1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of Minutes from January 26, 2015 and March 9, 2015

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

4. BUSINESS MEETING

5. CAWG REPORT AND VOTING ITEMS
   a. CAWG Report……………………………………………………………………………Jason Chaplin
      This report provides an update on CAWG activity.
   b. Aggregate Study Waiver Request [Potential Voting Item]…………………………..Lanny Nickell
      This voting item is the consideration of a request by Western Farmers Electric Cooperative for a
      waiver of the conditions of Section III.B.1 of Attachment J for a request for a new Designated
      Resource. Staff recommends denial. CAWG voted on April 7, 2015 in favor of denial. MOPC
      voted on April 15, 2015 in favor of denial.
   c. Regional Allocation Review Task Force…………………………………………………..Steve Stoll
      This item will provide an update on the activities of the RARTF and include a voting item on the
      endorsement of delaying the RCAR II process until July 2016.

6. REPORTS/PRESENTATIONS
   a. ITP10 Update………………………………………………………………………………..Alan Myers
      This report will provide an update on both the 2015 Renewables Survey and the ITP10 Futures.
   b. EPA Rule 111(d) Update………………………………………………………………………….Lanny Nickell
      This report will update and provide for discussion from the RSC on SPP’s analysis related to
      proposed Rule 111(d).
   c. Reevaluation of Walkemeyer Project…………………………………………………..Lanny Nickell
      This report will provide an update of Staff’s reevaluation of a project identified in the last ITP10
      and ITPNT.
d. **HPILS Update** .......................................................... Lanny Nickell
   This report will provide an update on the quarterly validation of HPILS project needs.

e. **Seams Update** .......................................................... Carl Monroe
   This report will provide an update on the pending matters at FERC related to SPP’s seams.

f. **Integrated Marketplace Update** ........................................ Bruce Rew
   This report will update the RSC on the Integrated Marketplace.

7. **OTHER RSC MATTERS**

8. **ACTION ITEMS**

9. **SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS**

   **RSC Meetings:**
   - July 27, 2015 – Kansas City, MO
   - October 26, 2015 – Little Rock, AR

10. **ADJOURN**

*NOTE: ADDITIONAL INFORMATIONAL MATERIAL ATTACHED*

Attached to the RSC’s meeting agenda and background material is additional material that is either for informational or reporting purposes.
Southwest Power Pool

REGIONAL STATE COMMITTEE
Southwest Power Pool Corporate Office
January 26, 2015

• MINUTES •

ADMINISTRATIVE ITEMS:
The following members were in attendance:

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

President Dana Murphy called the Regional State Committee (RSC) meeting to order at 1:17 p.m. with roll call and a quorum was declared. She then requested introductions of those in attendance. There were 114 in attendance, either in person or via the phone (Attendance & Proxies – Attachment 1).

President Murphy requested approval of the following October 27, 2014 and December 1, 2014 meeting minutes (RSC Minutes 10/27/14 and 12/01/14 – Attachment 2). Commissioner Patrick Lyons moved to approve the two sets of minutes; Commissioner Steve Lichter seconded. The motion passed unanimously.

UPDATES

RSC Fourth Quarter Financial Report
Mr. Paul Suskie, Southwest Power Pool, Inc. (SPP) Staff provided the financial report (RSC 2014 Q4 Financials – Attachment 3). He noted that everything was below budget except travel.

SPP Report
Mr. Nick Brown (SPP) welcomed everyone. He stated that it is a significant part of the SPP strategic plan to keep the RSC well informed and the lines of communication open. He expressed appreciation to Commissioner Lamar Davis and Chairman Ted Thomas of the Arkansas Public Service Commission for coming to the SPP offices last week. He noted that the SPP continues to evaluate the Clean Power Plan (CPP) 111(d) from the Environmental Protection Agency (EPA). The Strategic Planning Committee will be making some recommendations to the Board for some additional follow-up studies related to the CPP 111(d).

FERC
Mr. Patrick Clarey, Federal Energy Regulatory Commission (FERC) staff, provided an update on recent FERC activities. Mr. Clarey reported that first reports on fuel assurances are due in mid-February. He also provided an overview of staff enforcement activities for 2014. In December FERC announced a national technical conference and regional technical conferences on the CPP. The conference for the SPP Region will be March 31, 2015 in St. Louis. Mr. Clarey stated that Colette Honorable was sworn in as a FERC commissioner on January 25. He also listed staff changes recently announced by Chairman LaFleur. He noted that FERC conditionally accepted SPP’s proposed market-to-market coordination process with MISO.
Regional State Committee  
January 26, 2015  

BUSINESS MEETING  

Auditor Cost for Audit and Taxes for 2014  
Paul Suskie presented a proposed engagement letter from Thomas and Thomas LLP Certified Public Accountants (Auditor Engagement Letter – Attachment 4). President Murphy asked for approval of the auditor for the RSC. Commissioner Patrick Lyons moved for approval of Thomas and Thomas to perform the audit and prepare the tax form for the year 2014; Commissioner Shari Albrecht seconded the motion. The motion passed unanimously.  

COST ALLOCATION WORKING GROUP (CAWG) REPORT AND VOTING ITEMS  

CAWG Report  
CAWG Chair Jason Chaplin provided the CAWG report (CAWG Report – Attachment 5) and covered the following topics:  
1. Cost Allocation for Non-Order 1000 Seams Projects  
2. Congestion Rights in Integrated Marketplace  
   a. CAWG recommends RS C approve MPRR 227 as approved by the RTWG.  
   b. CAWG recommends RSC approve MPRR 221 as approved by MOPC.  
3. Capacity Margin Task Force Update  
4. Aggregate Study Waiver Process  

Strategic Planning Committee Task Force on New Members (SPC TF on New Members)  
Ms. Kristine Schmidt, Chairman of the (SPC TF on New Members – Attachment 6 and New Member Process Document – Attachment 7) addressed the following items that are under review by the RSC:  
1. Can/should RSC, CAWG or State Commission staff attend the SPC meetings’ Executive Sessions, and to possibly join the ad hoc Members Forum?  
   a. Asking for RSC feedback on if the states want to participate, and an assurance that the states can protect the confidential information that may be subject to FOIA and state open meeting laws, and assurance that confidential information from these meetings would not be used in other adjudicatory cases;  
2. When SPP Staff convenes an all-Member special meeting on new members, does SPP Staff convene a separate RSC/CAWG special meeting so that Commissioners/Staff can hear the issues of concern?  
   a. Asking for RSC feedback on if there is a preference to have a second SPP Staff convened special meeting for the states;  
3. The Task Force requests more information from the RSC as to how it views its role regarding the Bright Line date.  

President Murphy asked for action on Items 1 and 2 above and thought that discussions should continue on Item 3. Commissioner Stoll expressed it is important that RSC members have a role in the initial discussions, particularly regarding Items 1 and 2. Commissioner Albrecht noted that the draft process document should be made consistent with the information in the presentation and Ms. Schmidt stated that this would be addressed in the final draft process report from the task force. Chairman Nelson expressed that she had no concerns with the ability to keep information discussed in executive sessions confidential. Commissioner Lichter expressed that confidentiality is important and that a confidentiality agreement for executive sessions should be considered. SPP Board of Directors Chairman, Jim Eckelberger, explained that the SPP Board does not have concerns with RSC participation as long as confidentiality was maintained. President Murphy expressed concern in the past with a lack of clarity in advance regarding the issues covered in executive sessions confidential. Commissioner Lichter expressed that confidentiality is important and that a confidentiality agreement for executive sessions should be considered. SPP Board of Directors Chairman, Jim Eckelberger, explained that the SPP Board does not have concerns with RSC participation as long as confidentiality was maintained. President Murphy expressed concern in the past with a lack of clarity in advance regarding the issues covered in executive sessions confidential. Commissioner Lichter expressed that confidentiality is important and that a confidentiality agreement for executive sessions should be considered.
Cost Allocation for Non-Order 1000 Seams Projects

Mr. Dennis Reed provided the report on cost allocation for non-order 1000 seams projects (Cost Allocation for Non-Order 1000 Seams Projects – Attachment 8). The Whitepaper was approved by the MOPC and the Board in October. The RSC modified its October 2014 motion in December 2014 to set the threshold for review of cost allocation if a Zone gets at least 60% of the benefits. The Seams Steering Committee (SSC) also wanted to be sure the Zone where the project is built does not drop below a benefit/cost ratio of 1.0. TRR144 was approved by the RTWG at its December meeting. It was approved by the MOPC in January and reviewed by the RSC.

Commissioner Lichter moved to adopt the recommendation of the SSC. The motion was seconded by Commissioner Stoll. The motion was adopted unanimously.

Long Term Congestion Rights in the Integrated Marketplace

CAWG Member, Mr. John Krajewski, provided a report on Congestion Rights in the Integrated Marketplace (Congestion Rights Presentation – Attachment 9). He outlined three issues with respect to MPRR 227:

i. changes to the Long Term Congestion Rights Methodology for entities who sponsor transmission system upgrades and the applicable criteria;

ii. a change that would allow entities to nominate the Long Term Congestion Rights they want before preparing simultaneous feasibility study; and

iii. assurance of inclusion of LTCRs in the long-term planning processes to determine if they are feasible.

Mr. Krajewski shared the CAWG recommendation that the RSC approve MPRR 227 as presented to the CAWG on January 6, 2015. Commissioner Lyons moved that the RSC approve MPRR 227. The motion was seconded by Commissioner Stoll, and approved unanimously.

Mr. Krajewski explained that MPRR 221 provides the opportunity for transmission owner and new transmission service customers a transitional allocation. This issue has come up with the Integrated System owners. Mr. Krajewski stated that there are no policy changes being made to ARR/TCR eligibility. The CAWG recommends MPRR 221, Transitional Auction Revenue Rights Allocation Process, to be consistent with past policy decisions by the RSC related to the award of Auction Revenue Rights and Transmission Congestion Rights.

Commissioner Lichter moved that the RSC approve MPRR 221. The motion was seconded by Commissioner Lyons, and approved unanimously.

REPORTS/PRESENTATIONS

Integrated Transmission Planning (ITP) Near Term and ITP10 Update and SPP Transmission Expansion Plan (STEP)

Lanny Nickell, SPP Staff, provided an update on the ITP planning process (2015 ITP Update – Attachment 10 and 2015 STEP – Attachment 11). In response to a question from Chairman Ted Thomas, Mr. Nickell explained that these projects are not intended to comply with the Clean Power Plan but that it is not expected that the benefits of the portfolio would be undone by the Clean Power Plan. In his report on the ITP Near Term, Mr. Nickell reviewed the scenarios used. Chairman Nelson expressed concern about the amount of wind modeled in Scenario 5. She stated that planning for wind, capacity ratings, and firm transmission service may be issues for a future educational session.

Seams Update

Mr. Carl Monroe, SPP Staff, provided the Seams Update (Seams Update – Attachment 12). He described the current status of discussions with MISO. In addition, Mr. Monroe explained that SPP-AECI Joint and Common Study Process had concluded and that there were no projects identified but the parties will continue to coordinate.

Regional Allocation Review Task Force (RARTF)

Mr. Paul Suskie, SPP, provided an update on the RARTF (RARTF Status – Attachment 13). Mr. Suskie reported that the RARTF had taken a unanimous vote to extend the RCAR Final Report approval to July 2015 in order to accommodate the members’ request for more time for review. The next meeting of the RARTF is February 27, 2015. There is a vacancy on the RARTF with Commissioner Reeves’s term ending. He has served as both a representative and was also the chairman of the RARTF. President Murphy announced that after consulting with the Markets and Operations Policy Committee Chair, that Steve Stoll would become the new chairman and appointed Commissioner Lamar Davis to fill the vacancy on the RARTF.
Regional State Committee  
January 26, 2015

**Integrated Marketplace**  
Mr. Bruce Rew, SPP Staff, provided the Integrated Marketplace update (Integrated Marketplace Update – Attachment 14). He noted that SPP has established a new winter peaks for winter load on 1/8/15 and generation on 12/23/14. Currently there are 138 market participants. He was asked how much financial participants are paid on a monthly basis.

**EPA’s Clean Power Plan – SPP Update**  
Mr. Lanny Nickell, SPP Staff, provided an update on SPP’s plan for further analysis of the EPA Clean Power Plan that was requested by the SPC. The last analysis by SPP looked at reliability implications based on EPA’s projected retirements. The SPC requested analysis will require SPP to develop its own list of retirements. SPP’s approach will use existing and current IRP information (what has been filed by members, where available) to as the base case. Using that information and load forecasts, SPP will evaluate two time points: 2020 and 2030. SPP expects to have that analysis available on March 1, 2015. In addition, SPP will develop a timeline of events. This analysis will allow SPP to also consider the timeline needed for new generation. SPP intends to provide its results at the FERC regional technical conference on March 31st. SPP will also develop a state-by-state analysis that will mirror the regional analysis. The results will hopefully provide valuable information to states, EPA and FERC, as well as in next ITP and should be available during the summer. Chairman Nelson asked if a survey of generation was going to be conducted. Mr. Nickell stated that if the information is publically available and if not will go directly to generators. Chairman asked how SPP will address states in multiple RTOs. Mr. Nickell indicated that SPP intends to present results that address the SPP region in each state.

**ACTION ITEMS:**  
List is attached at the end of the minutes (Action Items – Attachment 15).

**SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:**  
President Murphy noted that there will be a net conference on March 9th prior to the April meeting. The SPP staff will follow-up with the Commissioners to find a convenient time.

<table>
<thead>
<tr>
<th>Date</th>
<th>Location</th>
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<tbody>
<tr>
<td>March 9, 2015</td>
<td>Conference Call</td>
</tr>
<tr>
<td>April 27, 2015</td>
<td>Tulsa, OK</td>
</tr>
<tr>
<td>July 27, 2015</td>
<td>Kansas City, MO</td>
</tr>
<tr>
<td>October 26, 2015</td>
<td>Little Rock, AR</td>
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</tbody>
</table>

With no further business, the meeting adjourned at 4:10 p.m.

Respectfully Submitted,

Paul Suskie
Southwest Power Pool

REGIONAL STATE COMMITTEE
Conference Call
March 9, 2015

• MINUTES •

ADMINISTRATIVE ITEMS:
The following members were in attendance:

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

Adam McKinnie was in attendance on behalf of Commissioner Steve Stoll and the Missouri Public Service Commission.

President Dana Murphy called the Regional State Committee (RSC) meeting to order at 1:06 p.m. with roll call and a quorum was declared. She then requested introductions of those in attendance. There were 41 in attendance on the conference call (Attendance & Proxies – Attachment 1).

President Murphy noted that this might be Tom DeBaun’s (KCC staff) last meeting and expressed appreciation to Tom for his commitment and involvement with the RSC and assisting Commissioner Albrecht. Chair Nelson also expressed her appreciation to Tom for his years of service.

5. REPORTS/PRESENTATIONS

SPC Task Force on New Members:

Kristine Schmidt, chairman of the Strategic Planning Committee Task Force on New Members (SPCTF on New Members) provided an update on the task force. This update was requested following the submission by the Oklahoma Corporation Commission (OCC), Kansas Corporation Commission (KCC), and the Public Utility Commission of Texas (PUCT) of input to the SPCTF on New Members draft process document.

Ms. Schmidt provided a recap of the SPCTF on New Members activities including a series of recommendations made after a number of meetings that took place during the fall of 2014 and brought to the RSC three specific items:

1. Attendance by the RSC at Strategic Planning Committee (SPC) meetings to include those in Executive Session;
2. Attendance by the RSC at the Membership meetings. The RSC understands the cost concern associated with having a single meeting but reserves the right to have a separate meeting for the RSC; and
3. Brightline date. The SPCTF on New Members decided this is outside the scope of the task force. There was a discussion among the members to what role the RSC had with regard to cost allocation and the brightline date. The RSC would take this issue up as an action item in 2015.
Ms. Schmidt noted that the SPCTF on New Members has been directed to have its final report to the SPC at the April 2015 meeting and then to the Board in April 2015. She noted that some of the items that were proposed are significant changes in the process already approved by the SPC and SPP Board in the draft report. For this reason, the proposed changes would need to be submitted to MOPC and to the full Membership as well for further consideration. Ms. Schmidt suggested that the RSC collaborate and incorporate all of the proposed changes into one document. Ms. Schmidt indicated that the initial goal was to complete this process in 2014.

Jason Chaplin, OCC staff and Chairman of the Cost Allocation Working Group (CAWG), stated that SPP staff is putting together a presentation for CAWG in April and CAWG could provide input on the Brightline issue at the RSC educational session in April.

Chairman Nelson commented about concerns with the RSC’s need for involvement earlier in the new member process including cost allocation issues involved with bringing on a new member. Commissioner Albrecht asked for more clarification about the Brightline date. Paul Suskie (SPP staff) explained that “brightline” is just a phrase to describe cost allocation or how the highway/byway methodology would apply to the Integrated System (IS) entities. He noted that it is not really a process.

President Murphy discussed efforts to include the RSC in the front end and referenced RSC input being sought out earlier such as when the negotiations are occurring with prospective entities. The draft process document of the SPCTF on New Members does appear to address the issue of early RSC involvement. Commissioners expressed concerns with cost allocation and how that affects the new members and existing members, which is not addressed in the draft process document.

Kristine Schmidt expressed her appreciation for the input from the RSC. She requested clarification on the following questions: Is there some additional language the RSC would propose to see put in place? Are there work processes that the RSC needs to have in place? Ms. Schmidt said she would take the document produced by the RSC back to the SPCTF on New Members.

Commissioner Albrecht agreed to put together a draft document to distribute to the RSC. Chairman Nelson volunteered Meena Thomas and Laura Kennedy from her staff to assist with drafting language. Jason Chaplin will also help provide input. President Murphy requested a draft be circulated to the RSC by Monday, March 23.

2015 RSC Goals:

President Murphy reported on status of the 2015 RSC goals (2015 RSC Goals – Attachment 2):

1. Long-term Congestion Rights: This goal was completed in January.
2. Provide RSC Input to the SPCTF on New Members: Still in the process.
3. Add new members to the Regional State Committee:
   a. Incorporating in the New Members. Commissioner Murphy thanked Brian Kalk for listening in and participating. The Bylaw group is meeting at the conclusion of the RSC call.
4. EPA Clean Power Plan: Moving forward. Lanny Nickell will discuss this in some detail on the SPC conference call next week, Monday, March 16 at 1:30.
5. RSC Retreat: The retreat will be held in Kansas City in July.

RSC Draft Agenda – April 2015:

President Murphy reviewed the draft agenda, noting that at this time there are no voting items on the agenda for April (Draft Agenda – Attachment 3).

Topics for April Educational Session and July Retreat:

President Murphy discussed possible topics for the April Educational Session and July Retreat. (Potential topics for April Education Session and July Retreat – Attachment 4). In April, the educational session will include the Brightline concept for the integration of new members and will include comments from CAWG and a summary
Regional State Committee  
March 9, 2015

and historical information from SPP Staff. In addition, Staff will provide a high level overview of cost allocation and rates. In addition, President Murphy discussed that some entities like Wal-Mart and Google are interested in discussing the issues they have in purchasing power which may make a good education item. Commissioner Steven Lichter mentioned a possible topic for the July retreat that has come up at the Regional Allocation Review Task Force (RARTF) which is the modeling process, which is the basis for benefit analysis. Other areas of interest for topics are:

1. High Level Overview of Cost Allocation and Rates
2. Process for Project Reevaluation
3. SPP “Building Blocks”
4. Bright Line date for new members
5. Company Perspective on Renewables

SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:

President Murphy noted that the next meeting will take place in April in Tulsa, OK.

<table>
<thead>
<tr>
<th>Date</th>
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<tbody>
<tr>
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</tr>
<tr>
<td>October 26, 2015</td>
<td>Little Rock, AR</td>
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With no further business, the meeting adjourned at 2:07 p.m.

Respectfully Submitted,

Paul Suskie
### Regional State Committee
#### For the Three Months Ending March 31, 2015
#### Budget vs. Actual

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<tr>
<td>Other Income</td>
<td>44,303</td>
<td>65,250</td>
<td>(20,947)</td>
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<tr>
<td><strong>Total Income</strong></td>
<td>44,303</td>
<td>65,250</td>
<td>(20,947)</td>
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<td><strong>Expense</strong></td>
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<td>(250)</td>
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<tr>
<td><strong>Total Expense</strong></td>
<td>44,303</td>
<td>65,250</td>
<td>(20,947)</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
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<td>-</td>
<td>-</td>
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</table>
Report to the Regional State Committee
April 27, 2015

Cost Allocation Working Group (CAWG)

Jason Chaplin
Oklahoma Corporation Commission
Topics:

- Capacity Margin Task Force (CMTF) Update
- 2017 ITP10 Renewable Survey Process Improvements Update
- SPP Regional Order 1000 Process Update
- Aggregate Study Waiver Request

Agenda Item 5.b. – Aggregate Study Waiver Request: Lanny Nickell to present consideration of request by Western Farmers Electric Cooperative.
Need first introduced at April 2014 MOPC, Carl Monroe discussed background, requirements, and proposed a plan of action. MOPC took an Action Item for Staff to send out questions about Capacity Margin for input from Members.

Two rounds of Questions sent out to for feedback.

July 2014 MOPC, to develop solutions to the issues framed by the questions sent out for feedback, Staff recommends that a task force reporting to MOPC be formed in accordance with the charter provided.

Motion to approve the draft charter and create a task force was passed unanimously.
Summary of CMTF Scope:
- An update to SPP’s Capacity Margin requirements and methodology is needed to address changes in the SPP marketplace, provide clarification for entities required to maintain a calculated Capacity Margin, and evaluate affects of a changing footprint and operations.

Representation:
- SPP Member companies could nominate one person from their company.
- CAWG/RSC representation encouraged.
Load Responsible Entity (LRE) Definition:
- CMTF approved the LRE definition on December 10, 2014.
- Load Responsible Entity (LRE) definition:
  “Any entity with the obligation to serve capacity and load requirements of end-use retail customers pursuant to state or local law, regulatory requirement, or franchise, where such load is connected to the Transmission System or included in the SPP Balancing Authority Area.”
Capacity Margin vs. Reserve Margin:

- CMTF approved moving from the Capacity Margin terminology to Reserve Margin terminology on February 10, 2015.
- **Capacity Margin%** = \( \frac{\text{Net Total Capacity} - \text{Net Total Load}}{\text{Net Total Capacity}} \times 100 \) – Amount of spare capacity available for planned and emergency use within a zone.
- **Reserve Margin%** = \( \frac{\text{Net Total Capacity} - \text{Net Total Load}}{\text{Net Total Load}} \times 100 \) – Amount that load can grow and still be served from spare capacity within a zone.
CMTF Current Efforts

- **Reserve Margin Requirement:**
  - Performing LOLE analysis to determine what new Reserve Margin SPP could move to and still remain reliable.

- **Load Responsible Entity:**
  - Developing LRE applicability in SPP processes.

- **Enforcement Policy:**
  - Developing enforcement guidelines for Reserve Margin requirement.

- **Deliverability Study:**
LOLE Sensitivity Study Process:
- Performing sensitivity LOLE studies to finalize future LOLE study assumptions.
- SPP staff presenting results to the CMTF as available for guidance on LOLE study assumptions.

LOLE Sensitivity Study Scenarios:
- Changes in max number of generator forced outages.
- Changes in load uncertainty.
- Coincident peak demand.
- Depleting Operating Reserves.
**Expected timeline for future MOPC approval items**

- **Load Responsible Entity:**
  - Expect to present to MOPC for approval at the July meeting.

- **Enforcement Policy:**
  - Expect to present to MOPC for approval at the July meeting.

- **Deliverability Study:**
  - Expect to present to MOPC for approval at the October meeting.

- **New Reserve Margin requirement:**
  - Expect to present to MOPC for approval at the October meeting.
Background

- At February CAWG meeting SPP Staff made a presentation on the 2017 ITP10 Renewable Survey Process Improvements. SPP Staff stated they are pursuing methods to simplify the process. Items presented include various aspects of the data submittal form, siting considerations, and high-level summary of the benefits.

- Benefits include: reduce amount of data requested, condensing data tables, clarify what is requested, and provide more meaning and application to planned renewables.
Background Cont…

- At March CAWG meeting SPP Staff raised some Policy Issues discussed by the Economic Studies Working Group (ESWG) meeting.

- CAWG members requested to review feedback from the March Transmission Working Group (TWG) and/or Economic Studies Working Group (ESWG) meetings as information becomes available.
April CAWG Meeting:

- SPP Staff presented additional information relating to the Process Improvements and provided additional discussion on areas relating to the Data Submittal Form.

- SPP Staff provided an Economic Studies Working Group (ESWG) update from their March 31st meeting. The ESWG did not object to Staff-proposed approach but did not take action to allow Staff to work on some details.

- ESWG net-conference will be set up to discuss the proposal further.
CAWG Action/Motion:

- CAWG does not oppose the changes to the Renewable Survey and recommends taking an action item to discuss before the next ITP cycle, expected to begin in 2017: the purpose of the Renewable Survey, how the Renewable Survey is used in Transmission Planning, and whether it is still appropriate for the CAWG to be responsible for the Renewable Survey.

The motion was approved unanimously.
At the October 2014 RSC meeting, the CAWG presented to the RSC examples of concerns raised by SPP members which included:

- Should there be an expedited state process for granting utility status to a winning bidder that is not a utility?
- Should the Certificate of Convenience and Necessity (CCN) process for Order 1000 projects be expedited?
SPP Regional Order 1000 Update

- SPP staff, along with state regulators, did research the statutes on the current processes for granting utility status and CCN in various states.

- Based on the different state processes of granting utility status or a CCN and the highly litigious nature of the concerns, the CAWG at their February meeting did not find it necessary or under CAWG purview to take any further action on this topic.
Summary:
- Transmission Service Request 80912733
- Western Farmers Electric Cooperative (WFEC)
- Aggregate Study 2015-AG1
- Requested Capacity: 100 MW
- New Wind Resource
- Requested Term: 19.75 years (9/1/2015 – 6/1/2035)

This transmission service request is not eligible for Base Plan funding under Attachment J because the wind/load ratio exceeds 20%.
Cost Allocation Under Attachment J

- Service upgrades associated with new or changed Designated Resources shall be classified as Base Plan Upgrades for cost allocation if the following conditions are met:
  - Commitment must be at least 5 years
  - Designated Resources/Load Ratio ≤ 125%
  - Designated Wind Resources/Load Ratio ≤ 20%
    (applies only to wind)
- Cost that exceed the Safe Harbor Cost Limit of $180,000/MW times the requested capacity are directly assigned.
A Transmission Customer may seek a waiver so that costs that otherwise would be directly assigned may be classified as Base Plan Upgrades Cost if:

- One or more of the conditions are not met, or
- The Cost exceeds the Safe Harbor Cost Limit

The wind/load ratio for this request is 25% in the first year, and remains above 20% through 2025.
Factors for Consideration

- There are insufficient competitive resource alternatives for one or more Transmission Customers.
- The extent to which the duration of the Transmission Customers commitment exceeds the 5 year commitment period.

While the 5 year commitment period was met, the CAWG contends that WFEC did not demonstrate that competitive resource alternatives were insufficient.
Based on this analysis presented to the CAWG at their April 2015 meeting, the CAWG took the following action:

- **SPP Staff Recommendation**
  - SPP Staff recommends that the waiver not be approved.

- The CAWG endorses SPP Staff’s recommendation that the waiver not be approved. (Motion passed with 6-0-1 vote)
Questions?

Submitted by:
Jason Chaplin
CAWG Chairman
April 27, 2015
Aggregate Study
Waiver Request

April 27, 2015
Lanny Nickell
Summary

- Transmission Service Request 80912733
  - Western Farmers Electric Cooperative (WFEC)
  - Aggregate Study 2015-AG1
  - Requested Capacity: 100 MW
  - New wind resource
  - Requested Term: 19.75 years (9/1/2015 – 6/1/2035)

- Transmission service request is not eligible for Base Plan funding under Attachment J because the wind/load ratio exceeds 20% in the first year.
- The wind/load ratio for this request is 25% in the first year, and remains above 20% through 2025.
- Waiver request must be presented to SPP Board at the regular April meeting in order to meet the 120-day (July 3) tariff deadline.
20% Wind/Load Ratio Background

SPP’s April 24, 2009 filing letter in Docket ER09-1039: Part III.C

- Limit recognizes the operational challenges of integrating large amounts of intermittent generation, such as wind, into the SPP transmission system.

- The Commission previously has recognized SPP's need to safeguard its ability to reliably serve load by imposing limits on the amount of generation that can be injected into the SPP transmission system.

- CAWG suggested a 20% limit that was subsequently endorsed by the RSC.

- This is consistent with the Renewable Portfolio Standards requirements that have been adopted within SPP's region.
WFEC View of 20% Limit

• Changes since the 20% limit was approved
  – The SPP Integrated Marketplace has demonstrated its ability to balance generation-to-load control.
  – IM protocols require all new intermittent resources to be dispatchable (DVER).
  – Generator Interconnection Agreement provisions now require power factor to be maintained within +/- 95%

• Any operational challenges will exist even if the wind farm does not gain DR status.

• 20% limit is arbitrary and WFEC exceeds the ratio only slightly.
Customer Support for Waiver Request

WFEC cites the following points in support of its request for waiver of the eligibility requirements:

1. SPP OATT Attachment J Section III.C.2.i, which states that one factor to be considered in evaluating waiver requests is:

   “There are insufficient competitive resource alternatives for one or more Transmission Customers”

   “Intermittent resources continue to be a less costly energy alternative to fossil fuel power plant construction while providing some level of capacity as well.”

2. Power Purchase Agreement covers a term of 20 years—“much longer than the required 5-year minimum.”
Customer Support for Waiver Request, cont.

3. Commitment to renewable energy and a diversified portfolio supports delivery of wind generation into the SPP region.

4. Commitment lessens WFEC’s carbon emissions in the wake of more EPA regulations.

5. WFEC’s projected future load growth is substantial. Oil and gas industry continues to increase in WFEC area.

6. Load growth will decrease the wind/load ratio below 20% in near future.
SPP Staff Analysis

• Insufficient Competitive Resource Alternatives
  – The Attachment J consideration for “insufficient competitive resource alternatives” implies that there may be a basis for waiving the requirement when this situation exists.
  – In order to reach this conclusion, the customer should be able to demonstrate that either there are no alternatives, or the alternatives that exist are not competitive.
  – The customer states that the resource has economic advantages over other alternatives and would bring regulatory and environmental benefits.
  – These advantages don’t by themselves support a finding that there are insufficient competitive resource alternatives.
SPP Staff Analysis

• The 20% wind/load ratio limit
  – Limits the costs borne by SPP ratepayers to support integration of resources that have both operational challenges and limited value as a capacity resource.
  – Recommended by CAWG and approved by RSC.
  – Customer’s existing wind DRs result in a wind/load ratio of 19%. With this request, the ratio would increase to 25% in the first year. It would remain above 20% through at least 2025.
  – No compelling reason to waive the 20% requirement in this specific case.
Options for Customer

• Proceed with waiver request to MOPC and BOD
• Proceed with study without waiver and either:
  – Un-designate existing resources to meet the requirement
  – Withdraw if substantial costs are allocated
  – Accept any directly assigned upgrade costs
    ▪ Receive revenue credits, or
    ▪ Pursue incremental LTCR for upgrades
• Withdraw from study process and request designation in future when the situation changes
Recent Stakeholder Group Actions

• **CAWG (April 7)**
  – Motion to support SPP Staff recommendation not to approve waiver request passed with none opposed and one abstention.

• **MOPC (April 15)**
  – Motion to approve waiver request failed with 32.6% voting in favor.
SPP Staff Recommendation

• SPP Staff Recommendation

SPP Staff recommends that the waiver not be approved.
RARTF Update to MOPC

April 2015

Commissioner Steve Stoll
Chair RARTF

Southwest Power Pool

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

• History of RCAR II
  – Planned to be completed after 2015 ITP10; to include ITP10 and ITPNT approved projects
  – Utilize same models and assumptions
  – RCAR I deficient zone projects studied as part of ITP10

• Stakeholder concerns
  – After the completion of ITP10 stakeholders voiced concerns over model accuracy
    ▪ KCPL decision on Montrose units
    ▪ EDE concerned over generation modeling
RARTF Update

• RARTF Action
  – Feb 27 – RARTF asked staff to look at options of addressing stakeholder concerns of models
  – Mar 13 – Staff presented 3 options to RARTF for consideration
    1. Continue RCAR II with 2015 ITP10 models and complete RCAR II in July 2015
    2. Update 2015 ITP10 models with KCPL, EDE and other changes and complete RCAR II in January 2016
    3. Delay current RCAR II using the 2015 ITP10 models and utilize the models currently being built for the 2017 ITP10 and complete RCAR II in July 2016.
RARTF Update

• In April 2014, MOPC and the RSC approved Lessons Learned from RCAR I including:

• **Recommendation #5**
  
  – That SPP staff utilize, to the maximum extent possible, models used in the Integrated Transmission Plan 10-year planning horizon assessment (ITP10) for RCAR II. Conducting the ITP10 and RCAR II processes in parallel should allow leveraging of models and promote consistency and efficiency in the model vetting process. This measure could reduce cost and help to eliminate redundancy of efforts between SPP staff and stakeholders.
RARTF Update

- Ultimately the RARTF voted 7-2 for Option 3 and to delay completion of the RCAR II until July 2016.
  - Lamar Davis (APSC) and Shari Albrecht (KCC) voted against this motion

- This delay will still allow for SPP to meet the “at least every 3 years” requirement in the Tariff
  - RCAR I was completed in October 2013
Recommendation

• The RARTF is a jointly appointed task force
  – 4 MOPC Members (Ross, Crissup, Grant, Warren)
  – 4 RSC Members (Stoll, Albrecht, Davis, Lichter)
  – 1 SPP BOD Member (Skilton)
  – This recommendation was presented to the MOPC on 4/14/15
    ▪ The recommendation passed with Kristine Schmidt (ITC) opposing and Dennis Florom (LES) and Aaron Pupa (Midwest Gen) abstaining.

• RARTF recommends that the MOPC endorse the decision to delay the completion of the RCAR II to allow for the use of the 2017 ITP10 models.
QUESTIONS?
2017 ITP10
Renewable Survey

Lanny Nickell
April 27, 2015
Renewable Survey Process Improvements

Data Submittal Form

– Incorporating existing renewable data in Generation Review
  ▪ Allows all information on existing generation to be in one data request

– Consolidating mandate and goal info into single table of entry

– Adding flexibility to accurately reflect mandates or goals
  ▪ Can submit Capacity (MW) or Energy (MWh)
  ▪ Allows Staff to determine any shortfall with more certainty
  ▪ Reduces confusion in overall completion of the survey
Renewable Survey Process Improvements

Data Submittal Form

- Removing the “Other” renewable category
  - Improves accuracy in determination of policy vs. non-policy information
  - Reduces data being requested
  - Reduces confusion in overall completion of survey
  - Provides means to improve transparency through stakeholder review

- Providing options for siting considerations
  - Allows flexibility for Staff or utilities to site resources
  - Feeds into development of conventional resource plan
  - Reduces confusion in overall completion of survey
Summary of Benefits

- Reduces amount of data requested through this survey
- Streamlines data input
- Clarifies what is being requested
- Provides more meaning and application to planned renewables
- Allows flexibility for utilities to submit requirements and siting information
- Removes potential delays in study process
CAWG Approval

CAWG does not oppose the changes to the Renewable Survey and recommends taking an action item to discuss before the next ITP cycle, expected to begin in 2017: the purpose of the Renewable Survey, how the Renewable Survey is used in Transmission Planning, and whether it is still appropriate for the CAWG to be responsible for the Renewable Survey.
Introduction

- In October 2014, the SPP BOD directed SPP “For the three year planning cycle commencing in January 2015... request a waiver from FERC of 1) the requirements to perform the ITP20 and 2) the timing requirements related to the ITP10 to permit SPP to commence the ITP10 in January 2015, to be completed no later than January 2017.”

  - EPA Clean Power Plan section 111(d) impacts, nationwide 30% reduction of CO\textsubscript{2} by 2030, final rule expected June, 2015

- ESWG has discussed how to approach the scope and timeline for the next 2017 ITP10
PROCESS
ESWG Proposed Scope Process Summary

• Propose an expanded set of potential scenarios/drivers
  – MOPC/SPC provided feedback in January meetings
  – Narrowed down to four proposed futures for April MOPC Meeting
  – Remaining scope details to be finalized in July 2015

• Phased approach
  – Phase 1: discussed multitude of potential scenarios/drivers
  – Phase 2: reduced list by ranking of occurrence/impact
  – Phase 3: propose set of futures around drivers
ESWG Proposed Futures

- Four futures driven by EPA Clean Power Plan Section 111(d) impacts
  - Future 1
    - Regional Clean Power Plan solution
  - Future 2
    - State Level Clean Power Plan solution
  - Future 3
    - No Clean Power Plan solution incorporated
  - Future 4
    - Clean Power Plan ‘Extreme Case’
Future 1 – Regional Clean Power Plan Solution

Assumes that the EPA Clean Power Plan will be implemented at a Regional level by meeting emissions targets within the SPP footprint. Additional significant features include:

– Competitive Wind (Sub $24/MWh prices)

– High availability of natural gas due to hydraulic fracturing (fracking)

– Large scale solar generation development

– Normal load growth
Future 2 – State Level Clean Power Plan Solution

Assumes that the EPA Clean Power Plan will be implemented at a State level under the following conditions:

– Each state has its own compliance plan and each utility meets the EPA determined emission rate

– Competitive Wind (Sub $24/MWh prices)

– High availability of natural gas due to hydraulic fracturing

– Large scale solar generation development

– Normal load growth
Future 3 – No Clean Power Plan Solution

Assumes that the EPA Clean Power Plan is not implemented, and also assumes the following significant features:

– Competitive Wind (Sub $24/MWh prices)
– High availability of natural gas due to hydraulic fracturing (fracking)
– A mix of large-scale solar generation development along with smaller scale solar generation methods such as rooftop
– Increased load growth (ESWG Recommendation)
– Normal load growth (MOPC Recommendation)
Future 4 – Clean Power Plan ‘Extreme Case’

Assumes Clean Power Plan is implemented in a manner that the current electrical grid is least prepared including:

– Onerous Carbon Tax
– Enhanced metric for retiring generating units (age, size)
– Loss of Production Tax Credit, resulting in higher wind prices
– Lower availability of natural gas due to hydraulic fracturing (fracking) regulation
– A higher number of Large Scale Solar generators
– Decreased load growth
– MOPC recommended cutting this future
## Futures Development – Key Drivers

<table>
<thead>
<tr>
<th>Driver</th>
<th>Regional CPP</th>
<th>State CPP</th>
<th>No CPP</th>
<th>Extreme Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPP Disposition</td>
<td>Regional compliance</td>
<td>State Compliance</td>
<td>No CPP Approved</td>
<td>CPP approved</td>
</tr>
<tr>
<td>Competitive Wind</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No PTC, Higher Wind Prices</td>
</tr>
<tr>
<td>NG Supply Due to Fracking</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Solar Development (Substantial)</td>
<td>Large Scale</td>
<td>Large Scale</td>
<td>Mix of Large Scale and Roof Top</td>
<td>Large Scale</td>
</tr>
<tr>
<td>Load Growth</td>
<td>Normal</td>
<td>Normal</td>
<td>Increased (ESWG)/ Normal (MOPC)</td>
<td>Decreased</td>
</tr>
</tbody>
</table>
Recommendations

• ESWG Presented 4 futures to MOPC showing that F1-F3 (Regional 111D, State 111D, no 111D) are higher priority as recommended by ESWG. Also, recommend the low load growth and low gas supply drivers from F4 as a sensitivity in F3 should F4 be eliminated.

• ESWG has not yet substantially discussed how these futures would be utilized to construct a recommended portfolio.

• MOPC voted to approve Futures 1, 2, &3 and change the load growth to normal on Future 3.
Introduction

• June 2014: EPA’s proposed CPP rule issued

• October 2014: SPP published its assessment of reliability impacts of EPA’s proposed CPP
  o The EPA projected approximately 9 GW of existing coal- and gas-fired generating capacity in the SPP Region will be retired by 2020

• January 2015: The Strategic Planning Committee (SPC) directed SPP to perform additional assessment of the proposed CPP
  o The SPC instructed SPP to analyze a regional compliance basis first followed by a state-by-state compliance basis
  o Assessment scope developed with feedback from SPP staff and members
Clean Power Plan Milestones

- **June 2, 2014**
  - Draft rule issued

- **June 2015**
  - Final rule expected

- **June 2017**
  - State plans due (with one-year extension)

- **January 2018**
  - State plans due (with two-year extension)

- **June 2019**
  - Multi-state plans due (with two-year extension)

- **January 2020-29**
  - Interim goal in effect

- **January 2030**
  - Final goal in effect
2015 CPP ASSESSMENT
Analysis Steps for Regional Compliance

• Estimate an SPP regional share of the state carbon emissions goals

• Develop a 2030 Business as Usual Reference Case
  o Incrementally apply resource changes from publically available data

• Evaluate range of carbon reduction measures for SPP region
  o Implement a reasonable carbon cost adder
  o Implement incremental resource plan changes capable of meeting the SPP regional emission goal
  o Test potential energy efficiency measures

• Identify impacts on existing and planned resources
REGIONAL EMISSION GOAL
SPP Regional Emission Goal Estimate

• Used EPA’s Technical Support Documents

• Identified SPP portion of each state
  o Existing Generation Units (EGUs)
  o At-risk nuclear capacity
  o Renewable energy (existing and potential)
    ▪ Excludes existing hydro
  o Energy efficiency

• Determined weighted average emissions goal for region
### SPP Regional Emission Goal Estimate

<table>
<thead>
<tr>
<th>State</th>
<th>Final Goal</th>
<th>Energy Efficiency</th>
<th>Renewable</th>
<th>Nuclear</th>
<th>Redispatch CCs</th>
<th>Heat Rate Improvement</th>
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<tbody>
<tr>
<td>North Dakota</td>
<td>1783</td>
<td>2368</td>
<td>1499</td>
<td>1301</td>
<td>2197</td>
<td>2162</td>
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<tr>
<td>Wyoming</td>
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<td>2331</td>
<td>1499</td>
<td>1301</td>
<td>2197</td>
<td>2162</td>
</tr>
<tr>
<td>Kansas</td>
<td>1499</td>
<td>2320</td>
<td>1301</td>
<td>2197</td>
<td>2162</td>
<td>2010</td>
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<td>South Dakota</td>
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<td>1544</td>
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<tr>
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<td>1301</td>
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<td>1544</td>
<td>1798</td>
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<tr>
<td>Nebraska</td>
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<td>2162</td>
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<td>1798</td>
<td>1722</td>
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<tr>
<td>Missouri</td>
<td>1544</td>
<td>2010</td>
<td>1798</td>
<td>1722</td>
<td>1562</td>
<td>1533</td>
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<td>New Mexico</td>
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<td>1562</td>
<td>1533</td>
<td>1562</td>
<td>1420</td>
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<td>1309</td>
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<td>Oklahoma</td>
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<td>Louisiana</td>
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<td>1420</td>
<td>1309</td>
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<tr>
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<td>1420</td>
<td>1309</td>
<td></td>
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<tr>
<td>Spp Region</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

**Notes:**

- Final Goal
- Energy Efficiency
- Renewable
- Nuclear
- Redispatch CCs
- Heat Rate Improvement

*SPP States with applicable Existing Generating Units"
REFERENCE CASE DEVELOPMENT
2030 Business as Usual Reference Case

- Used resource and load projections approved by ESWG
  - 2015 ITP10 2024 Future 1
    - Software based resource expansion
  - RCAR II 2034
    - Projected expansion based on CC/CT ratio from software analysis
    - 2030 projections interpolated
- Incorporated IRP (and other publicly available) resource changes
- Maintained $\geq 12\%$ capacity margin and CC/CT ratio
- Used “Copper Sheet” approach
  - No transmission constraints
  - No interchange with adjacent pools
Reference Case Resource Plan
COMPLIANCE SCENARIO DEVELOPMENT
- Identify Reasonable Carbon Cost Adder
Average Capacity Factor by Unit Type

![Bar chart showing average capacity factor by unit type for different carbon costs (in $/Ton)].

- **Combined Cycle**
- **CT Gas**
- **Internal Combustion**
- **ST Coal**
- **ST Gas**

The chart indicates the capacity factor (%) for each unit type at various carbon costs ($/Ton).
Coal Capacity by Average Capacity Factor

![Coal Capacity by Average Capacity Factor](image-url)

- **Carbon Cost ($/Ton)**
  - >80%
  - 60%-80%
  - 40%-60%
  - 30%-40%
  - <30%

- **Capacity (GW)**
  - $0
  - $15
  - $30
  - $45
  - $60
  - $75
  - $100

- **Legend**
  - $0
  - $15
  - $30
  - $45
  - $60
  - $75
  - $100

- **SPP**
Carbon Cost Adder Emission Rate Results

![Graph showing the relationship between Emissions Rate (lbs/MWh) and Carbon Cost ($/ton). The emissions rate decreases as the carbon cost increases.](image-url)
Rate of Change of Emission Rate

![Graph showing the rate of change of emission rate against carbon cost (\$/Ton). The graph displays a significant increase in rate of change as carbon cost increases from $0 to $45, followed by a decrease as carbon cost increases from $45 to $100.](image-url)
COMPLIANCE SCENARIO DEVELOPMENT
- Resource Plan Augmentation
Incremental Coal Retirements

• Potential “At-Risk” capacity
  o At $0 (zero) carbon cost adder, nearly all coal units > 80% capacity factor
  o At $45/Ton carbon cost adder scenario, ~12,200 MW below 80% capacity factor

• Assumed Retirements for Compliance Analysis
  o Conservative: identified those units operating below 30% capacity factor with a $45/Ton carbon cost adder
  o ~2,000 MW retired for compliance scenario
Coal Capacity by Capacity Factor Carbon Cost Adder @ $45/Ton
Resource Mix Changes

• Added resources to cost effectively maintain required capacity margin and reduce emissions

• 5.6 GW wind added
  o Based on Attachment J allowance for safe harbor
  o Assumed 25% of system peak responsibility given SPP renewable expectations
  o Assumed 10% wind capacity accreditation

• 1.2 GW of NGCCs and CTs added

• Converted 3.6 GW of currently planned CCs to CTs
  o To reliably support additional wind
Resource Plan Comparison

The diagram compares the capacity (GW) across different categories such as Retirements, Coal to Gas Conversions, Coal Derate, Wind, Solar, CC to CT conversion, CT, and CC, between CPP Compliance, CPP BAU, and 2015 ITP10.
COMPLIANCE SCENARIO RESULTS
SPP Carbon Emission Rate Results

Regional Goal (1309 lbs/MWh)

- 2030 Base ($0/Ton): 1,577 lbs/MWh
- 2030 $45/Ton: 1,431 lbs/MWh
- 2030 Compliance: 1,285 lbs/MWh
Coal Capacity Factor Comparison

- 2030 Base
- 2030 $45/Ton
- 2030 Compliance

Capacity (GW)

- >80%
- 60%-80%
- 40%-60%
- 30%-40%
- <30%
- Retired
Capacity Factor by Unit Type (Compliance)
Estimated Costs of Compliance

- **Costs of “Uncommitted” BAU Resources**

<table>
<thead>
<tr>
<th>Type</th>
<th>Capacity (GW)</th>
<th>2015 $B (Total)</th>
<th>2015 $B (1-Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>3.9</td>
<td>9.3</td>
<td>1.6</td>
</tr>
<tr>
<td>CC</td>
<td>8.8</td>
<td>9.8</td>
<td>1.7</td>
</tr>
<tr>
<td>CT</td>
<td>13.2</td>
<td>9.7</td>
<td>1.6</td>
</tr>
<tr>
<td>Solar</td>
<td>0.2</td>
<td>0.8</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>26.1</strong></td>
<td><strong>29.6</strong></td>
<td><strong>5.0</strong></td>
</tr>
</tbody>
</table>

**“Uncommitted” represents resources that do not have SPP Generation Interconnection Agreements**

- **Incremental Costs of Compliance Scenario**

<table>
<thead>
<tr>
<th>Type</th>
<th>Capacity (GW)</th>
<th>2015 $B (Total)</th>
<th>2015 $B (1-Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Wind</td>
<td>5.6</td>
<td>13.5</td>
<td>2.3</td>
</tr>
<tr>
<td>New CC</td>
<td>0.4</td>
<td>0.4</td>
<td>0.1</td>
</tr>
<tr>
<td>New CT</td>
<td>0.8</td>
<td>0.6</td>
<td>0.1</td>
</tr>
<tr>
<td>CC to CT Conversion</td>
<td>3.6</td>
<td>-1.2</td>
<td>-0.2</td>
</tr>
<tr>
<td>Production Cost</td>
<td>-</td>
<td>-</td>
<td>0.6</td>
</tr>
<tr>
<td><strong>Total Incremental</strong></td>
<td><strong>6.9</strong></td>
<td><strong>13.3</strong></td>
<td><strong>2.9</strong></td>
</tr>
</tbody>
</table>

*Does not consider cost of transmission additions, transmission congestion, gas infrastructure, and market enhancements*
Energy Efficiency Sensitivity

• Tested impact of additional energy efficiency measures incremental to compliance scenario
  o Implemented 2015 ITP10 Future 3 reduction methodology
    ▪ 1% reduction in load growth per year
  o Other assumptions will need to be adjusted during refinement

• Projected to result in additional 75 lb/MWh reduction in emission rate
Process Timelines

- **GI Study**
  - GIA Process
  - CT
  - NGCC
  - Wind

- **Gas Infrastructure**
  - Intrastate
  - Interstate

- **TS Study**
  - NTC Process
  - Rebuild (New <300 kV, New >300 kV)

- **ITPNT Study**
  - NTC Process
  - Rebuild (New <300 kV, New >300 kV)

- **ITP10 Study**
  - NTC Process
  - Rebuild (New <300 kV, New >300 kV)

- **Markets**
  - Design
Next steps

• Perform state-by-state analysis using comparable assumptions - results expected in early June

• Refine regional analysis as necessary based on learning generated from state-by-state approach development

• Share results with members, utility regulators, and environmental agencies
Additional Information

2014 Reliability Assessment Report
http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf

2014 Letter to EPA

Lanny Nickell
Vice President, Engineering
501-614-3232
lnickell@spp.org
Walkemeyer
Re-evaluation

Lanny Nickell
Vice President, Engineering

Southwest Power Pool

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

• January: BOD approved the 2015 ITPNT & 2015 ITP10 as presented, while requesting a re-evaluation of the 21 mile 115 kV line from Walkemeyer – North Liberal and associated projects

• In response to Sunflower’s suggestion that redispatch of existing generation in the area could mitigate the need

• Projects being re-evaluated included:
  – Hitchland - Finney tap, transformer, one-mile line, and new substation (Phase 1)
    ▪ 2014 E&C Costs = $17.8 M
    ▪ Recommended by 2015 ITPNT with In-Service Date of 2018
  – 21-mile Walkemeyer to North Liberal 115 kV line (Phase 2)
    ▪ 2014 E&C Costs = $17.5 M
    ▪ Recommended by 2015 ITP10 with In-Service Date of 2019
Proposed Planning Guide

- Sunflower provided a new planning guide requesting 58 MW of support from CRS for this re-evaluation.

- Use when load level in the area reaches a value where potential violations (thermal or voltage) begin.
Projects Located in Southwestern Kansas

- Phase 1
- CR1 & CR2 (CRS)
- Phase 2

Southwestern Kansas Upgrades

(April 2015)

- New Line, 115
- Rebuild, 115
- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- 500 kV

Southwest Power Pool

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Analysis

• Quantitative
  – Reliability of planning guide vs. transmission expansion
  – Economics of planning guide vs. transmission expansion

• Qualitative Reliability Considerations
  – Generation unit specific characteristics
  – Appropriateness of Reliability Must-Run (RMR) solution to address long-term planning needs
Reliability Analysis

- Began with ITP10 models for 2024 SP Future 1
- Applied each solution to the base models
- Performed N-1 Contingency Analysis for each solution
- Determined system needs resolved and unresolved by each solution
  - Thermal needs
  - Voltage needs
## Options Evaluated and Reliability Results

<table>
<thead>
<tr>
<th>In-Service Date</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>Phase 1 Upgrades: 345/115 kV transformer, 1 mile 115 kV line, new substation</td>
<td>Phase 1 Upgrades: 345/115 kV transformer, 1 mile 115 kV line, new substation</td>
<td>Dispatch CR1 &amp; CR2 at 58 MW</td>
</tr>
<tr>
<td>2019</td>
<td>Dispatch of CR1 &amp; CR2 as needed</td>
<td>Phase 2 Upgrade: 21 mile 115 kV Line</td>
<td></td>
</tr>
</tbody>
</table>

- **All Options solve all Thermal and Voltage Violations**
- **Estimated longevity of Voltage Violations mitigation***
  - Option 1 ≈ Until 2045
  - Option 2 ≈ Until 2069
  - Option 3 ≈ Until 2029

*Assumptions: 0.88% annual load growth, constant P-Q ratio
Economic Analysis – Option 1

- Transmission cost includes ATRR for Phase 1 beginning in 2019 and Phase 2 beginning in 2030
- CRS dispatch needed for ~40 hours across 45 days (2024)
- Phase 2 of project in-service upon CRS retirement

Cumulative Cost of Option 1 from 2019 to 2058
(2015 Present Value)

- Phase 1 is Walkemeyer tap, transformer, one-mile line, new substation
- Redispatch cost is increase in Adjusted Production Cost (APC) from the dispatch of CRS
- Phase 2 is 21-mile Walkemeyer to North Liberal 115 kV line
Economic Analysis – Option 2

- Transmission cost includes ATRR for Phase 1 and Phase 2 beginning in 2019
- No dispatch from CRS needed
- CRS retirement does not affect Option 2

Cumulative Cost of Option 2 from 2019 to 2058
(2015 Present Value)

Projected CRS Retirement

Option 2 includes Walkemeyer tap, transformer, one-mile line, new substation, and 21-mile line from Walkemeyer Tap to North Liberal
Economic Analysis – Option 3

- Transmission cost includes ATRR for Phase 1 and Phase 2 beginning in 2030
- CRS dispatch needed for ~1000 hours across 184 days (2024)
- Both Phases 1 & 2 in-service upon CRS retirement

Cumulative Cost of Option 3 from 2019 to 2058
(2015 Present Value)

- Option 3 is the dispatch of CRS at 58 MW
- Walkemeyer tap, transformer, one-mile line, new substation, and 21-mile line from Walkemeyer Tap to North Liberal in 2030
Economic Analysis – All Options

Cumulative Cost of Reliability Options from 2019 to 2058
(2015 Present Value)
Economic Analysis – All Options

Cumulative Cost of Reliability Options from 2019 to 2058
(2015 Present Value)

<table>
<thead>
<tr>
<th>Reliability Option</th>
<th>2015 Present Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>$68,904,455</td>
</tr>
<tr>
<td>Option 2</td>
<td>$67,519,835</td>
</tr>
<tr>
<td>Option 3</td>
<td>$84,052,650</td>
</tr>
</tbody>
</table>
Qualitative Analysis

• Unit Specific Characteristics
  – 45-50 years in service
  – Uncertain capacity availability after 2025
  – 30 hour startup for CR1, 30 minute startup for CR2

• Appropriateness of RMR generation solution to address long-term planning needs
  – SPP staff believes that in general, RMR should only be considered short term solutions
  – 2015 ITP10 was performed so that transmission solutions were preferred over RMR
MOPC Review

- SPP staff recommended NTCs be issued according to the needs in the 2015 ITPNT and 2015 ITP10 performed in accordance with the respective study scopes
- Motion was to endorse staff’s recommendation
- Motion failed with 63.8% in favor
- MOPC did not propose an alternative recommendation
Directive

On April 29, 2014 the BOD approved the HPILS Report and directed issuance of NTCs and NTC-Cs as shown in Appendix C of the report. The BOD also directed,

“...the members in whose systems the additional HPILS loads and assumed generation additions reside will provide updated forecasts of these loads and generators prior to each subsequent quarterly meeting of the SPP BOD, and in addition, will notify the SPP staff immediately upon receipt of any information that, in their judgment, would impact the need for one or more of the previously issued NTCs.”
History

• Procedure developed in July 2014
• Data requests and reporting started in October 2014
• To ease administrative burden on members, staff has been leveraging long term planning model build process which includes load updates
• About $97 million of projects in south central KS have been withdrawn due to reductions in oil development
• At Jan 2015 MOPC, members expressed interest in staff also reviewing WAPA/Basin IS developments
HPILS Validation Process

• Models compared
  – HPILS, MDWG Pass 4, MDWG Pass 6, & 2015 ITPNT
  – 2014 through 2025
  – Evaluated on a bus-by-bus and area-by-area basis

• Also comparing load reported in Network Integration Transmission Service Agreements against planning models
HPILS Load Evaluation - BEPC

- Compared currently available models with recent winter peak load updates provided by BEPC
  - Midwest Reliability Organization (MRO) 2014 model series loads that contains 2013 load forecasts for BEPC
  - Recent peak updates provided by BEPC show 200 MW of increased load
  - Data not in 2015 MDWG final models but will be included in the 2016 ITPNT
HPILS Unserved Load

- **SPS**

![SE NM Unserved Load (MW)](chart.png)
HPILS Unserved Load

- MKEC Wheatland Electric Cooperative
  - Total 56 MW of unserved and near-term load growth in Harper/Sumner County
  - Harper 138 kV projects will address
- No other changes observed
The AVS-Charlie Creek-Judson-Tande 345kV Project:

- This Bakken project was re-evaluated by comparing updated load forecast data submitted by the members for the Williston Pocket with data in SPP’s newest planning models.

- Load forecasts are showing steady growth at levels higher than originally anticipated demonstrating that these projects will still be needed.
Bakken Winter Load Evaluation, ND

Bakken Analysis

(MW)


MDWG P6
Williston Pocket
Generation Changes

• Generation advancement
  – No change

• Generation retirements
  – No change
Keystone XL Pipeline Status*

I. http://keystone-xl.com/about/the-keystone-xl-oil-pipeline-project/

II. Figure ES-5 in TransCanada Application for Presidential Permit

*President Obama vetoed enabling legislation on February 24th
Conclusion

• Most recent model updates, NITS loads, and member survey results show current HPILS NTCs remain appropriate

• Keystone XL pipeline loads need to be reviewed and refined, as appropriate in ITPNT

• SPP Staff will continue to validate HPILS project needs quarterly as directed by the BOD
Seams Update

Carl Monroe
EVP & COO
April 27, 2015

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
MISO Dispute Update

- MISO filed a motion for expedited consideration of MISO’s rehearing request on November 7, 2014
  - SPP responded on November 17, 2014 opposing MISO’s motion and stated SPP’s preference to continue the ongoing settlement process

- Settlement conferences
  - 5 held in 2014
  - Most recent conference was on January 29, 2015
  - Additional negotiations between the Parties in Atlanta
  - Next conference scheduled for June 9, 2015
Transmission Charges for MISO Usage

- **Tariff Charges**
  - Q1 2014: $8,629,000
  - Q2 2014: $6,715,467
  - Q3 2014: $10,827,182
  - Q4 2014: $9,177,585
  - Q1 2015: $9,027,495

- **Service Agreement Charges**
  - Q1 2014: $14,615,495
  - Q2 2014: $10,827,182
  - Q3 2014: $9,177,585
  - Q4 2014: $9,027,495
  - Q1 2015: $50,363,224

- **Accrued Interest**
  - Total: $58,992,224

- **Losses**
  - Total: $50,363,224

- **Penalties**
  - Total: $9,027,495

- **Charges**
  - Total: $58,992,224
INTERREGIONAL ORDER 1000
## FERC Orders

<table>
<thead>
<tr>
<th>MISO</th>
<th>SERTP</th>
</tr>
</thead>
<tbody>
<tr>
<td>ER13-1937</td>
<td>ER13-1939</td>
</tr>
<tr>
<td>FERC Response: Feb 19</td>
<td>FERC Response: Mar 19</td>
</tr>
<tr>
<td>Due Date: August 18</td>
<td>Due Date: May 18</td>
</tr>
<tr>
<td>SPP-MISO JOA</td>
<td>OATT Language</td>
</tr>
</tbody>
</table>
FERC Response on Regional Cost Allocation of an Interregional Project

• FERC only accepted the proposed regional highway funding for projects over 300 kV
  – FERC said highway funding for projects less than 300 kV moot in light of SERTP requirement that interregional projects must be at least 300 kV
  – Decision was included in SERTP order but not addressed in MISO order which is relevant for less than 300 kV

• Further justification required for highway cost allocation for projects 100 kV – 300 kV
SPP-MISO ORDER
Project Applicability Criteria

- FERC agreed with four of the criteria which were jointly proposed by MISO and SPP
  - Minimum project cost of $5 million
  - Be evaluated as part of the Coordinated System Plan and recommended by the Joint Planning Committee
  - At least 5% of total benefits to both SPP and MISO
  - In-service date within 10 years
Project Applicability Criteria

- **MISO proposal**: Must be approved as a MISO Market Efficiency Project & as an SPP Interregional Project
  - Limits an interregional project to only economic projects and those greater than 300 kV
- **SPP proposal**: Must be approved by both Parties in their respective regional planning process
  - Projects greater than 100 kV
  - Economic, reliability, or public policy
- **FERC accepted SPP’s proposal and directed MISO to file language proposed by SPP**
Metrics for Allocating Costs

SPP proposed
- APC as metric for economic projects
- APC and avoided cost for reliability projects
- Undetermined metric for public policy

MISO proposed
- APC as metric for economic projects
FERC Decision on Metrics For Allocating Costs

- Accepted MISO and SPP’s proposal to use APC for economic projects
- MISO’s and SPP’s proposals failed to include a cost allocation method for public policy projects
  - FERC directed SPP and MISO to propose a cost allocation methodology for public policy projects
- MISO’s proposal did not include a cost allocation method for reliability projects
  - FERC directed MISO to submit a compliance filing to revise its version of the SPP-MISO JOA to adopt SPP’s cost allocation method for reliability projects
  - SPP has no further compliance obligation on the issue
Next Steps

• On April 2, SPP and MISO jointly requested a 120 day compliance deadline extension
  – Accepted by FERC on April 24
  – New deadline of August 18, 2015
• Revisions to the SPP-MISO JOA
  – Seams Steering Committee
• No planned OATT revisions
Waiver Request

• SPP requested a waiver from the interregional Order 1000 requirements for the SPP-SERTP seam
  – AECI and other non-jurisdictional SERTP participants not including compliance language in their OATTs
  – No other interconnection with SERTP

• FERC denied SPP’s waiver request
  – AECI’s participation with SERTP creates an interregional seam requiring compliance with the interregional requirements of Order 1000
Next Steps

• Further compliance requirements are prescriptive
• SERTP coordination provisions included in the SPP OATT
  – Will require the revisions prescribed by FERC
  – Stakeholder participation via the SSC and the RTWG
Joint Study Process

- Joint evaluation expected to conclude in June
- SPP-MISO Interregional Stakeholder Advisory Committee Meeting on May 6
  - Draft report
  - Reliability and economic assessment results
  - Proposed projects, if any
- If a project is proposed it would be reviewed by each region resulting in a review by the SPP Board of Directors no later than January 2016
Integrated Marketplace: First Year Update

Bruce Rew
First 12 months of Integrated Marketplace

- Integrated Marketplace operated very well
- System Availability exceeding expectations
- Great engagement with market participants
- SPP continues to work on market improvements
SPP Second lowest Market Spot Price

On-Peak Day-Ahead 2014 Electric Spot Prices

Mid-Columbia $39 3%
NP 15 $52 17%
Palo Verde $42 13%
SPP $40 18%
ERCOT North $45 20%

Indiana Hub $48 26%
PJM West $63 38%
Into Southern $42 22%

Mass Hub $76 18%
NYISO ZJ $73 19%

$ = Average 2014 Spot Price
% Increase from 2013

Source: Derived from SNL and PLATTS data

Graphic FERC 2014 State of the Market report delivered to FERC Commissioners on March 19, 2015
# Project Pinnacle - Completed

*The Pinnacle Program was delivered on time and under budget.*

<table>
<thead>
<tr>
<th>PINNACLE PROJECTS - DELIVERED</th>
<th>GO-LIVE DATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pseudo-Tie Out (PTO)</td>
<td>June 12, 2014</td>
</tr>
<tr>
<td>Environment Build-Out (EBO)</td>
<td>August 1, 2014</td>
</tr>
<tr>
<td>Long-Term Congestion Rights (LTCR)</td>
<td>February 1, 2015</td>
</tr>
<tr>
<td>Regulation Compensation (REG COMP)</td>
<td>March 1, 2015</td>
</tr>
<tr>
<td>Market to Market (M2M)</td>
<td>March 1, 2015</td>
</tr>
<tr>
<td>Live Track Work</td>
<td>On-going</td>
</tr>
<tr>
<td>Enhanced Combined Cycle (ECC)</td>
<td>Suspended; Scheduled to restart October 2015</td>
</tr>
</tbody>
</table>
Status of Market to Market

- M2M manages market congestion and replaces TLR for flowgates on seam with both SPP and MISO impacts
- Redispatches lowest cost RTO to relieve congestion on transmission constraints and settles financially
- Implemented on March 1, 2015 in accordance with Joint Operating Agreement
- Includes business, process, and SOC-1 controls
M2M first month of activity

- M2M activity every day in March except for two
- Both MISO and SPP flowgates have used the process to economically relieve congestion
- Compensation for optimized market dispatch has occurred in both directions (SPP to MISO and MISO to SPP)
- SPP and MISO are working closely together reviewing M2M activity and to optimize its use
Integrated Marketplace Benefits Study

• Initial Cost Benefit Analysis by CRA projected savings to be $100 million annually

• Timeframes:
  – March 1, 2014 – February 28, 2015 (First 12 months)
  – April 1, 2014 – March 31, 2015 (Rolling 12 months)

• Hourly solver utilized, similar to Market Clearing Engine logic

• Analysis compared Integrated Marketplace Energy + No Load versus individual 16 former Balancing Authorities (BAs) Energy + No Load
Study Overview

• **Timeframes:**
  – March 1, 2014 – February 28, 2015 (First 12 months)
  – April 1, 2014 – March 31, 2015 (Rolling 12 months)

• **Hourly solver utilized, similar to Market Clearing Engine logic**

• **Analysis compared Integrated Marketplace Energy + No Load versus individual 16 former Balancing Authorities (BAs) Energy + No Load**
  – Assumes the 16 BAs did not have a Market in place and dispatch to their obligation
Summary of Assumptions

• Load
  – Each BA served its Load and NSI
  – SPP equal to Integrated Marketplace Load and NSI

• Generation
  – Projected Headroom based on historical EIS for BA’s
  – Operating Reserves (OR) for BA’s on Load ratio share
  – DVER logic and outaged units are not dispatched

• Transmission
  – Existing flowgate RTBM constraints used
Optimization

• Unit Commitment run minimized
  – No Load & Energy cost to serve Load
  – Net Scheduled Interchange
  – Headroom Requirement per historical Balancing Authority

• Energy Dispatch run minimized
  – Energy cost to meet Load
  – NSI using the resources selected in the Commitment run
Benefits Unquantified

- Startup cost was not included in analysis, Resources were committed based on No Load + Energy costs
- Only RTBM constraints were enforced
  - Other constraints could have been present due to a change in commitment pattern, which would have increased the production cost
- No DVER logic which could improve dispatch
- Distributed SPP OR requirement gave entities a lower individual requirement than if they were individual Balancing Authorities
Capacity, with daily average per month shown

Max Capacity - IM vs No Market (13 months)

- IM Actual - Average of Load Forecast
- IM Actual - Average of Max Capacity
- No Market - Average of Max Capacity

[Graph showing capacity trends over 13 months with different markers for IM Actual and No Market.]
Production Cost monthly comparison

Cost To Serve Load (13 months)

<table>
<thead>
<tr>
<th>Month</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mar</td>
<td>$500,000,000</td>
<td>$600,000,000</td>
</tr>
<tr>
<td>Apr</td>
<td>$450,000,000</td>
<td>$500,000,000</td>
</tr>
<tr>
<td>May</td>
<td>$400,000,000</td>
<td>$450,000,000</td>
</tr>
<tr>
<td>Jun</td>
<td>$350,000,000</td>
<td>$400,000,000</td>
</tr>
<tr>
<td>Jul</td>
<td>$300,000,000</td>
<td>$350,000,000</td>
</tr>
<tr>
<td>Aug</td>
<td>$700,000,000</td>
<td>$600,000,000</td>
</tr>
<tr>
<td>Sep</td>
<td>$650,000,000</td>
<td>$550,000,000</td>
</tr>
<tr>
<td>Oct</td>
<td>$500,000,000</td>
<td>$450,000,000</td>
</tr>
<tr>
<td>Nov</td>
<td>$400,000,000</td>
<td>$350,000,000</td>
</tr>
<tr>
<td>Dec</td>
<td>$350,000,000</td>
<td>$300,000,000</td>
</tr>
<tr>
<td>Jan</td>
<td>$300,000,000</td>
<td>$250,000,000</td>
</tr>
<tr>
<td>Feb</td>
<td>$250,000,000</td>
<td>$200,000,000</td>
</tr>
<tr>
<td>Mar</td>
<td>$200,000,000</td>
<td>$150,000,000</td>
</tr>
</tbody>
</table>

Legend: IM Actual, No Market
Study Highlights

• March of 2014 was the only month study showed higher cost for Integrated Marketplace
  – Intentionally operated with a higher unit commitment than required for conservative operations during the first month

• An average 4,902 MW capacity increase in no market situation
  – Very comparable to IM vs EIS capacity comparison

• Gross benefit to serve load in Integrated Marketplace was $430 Million for rolling 12 months (April 1, 2014 – March 31, 2015)
### Integrated Marketplace Annual Savings

#### Calculation (First 12 months) Financial Impact (millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Financial Impact (millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Study Benefit</td>
<td>$351</td>
</tr>
<tr>
<td>EIS Historical Savings</td>
<td>($170)</td>
</tr>
<tr>
<td>Integrated Marketplace Annual Cost</td>
<td>($50)</td>
</tr>
<tr>
<td>Net Integrated Marketplace Savings</td>
<td>$131</td>
</tr>
</tbody>
</table>

#### Calculation (Rolling 12 months) Financial Impact (millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Financial Impact (millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Study Benefit</td>
<td>$430</td>
</tr>
<tr>
<td>EIS Historical Savings</td>
<td>($170)</td>
</tr>
<tr>
<td>Integrated Marketplace Annual Cost</td>
<td>($50)</td>
</tr>
<tr>
<td>Net Integrated Marketplace Savings</td>
<td>$210</td>
</tr>
</tbody>
</table>
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Second Quarterly Project Tracking Report 2015

April 2015
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Executive Summary

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

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

The reporting period for this report is November 1, 2014 through January 31, 2015. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades in which construction activities are ongoing, or construction has completed but not all the close-out requirements have been fulfilled in accordance to Section 13 of Business Practice 7060. The PTP includes all active Network Upgrades including transmission lines, transformers, substations, and devices.

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

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>No. of Upgrades</th>
<th>Estimated Cost</th>
<th>Miles of New</th>
<th>Miles of Rebuild</th>
<th>Miles of Voltage Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balanced Portfolio</td>
<td>4</td>
<td>$258,217,874</td>
<td>226.6</td>
<td>0.0</td>
<td>0.0</td>
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<tr>
<td>Economic</td>
<td>4</td>
<td>$15,780,573</td>
<td>0.0</td>
<td>0.0</td>
<td>18.2</td>
</tr>
<tr>
<td>High Priority</td>
<td>102</td>
<td>$2,218,781,792</td>
<td>1741.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>308</td>
<td>$2,661,130,594</td>
<td>1313.9</td>
<td>587.6</td>
<td>256.6</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>23</td>
<td>$105,555,855</td>
<td>12.7</td>
<td>31.6</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$109,245,734</td>
<td>34.7</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td><strong>450</strong></td>
<td><strong>$5,368,712,422</strong></td>
<td><strong>3328.9</strong></td>
<td><strong>647.7</strong></td>
<td><strong>274.7</strong></td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>37</td>
<td>$162,983,052</td>
<td>39.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>5</td>
<td>$23,567,090</td>
<td>0.0</td>
<td>11.8</td>
<td>0.0</td>
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<tr>
<td>TO - Sponsored</td>
<td>18</td>
<td>$100,323,843</td>
<td>12.0</td>
<td>0.0</td>
<td>46.0</td>
</tr>
<tr>
<td><strong>Non-NTC Projects Subtotal</strong></td>
<td><strong>60</strong></td>
<td><strong>$286,873,985</strong></td>
<td><strong>51.5</strong></td>
<td><strong>11.8</strong></td>
<td><strong>46.0</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>510</strong></td>
<td><strong>$5,655,586,407</strong></td>
<td><strong>3380.4</strong></td>
<td><strong>659.6</strong></td>
<td><strong>320.7</strong></td>
</tr>
</tbody>
</table>

*Table 1: Q1 2015 Portfolio Summary*
**Figure 1: Percentage of Project Type on Cost Basis**

- Balanced Portfolio: 48%
- Economic: 0.3%
- Generation Interconnection: 5%
- High Priority: 3%
- Regional Reliability: 40%
- Transmission Service: 2%
- Zonal Reliability: 2%

**Figure 2: Percentage of Project Status on Cost Basis**

- Complete: 27%
- On Schedule < 4: 8%
- On Schedule > 4: 22%
- Delay - Mitigation: 0.5%
- NTC Suspension: 1%
- NTC - Commitment Window: 1%
- NTC-C Project Estimate Window: 5%
- Re-evaluation: 1%
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to commence the construction of Network Upgrades that have been approved or endorsed by the SPP Board of Directors (BOD) intended to meet the construction needs of the STEP, OATT, or Regional Transmission Organization (RTO).

Figure 3 reflects project status within each source study, and Table 2 provides the supporting data. Figure 4 shows the amount of estimated cost by in-service year for all Network Upgrades that have been issued an NTC or NTC-C. Figure 5 shows the cost trend of all the SPP BOD-approved studies that have resulted in NTCs.

Note: Figures 3, 4, and 5, and Table 2 provide data for all projects for which SPP has issued an NTC or NTC-C, regardless of completion date, and therefore include data from Network Upgrades no longer included in PTP.
<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>$230,534,912</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$230,534,912</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$408,407,905</td>
<td>$33,962,000</td>
<td>$0</td>
<td>$0</td>
<td>$442,369,905</td>
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<tr>
<td>2008 STEP</td>
<td>$416,972,455</td>
<td>$2,943,000</td>
<td>$0</td>
<td>$0</td>
<td>$419,915,455</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$756,878,564</td>
<td>$0</td>
<td>$0</td>
<td>$65,342,060</td>
<td>$822,220,624</td>
</tr>
<tr>
<td>2009 STEP</td>
<td>$537,786,819</td>
<td>$18,730,512</td>
<td>$0</td>
<td>$0</td>
<td>$556,517,331</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$853,450,899</td>
<td>$127,995,000</td>
<td>$0</td>
<td>$407,791,450</td>
<td>$1,389,237,349</td>
</tr>
<tr>
<td>2010 STEP</td>
<td>$104,493,619</td>
<td>$27,912,991</td>
<td>$0</td>
<td>$27,149,017</td>
<td>$159,555,627</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$120,983,841</td>
<td>$76,675,863</td>
<td>$0</td>
<td>$6,300,000</td>
<td>$203,959,705</td>
</tr>
<tr>
<td>2012 ITP10</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$773,176,433</td>
<td>$773,176,433</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$98,676,606</td>
<td>$347,451,442</td>
<td>$0</td>
<td>$76,785,367</td>
<td>$522,913,415</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$4,063,262</td>
<td>$389,407,116</td>
<td>$0</td>
<td>$265,090,771</td>
<td>$658,561,149</td>
</tr>
<tr>
<td>HPILS</td>
<td>$53,638,786</td>
<td>$198,351,680</td>
<td>$0</td>
<td>$579,052,943</td>
<td>$831,043,409</td>
</tr>
<tr>
<td>2015 ITPNT</td>
<td>$0</td>
<td>$44,934,263</td>
<td>$0</td>
<td>$170,644,016</td>
<td>$215,578,279</td>
</tr>
<tr>
<td>2015 ITP10</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$48,901,299</td>
<td>$48,901,299</td>
</tr>
<tr>
<td>Ag Studies</td>
<td>$704,499,775</td>
<td>$88,188,518</td>
<td>$18,616,980</td>
<td>$68,557,712</td>
<td>$879,862,985</td>
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<tr>
<td>DPA Studies</td>
<td>$106,082,972</td>
<td>$74,202,078</td>
<td>$0</td>
<td>$5,085,427</td>
<td>$185,370,476</td>
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<tr>
<td>GI Studies</td>
<td>$349,500,518</td>
<td>$17,009,632</td>
<td>$8,033,890</td>
<td>$116,643,821</td>
<td>$491,187,861</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$4,745,970,933</strong></td>
<td><strong>$1,447,764,096</strong></td>
<td><strong>$26,650,870</strong></td>
<td><strong>$2,610,520,316</strong></td>
<td><strong>$8,830,906,215</strong></td>
</tr>
</tbody>
</table>

**Table 2: Project Status by NTC Source Study**

![Figure 4: Estimated Cost for NTC Projects per In-Service Year](image)
Figure 5: Cost Trend per BOD-Approved Study
Southwest Power Pool, Inc.

**NTC Issuance**

Twenty-six NTCs were issued since the last quarterly report for new and previously approved projects with a total cost estimate of the included Network Upgrades totaling $371 million.

Two NTCs were issued as a result of the completion of Aggregate Studies, SPP-2012-AG2-AFS-8 and SPP-2013-AG1-AFS-7. The total estimated cost of the Network Upgrades listed in these NTCs is $147.8 thousand.

Twenty NTCs and one Notification to Construct with Conditions (NTC-C) were issued as a result of the BOD approval of both the 2015 Integrated Transmission Planning Near-Term Assessment (ITPNT) and Integrated Transmission Planning 10-Year Assessment (ITP10) in January. The total estimated cost of the Network Upgrades included in these NTCs is $260.6 million.

Two NTCs were issued as a result of the BOD in January approving recommendations from Staff to remove the conditions of previously issued NTC-Cs. For these projects, the NTC-C Project Cost Estimates (CPEs) were previously found to be outside the bounds of the conditional requirements of the NTC-C, and therefore were re-evaluated as a part of the 2015 ITPNT. The total estimated cost of the Network Upgrades listed in these NTCs is $103.2 million.

One NTC was issued to American Electric Power (AEP) as a result of the completion of the Delivery Point Addition study, DPA-2013-March-296. The total estimated cost of the Network Upgrade described in this NTC is $7.3 million.

Table 3 summarizes the NTC activity from January 6, 2015 through March 31, 2015. NTC ID values in **bold** font indicate NTC-Cs.
<table>
<thead>
<tr>
<th>NTC ID</th>
<th>DTO</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>200307</td>
<td>OPPD</td>
<td>1/23/2015</td>
<td>Transmission Service</td>
<td>SPP-2013-AG1-AFS-7</td>
<td>2</td>
<td>$63,389</td>
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</tr>
<tr>
<td>200313</td>
<td>OGE</td>
<td>1/30/2015</td>
<td>Transmission Service</td>
<td>SPP-2012-AG2-AFS-8</td>
<td>1</td>
<td>$84,327</td>
<td></td>
</tr>
<tr>
<td>200314</td>
<td>AEP</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>6</td>
<td>$38,595,282</td>
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</tr>
<tr>
<td>200315</td>
<td>GMO</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>1</td>
<td>$4,329,248</td>
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</tr>
<tr>
<td>200316</td>
<td>GRDA</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>6</td>
<td>$1,667,189</td>
<td></td>
</tr>
<tr>
<td>200317</td>
<td>KCPL</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>2</td>
<td>$1,441,610</td>
<td></td>
</tr>
<tr>
<td>200318</td>
<td>NPPD</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>3</td>
<td>$11,197,764</td>
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</tr>
<tr>
<td>200319</td>
<td>OGE</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
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<tr>
<td>200320</td>
<td>OPPD</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
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<td>$35,091,946</td>
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<tr>
<td>200321</td>
<td>WFEC</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>2</td>
<td>$385,141</td>
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</tr>
<tr>
<td>200322</td>
<td>WR</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>2</td>
<td>$2,535,245</td>
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</tr>
<tr>
<td>200323</td>
<td>SPS</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>13</td>
<td>$71,780,471</td>
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<tr>
<td>200324</td>
<td>SPS</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>3</td>
<td>$7,460,164</td>
<td></td>
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<tr>
<td>200325</td>
<td>SEPC</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>9</td>
<td>$27,656,587</td>
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<tr>
<td>200326</td>
<td>SPS</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>1</td>
<td>$10,018,471</td>
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</tr>
<tr>
<td>200327</td>
<td>AEP</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
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<td>$15,726,289</td>
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</tr>
<tr>
<td>200328</td>
<td>KCPL</td>
<td>2/25/2015</td>
<td>Economic</td>
<td>2015 ITP10</td>
<td>1</td>
<td>$15,726,289</td>
<td></td>
</tr>
<tr>
<td>200329</td>
<td>OGE</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITP10</td>
<td>2</td>
<td>$4,651,118</td>
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</tr>
<tr>
<td>200330</td>
<td>OPPD</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITP10</td>
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<td>$7,976,819</td>
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<tr>
<td>200331</td>
<td>SEPC</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2015 ITP10</td>
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</tr>
<tr>
<td>200332</td>
<td>SPS</td>
<td>2/18/2015</td>
<td>Economic/Regional Reliability</td>
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<tr>
<td>200333</td>
<td>SPS</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
<td>7</td>
<td>$49,643,005</td>
<td></td>
</tr>
<tr>
<td>200334</td>
<td>MKEC</td>
<td>2/18/2015</td>
<td>High Priority</td>
<td>HPI1S</td>
<td>5</td>
<td>$53,530,307</td>
<td></td>
</tr>
<tr>
<td>200335</td>
<td>SPS</td>
<td>2/26/2015</td>
<td>Regional Reliability</td>
<td>2015 ITP10</td>
<td>1</td>
<td>$809,640</td>
<td></td>
</tr>
<tr>
<td>200336</td>
<td>GMO</td>
<td>2/25/2015</td>
<td>Economic</td>
<td>2015 ITP10</td>
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<td>Included in NTC 200238</td>
<td></td>
</tr>
<tr>
<td>200337</td>
<td>WR</td>
<td>2/25/2015</td>
<td>Economic</td>
<td>2015 ITP10</td>
<td>1</td>
<td>Included in NTC 200238</td>
<td></td>
</tr>
<tr>
<td>200338</td>
<td>AEP</td>
<td>3/17/2015</td>
<td>Regional Reliability</td>
<td>DPA-2013-MAR-296</td>
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<td>$7,282,123</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Total</td>
<td>86</td>
<td>$232,955,080</td>
</tr>
</tbody>
</table>

Table 3: Q1 2015 NTC Issuance Summary
NTC Withdraw

Four NTCs were withdrawn since the last quarterly report. Three of the NTCs included projects that were requested to be restudied by the DTO, and were determined to be no longer needed in the 2015 ITPNT.

Table 4 lists the NTC Withdraw activity from January 6, 2016 through March 31, 2015. NTC ID values in bold font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>DTO</th>
<th>NTC Issue Date</th>
<th>Upgrade Type</th>
<th>Original Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of Withdrawn Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200316</td>
<td>GRDA</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2008 STEP</td>
<td>1</td>
<td>$374,000</td>
</tr>
<tr>
<td>200322</td>
<td>WFEC</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2007 STEP/HPILS</td>
<td>2</td>
<td>$8,000,000</td>
</tr>
<tr>
<td>200326</td>
<td>SPS</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2013 ITPNT</td>
<td>1</td>
<td>$21,078,890</td>
</tr>
<tr>
<td>200334</td>
<td>AEP</td>
<td>2/18/2015</td>
<td>Regional Reliability</td>
<td>2007 STEP</td>
<td>3</td>
<td>$101,000,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
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<td>Total 7</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$130,452,890</td>
</tr>
</tbody>
</table>

Table 4: Q1 2015 NTC Withdraw Summary

Completed Projects

Eight (8) Network Upgrades with NTCs and five (5) Generation Interconnection Network Upgrades were completed during the reporting period, totaling an estimated $244 million.

Approved as a part of the Priority Projects report in April 2010, Prairie Wind Transmission (PW) and Oklahoma Gas and Electric Co. (OGE) notified SPP that the new 109-mile double circuit 345 kV line from the Woodward District EHV substation in northwestern Oklahoma to the Thistle substation located in south central Kansas was energized on November 4th. OGE constructed 79 miles of the new double circuited line from Woodward District EHV up to the Oklahoma/Kansas border, while PW built the 30-mile portion of the line located in Kansas. The project is estimated to cost $187.3 million, and was originally not expected to be complete until late December.

Also a part of the Priority Projects, ITC Great Plains, LLC (ITCGP) announced the completion of the 113.5-mile double circuit 345 kV line from the Spearville to Ironwood to Clark Co. to Thistle in the southwest quadrant of Kansas on December 17th. Originally designated to Mid-Kansas Electric Company, the project was novated to ITCGP shortly after the Priority Projects report was approved. Estimated to cost $309 million, the project completed two weeks prior to the expected in-service date.

Table 5 lists the Network Upgrades completed during the reporting period. Table 6 summarizes the completed projects over the previous year. Figure 6 reflects the completed projects by upgrade type on a cost basis for the current year and the following year based on current projected in-service dates. Tables 7 and 8 summarize all Network Upgrades that include construction of transmission.
Southwest Power Pool, Inc.

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>10179</td>
<td>ACME - WEST NORMAN 69KV CKT 1</td>
<td>WFEC</td>
<td>2006 STEP</td>
<td>$912,000</td>
</tr>
<tr>
<td>10648</td>
<td>Diana - Perdue 138 kV Ckt 1</td>
<td>AEP</td>
<td>2012 ITPNT</td>
<td>$1,004,187</td>
</tr>
<tr>
<td>10898</td>
<td>Broadmoor - Fern Street 69 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$4,923,124</td>
</tr>
<tr>
<td>11041</td>
<td>NEWHART 230 - SWISHER COUNTY INTERCHANGE 230KV CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$19,959,385</td>
</tr>
<tr>
<td>11045</td>
<td>HART INDUSTRIAL - LAMTON INTERCHANGE 115KV CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$17,384,254</td>
</tr>
<tr>
<td>11052</td>
<td>PLEASANT HILL 230/115KV TRANSFORMER CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$15,713,303</td>
</tr>
<tr>
<td>11053</td>
<td>OASIS INTERCHANGE - PLEASANT HILL 230KV CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$13,694,777</td>
</tr>
<tr>
<td>11054</td>
<td>PLEASANT HILL - ROOSEVELT COUNTY INTERCHANGE 230KV CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$15,180,231</td>
</tr>
<tr>
<td>11107</td>
<td>Kress Interchange - Kiser 115 kV Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$13,584,121</td>
</tr>
<tr>
<td>11246</td>
<td>Thistle - Woodward EHV 345 kV Ckt 1 (OGE)</td>
<td>OGE</td>
<td>Priority Projects</td>
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</tr>
<tr>
<td>11247</td>
<td>Thistle - Woodward EHV 345 kV Ckt 2 (OGE)</td>
<td>OGE</td>
<td>Priority Projects</td>
<td>$50,565,144</td>
</tr>
<tr>
<td>11248</td>
<td>Thistle - Woodward EHV 345 kV Ckt 1 (PW)</td>
<td>PW</td>
<td>Priority Projects</td>
<td>$22,610,000</td>
</tr>
<tr>
<td>11249</td>
<td>Thistle - Woodward EHV 345 kV Ckt 2 (PW)</td>
<td>PW</td>
<td>Priority Projects</td>
<td>$22,610,000</td>
</tr>
<tr>
<td>11252</td>
<td>Ironwood - Clark Co. 345 kV Ckt 1</td>
<td>ITCGP</td>
<td>Priority Projects</td>
<td>$50,565,144</td>
</tr>
<tr>
<td>11253</td>
<td>Ironwood - Clark Co. 345 kV Ckt 2</td>
<td>ITCGP</td>
<td>Priority Projects</td>
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</tr>
<tr>
<td>11254</td>
<td>Clark Co 345 kV - Thistle 345 kV Ckt 1</td>
<td>ITCGP</td>
<td>Priority Projects</td>
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<tr>
<td>11255</td>
<td>Clark Co 345 kV - Thistle 345 kV Ckt 2</td>
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<td>Priority Projects</td>
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<td>11260</td>
<td>Thistle 345/138 kV Transformer</td>
<td>ITCGP</td>
<td>Priority Projects</td>
<td>$6,284,694</td>
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<tr>
<td>11314</td>
<td>Jones Station Bus#2 - Lubbock South Interchange 230 kV CKT 2 terminal upgrade</td>
<td>SPS</td>
<td>Ag Studies</td>
<td>$190,000</td>
</tr>
<tr>
<td>11331</td>
<td>Diana - Perdue 138 kV Ckt 1 #2</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$18,805,489</td>
</tr>
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<td>11383</td>
<td>North Plainview 115 kV</td>
<td>SPS</td>
<td>2010 STEP</td>
<td>$330,000</td>
</tr>
<tr>
<td>11384</td>
<td>Kress Rural 115 IV</td>
<td>SPS</td>
<td>2010 STEP</td>
<td>$400,000</td>
</tr>
<tr>
<td>50384</td>
<td>Flat Ridge - Thistle 138 kV</td>
<td>ITCGP</td>
<td>Priority Projects</td>
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</tr>
<tr>
<td>50438</td>
<td>Cornville 138 kV</td>
<td>AEP</td>
<td>2012 ITPNT</td>
<td>$21,664,838</td>
</tr>
<tr>
<td>50450</td>
<td>Kiser Substation 115/69 kV Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$6,780,000</td>
</tr>
<tr>
<td>50504</td>
<td>Howard 115/69 kV Transformer Ckt 1</td>
<td>SPS</td>
<td>DPA Studies</td>
<td>$1,516,548</td>
</tr>
<tr>
<td>50505</td>
<td>Kingsmill 115 kV Capacitors</td>
<td>SPS</td>
<td>DPA Studies</td>
<td>$937,420</td>
</tr>
<tr>
<td>50531</td>
<td>New Gladewater - Perdue 138 kV Ckt 1</td>
<td>AEP</td>
<td>2013 ITPNT</td>
<td>$1,000,000</td>
</tr>
<tr>
<td>50610</td>
<td>Buffalo Bear - Buffalo 69 kV Ckt 1</td>
<td>WFEC</td>
<td>DPA Studies</td>
<td>$1,500,000</td>
</tr>
<tr>
<td>50611</td>
<td>Buffalo Bear - Ft. Supply 69 kV Ckt 1 #2</td>
<td>WFEC</td>
<td>DPA Studies</td>
<td>$2,056,746</td>
</tr>
<tr>
<td>50625</td>
<td>Coyote - Medford Tap 138 kV</td>
<td>OGE</td>
<td>DPA Studies</td>
<td>$11,165,950</td>
</tr>
<tr>
<td>50627</td>
<td>Chikaskia - Coyote 138 kV</td>
<td>OGE</td>
<td>DPA Studies</td>
<td>$5,256,327</td>
</tr>
<tr>
<td>50629</td>
<td>Coyote 138 kV Switching Station</td>
<td>OGE</td>
<td>DPA Studies</td>
<td>$3,041,661</td>
</tr>
<tr>
<td>50792</td>
<td>Ironwood 345 kV Substation</td>
<td>ITCGP</td>
<td>Priority Projects</td>
<td>$1,850,000</td>
</tr>
<tr>
<td>50793</td>
<td>Ironwood - Spearville 345 kV Ckt 2</td>
<td>ITCGP</td>
<td>Priority Projects</td>
<td>$9,191,986</td>
</tr>
</tbody>
</table>
### Table 5: Q1 2015 Completed Network Upgrades

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Q2 2014</th>
<th>Q3 2014</th>
<th>Q4 2014</th>
<th>Q1 2015</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>22</td>
<td>28</td>
<td>5</td>
<td>23</td>
<td>78</td>
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<tr>
<td></td>
<td>$142,685,134</td>
<td>$149,739,161</td>
<td>$18,242,224</td>
<td>$182,810,361</td>
<td>$493,476,880</td>
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<tr>
<td>Transmission Service</td>
<td>0</td>
<td>4</td>
<td>0</td>
<td>1</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$23,499,683</td>
<td>$0</td>
<td>$190,000</td>
<td>$23,689,683</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>0</td>
<td>4</td>
<td>1</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$127,550,762</td>
<td>$192,875,814</td>
<td>$0</td>
<td>$320,426,576</td>
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<tr>
<td>High Priority</td>
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<td>8</td>
<td>2</td>
<td>17</td>
<td>29</td>
</tr>
<tr>
<td></td>
<td>$4,212,722</td>
<td>$356,230,003</td>
<td>$2,248,743</td>
<td>$511,897,571</td>
<td>$874,589,039</td>
</tr>
<tr>
<td>Economic</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
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<td>Zonal Reliability</td>
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</tr>
<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>1</td>
<td>1</td>
<td>4</td>
<td>5</td>
<td>11</td>
</tr>
<tr>
<td></td>
<td>$399,000</td>
<td>$399,300</td>
<td>$32,118,311</td>
<td>$14,791,805</td>
<td>$47,708,416</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>$709,775,843</strong></td>
</tr>
</tbody>
</table>

---

### Table 6: Completed Project Summary through 1st Quarter 2015

| Upgrade Type | Q2 2015 Project Tracking Report | 11 | 166 of 190 |
Table 7: Line Upgrade Summary for Previous 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>12</td>
<td>15.0</td>
<td>55.0</td>
<td>0.0</td>
<td>$58,541,428</td>
</tr>
<tr>
<td>115</td>
<td>10</td>
<td>86.7</td>
<td>50.1</td>
<td>4.5</td>
<td>$102,293,864</td>
</tr>
<tr>
<td>138</td>
<td>18</td>
<td>53.2</td>
<td>25.1</td>
<td>88.3</td>
<td>$118,241,031</td>
</tr>
<tr>
<td>161</td>
<td>5</td>
<td>9.0</td>
<td>18.1</td>
<td>0.0</td>
<td>$27,260,408</td>
</tr>
<tr>
<td>230</td>
<td>4</td>
<td>61.1</td>
<td>0.0</td>
<td>0.0</td>
<td>$52,626,801</td>
</tr>
<tr>
<td>345</td>
<td>20</td>
<td>1170.9</td>
<td>0.0</td>
<td>0.0</td>
<td>$1,175,398,580</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>69</strong></td>
<td><strong>1395.8</strong></td>
<td><strong>148.2</strong></td>
<td><strong>92.8</strong></td>
<td><strong>$1,534,362,111</strong></td>
</tr>
<tr>
<td>Voltage Class</td>
<td>Number of Upgrades</td>
<td>Miles of New</td>
<td>Miles of Rebuild/Reconductor</td>
<td>Miles of Voltage Conversion</td>
<td>Estimated Cost</td>
</tr>
<tr>
<td>---------------</td>
<td>--------------------</td>
<td>--------------</td>
<td>-------------------------------</td>
<td>---------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>69</td>
<td>21</td>
<td>70.3</td>
<td>88.6</td>
<td>0.0</td>
<td>$139,918,920</td>
</tr>
<tr>
<td>115</td>
<td>13</td>
<td>156.7</td>
<td>0.0</td>
<td>4.5</td>
<td>$137,303,071</td>
</tr>
<tr>
<td>138</td>
<td>10</td>
<td>23.7</td>
<td>20.0</td>
<td>22.0</td>
<td>$37,389,314</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>3</td>
<td>40.4</td>
<td>0.0</td>
<td>122.0</td>
<td>$62,708,173</td>
</tr>
<tr>
<td>345</td>
<td>2</td>
<td>107.3</td>
<td>0.0</td>
<td>0.0</td>
<td>$184,043,696</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>49</strong></td>
<td><strong>398.29</strong></td>
<td><strong>108.58</strong></td>
<td><strong>148.5</strong></td>
<td><strong>$561,363,174</strong></td>
</tr>
</tbody>
</table>

*Table 8: Line Upgrade Projections for Next 12 Months*
Southwest Power Pool, Inc.

**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
- **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
- **Re-evaluation:** NTC/NTC-C active; pending re-evaluation
- **NTC Suspension:** NTC/NTC-C suspended; pending re-evaluation

Figure 7 reflects a summary of project status by upgrade type on a cost basis.
Approved in April 2009, the Balanced Portfolio was an initiative to develop a group of economic transmission upgrades that benefit the entire SPP region, and to allocate those project costs regionally. The projects that were issued NTCs as a result of the study include a diverse group of projects, estimated to add approximately 680 miles of new 345 kV transmission line to the SPP system.

The total cost estimate of $822.2 million for the projects making up the Balanced Portfolio did not change from the previous quarter’s cost estimate total.

Figure 8 below depicts a historical view of the total estimated cost of the Balanced Portfolio. Table 9 provides a project summary of the projects making up the Balanced Portfolio.
Table 9: Balanced Portfolio Summary

Only one project from the Balanced Portfolio remains under construction, the 30-mile 345 kV line from Iatan to Nashua in northwest Missouri being constructed by Transource Missouri. The project is on schedule to be completed by June 1st of 2015.

Table 10 provides a construction status update for the Balanced Portfolio project not yet completed.
Priority Projects

In April 2010 the SPP Board of Directors and Members Committee approved for construction a group of "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects issued NTCs as a result of the study are estimated to add 291 miles of new single circuit 345 kV transmission line and 431 miles of double circuit 345 kV transmission to the SPP region.

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

The total cost estimate of $1.39 billion for the projects making up the Priority Projects did not change from the previous quarter’s cost estimate total.

Figure 9 below depicts a historical view of the total estimated cost of the Priority Projects. Table 11 provides a project summary of the projects making up the Priority Projects.
Table 12 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>Q4 2014 Cost Estimates</th>
<th>Q1 2015 Cost Estimates</th>
<th>Var. %</th>
</tr>
</thead>
<tbody>
<tr>
<td>937</td>
<td>AEP</td>
<td>Tulsa Power Station 138 kV Reactor</td>
<td>N/A</td>
<td>$842,847</td>
<td>$960,895</td>
<td>$960,895</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>122.0</td>
<td>$221,572,283</td>
<td>$229,203,065</td>
<td>$229,203,065</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>109.4</td>
<td>$201,940,759</td>
<td>$187,260,000</td>
<td>$187,260,000</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>$309,000,001</td>
<td>$309,000,001</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>$127,026,938</td>
<td>$127,026,938</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>$127,995,000</td>
<td>$127,995,000</td>
<td>0.0%</td>
</tr>
<tr>
<td>938/939</td>
<td>OPPD/TSMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV</td>
<td>215.0</td>
<td>$403,740,000</td>
<td>$407,791,450</td>
<td>$407,791,450</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

**Table 11: 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>10/1/2015</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>938</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (TSMO)</td>
<td>6/1/2017</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>939</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
<td>6/1/2017</td>
<td>IP</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>NS</td>
<td>NS</td>
</tr>
</tbody>
</table>

**Table 12: 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.

One project with a cost estimate greater than $5 million was identified as having exceeded the ±20% bandwidth requirement during the reporting period.

Table 13 provides summary information and Table 14 lists the cost detail for the out-of-bandwidth project for Q2 2015.

<table>
<thead>
<tr>
<th>PID</th>
<th>Project Name</th>
<th>Owner(s)</th>
<th>NTC Source Study</th>
<th>Upgrade Type</th>
<th>In-Service Date</th>
</tr>
</thead>
</table>

Table 13: 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>30501</td>
<td>$31,892,184</td>
<td>2014</td>
<td>$32,780,201</td>
<td>$25,246,084</td>
<td>($7,534,117)</td>
<td>-23.0</td>
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</table>

Table 14: Out-of-Bandwidth Project Cost Detail
Table 15 and Figures 10 and 11 provide insight into the responsiveness of DTOs constructing Network Upgrades within SPP in the Quarterly Project Tracking Report for Q2 2015. **Note:** Network Upgrades with statuses of “NTC Suspension”, “Re-evaluation”, “Within NTC Commitment Window”, and “Within NTC-C Project Estimate Window” were excluded from this analysis.

### Table 15: Responsiveness Summary by Project Owner

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Number of Upgrades</th>
<th>Number of Upgrades Reviewed</th>
<th>Reviewed %</th>
<th>Number of ISD Changes</th>
<th>ISD Change %</th>
<th>Number of Cost Changes</th>
<th>Cost Change %</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>49</td>
<td>49</td>
<td>100%</td>
<td>12</td>
<td>24.5%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>GMO</td>
<td>5</td>
<td>5</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>GRDA</td>
<td>5</td>
<td>1</td>
<td>20%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>ITCGP</td>
<td>13</td>
<td>6</td>
<td>46%</td>
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<td>0.0%</td>
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<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>1</td>
<td>50.0%</td>
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<td>LES</td>
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<td>1</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>MIDW</td>
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<td>0.0%</td>
<td>1</td>
<td>9.1%</td>
</tr>
<tr>
<td>MKEC</td>
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<td>9</td>
<td>82%</td>
<td>4</td>
<td>36.4%</td>
<td>2</td>
<td>18.2%</td>
</tr>
<tr>
<td>NPPD</td>
<td>23</td>
<td>2</td>
<td>9%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>OGE</td>
<td>42</td>
<td>27</td>
<td>64%</td>
<td>10</td>
<td>23.8%</td>
<td>1</td>
<td>4.8%</td>
</tr>
<tr>
<td>OPPD</td>
<td>10</td>
<td>10</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
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<td>PW</td>
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<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>SPS</td>
<td>123</td>
<td>123</td>
<td>100%</td>
<td>31</td>
<td>25.2%</td>
<td>21</td>
<td>17.1%</td>
</tr>
<tr>
<td>TSMO</td>
<td>5</td>
<td>5</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>5</td>
<td>100.0%</td>
</tr>
<tr>
<td>WFEC</td>
<td>45</td>
<td>45</td>
<td>100%</td>
<td>7</td>
<td>15.6%</td>
<td>1</td>
<td>2.2%</td>
</tr>
<tr>
<td>WR</td>
<td>49</td>
<td>27</td>
<td>55%</td>
<td>15</td>
<td>30.6%</td>
<td>3</td>
<td>6.1%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>398</strong></td>
<td><strong>322</strong></td>
<td><strong>81%</strong></td>
<td><strong>79</strong></td>
<td><strong>19.8%</strong></td>
<td><strong>36</strong></td>
<td><strong>9.0%</strong></td>
</tr>
</tbody>
</table>
Figure 10: In-Service Date Changes by Project Owner

Figure 11: Cost Changes by Project Owner
Appendix I

See accompanying list of Network Upgrades
<table>
<thead>
<tr>
<th>PID</th>
<th>Number</th>
<th>Project Name</th>
<th>Description</th>
<th>Owner</th>
<th>Start Date</th>
<th>Completion Date</th>
<th>Indication</th>
<th>Delay Mitigation</th>
<th>Baseline Cost</th>
<th>Current Cost</th>
<th>In-Service</th>
<th>Indication</th>
</tr>
</thead>
<tbody>
<tr>
<td>507</td>
<td>507723</td>
<td>Ellerbe Road 69kV Line</td>
<td>Build new 2.0-mile 69 kV line from Ellerbe Road to Forbing T with 1233.6 ACSR/TW conductor.</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>2/13/2008</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
<td>5,069,314</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
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<tr>
<td>508</td>
<td>520882</td>
<td>Dover SW 69kV Line</td>
<td>Upgrade line from 1/0 to 336.4, 4.85 miles</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>8/4/2014</td>
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<td>COMPLETE</td>
<td>5,338,834</td>
<td>5,376,213</td>
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<td>616</td>
<td>520911</td>
<td>Fletcher 69kV Line</td>
<td>Upgrade 7 miles to 795 ACSR from Fletcher SW to Marlow Junction</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>8/4/2014</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
<td>5,069,314</td>
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<tr>
<td>616</td>
<td>533756</td>
<td>Litchfield 69kV Line</td>
<td>Replace 69 kV disconnect switches at Aquarius with a minimum 600 amp emergency rating</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>8/4/2014</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
<td>5,069,314</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>616</td>
<td>520990</td>
<td>Marlow JCT 69kV Line</td>
<td>Upgrade 7 miles to 795 ACSR from Fletcher SW to Marlow Junction</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>8/4/2014</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
<td>5,069,314</td>
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<tr>
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<td>533765</td>
<td>Litchfield 69kV Line</td>
<td>Replace 69 kV disconnect switches at Aquarius with a minimum 600 amp emergency rating</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>8/4/2014</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
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<tr>
<td>616</td>
<td>520802</td>
<td>Acme 69kV Line</td>
<td>Reconductor 3.8 miles from 3/0 ACSR to 795 ACSR. Rate A=81MVA, Rate B=106MVA</td>
<td>NTPC</td>
<td>6/1/2013</td>
<td>8/4/2014</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
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<td>COMPLETE</td>
<td>COMPLETE</td>
<td>5,024,449</td>
<td>5,069,314</td>
<td>COMPLETE</td>
<td>COMPLETE</td>
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</tbody>
</table>
Alternative 1: Swap Swisher Co-op load onto Kress Interchange, bus 525192, CL

Build new line from Petersburg to new ERICSON 7.

Radial 115 kV line for TransCanada Keystone XL project.

Build new line from Petersburg to new ERICSON 7.

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Build new line from Petersburg to new ERICSON 7.

Radial 115 kV line for TransCanada Keystone XL project.
Build new substation at Kiser and install a 115/69 kV transformer and 69 kV terminal equipment

Construction labor estimates provided by bidding contractors were less than

Delayed

909 50579 WFEC Multi - Payne Switching Station - OU 138 kV conversion Criner - Payne Switching Station 138 kV Regional Reliability 9/25/2015 6/1/2013 2/20/2013 2013 ITPNT $3,000,000 2013 $3,151,875 $3,000,000

DELAY - MITIGATION

Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double

941 11245 OGE Line - Hitchland - Woodward 345 kV dbl Ckt (OGE)

647917 Sub 917 647918 Sub 918

Ironwood 345kV 531469 SPEARVILLE

COMPLETE

Hitchland Interchange - WOODWARD DISTRICT EHV 345KV CKT 2

856 11127 SPS XFR - Graham 115/69 kV Ckt 1 Graham Interchange 115/69 kV Transformer Ckt 1 Regional Reliability

200239 200162 945 11252 ITCGP

COMPLETE

COMPLETE

High Priority

Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double


76.25

COMPLETE

115/69 20.83

945 50384 ITCGP

COMPLETE

COMPLETE

High Priority


The Midwest Transmission Project (Sibley-Nebraska City) is on schedule. The length of line in Missouri routing and siting of SPP projects 938 & 939 is complete. On the Nebraska City to Mullin Creek segment (UID-11239 & 11240), the length of line in Missouri estimate has been reduced from $153 million to $91 million. OPPD's length to Mullin Creek segment (UID-11239 & 11240), the length of line in Missouri

Routing and siting of SPP projects 938 & 939 is complete. On the Nebraska City

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Routing and siting of SPP projects 938 & 939 is complete. On the Nebraska City

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Routing and siting of SPP projects 938 & 939 is complete. On the Nebraska City
<table>
<thead>
<tr>
<th>Project</th>
<th>Description</th>
<th>Status</th>
<th>Dates</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Convert 26 miles of 115 kV line from Channing to Potter to 230 kV and upgrade necessary terminal</td>
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<tr>
<td>AECI Line - Bristow - Gypsy 138 kV</td>
<td>Warwick - Luther Regional Reliability - Non OATT 7/1/2014 5/1/2015</td>
<td></td>
<td>$2,240,000</td>
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<tr>
<td>Upgrade the Wichita substation with the necessary breakers and terminal equipment to</td>
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<tr>
<td>COLBY 115/34.5 kV transformer Ckt 4</td>
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<tr>
<td>AECI Line - Bristow - Gypsy 138 kV</td>
<td>Gypsy - Stroud City 138 kV Regional Reliability - Non OATT</td>
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<td>$3,900,000</td>
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<tr>
<td>SPS XFR - Swisher 230/115 kV Ckt 1</td>
<td>Swisher County Interchange 230/115 kV Ckt 1 Transformer Regional Reliability</td>
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<td>$4,139,406</td>
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<tr>
<td>SPS Convert Lynn load to 115 kV Lynn County Interchange 115 kV Regional Reliability</td>
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<td>$300,000 2014 $307,500 $300,000</td>
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<td>SPS Line - North Plainview line tap 115 kV North Plainview 115 kV Regional Reliability</td>
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<td>SPS Line - Soncy convert load to 115 kV Soncy Tap 115 kV - New Soncy 115 kV Regional Reliability</td>
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<td>$10,316,217 2014 $10,574,122 $10,316,217</td>
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<td>Litchfield 69 kV.</td>
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<td>Litchfield 69 kV.</td>
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<tr>
<td>Q4-2012 updated ISD; Current Cost Estimate remains valid. MN-9/19/12.</td>
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<tr>
<td>Q4-2012 Cost Estimate updated. MN-9/19/12. Q1-2013 Cost Estimate 11/15/13. All remains unchanged MYT 02/14/14. Updated mitigation TRM 3/12/14</td>
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<tr>
<td>The existing transformer foundation will be replaced.</td>
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<tr>
<td>The existing equipment variance report MYT 02/14/14. Project unsuspended, updated ISD, 2/13/15, JRK.</td>
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<tr>
<td>Q4-2013 All remains unchanged. TRM 8/16/13. Updated Mitigation plan 5/29/13. TRM. Q4-2013</td>
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<td>Q4-2013 All remains unchanged. TRM 8/16/13. Updated ISD, 2/13/15, JRK.</td>
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<td>Q4-2013 All remains unchanged. TRM 8/16/13. Updated ISD, 2/13/15, JRK.</td>
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<td>Q4-2013 All remains unchanged. TRM 8/16/13. Updated ISD, 2/13/15, JRK.</td>
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<td>TRM - 5/20/13. Q4-2013 All remains unchanged. TRM 8/16/13. Updated Mitigation Plan 5/29/13. TRM. Q4-2013</td>
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<tr>
<td>JS_Smith. OPEN SW 7797 bus 526777 Goodpasture; then CLOSE SW 6817 bus Central, bus 526666.</td>
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<td>Alternative 2: CLOSE switch 6745 LS, bus 526979 LG-</td>
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<td>Updated final ISD, 2/13/15, JRK.</td>
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<td>Updated ISD, 2/13/15, JRK.</td>
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<td>MYT 02/14/14. Updated ISD TRM 3/12/14</td>
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<td>TRM 8/15/13. Updated Mitigation plan 5/29/13. TRM. Q4-2013</td>
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<td>Q4-2013 All remains unchanged. TRM 8/16/13. Updated ISD, 2/13/15, JRK.</td>
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<td>Updated ITM 02/14/14. Updated ISD, 2/13/15, JRK.</td>
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<td>TRM 5/20/13. Q4-2013 All remains unchanged. TRM 8/16/13. Updated ISD, 2/13/15, JRK.</td>
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<td>Updated cost. TRM 5/14/13. Q4-2013 All remains unchanged. TRM 8/16/13. Updated ISD, 2/13/15, JRK.</td>
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<tr>
<td>WFEC Device</td>
<td>Esquandale</td>
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<td>WR Device</td>
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<td>Upgrade CT 161</td>
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<td>MIDW Device</td>
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<td>Build 6.7-mile Clay Center Switching Station to TC Riley 115 kV line with Single 1192.5 kcmil ACSR</td>
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<td>AEP Device</td>
<td>Coweta</td>
<td>Install 2 stages of 5 MVAR and 2 stages of 10 MVAR reactor at Norton Switching Station 115</td>
<td>6/1/2014</td>
<td>4/9/2012</td>
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<tr>
<td>VBI</td>
<td>North</td>
<td>Upgrade CT 161</td>
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<td>WR Line</td>
<td>Clay Center Switching Station - TC Riley 115 kV ckt 1</td>
<td>Install terminal equipment at new Bushton 115 kV substation to accommodate the new 115 kV line</td>
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<td>NPPD Device</td>
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<td>Replace CTs and relays at Jewell substation and Smith Center substation 115</td>
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<td>SPS Multi</td>
<td>Potter - Channing - Dallam 230 kV Conversion</td>
<td>Install 3-breaker ring bus at Ellsworth Tap 115</td>
<td>5/31/2015</td>
<td>Q4-2012</td>
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<tr>
<td>OGE Multi</td>
<td>Chisholm - Gracemont 345 kV</td>
<td>Install terminal equipment at new Bushton 115 kV substation to accommodate the new 115 kV line</td>
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<td>12/20/2013</td>
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<td>4/9/2012</td>
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<td>SPS Multi</td>
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<td>2/6/2014</td>
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<td>Description</td>
<td>Estimated Cost</td>
<td>Type</td>
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<td>30364 50456</td>
<td>OGE Multi - Gentleman - Cherry Co. - Holt Co. 345 kV Cherry Co. - Holt Co. 345 kV Ckt 1 Regional Reliability 1/1/2018 1/1/2018 3/11/2013 2012 ITP10</td>
<td>$146,065,000</td>
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<td>OGE</td>
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<tr>
<td>30375 50445</td>
<td>NPPD Multi - Gentleman - Cherry Co. - Holt Co. 345 kV Cherry Co. - Holt Co. 345 kV Ckt 1 Regional Reliability 1/1/2018 1/1/2018 3/11/2013 2012 ITP10</td>
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</table>
Clearwater and Gill infrastructure, a 138kV ring bus expandable to a breaker and half will be constructed at Viola as part of the 345-138kV TX addition. Gill will be replaced when the line is rebuilt.

Al information taken from MN hard copy files - Bryan Cook has approved all acquisitions, permitting, and site prep. Initial design will include a 400MVA transformer and 138kV terminal equipment. This SCERT only includes the 345kV work.

Costs will be matched to new breaker and half configuration. LGIA revisions in progress concerning these costs. 

Before submission TA 01/03/13. NPE entered by TRM 5/20/13. Q4-2013 All information contained in the MN hard copy files. Bryan Cook approved all acquisition, permitting, and site prep.

On schedule for indicated In-Service date. Expand North Fort Dodge to a 9 terminal. Crooked Creek (at Fort Dodge) upgraded to current standards. New structures and 138kV breaker at NFD to be relocated to different terminals. Gill 138kV breaker to be replaced when the line is rebuilt.

MYT 11/15/13. All remains unchanged. MYT 02/14/14.

Construction costs pending. Study estimate (escalation costs are included in Contingency costs: escalation: $164,370). Bryan Cook requested update on NTC Submission before submission.

Permitted acquisition, permitting, and site prep. Initial design will include a 400MVA transformer and 138kV terminal equipment. This SCERT only includes the 345kV work.

Costs will be matched to new breaker and half configuration. LGIA revisions in progress concerning these costs.

Before submission TA 01/03/13. NPE entered by TRM 5/20/13. Q4-2013 All information contained in the MN hard copy files. Bryan Cook approved all acquisition, permitting, and site prep.

On schedule for indicated In-Service date. Expand North Fort Dodge to a 9 terminal. Crooked Creek (at Fort Dodge) upgraded to current standards. New structures and 138kV breaker at NFD to be relocated to different terminals. Gill 138kV breaker to be replaced when the line is rebuilt.

MYT 11/15/13. All remains unchanged. MYT 02/14/14.

Construction costs pending. Study estimate (escalation costs are included in Contingency costs: escalation: $164,370). Bryan Cook requested update on NTC Submission before submission.
<table>
<thead>
<tr>
<th>Description</th>
<th>Start</th>
<th>End</th>
<th>Cost Estimate</th>
<th>Completion Date</th>
<th>Progress</th>
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<td>CHIKASKIA 138kV Build new 5-mile 138 kV line from Chikaskia to new Coyote substation.</td>
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<td>3/1/2016</td>
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<td>Doolin 138kV Build new 4-mile 138 kV line from Renfrow to Medford Tap.</td>
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<tr>
<td>Fordham Tap 138kV Build new 4-mile 138 kV line from Fordham Tap to Hartburg.</td>
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<td>3/1/2016</td>
<td>$2,000,000</td>
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<td>Medford Tap 138kV Build new 4-mile 138 kV line from Medford Tap to Hartburg.</td>
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<td>Build new 138 kV line from Division Ave to Lakeside.</td>
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<tr>
<td>Increase terminal limits as necessary at Kismet.</td>
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<td>9/1/2016</td>
<td>$2,000,000</td>
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<tr>
<td>Rebuild and add a circuit to the 4 mile Kismet to Cimarron 115kV line with a change in the substation rating from 160MVA to 200MVA.</td>
<td>9/1/2016</td>
<td>12/1/2016</td>
<td>$2,000,000</td>
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<tr>
<td>Add a line switch at the Kismet substation to achieve the appropriate spacing and insulation.</td>
<td>9/1/2016</td>
<td>12/1/2016</td>
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<td>Increase terminal limits as necessary at Hartburg.</td>
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<td>12/1/2016</td>
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**Total Costs:** $23,820,104
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<td>Construct new 18-mile 138 kV line from Linwood to new SW Station switching station.</td>
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Updated ISD, 11/14/14, JRK.
Estimated window) JRK 8/15/14   Updated ISD, 11/14/14, JRK.

Cost and ISD submitted, 11/18/14, JRK.

WR Line - Gans 138 kV

Cost and ISD submitted, 11/18/14, JRK.

WR Line - Gano 138 kV

Cost and ISD submitted, 11/18/14, JRK.

WR Line - Gnos 138 kV

Cost and ISD submitted, 11/18/14, JRK.

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WR Line - Gnos 138 kV

Cost and ISD submitted, 11/18/14, JRK.

WR Line - Gnos 138 kV

Cost and ISD submitted, 11/18/14, JRK.
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<tr>
<th>Project Name</th>
<th>Description</th>
<th>Type</th>
<th>Start Date</th>
<th>End Date</th>
<th>Status</th>
<th>Completion Date</th>
<th>Total Cost</th>
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<tr>
<td>Tap the existing 115 kV line from Ochoa to Whitten to construct new 115 kV Ponderosa Tap</td>
<td>Tap the existing 115 kV line from Ochoa to Whitten to construct new 115 kV Ponderosa Tap</td>
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<td>Upgrade Yoakum County Interchange Ckt 1 230/115 kV transformer to 250 MVA. 230/115 kV transformer to 250 MVA.</td>
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<td>Add new 345kV line terminal to the OG&amp;E Tatonga 345kV substation.</td>
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<td>Interconnection Facilities: (TOIFs) (3) VTs, (3) CTs, metering and all associated bus, site, yard and facilities to tie transmission line into the new substation.</td>
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<td>Construct new 115 kV Battle Axe substation. Install any necessary 115 kV terminal equipment. 115 kV Battle Axe substation.</td>
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<td>Add breaker substation addition 230kV Line Terminal including four (4) breaker substation addition</td>
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</tbody>
</table>

**Notes:**
- **NTC-C PROJECT ESTIMATE** indicates projects funded by the NERC TCC.
- **NTC - COMMITMENT WINDOW** suggests projects that have significant commitment milestones.
- **Due** projects are subject to specific deadlines.
1. **SUNNY SIDE 138**
   - Rebuild approximately 0.75 miles of 138kV transmission line, double circuit, to new substation

2. **SPS Sub - TUCO 230kV Switching Station**
   - GEN-2012-020 Addition
   - Generation Interconnection 4/1/2016
   - $1,500,377

3. **ON SCHEDULE < 4**

4. **NPPD Line - Hoskins - Dixon County 230kV Ckt 1**
   - Hoskins - Dixon County 230kV Line Upgrade
   - Generation Interconnection 10/24/2015
   - $500,000
   - Add one (1) new 230kV breaker (breaker and one-half configuration).
   - Replace one (1) 230kV breaker.
   - Increase clearances on Hoskins - Dixon County 230kV line to accommodate 320MVA facility rating.

5. **WFEC Line - Lake Creek - Lone Wolf 69kV Ckt 1**
   - Lake Creek - Lone Wolf 69kV Ckt 1 Current Transformers
   - Generation Interconnection 8/8/2015
   - $197,972
   - Replace current transformers at Lake Creek and Lone Wolf substation.
   - (3) single wood poles to relocate existing distribution lines. Wire to terminate Slate Creek - Relay Panel, & All associated site, yard and conduit work;
   - 138kV Transmission Line Work: Three (3) 138kV Substation Work at Creswell Substation: Two (2) 138 kV 3000 Amp Breakers, Four (4) 138 kV Motor Operated Line Disconnect Switches and steel support structures; Four (4) 230kV 3000 Amp Breakers, Four (4) 230kV disconnect switches and support structures; Two (2) 69kV three phase motor operated line disconnect switches; Seven (7) 69kV CCVT, two (2) with carrier accessories; Two (2) 800A wave traps with tuning packs, pre-tuned; Six (6) 69kV station class arrestors; Control house for all protection and relay equipment; SCADA RTU and communications equipment for remote control and telemetry; All required protective relaying equipment for line and bus protection, including digital primary and backup relays, carrier equipment, etc.; 125VDC battery and charger system; Associated electrical, mechanical, structural, piping, and instrumentation and control appurtenances, and miscellaneous equipment and hardware; Associated steel, foundations, structures, insulators, bus, grounding, conduit, control cable, cable tray systems, lighting systems, etc.
   - Modifications to existing control house, including expansion of existing 230/115kV autotransformer and two existing 230kV transmission lines; Site preparation, clearing, leveling, trenching, and rock surfacing; Right of Way; Transmission line work to accommodate the interconnection facilities to be constructed by the Transmission Owner.  Property to be of sufficient size (expected to be approximately five acres) to accommodate the interconnection facilities to be constructed by the Transmission Owner.  Property to be acquired by Interconnection Customer and transferred to Transmission Owner.
   - Expansion of station AC power systems as required to accommodate new loads for equipment line relaying, disconnect switches, and associated equipment to the new 138kV substation;  Property to be acquired by Interconnection Customer and transferred to Transmission Owner.
   - Build 115 kV 3-ring bus; Right of Way; Transmission line work to accommodate the interconnection facilities to be constructed by the Transmission Owner; Disturbance Monitoring Device; Build 115 kV 3-ring bus; Right of Way; Transmission line work to accommodate the interconnection facilities to be constructed by the Transmission Owner; Disturbance Monitoring Device; Build 115 kV 3-ring bus; Right of Way; Transmission line work to accommodate the interconnection facilities to be constructed by the Transmission Owner; Disturbance Monitoring Device; Build 115 kV 3-ring bus; Right of Way; Transmission line work to accommodate the interconnection facilities to be constructed by the Transmission Owner; Disturbance Monitoring Device; Build 115 kV 3-ring bus; Right of Way; Transmission line work to accommodate the interconnection facilities to be constructed by the Transmission Owner.

6. **OGE Sub - Carter County 138kV Substation**
   - Carter County - Sunnyside 138kV Ckt 1 Generation Interconnection 6/30/2014
   - $621,118
   - Generation Interconnection 10/29/2015
   - $4,013,283
   - Generation Interconnection 10/29/2015
   - ON SCHEDULE < 4

7. **WR Sub - Cresswell 138kV Substation**
   - Cresswell 138kV Substation GEN-2011-057 Addition
   - Generation Interconnection 6/1/2015
   - $1,640,698

8. **MIDW Sub - Walnut Creek 69kV Substation**
   - Walnut Creek 69kV Substation Generation Interconnection 8/31/2015
   - $3,233,388

9. **MIDW Sub - South Hays 230kV Substation**
   - South Hays 230kV Substation GEN-2009-008 Addition
   - Generation Interconnection 10/16/2015
   - $2,949,038

10. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 230 kV
    - COMPLETE

11. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

12. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

13. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

14. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

15. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

16. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

17. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

18. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

19. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE

20. **Sub - Crosby County Interchange - Floyd County Interchange**
    - TUCO Interchange 115kV Ckt 1
    - COMPLETE