Time Max: 13,342 MW 2/9 @21:34
• All-Time Min*: 30 MW 3/1/2015

*Since Integrated Marketplace Go-Live 3/1/2014
Wind Penetration: April - June 2017

• Wind penetration represents the instantaneous wind output divided by the total load. (Wind Gen/SPP Load)

• Max % penetration: 54.47% of load 4/24 @02:12
  • Approximate generation mix at time:
    • Coal - 20% (17% Self)  Hydro – 4%  Nuclear – 9%  Nat. Gas - 17%  Wind – 49%
    • *SPP load @21,150 MW and wind @11,520 MW at the time*

• Min % penetration: 1.3% of load 6/4 @00:33
  • Approximate generation mix at time:
    • Coal - 66% (53% Self)  Hydro – 4%  Nuclear – 8%  Nat. Gas - 21%  Wind – 1%
    • *SPP load @25,950 MW and wind @330 MW at the time*

• Q2 Average daily % penetration: 25.2% of load
  • 2017 Q1 Average % penetration: 26.5% of load

• All-Time Max: 54.47% of load 4/24 @02:12
• All-Time Min*: 0.1% of load 3/1/2015

*Since Integrated Marketplace Go-Live 3/1/2014*
April - June 2017

Daily Averages

- Average of Wind Output MW
- Average of Wind Penetration

Wind MW

Wind Penetration

January – March 2017 Summary

<table>
<thead>
<tr>
<th></th>
<th>Wind Output</th>
<th>Wind Penetration (% of Load)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Max</strong></td>
<td>13,099 MW</td>
<td>54.47%</td>
</tr>
<tr>
<td></td>
<td>6/12 @25:52</td>
<td>4/24 @02:12</td>
</tr>
<tr>
<td><strong>Min</strong></td>
<td>317 MW</td>
<td>1.3%</td>
</tr>
<tr>
<td></td>
<td>6/4 @01:38</td>
<td>6/4 @00:33</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td>6,917 MW</td>
<td>25.2%</td>
</tr>
</tbody>
</table>
Min and Max Percent of Generation Mix Per Fuel Type

2nd Quarter - 2017

- **Coal**: Maximum 65.7%, Minimum 20.1%
- **Wind**: Maximum 49.5%, Minimum 1.3%
- **Natural Gas**: Maximum 40.1%, Minimum 7.8%
- **Nuclear**: Maximum 10.0%, Minimum 4.4%
- **Hydro**: Maximum 8.2%, Minimum 2.5%
Recently Implemented:

- RR175 – Compliance with FERC Order 825 on Shortage Pricing

On The Way:

- MP approved revision requests and enhancements including:
  - RR127 – JOU Combined Option – Aggregate Energy Curve
  - RR130 – Commitment Notification Enhancement
  - RR188 – Headroom in DA Market

Future:

- RR116 - Quick Start Real-Time Commitment design enhancements

- RR198 – Variable Demand Curve
  - On hold pending FERC approval
TCR Funding Update

• RR91 Design:
  • Adjust capacity made available in Annual ARR Allocation to match capacity available in Annual TCR Auction

• Desired impacts were to help address:
  • Limit expansion
  • Underfunding
  • Mismatch of ARR/TCR system capabilities being allocated/awarded
Limit Expansion Totals

• 2015-2016
  • 62 GWs of expansion
  • 28% average expansion per constraint

• 2016-2017
  • 12 GWs of expansion
  • 15% average expansion per constraint
Cumulative TCR Funding Percentages

![Cumulative TCR Funding Percentages Graph]
Congestion vs. TCR Payments

- **2015-2016**
  - DA Congestion Rents: 89%
  - TCR Payments: 100%

- **2016-2017**
  - DA Congestion Rents: 94%
  - TCR Payments: 100%
TCR Summary

- RR91 implementation 2016-2017 TCR Year:
  - Greatly improved limit expansion
  - Provided 94% funding (back in the Tariff implied 90% to 100% target range)
  - Matched Allocation and Auction available system capabilities

- RR91 was successful in aiding SPP Congestion Hedging market’s funding percentage
SPP-AECI Joint Projects
Morgan Transformer Project

- Addition of a new 400 MVA 345/161 kV Transformer at AECI’s Morgan substation and an uprate of the 161 kV line between Morgan and Brookline
  - Located in southwest Missouri
  - Wholly on AECI’s transmission system
  - $13.75M Cost Estimate
Brookline Reactor Project

- Addition of a 50 MVAR Reactor at City Utilities Brookline 345 kV substation
  - Located in southwest Missouri
  - Wholly on SPP’s transmission system
  - $5.0M Study-level Cost Estimate
Approvals

• SPP Board of Directors
  • Approved the Morgan Transformer Project as a part of the 2017 SPP ITP10 Portfolio
  • Approved Regional Cost Allocation of the Morgan Transformer Project
  • Approved the Brookline Reactor Project out of the Regional Review of the SPP-AECI JCSP

• Regional State Committee
  • Approved Regional Cost Allocation of the Morgan Transformer Project

• AECI Board of Directors
  • Met on May 24th, 2017 to approve AECI’s participation in both the Morgan Transformer and Brookline Reactor Projects
FERC Filings

- SPP will make a filing at FERC for the two projects
  - Approval of SPP-AECI Joint Projects
  - Cost Sharing between SPP and AECI
  - SPP Regional Cost Allocation
  - Other Issues Related to the Treatment of the Projects

- SPP and AECI met with FERC staff for a pre-filing meeting on June 13th to discuss the purpose of the filing

- SPP is targeting to make the filings shortly following Board of Director’s meeting in mid July
Cost Sharing between SPP and AECI

- **Morgan Transformer Project**
  - $9.2* Million Study Level Cost Estimate
    - SPP Cost Responsibility - $8.7 Million (94.6%)
    - AECI Cost Responsibility - $0.5 Million (5.4%)

- **Brookline Reactor Project**
  - $5.0 Million Study Level Cost Estimate
    - SPP Cost Responsibility - $4.85 Million (97%)
    - AECI Cost Responsibility - $150 Thousand (3%)

*New cost estimate for Morgan is $13.75M, so SPP is working to validate decision and renegotiating potential cost sharing with AECI*
Payment Obligations

• Morgan Transformer Project
  • SPP’s payment obligation for its portion of the Morgan Transformer Project shall be determined by utilizing SPP’s portion of the final costs of the Facility multiplied by a 16% levelized carrying charge for the physical service life of the Facility

• Brookline Reactor Project
  • AECI intends to provide its portion of the costs of the Brookline Reactor Project in a lump sum payment to SPP or CUS as a contribution in aid of construction
Ownership / Capacity

• **Morgan Transformer Project**
  - AECI will own 100% of the project
  - AECI will construct the project and be responsible for the maintenance and operation of the facility

• **Brookline Reactor Project**
  - City Utilities of Springfield will own 100% of the project and will be responsible for the maintenance and operation of the facility
  - SPP will assign City Utilities of Springfield to construct the project in accordance with the provisions of the Tariff

• **Allocation of Capacity**
  - SPP and AECI will allocate the additional transmission capacity based on the allocation of the cost assumed by each Party for the Facilities
  - “Capacity” includes physical capacity of the project and any change in flowgate allocations
Next Steps

• SPP will review the Morgan Transformer Project considering the revised cost estimate
  • Compare against SPP’s regional option “JTEC Project”
    • Utilize updated cost estimate for JTEC as well

• Bring recommendation to the SPP Board of Directors in July 2017

• Continue to move forward with the Brookline Reactor Project regardless of the outcome of the review on the Morgan Transformer Project
SPP-MISO CSP Regional Review

• 2016 SPP-MISO CSP Recommended Project
  • Loop One Split Rock – Lawrence 115 kV ckt into Sioux Falls (I18) benefit to SPP

• Regional Review
  • SPP staff is currently working with the ESWG and SSC to verify the project’s benefits to SPP
  • Process will conclude with recommendations to MOPC and SPP Board in October

• Regional Review Scope
  • Conduct the 2017 Regional Review utilizing the 2017 ITP10 Future 1 and Future 3 2025 sidebar model to calculate a 1-year B/C ratio on the approved Interregional Project
  • 1-year 1.0 B/C requirement (RR Criteria)
I18: Loop One Split Rock-Lawrence 115 kV ckt into Sioux Falls

- **Project Details:**
  - Location: South Dakota
  - **Congestion Analysis:**
    Completely relieves congestion on Lawrence – Sioux Falls 115 kV
  - **Need:**
    Sioux Falls – Lawrence 115kV FLO
    Sioux Falls – Split Rock 230kV
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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 regional grid reliability standards, firm transmission commitments, and Tariff cost recovery.

SPP staff solicits quarterly 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 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 is February 1, 2017 through April 30, 2017. 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 with 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>Economic</td>
<td>20</td>
<td>$71,937,774</td>
<td>5.6</td>
<td>0.0</td>
<td>28.8</td>
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<tr>
<td>High Priority</td>
<td>61</td>
<td>$1,140,193,631</td>
<td>757.7</td>
<td>5.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>316</td>
<td>$3,097,128,342</td>
<td>1554.5</td>
<td>377.1</td>
<td>457.1</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>18</td>
<td>$100,558,093</td>
<td>12.9</td>
<td>15.3</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$147,436,190</td>
<td>34.7</td>
<td>26.9</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td><strong>424</strong></td>
<td><strong>$4,557,254,031</strong></td>
<td><strong>2365.5</strong></td>
<td><strong>424.3</strong></td>
<td><strong>485.9</strong></td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>84</td>
<td>$283,332,302</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>1</td>
<td>$7,107,090</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>TO - Sponsored</td>
<td>2</td>
<td>$14,519,000</td>
<td>10.7</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Non-NTC Projects Subtotal</strong></td>
<td><strong>87</strong></td>
<td><strong>$304,958,392</strong></td>
<td><strong>10.7</strong></td>
<td><strong>0.0</strong></td>
<td><strong>0.0</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>511</strong></td>
<td><strong>$4,862,212,422</strong></td>
<td><strong>2376.2</strong></td>
<td><strong>424.3</strong></td>
<td><strong>485.9</strong></td>
</tr>
</tbody>
</table>

Table 1: Q3 2017 Portfolio Summary
Figure 1: Percentage of Project Type on Cost Basis

- Economic: 24%
- Generation Interconnection: 6%
- High Priority: 6%
- Regional Reliability: 1.5%
- Transmission Service: 2%
- Zonal Reliability: 3%

Figure 2: Percentage of Project Status on Cost Basis

- Closed Out: 0%
- Complete: 38%
- On Schedule < 4: 0%
- On Schedule > 4: 32%
- Delay - Mitigation: 28%
- Suspended: 1%
- NTC - Commitment Window: 0%
- Re-evaluation: 0%
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to begin work on Network Upgrades that have been approved or endorsed by the SPP Board 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 Notifications to Construct with Conditions (NTC-C). Note: Figures 3 and 4, 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.
<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>$202,493,500</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$202,493,500</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$498,733,734</td>
<td>$1,050,000</td>
<td>$0</td>
<td>$0</td>
<td>$499,783,734</td>
</tr>
<tr>
<td>2008 STEP</td>
<td>$415,126,157</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$415,126,157</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$834,724,320</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$834,724,320</td>
</tr>
<tr>
<td>2009 STEP</td>
<td>$533,469,214</td>
<td>$1,441,050</td>
<td>$0</td>
<td>$0</td>
<td>$534,910,264</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$1,272,261,003</td>
<td>$0</td>
<td>$0</td>
<td>$76,500,000</td>
<td>$1,348,761,003</td>
</tr>
<tr>
<td>2010 STEP</td>
<td>$109,968,782</td>
<td>$4,041,273</td>
<td>$0</td>
<td>$0</td>
<td>$114,010,055</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$182,110,561</td>
<td>$4,363,510</td>
<td>$0</td>
<td>$0</td>
<td>$186,474,071</td>
</tr>
<tr>
<td>2012 ITP10</td>
<td>$105,901,240</td>
<td>$342,148,981</td>
<td>$0</td>
<td>$314,259,556</td>
<td>$762,309,777</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$328,940,158</td>
<td>$135,172,767</td>
<td>$0</td>
<td>$41,462,612</td>
<td>$505,575,537</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$146,012,531</td>
<td>$333,951,469</td>
<td>$0</td>
<td>$104,457,095</td>
<td>$584,421,095</td>
</tr>
<tr>
<td>HPILS</td>
<td>$222,670,305</td>
<td>$80,624,129</td>
<td>$0</td>
<td>$379,788,613</td>
<td>$683,083,046</td>
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<tr>
<td>2015 ITPNT</td>
<td>$74,216,215</td>
<td>$133,497,595</td>
<td>$0</td>
<td>$6,976,873</td>
<td>$214,690,683</td>
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<tr>
<td>2015 ITP10</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$50,536,991</td>
<td>$50,536,991</td>
</tr>
<tr>
<td>IS Integration Study</td>
<td>$223,284,902</td>
<td>$38,000,000</td>
<td>$0</td>
<td>$111,000,000</td>
<td>$372,284,902</td>
</tr>
<tr>
<td>2016 ITPNT</td>
<td>$75,638,261</td>
<td>$426,300,387</td>
<td>$0</td>
<td>$38,230,111</td>
<td>$540,168,759</td>
</tr>
<tr>
<td>2017 ITP10</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$9,735,964</td>
<td>$9,735,964</td>
</tr>
<tr>
<td>Ag Studies</td>
<td>$690,017,190</td>
<td>$104,038,769</td>
<td>$0</td>
<td>$83,957,379</td>
<td>$878,013,338</td>
</tr>
<tr>
<td>DPA Studies</td>
<td>$179,431,455</td>
<td>$5,270,233</td>
<td>$0</td>
<td>$16,842,293</td>
<td>$201,543,981</td>
</tr>
<tr>
<td>GI Studies</td>
<td>$618,129,114</td>
<td>$20,000</td>
<td>$0</td>
<td>$160,077,233</td>
<td>$778,226,347</td>
</tr>
<tr>
<td>Total</td>
<td>$6,713,128,642</td>
<td>$1,609,920,163</td>
<td>$0</td>
<td>$1,393,824,718</td>
<td>$9,716,873,524</td>
</tr>
</tbody>
</table>

Table 2: Project Status by NTC Source Study

Figure 4: Estimated Cost for NTC Project per In-Service Year
**NTC ISSUANCE**
Ten new NTCs were issued since the last quarterly report totaling an estimated $32.9 million.

One new NTC was issued as a result of Aggregate Studies, 2015-AG2-AFS-3. Total estimated costs for upgrades resulting from that NTC was $2.7 million.

Eight new NTCs were issued as a result of the Board's approval of the 2017 Integrated Transmission Planning 10-Year Assessment (ITP10). Total estimated cost of upgrades described in those NTCs was $9.6 million.

One new NTC was issued as a result of the Board approval of the 2017 Integrated Transmission Planning Near-Term Assessment (ITPNT). Total estimated cost of the Network Upgrades described in this NTC is $20.5 million.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>Owner</th>
<th>NTC Issue Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of New Upgrades</th>
<th>Estimated Cost of Previously Approved Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200428</td>
<td>KCPL</td>
<td>2/22/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>1</td>
<td>$500,000</td>
<td></td>
</tr>
<tr>
<td>200429</td>
<td>MIDW</td>
<td>2/22/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>3</td>
<td>$3,306,360</td>
<td></td>
</tr>
<tr>
<td>200430</td>
<td>WR</td>
<td>2/21/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>2</td>
<td>$350,010</td>
<td></td>
</tr>
<tr>
<td>200431</td>
<td>AEP</td>
<td>2/21/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>1</td>
<td>$4,780,000</td>
<td></td>
</tr>
<tr>
<td>200432</td>
<td>GRDA</td>
<td>2/21/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>1</td>
<td>$279,400</td>
<td></td>
</tr>
<tr>
<td>200433</td>
<td>WFEC</td>
<td>2/21/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>1</td>
<td>$100,000</td>
<td></td>
</tr>
<tr>
<td>200434</td>
<td>OGE</td>
<td>2/21/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>1</td>
<td>$16,000</td>
<td></td>
</tr>
<tr>
<td>200436</td>
<td>SPS</td>
<td>2/22/2017</td>
<td>High Priority</td>
<td>2017 ITPNT</td>
<td>2</td>
<td>$20,502,997</td>
<td></td>
</tr>
<tr>
<td>200437</td>
<td>MIDW</td>
<td>2/8/2017</td>
<td>Regional Reliability</td>
<td>2015-AG2-AFS-3</td>
<td>1</td>
<td>$2,663,963</td>
<td></td>
</tr>
<tr>
<td>200444</td>
<td>SPS</td>
<td>2/22/2017</td>
<td>Economic</td>
<td>2017 IPT10</td>
<td>5</td>
<td>$356,757</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>18</strong></td>
<td><strong>$9,688,527</strong></td>
<td><strong>$23,166,960</strong></td>
</tr>
</tbody>
</table>

**Table 3: Q3 2017 NTC Issuance Summary**

**NTC WITHDRAW**
Seven NTCs were withdrawn for four Network Upgrades since the last quarterly report, totaling an estimated $22.3 million.

Upgrades included in NTCs listed in Table 4 were determined to no longer be needed as a part of the 2017 ITPNT Assessment. The Board approved the withdrawals at its January 2017 meeting.

Table 4 lists the NTC Withdraw activity from February 1, 2017 through April 30, 2017. NTC ID values in **bold** font indicate NTC-Cs.
### Table 4: Q3 2017 NTC Withdraw Summary

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>Owner</th>
<th>NTC Withdraw Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of Withdrawn Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200436</td>
<td>SPS</td>
<td>2/22/2017</td>
<td>High Priority</td>
<td>2017 ITPNT</td>
<td>3</td>
<td>$7,647,477</td>
</tr>
<tr>
<td>200438</td>
<td>SPS</td>
<td>2/22/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
<td>1</td>
<td>$3,659,456</td>
</tr>
<tr>
<td>200439</td>
<td>WR</td>
<td>2/22/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
<td>1</td>
<td>$767,165</td>
</tr>
<tr>
<td>200440</td>
<td>WR</td>
<td>2/22/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
<td>1</td>
<td>$1,390,166</td>
</tr>
<tr>
<td>200442</td>
<td>OPPD</td>
<td>2/22/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
<td>1</td>
<td>$3,141,600</td>
</tr>
<tr>
<td>200443</td>
<td>GRDA</td>
<td>2/22/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
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<td>$295,000</td>
</tr>
<tr>
<td>200435</td>
<td>SPS</td>
<td>2/22/2017</td>
<td>Regional Reliability</td>
<td>2017 ITPNT</td>
<td>5</td>
<td>$5,362,750</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Total</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>14</strong></td>
<td><strong>$22,263,614</strong></td>
</tr>
</tbody>
</table>

**COMPLETED PROJECTS**

Four Network Upgrades with NTCs were verified as completed during the reporting period, totaling an estimated $20.6 million.

Table 5 lists the Network Upgrades reported and confirmed as completed during the reporting period. Table 6 summarizes the completed projects over the previous year, including Network Upgrades not yet confirmed as completed. Figure 5 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 7 and 8 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>10604</td>
<td>Arkansas City - Paris 69 kV Terminal Upgrades</td>
<td>WR</td>
<td>Ag Studies</td>
<td>$229,690</td>
</tr>
<tr>
<td>10649</td>
<td>Brownlee - North Market 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$16,401,035</td>
</tr>
<tr>
<td>51331</td>
<td>Antelope - County Line - 115kV Rebuild</td>
<td>NPPD</td>
<td>GI Studies</td>
<td>$2,047,174</td>
</tr>
<tr>
<td>51340</td>
<td>Battle Creek - County Line 115kV Rebuild</td>
<td>NPPD</td>
<td>GI Studies</td>
<td>$1,952,826</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>$20,630,725</strong></td>
</tr>
</tbody>
</table>

**Table 5: Q3 2017 Completed Network Upgrades**
<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Q4 2016</th>
<th>Q1 2017</th>
<th>Q2 2017</th>
<th>Q3 2017</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>13</td>
<td>9</td>
<td>16</td>
<td>14</td>
<td>52</td>
</tr>
<tr>
<td></td>
<td>$157,765,704</td>
<td>$98,219,377</td>
<td>$121,481,442</td>
<td>$58,548,510</td>
<td>$436,015,033</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>2</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>$560,758</td>
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<td>$229,690</td>
<td>$0</td>
<td>$790,448</td>
</tr>
<tr>
<td>High Priority</td>
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<td>5</td>
<td>13</td>
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<tr>
<td></td>
<td>$0</td>
<td>$522,455,363</td>
<td>$0</td>
<td>$41,095,660</td>
<td>$563,551,023</td>
</tr>
<tr>
<td>Economic</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$13,512,897</td>
<td>$13,512,897</td>
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<tr>
<td>Generation Interconnection</td>
<td>18</td>
<td>12</td>
<td>8</td>
<td>7</td>
<td>45</td>
</tr>
<tr>
<td></td>
<td>$64,317,751</td>
<td>$38,294,567</td>
<td>$29,852,689</td>
<td>$15,673,080</td>
<td>$148,138,087</td>
</tr>
</tbody>
</table>

Table 6: Completed Project Summary as of 3Q 2017

Figure 5: Completed Upgrades by Type per Quarter
Table 7: Line Upgrade Summary for Previous 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>New</th>
<th>Rebuild/Reconductor</th>
<th>Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>5</td>
<td>6.7</td>
<td>15.9</td>
<td>0.0</td>
<td>$24,687,979</td>
</tr>
<tr>
<td>115</td>
<td>17</td>
<td>150.2</td>
<td>20.6</td>
<td>8.3</td>
<td>$170,693,581</td>
</tr>
<tr>
<td>138</td>
<td>4</td>
<td>55.1</td>
<td>8.3</td>
<td>8.3</td>
<td>$56,163,055</td>
</tr>
<tr>
<td>161</td>
<td>1</td>
<td>0.0</td>
<td>11.1</td>
<td>0.0</td>
<td>$12,705,537</td>
</tr>
<tr>
<td>230</td>
<td>1</td>
<td>30.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$41,100,000</td>
</tr>
<tr>
<td>345</td>
<td>5</td>
<td>319.7</td>
<td>0.0</td>
<td>0.0</td>
<td>$559,110,016</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>33</strong></td>
<td><strong>561.7</strong></td>
<td><strong>55.9</strong></td>
<td><strong>9.3</strong></td>
<td><strong>$864,460,168</strong></td>
</tr>
</tbody>
</table>

Table 8: Line Upgrade Projections for Next 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>New</th>
<th>Rebuild/Reconductor</th>
<th>Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>8</td>
<td>0.0</td>
<td>55.1</td>
<td>0.0</td>
<td>$68,621,988</td>
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<tr>
<td>115</td>
<td>23</td>
<td>169.2</td>
<td>39.9</td>
<td>5.0</td>
<td>$191,184,792</td>
</tr>
<tr>
<td>138</td>
<td>12</td>
<td>110.0</td>
<td>18.9</td>
<td>138.0</td>
<td>$121,571,727</td>
</tr>
<tr>
<td>161</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$0</td>
</tr>
<tr>
<td>230</td>
<td>4</td>
<td>85.8</td>
<td>0.0</td>
<td>0.0</td>
<td>$69,826,722</td>
</tr>
<tr>
<td>345</td>
<td>11</td>
<td>387.5</td>
<td>0.0</td>
<td>0.0</td>
<td>$511,337,230</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>58</strong></td>
<td><strong>752.5</strong></td>
<td><strong>113.9</strong></td>
<td><strong>143.0</strong></td>
<td><strong>$962,542,459</strong></td>
</tr>
</tbody>
</table>

**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**: Project active; pending re-evaluation
- **Suspended**: Project suspended; pending re-evaluation
Figure 6 reflects a summary of project status by upgrade type on a cost basis.
PRIORITY PROJECTS

In April 2010, the Board 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 were 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 Board 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 total cost estimate of $1.37 billion for the projects included in the Priority Projects report increased by 4.4% from the previous quarter’s total.

Figure 8 below depicts a historical view of the total estimated cost of the Priority Projects. Table 10 provides a project summary of the projects making up the Priority Projects. Table 11 lists construction status updates for the Priority Projects not yet completed.
<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project</th>
<th>Est. Line Length</th>
<th>BOD Approved Estimates (10/2010)</th>
<th>Q2 2017 Cost Estimates</th>
<th>Q3 2017 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>$614,753</td>
<td>$614,753</td>
<td>0.0%</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>$229,797,229</td>
<td>$229,797,229</td>
<td>0.0%</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>$185,403,885</td>
<td>$185,403,885</td>
<td>0.0%</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>$318,469,400</td>
<td>$318,469,400</td>
<td>0.0%</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>$120,016,474</td>
<td>$120,016,474</td>
<td>0.0%</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>$185,751,250</td>
<td>$185,751,250</td>
<td>0.0%</td>
</tr>
<tr>
<td>938/939</td>
<td>OPPD/GMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV</td>
<td>215</td>
<td>$403,740,000</td>
<td>$308,708,013</td>
<td>$308,708,013</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td>726.7</td>
<td>$1,416,270,139</td>
<td>$1,348,761,003</td>
<td>$1,348,761,003</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

Table 9: Priority Projects Summary

<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>12/16/2016</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
<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>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>939</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
<td>12/31/2016</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
</tbody>
</table>

Table 90: Priority Projects Construction Status
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.

Ten 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 cost detail for out-of-bandwidth projects for 3Q 2017.

<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>
</tr>
</thead>
<tbody>
<tr>
<td>30160</td>
<td>XFR - Ft Smith 500/161 kV Ckt 3 (Legacy Project)</td>
<td>OGE</td>
<td>SPP-2006-AG3-AFS-11</td>
<td>Transmission Service</td>
<td>5/1/2018</td>
</tr>
<tr>
<td>30361</td>
<td>Multi - Chisholm - Gracemont 345 kV</td>
<td>AEP/</td>
<td>2012 ITP10</td>
<td>Regional Reliability</td>
<td>3/1/2018</td>
</tr>
<tr>
<td>30374</td>
<td>Multi - Hoskins - Neligh 345 kV</td>
<td>NPPD</td>
<td>2014 ITPNT</td>
<td>Regional Reliability</td>
<td>4/1/2018</td>
</tr>
<tr>
<td>30484</td>
<td>Multi - Viola 345/138kV Transformer and 138 kV Lines to</td>
<td>WR</td>
<td>2013 ITPNT</td>
<td>Regional Reliability</td>
<td>12/31/2018</td>
</tr>
<tr>
<td></td>
<td>Clearwater and Gill</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>30497</td>
<td>Line - Buffalo - Buffalo Bear - Ft. Supply 69 kV</td>
<td>WFEC</td>
<td>DPA Studies</td>
<td>Regional Reliability</td>
<td>12/19/2014</td>
</tr>
<tr>
<td>30580</td>
<td>Line - Crestview - Kenmar 69 kV</td>
<td>WR</td>
<td>2014 ITPNT</td>
<td>Regional Reliability</td>
<td>11/13/2015</td>
</tr>
<tr>
<td>30694</td>
<td>Multi - Ponderosa - Ponderosa Tap 115 kV</td>
<td>SPS</td>
<td>HPILS</td>
<td>High Priority</td>
<td>6/1/2017</td>
</tr>
<tr>
<td>30873</td>
<td>Line - Southwestern Station - Carnegie 138kV Ckt 1 Rebuild</td>
<td>AEP</td>
<td>2015 ITPNT</td>
<td>Regional Reliability</td>
<td>12/31/2017</td>
</tr>
<tr>
<td>30988</td>
<td>Sub - Eddy Co. 230 kV Bus Tie</td>
<td>SPS</td>
<td>Ag Studies</td>
<td>Transmission Service</td>
<td>6/1/2019</td>
</tr>
<tr>
<td>909</td>
<td>Multi - Payne Switching Station - OU 138 kV conversion</td>
<td>WFEC</td>
<td>2013 ITPNT</td>
<td>Regional Reliability</td>
<td>7/1/2016</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>
</tr>
</thead>
<tbody>
<tr>
<td>30160</td>
<td>$14,000,000</td>
<td>2014</td>
<td>$15,076,469</td>
<td>$25,635,637</td>
<td>$10,559,168</td>
<td>70.04%</td>
</tr>
<tr>
<td>30361</td>
<td>$162,952,357</td>
<td>2013</td>
<td>$179,866,913</td>
<td>$25,635,637</td>
<td>$(52,190,784)</td>
<td>-29.02%</td>
</tr>
<tr>
<td>30374</td>
<td>$98,697,720</td>
<td>2014</td>
<td>$106,286,649</td>
<td>$25,635,637</td>
<td>$(24,742,130)</td>
<td>-23.28%</td>
</tr>
<tr>
<td>30484</td>
<td>$77,566,974</td>
<td>2013</td>
<td>$85,619,425</td>
<td>$25,635,637</td>
<td>$(18,552,451)</td>
<td>-21.67%</td>
</tr>
<tr>
<td>30497</td>
<td>$7,500,000</td>
<td>2013</td>
<td>$7,687,500</td>
<td>$25,635,637</td>
<td>$(2,632,713)</td>
<td>-34.2%</td>
</tr>
<tr>
<td>30580</td>
<td>$14,558,745</td>
<td>2014</td>
<td>$9,192,357</td>
<td>$25,635,637</td>
<td>$6,381,039</td>
<td>69.4%</td>
</tr>
<tr>
<td>30694</td>
<td>$5,170,931</td>
<td>2014</td>
<td>$5,568,527</td>
<td>$25,635,637</td>
<td>$8,375,792</td>
<td>150.4%</td>
</tr>
<tr>
<td>30873</td>
<td>$15,821,763</td>
<td>2015</td>
<td>$16,622,740</td>
<td>$25,635,637</td>
<td>$(7,225,429)</td>
<td>-43.5%</td>
</tr>
<tr>
<td>30988</td>
<td>$10,425,309</td>
<td>2016</td>
<td>$10,685,942</td>
<td>$25,635,637</td>
<td>$5,278,044</td>
<td>49.4%</td>
</tr>
<tr>
<td>909</td>
<td>$6,355,000</td>
<td>2013</td>
<td>$6,758,277</td>
<td>$25,635,637</td>
<td>$1,523,942</td>
<td>22.5%</td>
</tr>
</tbody>
</table>

Table 12: Out-of-Bandwidth Project Cost Detail
RESPONSIVENESS REPORT

Table 14 and Figures 9 and 10 provide insight into the responsiveness of DTOs constructing Network Upgrades within SPP in the Quarterly Project Tracking Report for Q2 2017. **Note:** Network Upgrades with statuses of "Suspended", "Re-evaluation", "Within NTC Commitment Window", "Within NTC-C Project Estimate Window", and "Within RFP Response Window" were excluded from this analysis.

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Number of Upgrades</th>
<th>Number of Upgrades Reviewed</th>
<th>Reviewed %</th>
<th>In-Service Date Changes</th>
<th>ISD Change %</th>
<th>Cost Changes</th>
<th>Cost Change %</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>59</td>
<td>59</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>BEPC</td>
<td>24</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>GMO</td>
<td>2</td>
<td>2</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>GRDA</td>
<td>11</td>
<td>2</td>
<td>18%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>ITCGP</td>
<td>8</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>KCPL</td>
<td>5</td>
<td>5</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>LES</td>
<td>0</td>
<td>0</td>
<td>#DIV/0!</td>
<td>0</td>
<td>#DIV/0!</td>
<td>#DIV/0!</td>
<td>#DIV/0!</td>
</tr>
<tr>
<td>MIDW</td>
<td>9</td>
<td>7</td>
<td>78%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>MKEC</td>
<td>7</td>
<td>7</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>NPPD</td>
<td>36</td>
<td>20</td>
<td>56%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>OGE</td>
<td>45</td>
<td>2</td>
<td>4%</td>
<td>1</td>
<td>2%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>OPPD</td>
<td>14</td>
<td>14</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>SPS</td>
<td>170</td>
<td>168</td>
<td>99%</td>
<td>5</td>
<td>3%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>TSMO</td>
<td>7</td>
<td>7</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>1</td>
<td>14%</td>
</tr>
<tr>
<td>WFEC</td>
<td>36</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>WR</td>
<td>33</td>
<td>33</td>
<td>100%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>479</strong></td>
<td><strong>330</strong></td>
<td><strong>69%</strong></td>
<td><strong>6</strong></td>
<td><strong>1%</strong></td>
<td><strong>1</strong></td>
<td><strong>0%</strong></td>
</tr>
</tbody>
</table>

**Table 13: Responsiveness Summary by Project Owner**
Figure 8: In-Service Date Changes by Project Owner

Figure 7: Cost Changes by Project Owner
APPENDIX 1

{See accompanying list of active Applicable Projects}
<table>
<thead>
<tr>
<th>Date</th>
<th>Priority</th>
<th>Project Name</th>
<th>Service</th>
<th>Ckt 69</th>
<th>Bus 69</th>
<th>MVA 69</th>
<th>SW 69</th>
<th>Load 69</th>
<th>Month 69</th>
<th>MVA 75</th>
<th>SW 75</th>
<th>Load 75</th>
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<td>SW 75</td>
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**Notes:**
- Ckt = Circuit
- SW = Substation
- Load = Load
- Month = Month
- MVA = MVA
- SW = Substation
- Load = Load
- Month = Month
- MVA = MVA

**Comments:**
- Priority
- Project Name
- Service
- Ckt
- Bus
- MVA
- SW
- Load
- Month
- MVA
- SW
- Load
- Month

**Table Details:**
- The table details the project names, service, circuit, bus, MVA, SW, load, and month for both 69 and 75 voltages. Each row represents a different project with specific details such as priority, project name, service, circuit, bus, MVA, SW, load, and month for both 69 and 75 voltages.

**Additional Information:**
- The table includes comments for each project, which can provide additional context or notes related to the project details.
<table>
<thead>
<tr>
<th>Project Description</th>
<th>Total Cost</th>
<th>Year 1</th>
<th>Year 2</th>
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