Monday, July 28, 2014
1:00 - 5:00 p.m.
Embassy Suites – Downtown Old Market
Omaha, NE

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of April 28, 2014 Minutes

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

4. BUSINESS MEETING
   a. RSC Audit Report, Related Letters and Form 990 [Voting Item]

5. REPORTS/PRESENTATIONS
   a. CAWG Report…………………………………………………………………………………..Meena Thomas
      This report provides an update on CAWG activity.
   b. Proposed Changes to RARTF Charter [Voting Item]……………………………..Donna Nelson/Rob Jansen
      Proposal to revise RARTF Charter to add an additional member representative.
   c. Process for Integrating New Members into SPP………………………………………Michael Desselle
      Discussion of the process for integrating new entrants into SPP and recommendations from the
      May 27, 2014 RSC Meeting.
   d. Proposed Changes to SPP Wind Accreditation [Possible Voting Item]……………Mitch Williams
      This report will provide information regarding a recommendation to modify the accreditation for
      wind which will have an impact on the SPP Methodology to determine planning capacity. This will
      include an update on the CAWG’s work on this issue.
   e. Capacity Margin Presentation………………………………………………………………………..Lanny Nickell
      This report will provide information regarding improvements that Staff will propose to RSC and
      CAWG in Fall 2014 to the Capacity Margin Criteria and an update on the formation of the
      Capacity Margin Task Force.
   f. Update on Integrated System (WAPA/Basin/Heartland)…………………………………Carl Monroe
      This report will provide an update on the process of consideration of the announced intent of the
      Integrated System entities becoming members of SPP.
   g. Update on Seams Related Dockets at FERC…………………………………………………Carl Monroe
      This report will provide an update on the pending matters at FERC related to the MISO Seam.
   h. Update on Seams Project Task Force……………………………………………………………..Paul Malone
      This report will provide an update on the progress of the Seams Project Task Force.
i. Order 1000 Update ........................................................................................................Paul Suskie
   This report will provide an update on SPP’s Order 1000 filings and SPP’s implementation of
   Order 1000.

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

k. Value of Transmission Presentation ......................................................................Lanny Nickell
   This report will provide an update on SPP’s study on the value of transmission as directed by the
   SPP Board

l. Benefit Metrics .........................................................................................................Lanny Nickell
   This report will provide an update on the current status of the benefit metrics, the allocation of the
   benefits from each metric and the stakeholder process.

m. SPP Strategic Plan ...................................................................................................Michael Desselle
   This report will update the RSC on the Strategic Plan.

n. Sub-synchronous Resonance ....................................................................................Lanny Nickell
   This report will provide an update to the RSC that there are no sub-synchronous resonance
   issues in SPP.

o. EPA Rule 111(d) .......................................................................................................Lanny Nickell
   This report will update the RSC on SPP’s efforts and activity related to EPA Rule 111 (d).

6. OTHER RSC MATTERS
   a. Frequency of RSC Meetings ....................................................................................Donna Nelson

7. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS
   RSC Meetings:
   October 27, 2014 – Little Rock, AR
   January 26, 2015 – Dallas, TX
   April 27, 2015 – Tulsa, OK
   July 27, 2015 – Kansas City, MO
   October 26, 2015 – Little Rock, AR

8. 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
Skirvin Hilton, Oklahoma City, OK
April 28, 2014
• M I N U T E S •

Administrative Items:
The following members were in attendance:

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

President Donna Nelson called the Regional State Committee (RSC) meeting to order at 1:10 p.m. with roll call and a quorum was declared. She then requested a round of introductions. There were 133 in attendance either in person or via the phone (Attendance & Proxies – Attachment 1).

President Nelson requested approval of the January 27, 2014 meeting minutes (RSC Minutes 1/27/14 – Attachment 2). Patrick Lyons moved to approve the January 27, 2014 minutes; Dana Murphy seconded. The motion passed.

UPDATES
RSC Financial Report
Paul Suskie provided the first quarter RSC Financial Report (Financial Report – Attachment 3). Mr. Suskie reported that the RSC is below budget and substantially below budget for the RSC consultant.

SPP Report
Nick Brown provided the SPP Report. Mr. Brown reported on one item of a policy nature that we are managing and that is our seam with the Midcontinent ISO in particular the docket now open before the Federal Energy Regulatory Commission (FERC) on the use of the SPP facilities for the integration of Entergy into the Midcontinent ISO. SPP's complaint with FERC on this issue has been set before an Administrative Law Judge for settlement.

FERC Report
Patrick Clarey provided the FERC Report. On April 1, FERC hosted a Commission-led technical conference on the 2013-2014 Winter season Operations and Market Performance in RTOs and ISOs. The conference explored the impacts of recent cold weather events on the RTOs and discussed actions taken to respond to those impacts. Mr. Clarey expressed appreciation for President Nelson’s and SPP’s participation in this technical conference. Written public comments may be submitted regarding the conference until May 15, 2014.

On March 4, the Commission submitted its FY2015 Budget Request and FY 2014-2018 Strategic Plan to Congress. The 2015 request is for $327 million up from $304 million in 2014 with a net appreciation of $0 due to offsetting collections from annual charges.
FERC initiated further steps to improve the coordination and scheduling of natural gas pipeline capacity with electricity markets in light of increased reliance on natural gas by electric generators. The steps include: a Notice of Proposed Rulemaking (NOPR) to seek public comments on proposals to revise the natural gas operating day and scheduling practices used by interstate pipelines to schedule natural gas transportation service; proceedings under the Federal Power Act (FPA) and Natural Gas Act (NGA) to ensure that these entities’ scheduling practices correlate with any revisions to the natural gas scheduling practices that may be adopted by the NOPR; and an NGA Section 5 Show Cause proceeding requiring all interstate natural gas pipelines to revise their tariffs to provide for the posting of offers to purchase released pipeline capacity in compliance with Commission’s regulations.

In late March FERC issued an initial order addressed multiple dockets involving a dispute between MISO and SPP regarding the electricity flows between the two organizations and transfers between MISO South and MISO Classic. FERC accepted and suspended for filing subject to refund a Service Agreement, as well as consolidated various related complaints between the two RTOs and set those for hearing and settlement judge proceedings, the first of which is being held April 29.

Mr. Clarey read the following is a message to the RSC from Acting FERC Chair Cheryl LaFleur:

"Congratulations to the SPP RSC on your 10-year anniversary. One of the early meetings I attended as a Commissioner was the SPP RSC. I learned more than I could ever have imagined about the Lesser Prairie Chicken, and I also learned so much about how the RSC operates. I was very impressed by how well you worked together, the engagement of the members, and the substance of the discussion. Just last year I was able to visit SPP’s new control center, and I continue to be impressed by the strides SPP is making, most notably with the commencement of the new market. It’s an important and exciting time to be involved with SPP. Congratulations again on your milestone anniversary."

BUSINESS MEETING

Commissioner Dana Murphy introduced the first item on the Business Meeting agenda, that of the Bylaws Amendment (SPP Regional State Committee Bylaw – Att 4a). The amendment to the RSC Bylaws would give the RSC the option to close their Educational Sessions and retreats. Commissioner Murphy expressed mixed feelings about this because she is a believer in openness and transparency.

Commissioner Stoll feels that the education sessions are very valuable. He spoke in support of the RSC having the option to close an educational meeting. President Nelson agreed with Commissioner Stoll and noted that with the numbers of non-RSC members attending, the educational sessions increasing there are logistical issues. President Nelson clarified that no deliberations or votes are taken at the RSC education sessions.

Dana Murphy made the motion to amend the Bylaws (RSC Bylaws – Proposed Amendment – Attachment 4b); Steve Lichter seconded. The motion passed with a 2/3 vote. The dissenting votes were Arkansas and Kansas. Texas, Oklahoma, Missouri, Nebraska, and New Mexico voted in favor.

REPORTS/PRESENTATIONS

Cost Allocation Working Group Report

Meena Thomas provided the Cost Allocation Working Group report (CAWG Report – Attachment 5). Ms. Thomas presented an overview of the group’s activities addressing the following topics

- MPRR 171 – Long Term Congestion Rights (LTCR) Clarifications
- Criteria Revisions for Wind and Solar Accreditation
- List of IS Integration Topics for CAWG Consideration
- Potential Issues for Future RSC Consideration

New Marketplace PRR 171 (LTCR Clarifications)
John Krajewski provided the RSC Presentation on the Long-Term Congestion Rights Task Force Principles, FERC Guidelines, and Design (RSC Presentation – Attachment 6). He presented an overview of LTCR, the current status and the two issues related to MPRR 171. He provided information on a design enhancement preserving the original intent of the MPRR 138 design.

Ms. Thomas asked the RSC to approve MPRR 171 – LRCR Clarifications (CAWG Recommendation to RSC – Attachment 7); Olan Reeves moved for approval; Steve Stoll seconded the motion. The motion passed.

RCAR Lessons Learned

Michael Siedschlag, former RSC member and former Chairman of the Nebraska Power Review Board and Co-Chair of the Regional Allocation Review Task Force, provided the RARTF Lessons Learned report (RARTF – RCAR Lessons Learned – Attachment 8).

President Donna Nelson asked for a motion to endorse the RARTF – RCAR Lessons Learned. Olan Reeves moved for approval; Patrick Lyons seconded the motion. The motion passed.

Paul Suskie discussed SPP efforts to address Deficient Zones in the RCAR Report and that SPP staff was directed to meet individually with each of the entities who were deficient and to discuss potential options. Mr. Suskie noted that this effort is still underway.

Proposed Changes to SPP Wind Accreditation

Mitchell Williams, Western Farmers Electric Cooperative, reported on efforts of the Generation Working Group to modify wind accreditation (Criteria Changes Wind Accreditation – Attachment 9a). Mr. Williams noted that the proposal, if adopted will have an impact on the SPP Methodology to determine planning capacity. Meena Thomas gave the CAWG report on this issue to the RSC. (CAWG Report to RSC – Attachment – 9b). After considering the methodology outlined in the criteria revision and the results based on the study of seventeen wind projects, CAWG reached the following conclusions during its April 17th meeting: 1) SPP should evaluate the current SPP capacity margin to ensure that it is adequate to meet the needs for a reliable system and 2) SPP should inform the RSC and the CAWG, on an ongoing basis, if the increase in accredited wind capacity, as a result of the criteria change, is partly or wholly responsible for causing any changes in the need for transmission upgrades in the SPP footprint.

Capacity Margin Presentation

Carl Monroe, SPP Staff, provided a report on the issue concerning capacity margin (Capacity Margin Discussion – Attachment 10). Mr. Monroe proposed five points to begin discussing possible action regarding the SPP capacity margin:

- SPP Staff to survey Members for additional questions about Capacity Margin. Then survey for Member answers to all submitted questions.
- SPP Staff propose in July MOPC and RSC meetings schedule of activities for review of Capacity Margin requirement language and applicability.
- SPP Staff propose Working Group assignment to Chair to start work before July.
- SPP Staff sponsor workshop on Resource Adequacy.
- SPP Staff revise and provide to WG the draft for review to bring to MOPC and RSC in January.

Update on the Integrated System

Carl Monroe provided the Update of Integrated System (Update Integration of WAPA, Basin, Heartland – Attachment 11) and the work being completed by the Stakeholders on Tariff changes and changes to the SPP Bylaws and the Membership Agreement.

Update on Seams Related Dockets at FERC

Carl Monroe reported on the Seams Update for the RSC (Seams Update – Attachment 12). He noted that SPP has been billing MISO for their unscheduled intentional use of our facilities.
Order 1000 Update

Paul Suskie reported on the Order 1000 Filings (Order 1000 Filings Update – Attachment 13a). Mr. Suskie said there have been no changes since January and we are still awaiting orders from FERC. He then went on to report on and explain the implementation of Order 1000 regarding the creation, role, and compensation of the Industry Expert Pool required by Order 1000 (FERC Order 1000 Independent Expert Pool/Panel – Attachment 13b).

Integrated Marketplace Update

Bruce Rew, SPP Staff, provided an update on the Integrated Marketplace (Integrated Marketplace Update – Attachment – 14). Mr. Rew reported that the Integrated Marketplace did launch on time on March 1 and it has been successful.

High Priority Increment Load Study

Lanny Nickell, SPP Staff, reported on the action by MOPC on HPILS and the next steps (HPILS Presentation – Attachment 15).

Strategic Plan

Michael Desselle reported on the three foundational strategies (2010 Strategic Plan – Attachment 16). Mr. Desselle listed the three foundational strategies as:

- Build a robust transmission system
- Develop efficient market processes
- Create Member Value

This is the collective work from many different working groups. The SPC had its retreat a couple of weeks ago in Oklahoma City and out of that effort the group has come up with a new additional focus and right now it is referred to as Reliability Assurance. It will be an additional circle. The new graphic was not available at this meeting so this issue will be revisited at a later date.

Report to FERC on 2013-14 Winter

President Nelson requested this agenda item after hearing Bruce Rew’s presentation at the FERC Technical Conference (Southwest Power Pool: Winter 2013-2014 – Attachment 17). The Integrated Marketplace went live on March 1st and there was a very severe cold weather event on March 1 through the 3rd and there were no reliability issues. Ms. Nelson commended SPP and the staff for their success.

OTHER RSC MATTERS

There were no additional RSC matters to discuss.

SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS

President Nelson noted the next RSC meeting will be in Omaha, NE on July 28, 2014 and in Little Rock, AR on October 27, 2014. A reminder that this evening does mark the 10th Anniversary of the RSC and there will be a celebration. There will be many past participants at the dinner.

With no further business, the meeting adjourned at 4:50 p.m.

Respectfully Submitted,

Paul Suskie
## Regional State Committee
For the Six Months Ending June 30, 2014
Budget vs. Actual

<table>
<thead>
<tr>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>122,824</td>
<td>137,650</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>122,824</td>
<td>137,650</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
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<tr>
<td>Travel/Meeting</td>
<td>121,174</td>
<td>87,150</td>
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<td>Audit</td>
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<td>-</td>
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<tr>
<td>Administrative Costs</td>
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<td>500</td>
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<tr>
<td>RSC Consultant</td>
<td>1,650</td>
<td>50,000</td>
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<tr>
<td>Technical Conference</td>
<td>-</td>
<td>-</td>
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<tr>
<td><strong>Total Expense</strong></td>
<td>122,824</td>
<td>137,650</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>-</td>
<td>-</td>
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</tbody>
</table>
Southwest Power Pool Regional State Committee

STATEMENTS OF CASH RECEIPTS AND DISBURSEMENTS
Years Ended December 31, 2013 and 2012

(With Independent Auditor’s Report Thereon)
INDEPENDENT AUDITOR’S REPORT

Members of the
Southwest Power Pool Regional State Committee

We have audited the accompanying statements of cash receipts and disbursements of Southwest Power Pool Regional State Committee (the Organization) for the years ended December 31, 2013 and 2012, and the related notes to the financial statements.

Management’s Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the cash basis of accounting described in Note 1; this includes determining that the cash basis of accounting is an acceptable basis for the preparation of the financial statements in the circumstances. Management is also responsible for the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatements of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity’s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity’s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we obtained is sufficient and appropriate to provide a basis for our audit opinion.
Members of the  
Southwest Power Pool Regional State Committee  
Page Two

Opinion
In our opinion, the financial statements referred to in the first paragraph present fairly, in all material respects, the statements of cash receipts and disbursements of the Organization for the years ended December 31, 2013 and 2012, in accordance with the cash basis of accounting described in Note 1.

Basis of Accounting
We draw attention to Note 1 of the financial statements, which describes the basis of accounting. These financial statements are prepared on the cash basis of accounting, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Certified Public Accountants

July 3, 2014  
Little Rock, Arkansas
Southwest Power Pool Regional State Committee

STATMENTS OF CASH RECEIPTS AND DISBURSEMENTS
Years Ended December 31, 2013 and 2012

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CASH RECEIPTS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reimbursements</td>
<td>$225,758</td>
<td>$472,161</td>
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<td></td>
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<td></td>
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<tr>
<td><strong>CASH DISBURSEMENTS</strong></td>
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</tr>
<tr>
<td>Administrative</td>
<td>2,120</td>
<td>2,988</td>
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<tr>
<td>Consultants</td>
<td>34,898</td>
<td>255,771</td>
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<tr>
<td>Meetings</td>
<td>18,711</td>
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<tr>
<td>Travel</td>
<td>165,413</td>
<td>161,676</td>
</tr>
<tr>
<td><strong>Total Cash Disbursements</strong></td>
<td>221,142</td>
<td>437,295</td>
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<td></td>
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<tr>
<td><strong>INCREASE IN CASH</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4,616</td>
<td>34,866</td>
</tr>
<tr>
<td><strong>NEGATIVE CASH, BEGINNING OF YEAR</strong></td>
<td>(5,707)</td>
<td>(40,573)</td>
</tr>
<tr>
<td><strong>NEGATIVE CASH, END OF YEAR</strong></td>
<td>$ (1,091)</td>
<td>$ (5,707)</td>
</tr>
</tbody>
</table>

See accompanying notes to financial statement.
NOTE 1: NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General
Southwest Power Pool Regional State Committee (the Organization) is a public-benefit corporation incorporated in the State of Arkansas. The primary purpose of the Organization is to provide collective state regulatory agency input to Southwest Power Pool, Inc. (SPP) on matters of regional importance related to the development and operation of bulk electric transmission. The Organization is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma and Texas.

All general and administrative functions related to the operation of the Organization are performed by employees of SPP at no charge to the Organization. In addition, SPP provides all financial support necessary to cover costs incurred by the Organization.

(b) Basis of Accounting
The accompanying financial statements have been prepared on the cash receipts and disbursements basis of accounting. Under this method, the only asset recognized is cash, and no liabilities are recognized. Non-cash transactions are not recognized. All transactions are recorded as either cash receipts or disbursements.

(c) Cash
These financial statements reflect all receipts and disbursements attributable to the Organization’s operating bank account maintained at a financial institution. Negative cash presented on the financial statements represents reimbursements due from SPP for operating costs incurred and paid by the Organization. These reimbursements are received the next business day.

(d) Income Taxes
The Organization is exempt from income taxes under Section 501(c)(4) of the Internal Revenue Code, except for taxes pertaining to unrelated business income.

The Organization may be subject to audit by the Internal Revenue Service; however there are currently no audits for any tax periods in progress. As of December 31, 2013, the Organization believes they are no longer subject to income tax examinations for years prior to 2010.

NOTE 2: SUBSEQUENT EVENTS

Management has evaluated subsequent events through July 3, 2014, the date that the financial statements were available to be issued.
Members of the
Southwest Power Pool Regional State Committee
Management of Southwest Power Pool, Inc.

We have audited the statement of cash receipts and disbursements of Southwest Power Pool Regional State Committee (the Organization) for the year ended December 31, 2013, and have issued our report thereon dated July 3, 2014. Professional standards require that we provide you with information about our responsibilities under generally accepted auditing standards, as well as certain information related to the planned scope and timing of our audit. We have communicated such information to you in our letter dated January 6, 2014. Professional standards also require that we communicate to you the following information related to our audit.

**Significant Audit Findings**

**Qualitative Aspects of Accounting Practices**

Management is responsible for the selection and use of appropriate accounting policies. The significant accounting policies used by the Organization are described in Note 1 to the financial statement. No new accounting policies were adopted and the application of existing policies was not changed during 2013. We noted no transactions entered into by the Organization during the year for which there is a lack of authoritative guidance or consensus. All significant transactions have been recognized in the financial statement in the proper period in accordance with the cash receipts and disbursements basis of accounting.

Accounting estimates are an integral part of the financial statement prepared by management and are based on management’s knowledge and experience about past and current events and assumptions about future events. Certain accounting estimates are particularly sensitive because of their significance to the financial statement and because of the possibility that future events affecting them may differ significantly from those expected. We noted no particularly sensitive accounting estimates applicable to the Organization’s December 31, 2013 financial statement.

The financial statement disclosures are neutral, consistent and clear.

**Difficulties Encountered in Performing the Audit**

We encountered no significant difficulties in dealing with management in performing and completing our audit.

**Corrected and Uncorrected Misstatements**

Professional standards require us to accumulate all misstatements identified during the audit, other than those that are clearly trivial, and communicate them to the appropriate level of management. We did not identify any misstatements to report.
Members of the
Southwest Power Pool Regional State Committee
Management of Southwest Power Pool, Inc.
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**Significant Audit Findings (Continued)**

*Disagreements with Management*

For purposes of this letter, a disagreement with management is a financial accounting, reporting or auditing matter, whether or not resolved to our satisfaction, that could be significant to the financial statement or the auditor’s report. We are pleased to report that no such disagreements arose during the course of our audit.

*Management Representations*

We have requested certain representations from management that are included in the management representation letter dated July 3, 2014, a copy of which is included in Attachment A.

*Management Consultations with Other Independent Accountants*

In some cases, management may decide to consult with other accountants about auditing and accounting matters, similar to obtaining a “second opinion” on certain situations. If a consultation involves application of an accounting principle to the Organization’s financial statement or a determination of the type of auditor’s opinion that may be expressed on the statement, our professional standards require the consulting accountant to check with us to determine that the consultant has all the relevant facts. To our knowledge, there were no such consultations with other accountants.

*Other Audit Findings or Issues*

We generally discuss a variety of matters, including the application of accounting principles and auditing standards, with management each year prior to retention as the Organization’s auditors. However, these discussions occurred in the normal course of our professional relationship and our responses were not a condition to our retention.

* * * * *

This information is intended solely for the use of the members and management of the Organization and is not intended to be, and should not be, used by anyone other than these specified parties.

Certified Public Accountants

July 3, 2014
Little Rock, Arkansas
July 3, 2014

Thomas & Thomas LLP
Heritage West Building
201 East Markham, Suite 500
Little Rock, Arkansas 72201

This representation letter is provided in connection with your audit of the financial statements of the Southwest Power Pool Regional State Committee (the Organization) which comprise the statements of cash receipts and disbursements for the years then ended December 31, 2013 and 2012, and the related notes to the financial statements, for the purpose of expressing an opinion as to whether the financial statements are presented fairly, in all material respects, in accordance with the cash receipts and disbursements basis of accounting.

Certain representations in this letter are described as being limited to matters that are material. Items are considered material, regardless of size, if they involve an omission or misstatement of accounting information that, in light of surrounding circumstances, makes it probable that the judgment of a reasonable person relying on the information would be changed or influenced by the omission or misstatement. An omission or misstatement that is monetarily small in amount could be considered material as a result of qualitative factors.

We confirm, to the best of our knowledge and belief, as of July 3, 2014, the following representations made to you during your audit.

Financial Statements

- We have fulfilled our responsibilities, as set out in the terms of the audit engagement letter dated January 6, 2014, including our responsibility for the preparation and fair presentation of the financial statements.

- The financial statements referred to above are fairly presented in conformity with the cash receipts and disbursements basis of accounting.

- We acknowledge our responsibility for the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

- We acknowledge our responsibility for the design, implementation and maintenance of internal control to prevent and detect fraud.
Financial Statements (Continued)

- Significant assumptions we used in making accounting estimates, including those measured at fair value, are reasonable.

- Related party relationships and transactions have been appropriately accounted for and disclosed in accordance with the cash receipts and disbursements basis of accounting.

- There are no events subsequent to the date of the financial statements and for which the cash receipts and disbursements basis of accounting requires adjustment or disclosure.

- We are not aware of any pending or threatened litigation, claims, or assessments or unasserted claims or assessments that are required to be disclosed in the financial statements in accordance with the cash receipts and disbursements basis of accounting and we have not consulted a lawyer concerning litigation, claims or assessments.

- Material concentrations have been properly disclosed in accordance with the cash receipts and disbursements basis of accounting.

- There are no guarantees, whether written or oral, under which the Organization is contingently liable that must be recorded or disclosed in the financial statements in accordance with the cash receipts and disbursements basis of accounting.

Information Provided

- We have provided you with:
  - Access to all information, of which we are aware, that is relevant to the preparation and fair presentation of the financial statements, such as records, documentation and other matters.
  - Additional information that you have requested from us for the purpose of the audit.
  - Unrestricted access to persons within the Organization from whom you determined it necessary to obtain audit evidence.

- All material transactions have been recorded in the accounting records and are reflected in the financial statements.

- We have disclosed to you the results of our assessment of the risk that the financial statements may be materially misstated as a result of fraud.

- We have no knowledge of any fraud or suspected fraud that affects the Organization and involves:
  - Management,
  - Other administrative officers who have significant roles in internal control or
  - Others where the fraud could have a material effect on the financial statements.
Information Provided (Continued)

- We have no knowledge of any allegations of fraud or suspected fraud affecting the Organization’s financial statements communicated by regulators or others.

- There are no known instances of noncompliance or suspected noncompliance with laws and regulations whose effects should be considered when preparing the financial statements.

- We are not aware of any pending or threatened litigation, claims, or assessments or unasserted claims or assessments that are required to be disclosed in the financial statements in accordance with the cash receipts and disbursements basis of accounting, and we have not consulted a lawyer concerning litigation, claims or assessments.

- We have disclosed to you the identity of the Organization’s related parties and all the related party relationships and transactions of which we are aware.

- We understand that you prepared the draft financial statements and related notes from the general ledger which we provided. We have reviewed and approved the financial statements and related notes and believe they are adequately supported by the books and records of the Organization.

- In regards to the tax preparation services and financial statement preparation services performed by you, we have:
  
  o Assumed all management responsibilities.
  
  o Overseen the services by designating an individual with suitable skill, knowledge or experience.
  
  o Evaluated the adequacy and results of the services performed.
  
  o Accepted responsibility for the results of the services.

Donna Nelson, President
Southwest Power Pool Regional State Committee

Paul Suskie, Executive Vice President Regulatory Policy and General Counsel
Southwest Power Pool, Inc.
A. For the 2013 calendar year, or tax year beginning and ending

B. Check if applicable:

C. Name of organization

Southwest Power Pool Regional State Committee

D. Employer identification number

20-1035424

E. Telephone number

501-682-5767

G. Gross receipts

225,758

H. Is this a group return

[X] Yes [No] No

If "No," attach a list. (see instructions)

I. Website:

[ ] N/A

J. Form of organization:

[X] Corporation [ ] Trust [ ] Association [ ] Other

K. Year of formation: 2004 [ ] State of legal domicile: AR

Part I - Summary

1. Briefly describe the organization’s mission or most significant activities: To provide collective state regulatory input.

2. Check this box [ ] if the organization discontinued its operations or disposed of more than 25% of its net assets.

3. Number of voting members of the governing body (Part VI, line 1a) 3

4. Number of independent voting members of the governing body (Part VI, line 1b) 7

5. Total number of individuals employed in calendar year 2013 (Part V, line 2a) 5

6. Total number of volunteers (estimate if necessary) 6

7. Total unrelated business revenue from Part VIII, column (C), line 12 7a 0

b Net unrelated business taxable income from Form 990-T, line 34 7b 0

8. Contributions and grants (Part VIII, line 1h) 0

9. Program service revenue (Part VIII, line 2g) 0

10. Investment income (Part VIII, column (A), lines 3, 4, and 7d) 0

11. Other revenue (Part VIII, column (A), lines 5, 6d, 8c, 9c, 10c, and 11e) 0

12. Total revenue - add lines 8 through 11 (must equal Part VIII, column (A), line 12) 472,161 225,758

13. Grants and similar amounts paid (Part IX, column (A), lines 1-3) 0

14. Benefits paid to or for members (Part IX, column (A), line 4) 0

15. Salaries, other compensation, employee benefits (Part IX, column (A), lines 5-10) 0

16a Professional fundraising fees (Part IX, column (A), line 11e) 0

b Total fundraising expenses (Part IX, column (D), line 25) 0

17. Other expenses (Part IX, column (A), lines 11a-11d, 11f-24e) 437,295 221,142

18. Total expenses. Add lines 13-17 (must equal Part IX, column (A), line 25) 437,295 221,142

19. Revenue less expenses. Subtract line 18 from line 12 34,866 4,616

Part II - Signature Block

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than officer) is based on all information of which preparer has any knowledge.

Sign Here

Donna Nelson, President

type or print name and title

Date

Preparer's signature

Check if self-employed [ ] Yes [ ] No

PTIN 00174819

Print/Type preparer's name

Sherry Chesser, CPA

Preparer's signature

Date

Firm's EIN 71-0271741

Firm's name Thomas & Thomas LLP

Phone no. 501-375-2025

Firm's address 201 E. Markham, Suite 500

Little Rock, AR 72201

May the IRS discuss this return with the preparer shown above? (see instructions)

[X] Yes [ ] No

Form 990 (2013)
Southwest Power Pool Regional State Committee 20-1035424

Part III  Statement of Program Service Accomplishments

1. Briefly describe the organization's mission:

   To provide collective state regulatory input.

2. Did the organization undertake any significant program services during the year which were not listed on the prior Form 990 or 990-EZ?  
   □ Yes  □ No

   If "Yes," describe these new services on Schedule O.

3. Did the organization cease conducting, or make significant changes in how it conducts, any program services?  
   □ Yes  □ No

   If "Yes," describe these changes on Schedule O.

4. Describe the organization's program service accomplishments for each of its three largest program services, as measured by expenses.

   Section 501(c)(3) and 501(c)(4) organizations are required to report the amount of grants and allocations to others, the total expenses, and revenue, if any, for each program service reported.

   4a (Code: _____)  (Expenses $ 221,142. including grants of $ )  (Revenue $ 225,758.)

   The Organization provided collective state regulatory agency input to Southwest Power Pool, Inc. (SPP) and SPP's board of directors, committees, working groups and task forces. The Organization is reimbursed for it's expenses by SPP. These reimbursements are the Organization's sole source of revenue.

   4b (Code: _____)  (Expenses $ including grants of $ )  (Revenue $ )

   4c (Code: _____)  (Expenses $ including grants of $ )  (Revenue $ )

   4d Other program services (Describe in Schedule O.)

   (Expenses $ including grants of $ )  (Revenue $ )

   4e Total program service expenses ▶ 221,142.
Part IV Checklist of Required Schedules

1. Is the organization described in section 501(c)(3) or 4947(a)(1) (other than a private foundation)?
   If "Yes," complete Schedule A
   1 Yes No

2. Is the organization required to complete Schedule B, Schedule of Contributors?
   2 Yes No

3. Did the organization engage in direct or indirect political campaign activities on behalf of or in opposition to candidates for
   public office? If "Yes," complete Schedule C, Part I
   3 Yes No

4. Section 501(c)(3) organizations. Did the organization engage in lobbying activities, or have a section 501(h) election in effect
   during the tax year? If "Yes," complete Schedule C, Part II
   4 Yes No

5. Is the organization a section 501(c)(4), 501(c)(5), or 501(c)(6) organization that receives membership dues, assessments, or
   similar amounts as defined in Revenue Procedure 98-19? If "Yes," complete Schedule C, Part III
   5 Yes No

6. Did the organization maintain any donor advised funds or any similar funds or accounts for which donors have the right to
   provide advice on the distribution or investment of amounts in such funds or accounts? If "Yes," complete Schedule D, Part I
   6 Yes No

7. Did the organization receive or hold a conservation easement, including easements to preserve open space, the environment, historic
   land areas, or historic structures? If "Yes," complete Schedule D, Part II
   7 Yes No

8. Did the organization maintain collections of works of art, historical treasures, or other similar assets? If "Yes," complete Schedule
   D, Part III
   8 Yes No

9. Did the organization report an amount in Part X, line 21, for escrow or custodial account liability; serve as a custodian for
   amounts not listed in Part X; or provide credit counseling, debt management, credit repair, or debt negotiation services?
   If "Yes," complete Schedule D, Part IV
   9 Yes No

10. Did the organization, directly or through a related organization, hold assets in temporarily restricted endowments, permanent
    endowments, or quasi-endowments? If "Yes," complete Schedule D, Part V
    10 Yes No

11. If the organization's answer to any of the following questions is "Yes," then complete Schedule D, Parts VI, VII, VIII, IX, or X
    as applicable.
    a. Did the organization report an amount for land, buildings, and equipment in Part X, line 10? If "Yes," complete Schedule D,
       Part VI
       11a Yes No
    b. Did the organization report an amount for investments - other securities in Part X, line 12 that is 5% or more of its total
       assets reported in Part X, line 16? If "Yes," complete Schedule D, Part VII
       11b Yes No
    c. Did the organization report an amount for investments - program related in Part X, line 13 that is 5% or more of its total
       assets reported in Part X, line 16? If "Yes," complete Schedule D, Part VIII
       11c Yes No
    d. Did the organization report an amount for other assets in Part X, line 15 that is 5% or more of its total assets reported in
       Part X, line 16? If "Yes," complete Schedule D, Part IX
       11d Yes No
    e. Did the organization report an amount for other liabilities in Part X, line 25? If "Yes," complete Schedule D, Part X
       11e Yes No
    f. Did the organization's separate or consolidated financial statements for the tax year include a footnote that addresses
       the organization's liability for uncertain tax positions under FIN 48 (ASC 740)? If "Yes," complete Schedule D, Part
       XI
       11f Yes No
    g. Did the organization obtain separate, independent audited financial statements for the tax year? If "Yes," complete
       Schedule D, Parts XI and XII
       12a Yes No
    h. Was the organization included in consolidated, independent audited financial statements for the tax year?
       If "Yes," and if the organization answered "No" to line 12a, then completing Schedule D, Parts XI and XII is optional
       12b Yes No
    12c Yes No

13. Is the organization a school described in section 170(b)(1)(A)(ii)? If "Yes," complete Schedule E
    13 Yes No

14a. Did the organization maintain an office, employees, or agents outside of the United States?
    14a Yes No

14b. Did the organization have aggregate revenues or expenses of more than $10,000 from grantmaking, fundraising, business,
    investment, and program service activities outside the United States, or aggregate foreign investments valued at $100,000
    or more? If "Yes," complete Schedule F, Parts I and IV
    14b Yes No

15. Did the organization report on Part IX, column (A), line 3, more than $5,000 of grants or other assistance to or for any
    foreign organization? If "Yes," complete Schedule F, Parts II and IV
    15 Yes No

16. Did the organization report on Part IX, column (A), line 3, more than $5,000 of aggregate grants or other assistance to
    or for foreign individuals? If "Yes," complete Schedule F, Parts III and IV
    16 Yes No

17. Did the organization report a total of more than $15,000 of expenses for professional fundraising services on Part IX,
    column (A), lines 6 and 11e? If "Yes," complete Schedule G, Part I
    17 Yes No

18. Did the organization report more than $15,000 total of fundraising event gross income and contributions on Part VIII, lines
    1c and 8a? If "Yes," complete Schedule G, Part II
    18 Yes No

19. Did the organization report more than $15,000 of gross income from gaming activities on Part VIII, line 9a? If "Yes,"
    complete Schedule G, Part III
    19 Yes No

20a. Did the organization operate one or more hospital facilities? If "Yes," complete Schedule H
    20a Yes No

20b. If "Yes" to line 20a, did the organization attach a copy of its audited financial statements to this return?
    20b Yes No
### Part IV Checklist of Required Schedules

<table>
<thead>
<tr>
<th>Schedule</th>
<th>Yes</th>
<th>No</th>
</tr>
</thead>
<tbody>
<tr>
<td>21 Did the organization report more than $5,000 of grants or other assistance to any domestic organization or government on Part IX, column (A), line 1?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>22 Did the organization report more than $5,000 of grants or other assistance to individuals in the United States on Part IX, column (A), line 2?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>23 Did the organization answer &quot;Yes&quot; to Part VII, Section A, line 3, 4, or 5 about compensation of the organization's current and former officers, directors, trustees, key employees, and highest compensated employees?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>24a Did the organization have a tax-exempt bond issue with an outstanding principal amount of more than $100,000 as of the last day of the year, that was issued after December 31, 2002?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>b Did the organization invest any proceeds of tax-exempt bonds beyond a temporary period exception?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>c Did the organization maintain an escrow account other than a refunding escrow at any time during the year to defease any tax-exempt bonds?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>d Did the organization act as an &quot;on behalf of&quot; issuer for bonds outstanding at any time during the year?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>25a Section 501(c)(3) and 501(c)(4) organizations. Did the organization engage in an excess benefit transaction with a disqualified person during the year?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>b Is the organization aware that it engaged in an excess benefit transaction with a disqualified person in a prior year, and that the transaction has not been reported on any of the organization's prior Forms 990 or 990-EZ?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>26 Did the organization report any amount on Part X, line 5, 6, or 22 for receivables from or payables to any current or former officers, directors, trustees, key employees, highest compensated employees, or disqualified persons?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>27 Did the organization provide a grant or other assistance to an officer, director, trustee, key employee, substantial contributor or employee thereof, a grant selection committee member, or to a 35% controlled entity or family member of any of these persons?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>28 Was the organization a party to a business transaction with one of the following parties (see Schedule L, Part IV instructions for applicable filing thresholds, conditions, and exceptions):</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>a A current or former officer, director, trustee, or key employee?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>b A family member of a current or former officer, director, trustee, or key employee?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>c An entity of which a current or former officer, director, trustee, or key employee (or a family member thereof) was an officer, director, trustee, or direct or indirect owner?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>29 Did the organization receive more than $25,000 in non-cash contributions?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>30 Did the organization receive contributions of art, historical treasures, or other similar assets, or qualified conservation contributions?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>31 Did the organization liquidate, terminate, or dissolve and cease operations?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>32 Did the organization sell, exchange, dispose of, or transfer more than 25% of its net assets?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>33 Did the organization own 100% of an entity disregarded as separate from the organization under Regulations sections 301.7701-2 and 301.7701-3?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>34 Was the organization related to any tax-exempt or taxable entity?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>35a Did the organization have a controlled entity within the meaning of section 512(b)(13)?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>b If &quot;Yes&quot; to line 35a, did the organization receive any payment from or engage in any transaction with a controlled entity within the meaning of section 512(b)(13)?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>36 Section 501(c)(3) organizations. Did the organization make any transfers to an exempt non-charitable related organization?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>37 Did the organization conduct more than 5% of its activities through an entity that is not a related organization and that is treated as a partnership for federal income tax purposes?</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>38 Did the organization complete Schedule O and provide explanations in Schedule O for Part VI, lines 11b and 19?</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>
### Part V Statements Regarding Other IRS Filings and Tax Compliance

#### 1a Enter the number reported in Box 3 of Form 1096. Enter -0- if not applicable. [2a]
- Yes [ ] No [ ]

#### 1b Enter the number of Forms W-2G included in line 1a. Enter -0- if not applicable [1b]
- Yes [ ] No [ ]

#### 1c Did the organization comply with backup withholding rules for reportable payments to vendors and reportable gambling winnings to prize winners? [1c]
- Yes [ ] No [ ]

#### 2a Enter the number of employees reported on Form W-3, Transmittal of Wage and Tax Statements, filed for the calendar year ending with or within the year covered by this return. [2a]
- Yes [ ] No [ ]

#### 2b If at least one is reported on line 2a, did the organization file all required federal employment tax returns? [2b]
- Yes [ ] No [ ]

#### 3a Did the organization have unrelated business gross income of $1,000 or more during the year? [3a]
- Yes [ ] No [ ]

#### 3b If “Yes,” has it filed a Form 990-T for this year? If “No,” to line 3b, provide an explanation in Schedule O [3b]
- Yes [ ] No [ ]

#### 3c Did the organization have unrelated business gross income of $1,000 or more during the year? [3c]
- Yes [ ] No [ ]

#### 4a At any time during the calendar year, did the organization have an interest in, or a signature or other authority over, a financial account in a foreign country (such as a bank account, securities account, or other financial account)? [4a]
- Yes [ ] No [ ]

#### 4b If “Yes,” enter the name of the foreign country. [4b]


#### 5a Was the organization a party to a prohibited tax shelter transaction at any time during the tax year? [5a]
- Yes [ ] No [ ]

#### 5b Did any taxable party notify the organization that it was or is a party to a prohibited tax shelter transaction? [5b]
- Yes [ ] No [ ]

#### 5c If “Yes,” to line 5a or 5b, did the organization file Form 8886-T? [5c]
- Yes [ ] No [ ]

#### 6a Does the organization have annual gross receipts that are normally greater than $100,000, and did the organization solicit any contributions that were not tax deductible as charitable contributions? [6a]
- Yes [ ] No [ ]

#### 6b If “Yes,” did the organization include with every solicitation an express statement that such contributions or gifts were not tax deductible? [6b]
- Yes [ ] No [ ]

#### 7 Organizations that may receive deductible contributions under section 170(c). [7]

- a Did the organization receive a payment in excess of $75 made partly as a contribution and partly for goods and services provided to the payor? [7a]

- b If “Yes,” did the organization notify the donor of the value of the goods or services provided? [7b]

- c Did the organization sell, exchange, or otherwise dispose of tangible personal property for which it was required to file Form 8282? [7c]

- d If “Yes,” indicate the number of Forms 8282 filed during the year [7d]

- e Did the organization receive any funds, directly or indirectly, to pay premiums on a personal benefit contract? [7e]

- f Did the organization, during the year, pay premiums, directly or indirectly, on a personal benefit contract? [7f]

- g If the organization received a contribution of qualified intellectual property, did the organization file Form 8899 as required? [7g]

- h If the organization received a contribution of cars, boats, airplanes, or other vehicles, did the organization file a Form 1098-C? [7h]

- i Sponsoring organizations maintaining donor advised funds and section 509(a)(3) supporting organizations. Did the supporting organization, or a donor advised fund maintained by a sponsoring organization, have excess business holdings at any time during the year? [7i]

#### 8 Sponsoring organizations maintaining donor advised funds. [8]

- a Did the organization make any taxable distributions under section 4966? [8a]

- b Did the organization make a distribution to a donor, donor advisor, or related person? [8b]

#### 10 Section 501(c)(7) organizations. Enter: [10]

- a Initiation fees and capital contributions included on Part VIII, line 12 [10a]

- b Gross receipts, included on Form 990, Part VIII, line 12, for public use of club facilities [10b]

#### 11 Section 501(c)(12) organizations. Enter: [11]

- a Gross income from members or shareholders [11a]

- b Gross income from other sources (Do not net amounts due or paid to other sources against amounts due or received from them.) [11b]

#### 12a Section 4947(a) non-exempt charitable trusts. Is the organization filing Form 990 in lieu of Form 1041? [12a]
- Yes [ ] No [ ]

- b If “Yes,” enter the amount of tax-exempt interest received or accrued during the year. [12b]

#### 13 Section 501(c)(29) qualified nonprofit health insurance issuers. [13]

- a Is the organization licensed to issue qualified health plans in more than one state? [13a]

- b Enter the amount of reserves the organization is required to maintain by the states in which the organization is licensed to issue qualified health plans [13b]

- c Enter the amount of reserves on hand [13c]

#### 14a Did the organization receive any payments for indoor tanning services during the tax year? [14a]
- Yes [ ] No [ ]

- b If "Yes," has it filed a Form 720 to report these payments? If "No," provide an explanation in Schedule O [14b]

See the instructions for additional information the organization must report on Schedule O.
### Section A. Governing Body and Management

1. Enter the number of voting members of the governing body at the end of the tax year.  
   - Yes: 7

2. Did any officer, director, trustee, or key employee have a family relationship or a business relationship with any other officer, director, trustee, or key employee?  
   - No: X

3. Did the organization delegate control over management duties customarily performed by or under the direct supervision of officers, directors, or trustees, or key employees to a management company or other person?  
   - No: X

4. Did the organization make any significant changes to its governing documents since the prior Form 990 was filed?  
   - No: X

5. Did the organization become aware during the year of a significant diversion of the organization’s assets?  
   - No: X

6. Did the organization have members or stockholders?  
   - No: X

7. Did the organization have members, stockholders, or other persons who had the power to elect or appoint one or more members of the governing body?  
   - No: X

8. Did the organization contemporaneously document the meetings held or written actions undertaken during the year by the following:  
   - a. The governing body?  
      - Yes: X
   - b. Each committee with authority to act on behalf of the governing body?  
      - Yes: X

9. Is there any officer, director, trustee, or key employee listed in Part VII, Section A, who cannot be reached at the organization’s mailing address? If “Yes,” provide the names and addresses in Schedule O.  
   - No: X

### Section B. Policies

10. Did the organization have local chapters, branches, or affiliates?  
    - No: X

11. Has the organization provided a complete copy of this Form 990 to all members of its governing body before filing the form?  
    - No: X

12. Did the organization have a written conflict of interest policy? If "Yes," describe in Schedule O how this was done.  
    - No: X

13. Did the organization have a written whistleblower policy?  
    - No: X

14. Did the organization have a written document retention and destruction policy?  
    - No: X

15. Did the organization invest in, contribute assets to, or participate in a joint venture or similar arrangement with a taxable entity during the year?  
    - No: X

### Section C. Disclosure

17. List the states with which a copy of this Form 990 is required to be filed.  
   - None

18. Section 6104 requires an organization to make its Forms 1023 (or 1024 if applicable), 990, and 990-T (Section 501(c)(3)s only) available for public inspection. Indicate how you made these available. Check all that apply.  
   - Own website: X  
   - Another’s website:  
   - Upon request:  
   - Other (explain in Schedule O):  

19. Describe in Schedule O whether (and if so, how) the organization made its governing documents, conflict of interest policy, and financial statements available to the public during the tax year.  

20. State the name, physical address, and telephone number of the person who possesses the books and records of the organization.  
    - The Organization  -  501-682-5767  
      - 1000 Center Street, Little Rock, AR  72203-0400
### Part VII Compensation of Officers, Directors, Trustees, Key Employees, Highest Compensated Employees, and Independent Contractors

Check if Schedule O contains a response or note to any line in this Part VII.

#### Section A. Officers, Directors, Trustees, Key Employees, and Highest Compensated Employees

1a Complete this table for all persons required to be listed. Report compensation for the calendar year ending with or within the organization’s tax year.

- List all of the organization’s current officers, directors, trustees (whether individuals or organizations), regardless of amount of compensation. Enter -0- in columns (D), (E), and (F) if no compensation was paid.
- List all of the organization’s current key employees, if any. See instructions for definition of “key employee.”
- List the organization’s five current highest compensated employees (other than an officer, director, trustee, or key employee) who received reportable compensation (Box 5 of Form W-2 and/or Box 7 of Form 1099-MISC) of more than $100,000 from the organization and any related organizations.
- List all of the organization’s former officers, key employees, and highest compensated employees who received more than $100,000 of reportable compensation from the organization and any related organizations.
- List all of the organization’s former directors or trustees that received, in the capacity as a former director or trustee of the organization, more than $10,000 of reportable compensation from the organization and any related organizations.

List persons in the following order: individual trustees or directors; institutional trustees; officers; key employees; highest compensated employees; and former such persons.

- Check this box if neither the organization nor any related organization compensated any current officer, director, or trustee.

#### Table

<table>
<thead>
<tr>
<th>(A) Name and Title</th>
<th>(B) Average hours per week (list any hours for related organizations below line)</th>
<th>(C) Position (do not check more than one box, unless person is both an officer and a director/trustee)</th>
<th>(D) Reportable compensation from the organization (W-2/1099-MISC)</th>
<th>(E) Reportable compensation from related organizations (W-2/1099-MISC)</th>
<th>(F) Estimated amount of other compensation from the organization and related organizations</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Thomas Wright</td>
<td>1.00 X X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(2) Dana Murphy</td>
<td>1.00 X X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(3) Donna Nelson</td>
<td>1.00 X X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(4) Patrick Lyons</td>
<td>1.00 X X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(5) Steve Stoll</td>
<td>1.00 X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(6) Olan Reeves</td>
<td>1.00 X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(7) Mike Siedschlag</td>
<td>1.00 X 0. 0. 0.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Part VII: Officers, Directors, Trustees, Key Employees, and Highest Compensated Employees

<table>
<thead>
<tr>
<th>(A) Name and title</th>
<th>(B) Average hours per week</th>
<th>(C) Position</th>
<th>(D) Reportable compensation from the organization (W-2/1099-MISC)</th>
<th>(E) Reportable compensation from related organizations (W-2/1099-MISC)</th>
<th>(F) Estimated amount of other compensation from the organization and related organizations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Individual trustee or director</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Institutional trustee</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Officer</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Highest compensated employee</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Key employee</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1b Sub-total ➤ 0. 0. 0.

c Total from continuation sheets to Part VII, Section A ➤ 0. 0. 0.
d Total (add lines 1b and 1c) ➤ 0. 0. 0.

2 Total number of individuals (including but not limited to those listed above) who received more than $100,000 of reportable compensation from the organization ➤ 0

3 Did the organization list any former officer, director, or trustee, key employee, or highest compensated employee on line 1a? If "Yes," complete Schedule J for such individual ➤ 3 Yes 4 No

4 For any individual listed on line 1a, is the sum of reportable compensation and other compensation from the organization and related organizations greater than $150,000? If "Yes," complete Schedule J for such individual ➤ 4 Yes 5 No

5 Did any person listed on line 1a receive or accrue compensation from any unrelated organization or individual for services rendered to the organization? If "Yes," complete Schedule J for such person ➤ 5 Yes 6 No

### Section B. Independent Contractors

1 Complete this table for your five highest compensated independent contractors that received more than $100,000 of compensation from the organization. Report compensation for the calendar year ending with or within the organization’s tax year.

<table>
<thead>
<tr>
<th>(A) Name and business address</th>
<th>(B) Description of services</th>
<th>(C) Compensation</th>
</tr>
</thead>
<tbody>
<tr>
<td>NONE</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2 Total number of independent contractors (including but not limited to those listed above) who received more than $100,000 of compensation from the organization ➤ 0
### Statement of Revenue

**Check if Schedule O contains a response or note to any line in this Part VIII**

<table>
<thead>
<tr>
<th>Contributions, Gifts, Grants and Other Similar Amounts</th>
<th>(A) Total revenue</th>
<th>(B) Related or exempt function revenue</th>
<th>(C) Unrelated business revenue</th>
<th>(D) Revenue excluded from tax under sections 512 - 514</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 a Federated campaigns</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 b Membership dues</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 c Fundraising events</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 d Related organizations</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 e Government grants (contributions)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 f All other contributions, gifts, grants, and similar amounts not included above</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 g Noncash contributions included in lines 1a-1f $</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 h Total. Add lines 1a-1f</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Program Service Revenue</th>
<th>Business Code</th>
<th>(A) Total revenue</th>
<th>(B) Related or exempt function revenue</th>
<th>(C) Unrelated business revenue</th>
<th>(D) Revenue excluded from tax under sections 512 - 514</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 a Reimbursed Expenses</td>
<td>900099</td>
<td>225,758.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 b</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 c</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 d</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 e</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 f All other program service revenue</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 g Total. Add lines 2a-2f</td>
<td></td>
<td>225,758.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other Revenue</th>
<th>Business Code</th>
<th>(A) Total revenue</th>
<th>(B) Related or exempt function revenue</th>
<th>(C) Unrelated business revenue</th>
<th>(D) Revenue excluded from tax under sections 512 - 514</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 a Gross rents</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6 b Less: rental expenses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6 c Rental income or (loss)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6 d Net rental income or (loss)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 a Gross amount from sales of assets other than inventory</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 b Less: cost or other basis and sales expenses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 c Gain or (loss)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 d Net gain or (loss)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 a Gross income from fundraising events (not including $ of contributions reported on line 1c). See Part IV, line 18</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 b Less: direct expenses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 c Net income or (loss) from fundraising events</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 a Gross income from gaming activities. See Part IV, line 19</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 b Less: direct expenses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 c Net income or (loss) from gaming activities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 a Gross sales of inventory, less returns and allowances</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 b Less: cost of goods sold</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 c Net income or (loss) from sales of inventory</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 a All other revenue</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 b</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 c</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 d All other revenue</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 e Total. Add lines 11a-11d</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Miscellaneous Revenue</th>
<th>Business Code</th>
<th>(A) Total revenue</th>
<th>(B) Related or exempt function revenue</th>
<th>(C) Unrelated business revenue</th>
<th>(D) Revenue excluded from tax under sections 512 - 514</th>
</tr>
</thead>
<tbody>
<tr>
<td>12 Total revenue. See instructions.</td>
<td></td>
<td>225,758.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Note:**
- Contributions, Gifts, Grants, and Other Similar Amounts
- Program Service Revenue
- Other Revenue
- Miscellaneous Revenue
### Part IX Statement of Functional Expenses

Section 501(c)(3) and 501(c)(4) organizations must complete all columns. All other organizations must complete column (A).

Do not include amounts reported on lines 6b, 7b, 8b, 9b, and 10b of Part VIII.

<table>
<thead>
<tr>
<th></th>
<th>(A) Total expenses</th>
<th>(B) Program service expenses</th>
<th>(C) Management and general expenses</th>
<th>(D) Fundraising expenses</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Grants and other assistance to governments and organizations in the United States. See Part IV, line 21</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Grants and other assistance to individuals in the United States. See Part IV, line 22</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Grants and other assistance to governments, organizations, and individuals outside the United States. See Part IV, lines 15 and 16</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Benefits paid to or for members</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Compensation of current officers, directors, trustees, and key employees</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Compensation not included above, to disqualified persons (as defined under section 4958(f)(1)) and persons described in section 4958(c)(3)(B)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Other salaries and wages</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Pension plan accruals and contributions (include section 401(k) and 403(b) employer contributions)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Other employee benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Payroll taxes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Fees for services (non-employees):</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a</td>
<td>Management</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b</td>
<td>Legal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c</td>
<td>Accounting</td>
<td>2,120.</td>
<td>2,120.</td>
<td></td>
</tr>
<tr>
<td>d</td>
<td>Lobbying</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>e</td>
<td>Professional fundraising services. See Part IV, line 17</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>f</td>
<td>Investment management fees</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>g</td>
<td>Other. (If line 11g amount exceeds 10% of line 25, column (A) amount, list line 11g expenses on Sch O.)</td>
<td>34,898.</td>
<td>34,898.</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Advertising and promotion</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Office expenses</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Information technology</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Royalties</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Occupancy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Travel</td>
<td>165,413.</td>
<td>165,413.</td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Payments of travel or entertainment expenses for any federal, state, or local public officials</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>Conferences, conventions, and meetings</td>
<td>18,711.</td>
<td>18,711.</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>Interest</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>21</td>
<td>Payments to affiliates</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>Depreciation, depletion, and amortization</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>Insurance</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>24</td>
<td>Other expenses. Itemize expenses not covered above. (List miscellaneous expenses in line 24e. If line 24e amount exceeds 10% of line 25, column (A) amount, list line 24e expenses on Schedule O.)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>d</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>e</td>
<td>All other expenses</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>Total functional expenses. Add lines 1 through 24e</td>
<td>221,142.</td>
<td>221,142.</td>
<td>0.</td>
</tr>
</tbody>
</table>

**Note:** Check if Schedule O contains a response or note to any line in this Part IX. [X]

Joint costs. Complete this line only if the organization reported in column (B) joint costs from a combined educational campaign and fundraising solicitation.
## Balance Sheet

- **Part X**

  Check if Schedule O contains a response or note to any line in this Part X: [ ]

### Assets

<table>
<thead>
<tr>
<th></th>
<th>(A) Beginning of year</th>
<th>(B) End of year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Cash - non-interest-bearing</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Savings and temporary cash investments</td>
<td>2</td>
</tr>
<tr>
<td>3</td>
<td>Pledges and grants receivable, net</td>
<td>3</td>
</tr>
<tr>
<td>4</td>
<td>Accounts receivable, net</td>
<td>4</td>
</tr>
<tr>
<td>5</td>
<td>Loans and other receivables from current and former officers, directors, trustees, key employees, and highest compensated employees. Complete Part II of Schedule L</td>
<td>5</td>
</tr>
<tr>
<td>6</td>
<td>Loans and other receivables from other disqualified persons (as defined under section 4958(f)(1)), persons described in section 4958(c)(3)(B), and contributing employers and sponsoring organizations of section 501(c)(9) voluntary employees' beneficiary organizations (see instr). Complete Part II of Sch L</td>
<td>6</td>
</tr>
<tr>
<td>7</td>
<td>Notes and loans receivable, net</td>
<td>7</td>
</tr>
<tr>
<td>8</td>
<td>Inventories for sale or use</td>
<td>8</td>
</tr>
<tr>
<td>9</td>
<td>Prepaid expenses and deferred charges</td>
<td>9</td>
</tr>
<tr>
<td>10a</td>
<td>Land, buildings, and equipment: cost or other basis. Complete Part VI of Schedule D</td>
<td>10a</td>
</tr>
<tr>
<td>10b</td>
<td>Less: accumulated depreciation</td>
<td>10b</td>
</tr>
<tr>
<td>11</td>
<td>Investments - publicly traded securities</td>
<td>11</td>
</tr>
<tr>
<td>12</td>
<td>Investments - other securities. See Part IV, line 11</td>
<td>12</td>
</tr>
<tr>
<td>13</td>
<td>Investments - program-related. See Part IV, line 11</td>
<td>13</td>
</tr>
<tr>
<td>14</td>
<td>Intangible assets</td>
<td>14</td>
</tr>
<tr>
<td>15</td>
<td>Other assets. See Part IV, line 11</td>
<td>15</td>
</tr>
<tr>
<td>16</td>
<td><strong>Total assets</strong>, Add lines 1 through 15 (must equal line 34)</td>
<td>0. 16 0.</td>
</tr>
</tbody>
</table>

### Liabilities

<table>
<thead>
<tr>
<th></th>
<th>(A) Beginning of year</th>
<th>(B) End of year</th>
</tr>
</thead>
<tbody>
<tr>
<td>17</td>
<td>Accounts payable and accrued expenses</td>
<td>17</td>
</tr>
<tr>
<td>18</td>
<td>Grants payable</td>
<td>18</td>
</tr>
<tr>
<td>19</td>
<td>Deferred revenue</td>
<td>19</td>
</tr>
<tr>
<td>20</td>
<td>Tax-exempt bond liabilities</td>
<td>20</td>
</tr>
<tr>
<td>21</td>
<td>Escrow or custodial account liability. Complete Part IV of Schedule D</td>
<td>21</td>
</tr>
<tr>
<td>22</td>
<td>Loans and other payables to current and former officers, directors, trustees, key employees, highest compensated employees, and disqualified persons. Complete Part II of Schedule L</td>
<td>22</td>
</tr>
<tr>
<td>23</td>
<td>Secured mortgages and notes payable to unrelated third parties</td>
<td>23</td>
</tr>
<tr>
<td>24</td>
<td>Unsecured notes and loans payable to unrelated third parties</td>
<td>24</td>
</tr>
<tr>
<td>25</td>
<td>Other liabilities (including federal income tax, payables to related third parties, and other liabilities not included on lines 17-24). Complete Part X of Schedule D</td>
<td>25</td>
</tr>
<tr>
<td>26</td>
<td><strong>Total liabilities</strong>, Add lines 17 through 26</td>
<td>5,707. 26 1,091.</td>
</tr>
</tbody>
</table>

### Organizations that follow SFAS 117 (ASC 958), check here [ ] and complete lines 27 through 29, and lines 33 and 34.

<table>
<thead>
<tr>
<th></th>
<th>(A) Beginning of year</th>
<th>(B) End of year</th>
</tr>
</thead>
<tbody>
<tr>
<td>27</td>
<td>Unrestricted net assets</td>
<td>-5,707. 27 -1,091.</td>
</tr>
<tr>
<td>28</td>
<td>Temporarily restricted net assets</td>
<td>28</td>
</tr>
<tr>
<td>29</td>
<td>Permanently restricted net assets</td>
<td>29</td>
</tr>
</tbody>
</table>

### Organizations that do not follow SFAS 117 (ASC 958), check here [ ] and complete lines 30 through 34.

<table>
<thead>
<tr>
<th></th>
<th>(A) Beginning of year</th>
<th>(B) End of year</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>Capital stock or trust principal, or current funds</td>
<td>30</td>
</tr>
<tr>
<td>31</td>
<td>Paid-in or capital surplus, or land, building, or equipment fund</td>
<td>31</td>
</tr>
<tr>
<td>32</td>
<td>Retained earnings, endowment, accumulated income, or other funds</td>
<td>32</td>
</tr>
<tr>
<td>33</td>
<td>Total net assets or fund balances</td>
<td>-5,707. 33 -1,091.</td>
</tr>
<tr>
<td>34</td>
<td>Total liabilities and net assets/fund balances</td>
<td>0. 34 0.</td>
</tr>
</tbody>
</table>
### Part XI Reconciliation of Net Assets

Check if Schedule O contains a response or note to any line in this Part XI

<table>
<thead>
<tr>
<th>Line</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total revenue (must equal Part VIII, column (A), line 12)</td>
</tr>
<tr>
<td>2</td>
<td>Total expenses (must equal Part IX, column (A), line 25)</td>
</tr>
<tr>
<td>3</td>
<td>Revenue less expenses. Subtract line 2 from line 1</td>
</tr>
<tr>
<td>4</td>
<td>Net assets or fund balances at beginning of year (must equal Part X, line 33, column (A))</td>
</tr>
<tr>
<td>5</td>
<td>Net unrealized gains (losses) on investments</td>
</tr>
<tr>
<td>6</td>
<td>Donated services and use of facilities</td>
</tr>
<tr>
<td>7</td>
<td>Investment expenses</td>
</tr>
<tr>
<td>8</td>
<td>Prior period adjustments</td>
</tr>
<tr>
<td>9</td>
<td>Other changes in net assets or fund balances (explain in Schedule O)</td>
</tr>
<tr>
<td>10</td>
<td>Net assets or fund balances at end of year. Combine lines 3 through 9 (must equal Part X, line 33, column (B))</td>
</tr>
</tbody>
</table>

### Part XII Financial Statements and Reporting

Check if Schedule O contains a response or note to any line in this Part XII

<table>
<thead>
<tr>
<th>Line</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Accounting method used to prepare the Form 990: Cash ☑ Accrual ☐ Other ☐</td>
</tr>
<tr>
<td>2a</td>
<td>Were the organization’s financial statements compiled or reviewed by an independent accountant? Yes ☐ No ☑</td>
</tr>
<tr>
<td>2b</td>
<td>Were the organization’s financial statements audited by an independent accountant? Yes ☑ No ☐</td>
</tr>
<tr>
<td>3a</td>
<td>As a result of a federal award, was the organization required to undergo an audit or audits as set forth in the Single Audit Act and OMB Circular A-133? Yes ☐ No ☑</td>
</tr>
<tr>
<td>3b</td>
<td>If “Yes,” did the organization undergo the required audit or audits? If the organization did not undergo the required audit or audits, explain why in Schedule O and describe any steps taken to undergo such audits Yes ☐ No ☑</td>
</tr>
</tbody>
</table>
**Part I: Organizations Maintaining Donor Advised Funds or Other Similar Funds or Accounts**

Complete if the organization answered "Yes" to Form 990, Part IV, line 6.

<table>
<thead>
<tr>
<th></th>
<th>(a) Donor advised funds</th>
<th>(b) Funds and other accounts</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total number at end of year</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Aggregate contributions to (during year)</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Aggregate grants from (during year)</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Aggregate value at end of year</td>
<td></td>
</tr>
</tbody>
</table>

5. Did the organization inform all donors and donor advisors in writing that the assets held in donor advised funds are the organization's property, subject to the organization's exclusive legal control? [ ] Yes [ ] No

6. Did the organization inform all grantees, donors, and donor advisors in writing that grant funds can be used only for charitable purposes and not for the benefit of the donor or donor advisor, or for any other purpose conferring impermissible private benefit? [ ] Yes [ ] No

**Part II: Conservation Easements**

Complete if the organization answered "Yes" to Form 990, Part IV, line 7.

1. Purpose(s) of conservation easements held by the organization (check all that apply):
   - Preservation of land for public use (e.g., recreation or education)
   - Preservation of an historically important land area
   - Protection of natural habitat
   - Preservation of a certified historic structure
   - Preservation of open space

2. Complete lines 2a through 2d if the organization held a qualified conservation contribution in the form of a conservation easement on the last day of the tax year.

   a. Total number of conservation easements
   b. Total acreage restricted by conservation easements
   c. Number of conservation easements on a certified historic structure included in (a)
   d. Number of conservation easements included in (c) acquired after 8/17/06, and not on a historic structure listed in the National Register

3. Number of conservation easements modified, transferred, released, extinguished, or terminated by the organization during the tax year

4. Number of states where property subject to conservation easement is located

5. Does the organization have a written policy regarding the periodic monitoring, inspection, handling of violations, and enforcement of the conservation easements it holds? [ ] Yes [ ] No

6. Staff and volunteer hours devoted to monitoring, inspecting, and enforcing conservation easements during the year

7. Amount of expenses incurred in monitoring, inspecting, and enforcing conservation easements during the year

8. Does each conservation easement reported on line 2(d) above satisfy the requirements of section 170(h)(4)(B)(i) and section 170(h)(4)(B)(ii)? [ ] Yes [ ] No

9. In Part XIII, describe how the organization reports conservation easements in its revenue and expense statement, and balance sheet, and include, if applicable, the text of the footnote to the organization's financial statements that describes the organization's accounting for conservation easements.

**Part III: Organizations Maintaining Collections of Art, Historical Treasures, or Other Similar Assets**

Complete if the organization answered "Yes" to Form 990, Part IV, line 8.

1a. If the organization elected, as permitted under SFAS 116 (ASC 958), not to report in its revenue statement and balance sheet works of art, historical treasures, or other similar assets held for public exhibition, education, or research in furtherance of public service, provide, in Part XIII, the text of the footnote to its financial statements that describes these items.

1b. If the organization elected, as permitted under SFAS 116 (ASC 958), to report in its revenue statement and balance sheet works of art, historical treasures, or other similar assets held for public exhibition, education, or research in furtherance of public service, provide, in Part XIII, the text of the footnote to its financial statements that describes these items:

   i. Revenues included in Form 990, Part VIII, line 1
   ii. Assets included in Form 990, Part X

2. If the organization received or held works of art, historical treasures, or other similar assets for financial gain, provide the following amounts required to be reported under SFAS 116 (ASC 958) relating to these items:

   a. Revenues included in Form 990, Part VIII, line 1
   b. Assets included in Form 990, Part X
### Part III Organizations Maintaining Collections of Art, Historical Treasures, or Other Similar Assets (continued)

3. Using the organization’s acquisition, accession, and other records, check any of the following that are a significant use of its collection items (check all that apply):
   - [ ] a. Public exhibition
   - [ ] b. Scholarly research
   - [ ] c. Preservation for future generations
   - [ ] d. Loan or exchange programs
   - [ ] e. Other

4. Provide a description of the organization’s collections and explain how they further the organization’s exempt purpose in Part XIII.

5. During the year, did the organization solicit or receive donations of art, historical treasures, or other similar assets to be sold to raise funds rather than to be maintained as part of the organization’s collection?  
   - [ ] Yes  
   - [ ] No

### Part IV Escrow and Custodial Arrangements

1a. Is the organization an agent, trustee, custodian or other intermediary for contributions or other assets not included on Form 990, Part X?  
   - [ ] Yes  
   - [ ] No

   b. If “Yes,” explain the arrangement in Part XIII and complete the following table:

<table>
<thead>
<tr>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>1c</td>
</tr>
<tr>
<td>1d</td>
</tr>
<tr>
<td>1e</td>
</tr>
<tr>
<td>1f</td>
</tr>
</tbody>
</table>

2a. Did the organization include an amount on Form 990, Part X, line 21?  
   - [ ] Yes  
   - [ ] No

   b. If “Yes,” explain the arrangement in Part XIII. Check here if the explanation has been provided in Part XIII.

### Part V Endowment Funds

1a. Beginning of year balance

<table>
<thead>
<tr>
<th>(a) Current year</th>
<th>(b) Prior year</th>
<th>(c) Two years back</th>
<th>(d) Three years back</th>
<th>(e) Four years back</th>
</tr>
</thead>
</table>

   b. Contributions

   c. Net investment earnings, gains, and losses

   d. Grants or scholarships

   e. Other expenditures for facilities and programs

   f. Administrative expenses

   g. End of year balance

2. Provide the estimated percentage of the current year end balance (line 1g, column (a)) held as:

   a. Board designated or quasi-endowment %

   b. Permanent endowment %

   c. Temporarily restricted endowment %

   The percentages in lines 2a, 2b, and 2c should equal 100%.

3a. Are there endowment funds not in the possession of the organization that are held and administered for the organization by:

   (i) unrelated organizations

   (ii) related organizations

   b. If “Yes” to 3a(ii), are the related organizations listed as required on Schedule R?

### Part VI Land, Buildings, and Equipment

Complete if the organization answered “Yes” to Form 990, Part IV, line 11a. See Form 990, Part X, line 10.

<table>
<thead>
<tr>
<th>Description of property</th>
<th>(a) Cost or other basis (investment)</th>
<th>(b) Cost or other basis (other)</th>
<th>(c) Accumulated depreciation</th>
<th>(d) Book value</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a. Land</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. Buildings</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c. Leasehold improvements</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>d. Equipment</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>e. Other</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total. Add lines 1a through 1e. (Column (d) must equal Form 990, Part X, column (B), line 10(c)).
### Part VII Investments - Other Securities

Complete if the organization answered "Yes" to Form 990, Part IV, line 11b. See Form 990, Part X, line 12.

<table>
<thead>
<tr>
<th>(a) Description of security or category  (including name of security)</th>
<th>(b) Book value</th>
<th>(c) Method of valuation: Cost or end-of-year market value</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Financial derivatives</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(2) Closely-held equity interests</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(3) Other</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(A)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(B)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(C)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(D)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(E)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(F)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(G)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(H)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total. (Col. (b) must equal Form 990, Part X, col. (B) line 12.)

### Part VIII Investments - Program Related

Complete if the organization answered "Yes" to Form 990, Part IV, line 11c. See Form 990, Part X, line 13.

<table>
<thead>
<tr>
<th>(a) Description of investment</th>
<th>(b) Book value</th>
<th>(c) Method of valuation: Cost or end-of-year market value</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(2)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(4)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(7)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(8)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(9)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total. (Col. (b) must equal Form 990, Part X, col. (B) line 13.)

### Part IX Other Assets

Complete if the organization answered "Yes" to Form 990, Part IV, line 11d. See Form 990, Part X, line 15.

<table>
<thead>
<tr>
<th>(a) Description</th>
<th>(b) Book value</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1)</td>
<td></td>
</tr>
<tr>
<td>(2)</td>
<td></td>
</tr>
<tr>
<td>(3)</td>
<td></td>
</tr>
<tr>
<td>(4)</td>
<td></td>
</tr>
<tr>
<td>(5)</td>
<td></td>
</tr>
<tr>
<td>(6)</td>
<td></td>
</tr>
<tr>
<td>(7)</td>
<td></td>
</tr>
<tr>
<td>(8)</td>
<td></td>
</tr>
<tr>
<td>(9)</td>
<td></td>
</tr>
</tbody>
</table>

Total. (Column (b) must equal Form 990, Part X, col. (B) line 15.)

### Part X Other Liabilities

Complete if the organization answered "Yes" to Form 990, Part IV, line 11e or 11f. See Form 990, Part X, line 25.

1. | (a) Description of liability | (b) Book value |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Federal income taxes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(2) Bank Overdraft</td>
<td>1,091.</td>
<td></td>
</tr>
<tr>
<td>(3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(4)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(7)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(8)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(9)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total. (Column (b) must equal Form 990, Part X, col. (B) line 25.) 1,091.

2. Liability for uncertain tax positions. In Part XIII, provide the text of the footnote to the organization's financial statements that reports the organization's liability for uncertain tax positions under FIN 48 (ASC 740). Check here if the text of the footnote has been provided in Part XIII.
### Part XI Reconciliation of Revenue per Audited Financial Statements With Revenue per Return

**Complete if the organization answered "Yes" to Form 990, Part IV, line 12a.**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total revenue, gains, and other support per audited financial statements</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Amounts included on line 1 but not on Form 990, Part VIII, line 12:</td>
<td></td>
</tr>
<tr>
<td>a</td>
<td>Net unrealized gains on investments</td>
<td>2a</td>
</tr>
<tr>
<td>b</td>
<td>Donated services and use of facilities</td>
<td>2b</td>
</tr>
<tr>
<td>c</td>
<td>Recoveries of prior year grants</td>
<td>2c</td>
</tr>
<tr>
<td>d</td>
<td>Other (Describe in Part XIII.)</td>
<td>2d</td>
</tr>
<tr>
<td>e</td>
<td>Add lines 2a through 2d</td>
<td>2e</td>
</tr>
<tr>
<td>3</td>
<td>Subtract line 2e from line 1</td>
<td>3</td>
</tr>
<tr>
<td>4</td>
<td>Amounts included on Form 990, Part VIII, line 12, but not on line 1:</td>
<td></td>
</tr>
<tr>
<td>a</td>
<td>Investment expenses not included on Form 990, Part VIII, line 7b</td>
<td>4a</td>
</tr>
<tr>
<td>b</td>
<td>Other (Describe in Part XIII.)</td>
<td>4b</td>
</tr>
<tr>
<td>c</td>
<td>Add lines 4a and 4b</td>
<td>4c</td>
</tr>
<tr>
<td>5</td>
<td>Total revenue. Add lines 3 and 4c. (<em>This must equal Form 990, Part I, line 12.</em>)</td>
<td>5</td>
</tr>
</tbody>
</table>

### Part XII Reconciliation of Expenses per Audited Financial Statements With Expenses per Return

**Complete if the organization answered "Yes" to Form 990, Part IV, line 12a.**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total expenses and losses per audited financial statements</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Amounts included on line 1 but not on Form 990, Part IX, line 25:</td>
<td></td>
</tr>
<tr>
<td>a</td>
<td>Donated services and use of facilities</td>
<td>2a</td>
</tr>
<tr>
<td>b</td>
<td>Prior year adjustments</td>
<td>2b</td>
</tr>
<tr>
<td>c</td>
<td>Other losses</td>
<td>2c</td>
</tr>
<tr>
<td>d</td>
<td>Other (Describe in Part XIII.)</td>
<td>2d</td>
</tr>
<tr>
<td>e</td>
<td>Add lines 2a through 2d</td>
<td>2e</td>
</tr>
<tr>
<td>3</td>
<td>Subtract line 2e from line 1</td>
<td>3</td>
</tr>
<tr>
<td>4</td>
<td>Amounts included on Form 990, Part IX, line 25, but not on line 1:</td>
<td></td>
</tr>
<tr>
<td>a</td>
<td>Investment expenses not included on Form 990, Part VIII, line 7b</td>
<td>4a</td>
</tr>
<tr>
<td>b</td>
<td>Other (Describe in Part XIII.)</td>
<td>4b</td>
</tr>
<tr>
<td>c</td>
<td>Add lines 4a and 4b</td>
<td>4c</td>
</tr>
<tr>
<td>5</td>
<td>Total expenses. Add lines 3 and 4c. (<em>This must equal Form 990, Part I, line 18.</em>)</td>
<td>5</td>
</tr>
</tbody>
</table>

### Part XIII Supplemental Information

Provide the descriptions required for Part II, lines 3, 5, and 9; Part III, lines 1a and 4; Part IV, lines 1b and 2b; Part V, line 4; Part X, line 2; Part XI, lines 2d and 4b; and Part XII, lines 2d and 4b. Also complete this part to provide any additional information.
Form 990, Part VI, Section B, line 11:

Explanation: A draft of the Form 990 is provided to the entire board for review and discussion before filing.

Form 990, Part VI, Section C, Line 19:

Explanation: Required documents are available upon request at the Organization's address listed on Page 1.

Form 990, Part IX, Line 11g, Other Fees:

Other Professional Services:

Program service expenses 34,898.

Management and general expenses 0.

Fundraising expenses 0.

Total expenses 34,898.

Total Other Fees on Form 990, Part IX, line 11g, Col A 34,898.
Report to the Regional State Committee
July 28, 2014

COST ALLOCATION WORKING GROUP (CAWG)

Meena Thomas
CAWG Chairman
CAWG REPORT TO RSC

TOPICS

I. Proposed Changes to Wind and Solar Accreditation (Separate Report)
II. Benefit Metrics Review
III. CAWG Comments on SPP Evaluation of Capacity Margin
IV. Integration of New Members into SPP
V. Potential Issues for Future RSC Consideration
I. Proposed Changes to Wind and Solar Accreditation

The Generation Working Group (GWG) has proposed changes to SPP Criteria 12.

SPP Criteria 12.1.5.3.g. outlines the methodology for the calculation of net capability for wind and solar facilities on a facility – specific basis.

These criteria revisions were first presented to CAWG in March and April.
I. Proposed Changes to Wind and Solar Accreditation

- CAWG considered the impact of the proposed criteria revisions on resource adequacy and transmission planning.

- CAWG’s conclusions were reported to the RSC at the April 2014 meeting.
I. Proposed Changes to Wind and Solar Accreditation

- At its April meeting, the Board remanded the criteria changes to MOPC for reconsideration by GWG in light of concerns expressed by stakeholders.

- On further consideration, GWG proposed changes to the criteria to allow use of lower capacity accreditation by load serving entities.
I. Proposed Changes to Wind and Solar Accreditation

- CAWG considered the impact of the additional criteria changes GWG proposed on resource adequacy and transmission planning.

- CAWG’s report will be presented following the presentation on the proposed changes to SPP wind accreditation under agenda item 5(c).
II. Benefit Metrics Review

SPP staff presented to CAWG the assessment of benefit metrics and alternative allocation methodologies for five metrics:

- Benefits of Mandated Reliability Projects
- Benefits from Meeting Public Policy Goals
- Mitigation of Transmission Outage Costs
- Increased Wheeling Through and Out Revenues
- Marginal Energy Losses Benefits
II. Benefit Metrics Review

- The Missouri CAWG member raised concerns about the use of the load ratio share approach for allocating benefits for mandated reliability projects and mitigation of transmission outage costs. The Kansas CAWG member shared this concern.

- The Nebraska CAWG member expressed strong objections to the use of the zonal allocation method based on the share of unmet renewable mandates or goals only in states driving the public policy projects, for purposes of allocating public policy benefits.
II. Benefit Metrics Review

- Questions were raised about SPP’s methodology for classifying projects as reliability, public policy, and economic projects as well as the calculation of benefits for projects that have multiple benefits.

- CAWG heard Brattle’s assessments, SPP staff recommendations, and ESWG’s decisions on the benefits metrics for the first time at its July meeting and decided not to take a position on the metrics at the meeting.
III. CAWG Comments on SPP Evaluation of Capacity Margin

- SPP staff surveyed stakeholders for information intended to help SPP in its evaluation of the existing capacity margin requirements.
- CAWG submitted comments on select questions and general comments on pertinent issues.
III. CAWG Comments on SPP Evaluation of Capacity Margin

- RSC and CAWG should have a significant role in the capacity margin evaluation process given that resource adequacy is listed as an area of responsibility in the RSC bylaws.

- It may be prudent for the capacity margin evaluation to include a discussion on the possibility of allowing states to set a separate capacity margin percentage, if they wish.
III. CAWG Comments on SPP Evaluation of Capacity Margin

- In recognition of the possible impact of wind and solar accreditation changes on capacity margins, the issue of changes in wind/solar accreditation along with accreditation evaluations for other types of resources should be included in the scope of the evaluation as necessary.
III. CAWG Comments on SPP Evaluation of Capacity Margin

- Based on CAWG’s understanding that SPP is not considering a MISO or PJM style capacity market during this evaluation, CAWG expressed support for SPP’s approach.

- CAWG suggested the development of a white paper on the issue during the evaluation process.
IV. Integration of New Members into SPP

- During its deliberations on the cost allocation issues relating to the IS membership, CAWG members expressed concerns about the process that was followed as SPP and IS worked towards SPP membership of IS entities.
- CAWG members suggested that SPP adopt a more collaborative stakeholder process in the future when evaluating the integration of new members into SPP.
IV. Integration of New Members into SPP

- The RSC could be kept informed early in the process on the specifics of the proposals being considered in the negotiations with new entities, especially with respect to issues that fall under the purview of the RSC.

- This topic will be taken up under agenda item 5 (b).
V. Potential Issues for Future RSC Consideration

- CAWG members continue to monitor pertinent Working Group/Task Force activity in anticipation of future RSC actions.

- Of relevance are three major issues that will likely come up for RSC consideration within the next year:
V. Potential Issues for Future RSC Consideration

1. Benefits Metrics Review for RCAR II Analysis

2. Tariff revisions including cost allocation for Non-Order 1000 Seams Projects

3. Capacity Margin Requirements
Questions?

Submitted by: Meena Thomas
CAWG Chairman
July 28, 2014
## Proposed Charter Revision and Appointments

<table>
<thead>
<tr>
<th>Original RARTF Membership</th>
<th>Entity</th>
<th>Proposed New Membership</th>
<th>Entity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Michael Siedschlag (Chair)</td>
<td>NPRB</td>
<td>Olan Reeves (Chair)</td>
<td>APSC</td>
</tr>
<tr>
<td>Richard Ross (Vice-Chair)</td>
<td>AEP</td>
<td>Richard Ross (Vice-Chair)</td>
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<td>Olan Reeve</td>
<td>APSC</td>
<td>Steve Stoll</td>
<td>MoPSC</td>
</tr>
<tr>
<td>Tom Wright</td>
<td>KCC</td>
<td>Shari Feist Albrecht</td>
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<tr>
<td>Barry Warren</td>
<td>EDE</td>
<td>Steve Lichter</td>
<td>NPRB</td>
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<tr>
<td>Phil Crissup</td>
<td>OG&amp;E</td>
<td>Barry Warren</td>
<td>EDE</td>
</tr>
<tr>
<td>Harry Skilton</td>
<td>SPP BOD</td>
<td>Phil Crissup</td>
<td>OG&amp;E</td>
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<tr>
<td></td>
<td></td>
<td>Bill Grant</td>
<td>SPS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Harry Skilton</td>
<td>SPP BOD</td>
</tr>
</tbody>
</table>

*Proposed Changes are in Red*
**PURPOSE**

The Regional Allocation Review Task Force (RARTF) is responsible for defining “the analytical methods to be used” to “review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology.” The analytical method shall be designed to “determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region.” (Reference the Southwest Power Pool Open Access Transmission Tariff, Attachment J, Section III.D.) The analytical methodology will form a basis for the RSC to consider improvements, if any, to the long term cumulative equity of cost allocation and benefits for members resulting from SPP’s Integrated Transmission Planning process.

After establishing proposed “analytical methods to be used” to “review the reasonableness” of the regional and zonal allocation methodology, the RARTF shall prepare and present a report to the Market and Operations Policy Committee (MOPC) and the Regional State Committee (RSC) for approval. As stated in Attachment J to the SPP Tariff, SPP Staff will use the approved “analytical methods” to perform a review to “determine the cost allocation impacts of the Base Plan Upgrades with NTCs issued after June 19, 2010 to each pricing zone within the SPP Region.” Further, after SPP Staff completes its determination of the cost allocation impacts and possible solutions, Staff shall publish the results on the SPP website and present the results to the Regional Tariff Working Group (RTWG), Cost Allocation Working Group (CAWG), MOPC, the RSC, and the SPP Board of Directors per Section III.D.3 of Attachment J to the SPP Tariff.

**REPRESENTATION**

The RARTF will be a seven-nine (79) member joint task force made up of representatives of the RSC and SPP Members and a member of the Board of Directors. Three-four (34) task force members shall be composed of members of the RSC and three-four (34) members shall be SPP Members. A RSC member shall serve as Chair and a SPP member shall serve as Vice-Chair. The RSC and SPP Members representatives shall be appointed by the RSC President and MOPC Chairman and shall represent diverse members. Selection of such representatives shall consider, among other factors, geography, member type and expertise. The seventh member of the RARTF will be appointed by the SPP Board of Directors.

Members of the RARTF shall have experience and knowledge in one or more of the following areas:

- Economics, economic modeling, modeling for simulation analysis, and/or cost of service determinations
- SPP Transmission Tariffs and Rates
- Cost allocation in general, and SPP regional cost allocation practices in particular
- Retail cost allocation recovery and rate payer impact for SPP members
- Quantitative methods for decision analysis

**DURATION**
The RARTF will be a temporary task force. It is anticipated that its initial work will be completed by December 20, 2011, though-and the task force will continue its work until it is completed and as needed for RCAR reviews.

Meetings
All meetings of the RARTF, whether in person or telephonic, shall be open to participation by all stakeholders in SPP, and advance notice of such meetings shall be provided via the SPP website. Meeting materials including discussion topics, handouts and other meeting information will be posted via the SPP website as early as possible. The task force may engage other SPP stakeholders and consultants (as deemed necessary by the RARTF) to participate in discussions related to particular topics, though this will not make such stakeholders voting members of the task force. Stakeholders with proposals or alternative ideas shall be allowed to present their proposals or alternatives to the task force.

SPP Staff Support
The SPP Staff shall have at least one individual in attendance for all meetings of the RARTF to serve as a Staff Liaison and Secretary for the task force who will be responsible for keeping and issuing minutes for the RARTF meetings. Other members of the SPP Staff may be requested to assist in particular endeavors of the task force.

REPORTING
The RARTF will provide status reports to the RSC and the MOPC at least on a quarterly basis at the regularly scheduled meetings. The task force may make additional status reports to the CAWG, RSC and MOPC as it deems necessary.

The RARTF will make final recommendations to the MOPC and the RSC regarding the analytical methods to be used to review the reasonableness of the regional allocation methodology for the approval of both the MOPC and RSC. In addition to developing the analytical methods to be used in the analysis, the RARTF will provide SPP Staff guidance as to the Task Force’s expectation for the threshold for an unreasonable impact or cumulative inequity. The RARTF shall prepare and issue the report by December 20, 2011.

COST ALLOCATION IMPACT ASSESSMENT BASED ON APPROVED ANALYTICAL METHODS
Upon the approval of the RARTF’s report by the MOPC and RSC, SPP staff, “in collaboration with the RSC” shall determine the cost allocation impacts and possible solutions utilizing the RARTF approved analytical methods. SPP Staff shall report the cost allocation impacts and possible solutions by July 1, 2013. Proposed solutions may include, but are not limited to, adjustments to the Highway/Byway, transfer payments, approval of projects in specific zones, etc.

After SPP Staff completes its determination of the cost allocation impacts and possible solutions, Staff shall publish the results on the SPP website and present the results to the RTWG, CAWG, MOPC the RSC, and the Board of Directors per Section III.D.3 of Attachment J to the SPP Tariff.

After receiving the Staff report on cost allocation impacts and possible solutions the RSC will consider issuance of recommendations. Upon any recommendation from the RSC, the necessary filing with the FERC will be made by SPP in accordance with SPP Bylaws and Section III.D.5 of Attachment J to the SPP Tariff.
KEY DELIVERABLES OF THE TASK FORCE

The RARTF scope of work and key deliverables include the following:

1. Development of and recommendation for a methodology to be used to determine the current and cumulative long-term equity/inequity of the currently effective cost allocation for transmission construction/upgrade projects on each SPP Pricing Zone and/or Balancing Authority.

2. Develop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.

3. Develop a list of possible solutions for SPP staff to study for any unreasonable impacts or cumulative inequities on an SPP Pricing Zone or Balancing Authority.

4. Final report containing such recommendations to be prepared and issued by December 20, 2011.
Criteria Changes
Wind Accreditation by Generation
Working Group

RSC/BOD July 2014

Mitchell Williams - WFEC
GWG Chair
CRR-012 Wind and Solar Capacity Accreditation

• April SPP Board Meeting Remanded Generation Working Group (GWG) to reconsider CRR-012:
  – The amount of increased wind accreditation would increase from 1.4% to 10% on average. Consider a confidence factor that would result in a lower capacity accreditation.
  – Add language to allow a load serving member to select a lower capacity accreditation if it desires to do so.
  – Some SPP member provided information for 2013 peak showing only 5% wind during peak periods. (Previous years’ generation during the peak load hour was 5.2, 16, and 22%).
CRR-012 Wind and Solar Capacity Accreditation

- May 16 - GWG held its monthly WebEx:
  - Added language stating “If a member’s desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:”
  - GWG chose to re-affirm CRR-012 (wind and Solar Capacity accreditation) with a vote of 6 to 2.
    - Two “no” votes wanted a lower accreditation proposing a Confidence Factor of 75%, instead of 60%.
CRR-012 Wind and Solar Capacity Accreditation

- June 19: Face to Face meeting with Operation Reliability WG (ORWG):
  - Presented results from GWG recommending 60% Confidence Factor during top 3% load hours of the peak month with Member option for lower accreditation.
  - Presentation by Dogwood Energy demonstrating about 5% wind generation during 2013 summer peak periods, peak periods occurred during a few peak days and during late afternoon hours. Report looked at only one year.
  - ORWG voted to approve the GWG CRR-012 as presented with a 6-5 vote.

- July 2: Presented to Transmission Working Group TWG
  - Previously Approved, and not considered for a vote due to time constraints.
CRR-012 Wind and Solar Capacity Accreditation

- June 20: Conference Call/WebEx with Cost Allocation Working Group:
  - Presented results from GWG recommending 60% Confidence Factor during top 3% load hours of the peak month with Member option for lower accreditation, and result of ORWG Vote.
  - CAWG Re-affirmed its previous three items:
    1. SPP to review Capacity Margin requirements.
    2. Will increased wind and solar accreditation increase the need for transmission? We think this is not directly related.
    3. GWG plans to prepare a report each year concerning wind and solar generation during peak period.
CRR-012 Wind and Solar Capacity Accreditation

- **July 16: MOPC Meeting:**
  - Recommended 60% Confidence Factor during top 3% load hours of the peak month with Member option for lower accreditation.
  - MOPC approved the recommendation with a 84.1% vote.
  - Disenting parties argued that the resulting capacity values will rely on wind too much for capacity.
CRR-012 Wind and Solar Capacity Accreditation

- Q2: Will increased wind accreditation drive additional Transmission Construction? Not Directly.

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<tr>
<th>MWs</th>
<th>Resources</th>
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</thead>
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<tr>
<td>Designated Network Resource</td>
<td>6100</td>
</tr>
<tr>
<td>Total Wind Resources</td>
<td>8607</td>
</tr>
</tbody>
</table>

(From State of Market report 3/14)

The majority of Wind Projects are DNR, and most have transmission service for the nameplate output of wind resource. Resources must go through the Aggregate Study Process to become DNR, and Transmission upgrades may be directed assigned to the transmission customer.
# Confidence Factor

<table>
<thead>
<tr>
<th>Confidence Factor</th>
<th>Estimate % of Name Plate</th>
<th>% of SPP Peak load (Capacity Margin)</th>
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<tbody>
<tr>
<td>50 – ELCC Method</td>
<td>14.4</td>
<td></td>
</tr>
<tr>
<td>60 – GWG Proposed</td>
<td>10.1</td>
<td>1.79%</td>
</tr>
<tr>
<td>70</td>
<td>6.6</td>
<td></td>
</tr>
<tr>
<td>75 – “No” Votes</td>
<td>4.5</td>
<td>0.89 %</td>
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<tr>
<td>85</td>
<td>1.9</td>
<td></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Wind % of Name Plate during Peak Hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>22.0</td>
</tr>
<tr>
<td>2011</td>
<td>16.1</td>
</tr>
<tr>
<td>2012</td>
<td>5.2</td>
</tr>
<tr>
<td>2013</td>
<td>5.0</td>
</tr>
</tbody>
</table>
Solar Capacity

Amber Metzker
Manager, Market Operations
Typical Solar Graph
# Data Sample – Top 25 Load hours for 2012 & 2013 Actuals

<table>
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<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min</td>
<td>22</td>
<td>27</td>
<td>24.5</td>
</tr>
<tr>
<td>Max</td>
<td>43</td>
<td>45</td>
<td>42.5</td>
</tr>
<tr>
<td>Average</td>
<td>37.680</td>
<td>37.600</td>
<td>37.640</td>
</tr>
<tr>
<td>Sdev</td>
<td>4.776</td>
<td>5.470</td>
<td>5.082</td>
</tr>
</tbody>
</table>

99% confidence interval: $35.71467 \leq x \leq 39.56533$

95% confidence interval: $36.19628 \leq x \leq 39.08372$

90% confidence interval: $36.43553 \leq x \leq 38.84447$

<table>
<thead>
<tr>
<th></th>
<th>Top 10 %</th>
<th>Top 3 %</th>
<th>Delta to %</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>AC MW</td>
<td>85th Percentile</td>
<td>60th Percentile</td>
<td>Current</td>
</tr>
<tr>
<td>MW</td>
<td>50</td>
<td>0</td>
<td>33</td>
<td>33</td>
</tr>
</tbody>
</table>
Sample Statistics for 2011, 2012, & 2013 Top 3% Loads

2010, 2012-2013 Top 3% of Hours
Average 25
Stddev 14.6
N 788

99% confidence interval: $23.65705 \leq x \leq 26.34295$
95% confidence interval: $23.97905 \leq x \leq 26.02095$
90% confidence interval: $24.14350 \leq x \leq 25.85650$
Summary of Different Methods

ELCC Calculations for Solar
2009 = 44% (based off forecasted data)
2012 = 66% (based off actual data)

July-August Analysis

<table>
<thead>
<tr>
<th>Solar Accreditation, Jul-Aug, 2008-2010,2012</th>
<th>Top 10 %</th>
<th>Top 3 %</th>
<th>Delta to %</th>
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<td>Current</td>
</tr>
<tr>
<td>MW</td>
<td>50</td>
<td>0</td>
<td>33</td>
</tr>
</tbody>
</table>

Full Year Analysis

SunEdison
2010, 2012, 2013 Data
85%, top 10% 0 50 0%
60%, top 3% 25 50 50%

July-August Analysis

<table>
<thead>
<tr>
<th>Solar Accreditation, Jul-Aug, 2008-2010,2012</th>
<th>Top 10 %</th>
<th>Top 3 %</th>
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</tr>
<tr>
<td>MW</td>
<td>50</td>
<td>0</td>
<td>33</td>
</tr>
</tbody>
</table>
Summary -

• Recommend Approval of CRR-012, Criteria Recommendation for Capacity Accreditation of Wind and Solar Resources.
  – On average wind projects will increase accreditation from 1.4% to about 10% of nameplate. Some more and some less depending on their demonstrated performance.
  – Solar projects will benefit with as much as 66% accredited capacity during summer months. Old method resulted in zero accreditation due to the number of hours included, (10% versus 3%)
Mitchell L Williams - WFEC
405-247-434
m_williams@wfec.com
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Background

- The Generation Working Group (GWG) has proposed changes to the section in Criteria 12. It delineates the methodology used to measure the performance of wind and solar facilities during peak hours on a facility-specific basis.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

- The proposed criteria changes would:
  - reduce the data requirement from the top 10% load hours to the top 3% load hours during the peak month
  - reduce the confidence factor from 85% confidence to 60% confidence that wind would be producing at or above a certain output
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

- These proposed changes to Criteria 12 were first presented to CAWG at its March and April meetings.

- CAWG determined that the RSC bylaws do not require it to approve the proposed changes in the SPP criteria.

- However, CAWG assessed whether the criteria changes could have an impact on areas that fall under the purview of the RSC’s authority, namely, resource adequacy and cost allocation for transmission planning.
Proposed Changes to SPP Wind Accreditation Impact on Resource Adequacy

The increase in wind accreditation as a result of the criteria change would allow Load Serving Members to rely more on wind to meet their capacity margin requirements of 12% under SPP criteria 2.1.9.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation Impact on Resource Adequacy

- However, over time, the accreditation change could drive the decisions regarding the installation of other generation facilities and possibly reduce the peaking capacity in the system.

- On a system wide basis, over time, the change could impact reliability and may necessitate an evaluation of whether the capacity margin of 12% is sufficient to support a reliable system.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Impact on Resource Adequacy

- Integrated Resource Plans (IRP): The increase in accredited capacity could delay the construction of new generation. This is because load serving entities can rely on the increase in accredited wind capacity to meet the capacity needs and requirements in their IRPs.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Impact on Transmission Planning:

➢ The change in wind accreditation could have implications for cost allocation if the increase in accredited wind capacity caused changes in the need for transmission upgrades.

➢ It is CAWG’s understanding that the increase in wind accreditation is not expected to have an impact on transmission planning in general.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

- At its April 17th meeting, CAWG reached three conclusions regarding the impact of the proposed changes on resource adequacy and transmission planning. These conclusions are listed later in this presentation.

- CAWG’s conclusions were presented in its report at the April 2014 RSC meeting.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

- RSC did not take action on the proposed criteria changes at its April RSC meeting.
- At its April meeting, the Board remanded the proposed criteria changes to MOPC for reconsideration by the GWG in light of the concerns raised by stakeholders.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

GWG’s proposed cap on net capability:

- Upon further consideration, the GWG added language to the criteria that would allow a load serving entity (LSE) to use a more restrictive methodology and thereby select a lower capacity accreditation for wind and solar if it desires to do so.

- As a result, the net capability determined by an LSE using GWG’s proposed methodology to its wind or solar facility would serve as the cap for that LSE.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

GWG’s proposed cap on net capability

- With respect to the proposed language establishing the cap, CAWG members did not express concerns with the proposed cap.

- CAWG members from states with IRPs noted that utilities may have to explain their use of net capability for wind and solar accreditation at or below the cap to meet their capacity margin requirements in state planning processes and rate case proceedings.
Proposed Changes to SPP Wind Accreditation

Empire District’s proposed alternative cap:

- CAWG also considered an alternative cap proposed by Empire District that would limit the maximum wind or solar accreditation a load serving member could use for capacity margin calculations.

- The wind or solar accreditation would be limited to the lesser of X% (e.g. 10%) or the net capability for a facility that would result from the application of GWG’s proposed methodology.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Empire District’s proposed alternative cap:

- CAWG members expressed concerns about the lack of flexibility for load serving members that could result from the adoption of the cap and the need for additional data evaluation before establishing a cap as suggested by Empire District.

- However, CAWG did not take a position on Empire District’s proposal.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

Action by Working Groups and Committees

- Prior to the remand, the Transmission Working Group (TWG) approved the proposed criteria change.
- Before the remand, the Operations Reliability Working Group (ORWG) expressed concern about the potential impact of the change on system reliability and commented on the need for SPP to monitor the actual wind output at peak hours. After the remand, the ORWG approved the criteria with a 6-5 vote.
- MOPC approved the proposed criteria change by a majority vote before the remand in April and after the remand in July.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Conclusions after Remand

After considering GWG’s proposed criteria revisions, CAWG reaffirmed its prior conclusions reached in April. In the event the Board approves the proposed criteria revisions:

1) SPP should evaluate the current SPP capacity margin to ensure that it is adequate to meet the needs for a reliable system.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Conclusions after Remand

2) SPP should inform RSC and CAWG, on an ongoing basis, if the increase in accredited wind capacity, as a result of the criteria change, is partly or wholly responsible for causing any changes in the need for transmission upgrades in the SPP footprint.
CAWG REPORT TO RSC

Proposed Changes to SPP Wind Accreditation

CAWG Conclusions after Remand

3) RSC and CAWG should be presented with the GWG annual report regarding the performance of wind and solar facilities. The report should include a yearly comparison of wind and solar output during peak periods. This would allow the criteria to be reevaluated, if necessary, based on information on actual wind and solar output at peak periods.
Questions?

Submitted by: Meena Thomas
CAWG Chairman
July 28, 2014
Capacity Margin Requirement Update

RSC
July 28, 2014
Background

• Need for an update of SPP’s Capacity Margin requirements
  – SPP is the Consolidated Balancing Authority
  – Issues raised with existing SPP Criteria language
  – Expanding footprint and operational changes need to be evaluated
  – Evaluate appropriate Capacity Margin requirement determination

• Recent Activity
  – Need first introduced at April MOPC meeting
  – Questions sent out to MOPC for feedback
  – Responses and feedback were compiled and a second round of questions were sent to MOPC for additional feedback
  – MOPC formed the Capacity Margin Task Force at their July meeting
Resource Adequacy - Capacity Margin vs. Reserve Margin

- SPP expresses its requirements in terms of Capacity Margin while NERC and other regions typically express their requirements in terms of Reserve Margin

  - **Capacity Margin** % = \( \frac{\text{Net Total Capacity} - \text{Net Total Load}}{\text{Net Total Capacity}} \times 100 \)

  - **Reserve Margin** % = \( \frac{\text{Net Total Capacity} - \text{Net Total Load}}{\text{Net Total Load}} \times 100 \)

- SPP’s 12% Capacity Margin requirement equals 13.6% Reserve Margin

- Example:

  \[
  \text{Capacity Margin} \% = \frac{54,545 - 48,000}{54,545} \times 100 = 12.0\%
  \]

  \[
  \text{Reserve Margin} \% = \frac{54,545 - 48,000}{48,000} \times 100 = 13.6\%
  \]
SPP’s 10 year Reserve Margin Outlook*

*From 2014 NERC LTRA

*Existing Certain + Net Firm Transfers
*Includes new generation (firm)
*13.6% Target Reserve Margin

SPP Region

*From 2014 NERC LTRA
NERC’s Projected Reserve Margins*

*From 2013 NERC LTRA Report
Reserve Margin Targets*

NERC Assessment Areas

*From 2013 NERC LTRA Report
Stakeholder Respondents to Survey

American Electric Power*
Calpine
City of Independence, Missouri
City Utilities of Springfield*
Coffeyville
Cost Allocation Working Group
Dogwood Energy
East Texas Electric Cooperative
Generation Working Group
Golden Spread Electric Cooperative
Grand River Dam Authority
Kansas City Power & Light Company*
Kansas Power Pool

Lincoln Electric System
Midwest Energy
Nebraska Public Power District
Omaha Public Power District*
Oklahoma Gas and Electric Company
Oklahoma Municipal Power Authority
Quanta
Southwest Power Pool
Sunflower Electric Power Corporation
Tex-La Cooperative of Texas
Westar Energy
Western Farmers Electric Cooperative
Xcel/Southwestern Public Service Co.*

*Responded to both sets of questions
Responses to MOPC questions*

1. Should Capacity Margin requirement apply to all load serving entities operating within the electrical boundaries of the SPP Balancing Authority?
   [20 responses] 100% Yes, 0% No

2. Should we use Coincident Peak loads to calculate each entity's Capacity Margin?
   [20 responses] 75% Yes, 20% No, 5% Undecided

3. Penalties for non-compliance?
   [18 responses] 67% Yes, 11% No, 22% Undecided

4. Any issues with IRP state laws?
   [17 responses] 65% No, 24% Yes, 11% Undecided

5. Should fuel supply and transportation firmness be documented?
   [19 responses] 42% Yes, 16% No, 32% Undecided, 10% Unrelated

6. Can anything other than firm transmission be used to demonstrate deliverability?
   [18 responses] 33% Yes, 22% No, 45% Undecided

7. Which SPP Working Group should own the Capacity Margin process?
   [18 responses] 31% GWG, 31% ORWG, 10% TWG, 28% Other

8. Do plants need to be available more than a certain percentage of the year?
   [18 responses] 28% Yes, 16% No, 56% Undecided

9. How do we factor in environmental limits?
   [19 responses] (Multiple types of responses)

*Additional questions moved to the Appendix due to small sample set
Capacity Margin Task Force

• 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 changing footprint and operations

• Representation
  – SPP Member companies can nominate one person from their company
  – CAWG/RSC representation encouraged
  – Variety of diverse experience desired, e.g. operational, planning, energy marketing, regulatory, etc.

• Target Completion
  – July 2015

• August 1 is deadline for nomination of participants
APPENDIX
Responses to MOPC questions

- **Should Capacity Margin requirement apply to all load serving entities operating within the electrical boundaries of the SPP Balancing Authority?**

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<th>Yes</th>
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<th>Unrelated</th>
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- **Which SPP Working Group should own the Capacity Margin process?**

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<tr>
<th>GWG</th>
<th>ORWG</th>
<th>TWG</th>
<th>Other</th>
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<td>9</td>
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- **Should we use Coincident Peak loads to calculate each entity's Capacity Margin?**

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<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Unrelated</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>4</td>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>

- **Should fuel supply and transportation firmness be documented?**

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Unrelated</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>3</td>
<td>6</td>
<td>2</td>
</tr>
</tbody>
</table>
Responses to MOPC questions

• Can anything other than firm transmission be used to demonstrate deliverability?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Unrelated</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>4</td>
<td>8</td>
<td>0</td>
</tr>
</tbody>
</table>

• Do plants need to be available more than a certain percentage of the year?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Unrelated</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>5</td>
<td>10</td>
<td>0</td>
</tr>
</tbody>
</table>

• How do we factor in environmental limits? (Multiple types of responses)

• Penalties for non-compliance?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Unrelated</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>2</td>
<td>4</td>
<td>0</td>
</tr>
</tbody>
</table>

• Any issues with IRP state laws?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Unrelated</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>11</td>
<td>2</td>
<td>0</td>
</tr>
</tbody>
</table>
Responses to additional MOPC questions

- Should you have a backup fuel source with enough storage or ability to replenish to meet the time requirement?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>0</td>
<td>2</td>
</tr>
</tbody>
</table>

- How much firm gas transport or days/hours of on-site fuel is required, if any?

<table>
<thead>
<tr>
<th>Criteria 12</th>
<th>None</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

- How many hours and days in a row would it take to have capacity accredited?

<table>
<thead>
<tr>
<th>Criteria 12</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>

- What type of demonstration would be required to prove capacity accreditation?

<table>
<thead>
<tr>
<th>Criteria 12</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>
Responses to additional MOPC questions

- **(Accreditation) Conditions of the demonstration or equalized to what?**

<table>
<thead>
<tr>
<th>Criteria 12</th>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>3</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

- **Can the capacity seasons be broken up with different accreditation levels? E.g. summer /winter**

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>1</td>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>

- **Need to document the conditions of the machine? E.g. firing rate, inlet air temp (if adjusted with coolers), water injection augmentation... (4 responses)**

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
</tbody>
</table>

- **Would longer operation runs be required to officially accredit a machine or re-accredit? (4 responses)**

<table>
<thead>
<tr>
<th>Criteria 12</th>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Responses to additional MOPC questions

• Should System Peak Responsibility be measured with or without losses?

<table>
<thead>
<tr>
<th>With</th>
<th>Without</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>2</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

• Do the Criteria 2 capacity requirements correspond with the Must-Offer requirement in the SPP IM? (4 responses)

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

• Is there a deliverability requirement associated with market participation? (4)

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>3</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

• What role does Demand Side Management (DSM) play in meeting capacity margin requirements?

<table>
<thead>
<tr>
<th>Include</th>
<th>Exclude</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Responses to additional MOPC questions

- Should SPP have both summer and winter peak season CM and capacity accreditation methodologies and testing for all LSEs?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>0</td>
<td>0</td>
<td>2</td>
</tr>
</tbody>
</table>

- Should extreme weather conditions and grid resiliency be considerations for CM?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>2</td>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>

- Should Demand Response (DR) and Distributed Generation (DG) be considered in CM and capacity accreditation discussions?

<table>
<thead>
<tr>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

- Are DR and DG reductions in an LSE’s peak demand or are they called upon during peak conditions and should be accredited toward meeting an LSE’s CM?

<table>
<thead>
<tr>
<th>Toward CM</th>
<th>Reduction</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>
Responses to additional MOPC questions

• Since the overall CM in SPP has been well above 12% for over a decade, would it be prudent to delay considering any reduction in the existing 12% value until there is actual operating experience at or near a 12% CM level?

<table>
<thead>
<tr>
<th></th>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Count</td>
<td>2</td>
<td>3</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

• Should SPP’s CM enforcement actions be extended into a daily activity in instances when enough of a load serving entity’s resources fail to be made available to meet the LSE’s daily peak load plus operating reserves obligation?

<table>
<thead>
<tr>
<th></th>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Count</td>
<td>1</td>
<td>2</td>
<td>0</td>
<td>2</td>
</tr>
</tbody>
</table>

• Can LSM’s with non-contiguous loads meet their obligation by securing Firm Capacity that is deliverable to one load in a quantity sufficient to cover their total requirement for all their loads?

<table>
<thead>
<tr>
<th></th>
<th>Yes</th>
<th>No</th>
<th>Undecided</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Count</td>
<td>4</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
</tbody>
</table>
Responses to additional MOPC questions

• In regards to fuel supply and transportation, what is the definition of “firmness”? (Multiple types of responses)

• How does this affect an LSE whose Load is included in another Entity’s Load? The City of Coffeyville’s Load is included in GRDA’s Load as per our contract. (Multiple types of responses)

• Should Resource Availability be broadly considered in capacity accreditation for generation resources as deductions to the maximum output developed by testing procedures? (Multiple types of responses)

• How should any changes to capacity margin requirements be phased in? (Multiple types of responses)
Southwest Power Pool, Inc.
CAPACITY MARGIN TASK FORCE
Charter
July 15, 2014

Purpose
The Capacity Margin Task Force (CMTF) is responsible for updating SPP Capacity Margin requirements and methodology based upon SPP Stakeholder and Staff input. A recommendation of updated requirements and methodology improvements will be made to the MOPC.

Scope of Activities
- Determine the Resource Adequacy (Capacity Margin) required in SPP
- Determine how Capacity Margin should be calculated
- Determine which SPP entities are required to meet the requirements
- Determine the processes and information necessary to show the entity is meeting its requirement
- Determine what, if any, penalties are needed for those that do not meet their requirements

Representation
The CMTF will be comprised of member company-nominated representatives and interested Cost Allocation Working Group and/or Regional State Committee representatives. Each member company has an opportunity to nominate a representative for the CMTF.

Members of the CMTF shall have experience and knowledge in one or more of the following areas:
- Capacity Margin or Reserve Margin calculation
- Energy marketing
- Operations
- Planning
- Generation
- Regulatory

The CMTF will be led by a Chairman and will be supported by a SPP staff secretary.
**Duration**

The CMTF is expected to have a new Capacity Margin requirement methodology by July 2015.

**Reporting**

The CMTF will report on progress and recommendations at the quarterly MOPC meetings as well as meetings, as needed, with various SPP working groups.
Update on Integrated System

July 2014

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
Approvals By SPP and IS Entities

• SPP Board Approved the SPP Tariff and Governing Document Changes needed to implement the integration of the IS Entities on June 9, 2014

• On July 8, 2014, Heartland Consumers Power District’s Board of Directors Approved a resolution authorizing execution of SPP Membership Agreement

• On July 9, 2014, WAPA approved and directed Western-UGP to take necessary actions to complete full membership with SPP

• On July 16, Basin Electric Power Cooperative’s Board of Directors authorized it to join SPP

• SPP expects to file with FERC on or around August 1
Update on Seams
Related Dockets at FERC

July 2014

Carl Monroe

Southwest Power Pool

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

- MISO filed request for declaratory order on interpretation of Section 5.2 of SPP-MISO JOA to effectuate integration of Entergy
  - FERC granted MISO’s request
- SPP appealed FERC’s decision to the D.C. Circuit
  - D.C. Circuit vacated and remanded FERC’s decision in January 2014
- SPP began billing MISO for usage beginning 12/19/13
- SPP made filing at FERC for Service Agreement under Section 205 (ER14-1174) and complaint under Section 206 (EL14-21)
- MISO filed Section 206 complaint (EL14-30)
Transmission Charges for MISO Usage

<table>
<thead>
<tr>
<th>Service</th>
<th>Tariff Charges</th>
<th>Service Agreement Charges</th>
<th>Total</th>
</tr>
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<tbody>
<tr>
<td>December</td>
<td>$2,473,916</td>
<td>$19,186,886</td>
<td>$27,815,886</td>
</tr>
<tr>
<td>Jan 1-28</td>
<td>$6,155,084</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan 29-31</td>
<td>$744,464</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feburay</td>
<td>$7,051,808</td>
<td></td>
<td></td>
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<tr>
<td>March</td>
<td>$6,427,942</td>
<td></td>
<td></td>
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<tr>
<td>April</td>
<td>$3,107,023</td>
<td></td>
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<tr>
<td>May</td>
<td>$1,855,650</td>
<td></td>
<td></td>
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<tr>
<td>Service</td>
<td></td>
<td></td>
<td>$19,186,886</td>
</tr>
<tr>
<td>Agreement</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Toal</td>
<td></td>
<td></td>
<td>$27,815,886</td>
</tr>
</tbody>
</table>
Settlement Proceedings

• In March 2014 FERC accepted SPP’s service agreement effective January 29, 2014 subject to refund and set all issues for hearing pending settlement proceedings

  – Parties to the settlement discussions primarily include SPP and SPP TO’s, MISO and MISO TO’s, and ORCA Joint Parties

• First settlement conference held on April 29, 2014

• Second settlement conference held on June 3, 2014
Other Relevant Regulatory Activity

- On April 12 MISO proposed to voluntarily restrict N-S dispatch flow to a target of 1000 MW (ER14-1713)
- On May 22 MISO requested waiver of tariff provisions for processing long-term transmission service requests that may cause MISO to exceed 1000 MW (ER14-2022)
- On June 16 FERC accepted MISO’s proposed cost recovery mechanism for charges under the SPP Service Agreement (ER14-1736)
- Expect another filing in near future to allow MISO to implement hurdle rate in dispatch to exceed 1000 MW
Seams Project
Task Force
Update
July 28, 2014

SPP Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future
SEAMS PROJECTS TASK FORCE
Seams Project Task Force Update

- Chartered to develop criteria for seams projects
- Developing a policy paper which outlines seams project criteria and the study/approval process
- Criteria
  - 100 kV and above that benefits SPP and at least one other Seams Partner
  - Cost > $5 million needed within 10 years and a B/C ratio of at least 1.0
  - Agreement on cost sharing
Definitions

• New Definitions
  – Seams Project: project which has agreement on cost sharing, 100 kV and above, SPP B/C ratio of at least 1.0, provides benefit to SPP
  – Seams Partner: non-SPP transmission owner which whom SPP is considering a Seams Project
  – Regional Review Process: Process used by SPP region to regionally evaluate a Seams Project. This is separate from any interregional or joint seams evaluation
Sources of Seams Projects

• Tariff Processes
  – ITPNT, ITP10, or other SPP Tariff planning process

• Non-Order 1000 Seams Planning Process
  – Joint study via SPP-AECI Joint Operating Agreement (JOA)
  – Any other study performed as a part of a defined seams planning process
  – SPP approval through the Regional Review Process

• Joint Special Study
  – Other study between SPP and a Seams Partner
  – SPP approval through the Regional Review Process
Joint Study Process

- If no predefined joint study process such as through a JOA, the joint study process described in the policy paper will be used

- Joint study components
  - Scope development
  - Benefit metrics
  - Timeline
    - No longer than 18 months
  - Deliverable
Seams Project Criteria

• 100 kV and above
  – Tie lines or wholly within SPP or a Seams Partner

• Minimum total project cost of $5 million

• Need date within 10-years

• SPP regional B/C ratio of 1.0
  – Benefits based upon agreed-to metrics
  – Provide 5% of benefits to SPP and each Seams Partner

• Cost sharing agreement between SPP and the Seams Partner
  – Could be with more than one Seams Partner
SPP Regional Review Process

• Consistent to Regional Review Process approved by SPP stakeholders for use in the Interregional Order 1000 planning process

• Used for regional review and decision on approval
  – SPP stakeholder directed
  – SPP assumptions, models, and metrics
Cost Sharing

- Cost shared between SPP and the Seams Partner(s) based on benefits
- Agreed-to metrics
- Principles used in arriving at equitable cost sharing:
  - Costs roughly commensurate with benefits
  - No cost sharing without receiving benefits
  - Transparent methodologies and identification of benefits
  - Share of benefits to SPP and its Seams Partners should be sufficient to support seams projects’ approval
Regional Cost Allocation Proposal

- Cost for Seams Projects greater than 300 kV will be recovered according to SPP’s highway/byway cost allocation methodology
- Projects less than 300 kV recovered regionally through “highway” funding
- Approved seams projects will be considered in the SPP Regional Cost Allocation Review (RCAR)
FERC Order 1000 Filings

- July 21, 2011 – FERC issued Order 1000
- May 17, 2012 – FERC issued Order 1000-A
- October 18, 2012 – FERC issued Order 1000-B
- November 13, 2012 – SPP filed Tariff revisions for regional compliance to Order 1000
- July 18, 2013 – FERC issued conditional acceptance of SPP compliance filing, subject to further compliance.
  - Set Tariff effective date for March 30, 2014
- November 15, 2013 – SPP filed additional revisions for regional compliance of Order 1000
- MOPC approved language (TRR 126) for SPP compliance filing related to Aggregate Study Upgrades.
May 15 - FERC Orders for PJM & MISO

- FERC Allows References to State, Local Laws in Transmission Tariffs
  - Previously FERC had ordered references to state, local laws (e.g., state ROFR) be removed from tariffs
  - Otherwise could cause inefficiencies and delay new transmission projects
  - Note: SPP made similar arguments in rehearing request; could conclude that SPP will get same treatment
    - Nebraska has state mandated ROFR
    - Oklahoma has state mandated ROFR below 300kV
SPP Order 1000 Process

1. Qualified RFP Participants (QRP)
2. Detailed Project Proposals (DPP)
3. Industry Expert Pool/Panel
4. Requests for Proposals (RFP)
5. Designated Transmission Owner (DTO)

Note: 2014 Activities
QUALIFIED RFP PARTICIPANTS (QRP)
Qualified RFP Participant

- **Qualified RFP Participant (QRP):** An entity that has been determined by SPP to satisfy the qualification criteria set forth in the Order.

- Any Entity can qualify to be a QRP and participate in the Transmission Owner Selection Process (TOSP).

- Only approved QRPs can participate in the TOSP.

- All interested entities must apply.

- Application fee may apply.

**Timetable**

- Annual Open Enrollment period for QRPs: April 1\(^{st}\) - June 30\(^{th}\). *(45 Applicants for 2015)*

- SPP will post all applicants by July 15\(^{th}\).

- SPP will notify Applicants by September 30\(^{th}\) of QRP determination.

- SPP will post all QRPs for following year by December 31\(^{st}\).
DETAILED PROJECT PROPOSALS (DPP)
DPP in the ITP

Scope Development

Needs Assessment

DPP Response Window

Solution Development

Portfolio Recommendation
What is a Detailed Project Proposal?

- Information about a proposed transmission project in the ITP process
  - Sufficient info to allow SPP to evaluate the proposed project
  - Encourage innovative ideas
- Required to qualify for incentive points in the competitive bidding process
- Must submit specific data to be eligible for DPP (Attachment O)
- Multiple project submissions could qualify DPP incentive points
- Cure period for incomplete DPP submissions
- Current avenues remain available to propose a transmission project (Order 890 submissions)
DPP Submissions

• Any entity may submit a DPP
• Submitted via link on SPP website
  – Tracked and maintained by SPP staff
• Submitter of a DPP project approved by SPP Board of Directors for construction may qualify for 100 incentive points
• All DPP submitters notified if their DPP was selected / not selected after the ITP Reports approved by SPP Board of Directors
• Eligible for incentive points for the remainder of the three year planning cycle of the ITP process
  – Must resubmit the DPP
• 2015 ITP10 – 1179 DPPs submitted
• 2015 ITPNT - Window currently open until July 30, 2015.
QUESTIONS
Integrated Marketplace Update

July 28, 2014

Bruce Rew, PE
BRew@spp.org 501.614.3214

Southwest Power Pool

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

- Integrated Marketplace Continues to perform well
- Summary of first four months
- Marketplace Statistical Information
- Marketplace improvements
Integrated Marketplace summary

- High market participant engagement
- Systems performing well
- Operated through some operations challenges
- Improving unit commitment processes and knowledge
- Summer Peak loading conditions have not occurred yet
Unit Commitment Improvement

Average RT Daily Capacity Overage*

*Overage = Economic Max - Load - NSI - (RegUp+SPIN+SUPP)
Unit Commitment Improvement

**RT Daily Capacity Overage***

*Overage = Economic Max - Load - NSI - (RegUp+SPIN+SUPP)*
Graph on Real-Time versus DA pricing

LMP ($/MWh)

Gas Cost ($/MMBtu)


DA LMP

RT LMP

Gas Cost
Graph on Dispatch by Fuel Type
Graph on Fuel on the Margin in RT

% Intervals on Margin


- Other
- Gas
- Coal
- Wind
Integrated Marketplace Improvements

• Integrated Marketplace Phase II
  – Market-to-Market solution
  – Enhanced Combined Cycle

• Operational Review of data
  – Enough experience now to begin reviews
  – Working with former Balancing Authorities to look for ways to improve reliability and economic operations

• SPP working on improvements
  – Prioritizing desired Market enhancements
Integrated Marketplace Summary

• Overall market has worked well
  – No major system concerns
  – Settlements functioning well with minimal disputes

• Financial savings being achieved
  – Continued energy savings similar to EIS market
  – New savings from improved unit commitment

• Continuous improvement
  – Working with BA’s to improve dispatch
  – Market enhancements evaluated
Value of SPP Transmission Assessment

Regional State Committee
July 28, 2014
Background

• MOPC Action Item 234: Review benefits of SPP approved transmission
  – Develop conceptual scope by the July MOPC
  – Develop detailed scope
  – Perform analysis
Stakeholder Involvement To-date

- CAWG
- ESWG
- TWG
- PCWG
- SSC
- MOPC
Assessment Goal

• Determine benefits attributable to transmission development in the SPP region
Holistic Approach

- MPG
- Air conditioning
- # of seats
- Automatic transmission

- Nav. system
- Backup camera
- Satellite radio
- Towing package
What it is...

- Staff-led with Stakeholder review
- Informational
- Holistic value of transmission approved since 2006
- Regional viewpoint
- Intended for a broad audience
- Enrich future decision making
What it is not...

- ...RCAR
- ...determining cost allocation
- ...assigning benefits to local zones
- ...second guessing past decisions
Value: Realized and Future

• Realized value
  – Value already realized
  – Historical operational data as inputs
  – Utilize real-time/planning models and tools as applicable

• Future Value
  – Expected value
  – Latest available forecast data as inputs
  – Utilize planning models and tools
Value Analysis

• Business-As-Usual base assumption

• Sensitivities considered:
  – Exports
  – Low hydro
  – High gas price
  – Low gas price
  – High load growth
  – Low load growth
  – Clean Power Plan / 111(d)
Value Reporting Approach

• Oriented for a broad audience

• Bandwidth
  – Multiple sensitivities
  – Accounts for limited precision

• Resist project categorization because value can change over time
Metrics Considered

✓ Adjusted Production Cost **$
✓ Marginal Energy Losses **$
✓ Unit Cycling **$
✓ Avoided or Delayed Reliability Projects **$
✓ Increased Wheeling Through and Out Revenues **$
✓ Assumed Benefit of Mandated Reliability Projects **$
✓ Public Policy Benefits **$
✓ Societal Economic Benefits **$
✓ Losses (capacity) **$
✓ TSR, GI, and Load Enablement **
✓ Reduction of Emission Rates and Values **
✓ Fuel Type Diversity **
✓ Savings Due to Lower Ancillary Service Needs and Production Costs **

• Reduction of Reserve Zones**
• Interconnection Reliability Operation Limit **
• Flowgate Reduction **
• Loss-of-Load-Probability **$
• Increased Market Competition **
• ARR Benefit *
• Voltage Stability **
• Transient Stability **
• Mitigating RMRs **
• Grid Flexibility **
• Imperfect Foresight *$
• Market to Market *$
• Impact of Extreme Events *

*Future Value *Realized Value $Monetized Value

✓ Sub-set of metrics
Different Options

- Sub-set of all metrics excluding sensitivities
- Sub-set of all metrics including sensitivities
- All metrics excluding sensitivities
- All metrics including sensitivities

Time (months) vs. Cost ($100,000)

- 1 Year
- Staff Proposal
- $750K
Staff Proposal

• Higher-likelihood sensitivities
  – High gas price, low load growth, 111(d)

• Metrics (13) which provide the most value while being more familiar to stakeholders
  - Adjusted Production Cost
  - Marginal Energy Losses
  - Unit Cycling
  - Avoided or Delayed Reliability Projects
  - Increased Wheeling Through and Out Revenues
  - Assumed Benefit of Mandated Reliability Projects
  - Public Policy Benefits
  - Societal Economic Benefits
  - Losses (capacity)
  - TSR, GI, and Load Enablement
  - Reduction of Emission Rates and Values
  - Fuel Type Diversity
  - Savings Due to Lower Ancillary Service Needs and Production Costs
Metrics Review & Recommendations

Regional State Committee
July 28, 2014

Southwest Power Pool

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

- MOPC directed ESWG to provide recommendations by July 2014
- ESWG evaluated the calculation and allocation of benefit metrics for:
  - 2015 ITP10
  - RCAR II
- Staff retained Brattle for an independent assessment of methodologies on metrics
- Today – will present ESWG and MOPC recommendations to RSC for review
## Benefit Metrics

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Calculated in RCAR I?</th>
<th>Considered for 2015 ITP10 and RCAR II?</th>
<th>Included in This Assessment?</th>
<th>Presented starting on slide....</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted Production Cost (APC)</td>
<td>✓</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Emission Rates and Values</td>
<td>✓</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Ancillary Service Needs and Production Costs</td>
<td>✓</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Avoided or Delayed Reliability Projects</td>
<td>✓</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Capacity Cost Savings due to Reduced On-Peak Transmission Losses</td>
<td>✓</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td><strong>A.</strong> Marginal Energy Losses Benefits</td>
<td></td>
<td>Yes</td>
<td>How to include</td>
<td>4</td>
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<tr>
<td><strong>B.</strong> Increased Wheeling Through and Out Revenues</td>
<td></td>
<td>Yes</td>
<td>How to include</td>
<td>7</td>
</tr>
<tr>
<td><strong>C.</strong> Mitigation of Transmission Outage Costs</td>
<td>✓</td>
<td>Yes</td>
<td>Allocation method</td>
<td>12</td>
</tr>
<tr>
<td><strong>D.</strong> Benefits of Mandated Reliability Projects</td>
<td>✓</td>
<td>Yes</td>
<td>Allocation method</td>
<td>16</td>
</tr>
<tr>
<td><strong>E.</strong> Benefits from Meeting Public Policy Goals</td>
<td>✓</td>
<td>Yes</td>
<td>Overall approach</td>
<td>20</td>
</tr>
<tr>
<td>Reducing the Cost of Extreme Events</td>
<td></td>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Capital Savings due to Reduction of Members’ Minimum Required Margin</td>
<td></td>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Reduced Loss of Load Probability</td>
<td></td>
<td></td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>
A. MARGINAL ENERGY LOSSES BENEFIT
Marginal Energy Losses Benefit

- Full MWh losses are not reflected in standard production cost simulations (therefore not captured in traditional APC metric)
  - To make run-times manageable, load is “grossed up” for average transmission losses
  - MWh quantity of losses is fixed and does not change with transmission additions
  - Therefore, the simulations do not capture that the savings from reduced MWh quantity of losses
    - Simulations only capture the change in the marginal cost of supplying the assumed fixed losses
  - Benefit of reduced MWh losses can be calculated post-processing through capturing the Marginal Loss Component of the LMP to calculate loss factors
Marginal Energy Losses – ESWG Recommendation & MOPC Position

• ESWG approved motion to implement the alternative approach for Marginal Energy Losses calculation using marginal loss components to compute loss factors. Inter-zonal transfers are captured in this alternative approach.

• MOPC approved ESWG Recommendation
B. INCREASED WHEELING THROUGH AND OUT REVENUES
Increased Wheeling Through and Out Revenues

- Increased ATC with neighbors can lead to increased through and out transactions which would increase SPP wheeling revenues and offset a portion of total project costs
  - Schedules 7, 8, 11
  - MW volume of transmission reservations for long-term service will exceed the MWh of energy scheduled, leaving room for additional non-firm exports

- Two complementary approaches were developed to estimate how increased export ATCs affect wheeling service sold
  - Impact on long-term reservations based on review of long-term firm TSRs enabled by projects
  - Hourly, non-firm transactions based on Promod simulations
  - Allocation based on current revenue sharing method in tariff
Increased Wheeling – ESWG Recommendation & MOPC Position

• ESWG approved motion to include the long term reservations calculation for wheeling. The benefit for non-firm transactions would be calculated for informational purposes but not included in the total benefits.

• ESWG approved motion to allocate benefits according to the methodology in the Tariff for allocating these revenues

• MOPC approved both ESWG motions
C. MITIGATION OF TRANSMISSION OUTAGE COSTS
Current & Alternative Allocation Approaches

• Benefits based on additional APC savings from market simulations that consider a subset of historical transmission outage events

• Currently, this benefit is calculated on an SPP-wide basis and allocated to zones based on load ratio share
  – Sep’12 MTF report recommended this approach since it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone over the next 10+ years

• Two alternative approaches considered to allocate SPP-wide benefits:
  – Alt. 1: Apply each zone’s share of APC benefits
  – Alt. 2: Apply each zone’s share of historical outage events
Current & Alternative Allocation Approaches

• Current allocation based on LRS is simple, easy to verify, and does not depend on the particular pattern of historical outages
  – But does not factor possible differences in resilience (e.g., it may overstate the allocated benefits of zones that are above-average resilient to transmission outages)

• APC savings in an outage-free environment will not be a good indicator of how the additional benefits related to outage costs will be distributed
  – Transmission outages can substantially change congestion patterns and distribution of APC savings
  – Zones with high APC savings may not realize additional benefits if already resilient
  – Zones with negative APC savings would also benefit from increased resilience

• Using frequency of historical outages could inform the allocation but would require long-term data
  – Outage frequencies by zone can change significantly from year to year
  – Number of events does not capture duration, voltage level, or resulting congestion
  – Result: High frequency does not necessarily mean “high impact” (and vice versa)
  – Preliminary results show shares of outage frequencies similar to LRS
Outage Metric – ESWG Recommendation & MOPC Position

• ESWG approved motion to use the APC savings methodology to calculate Mitigation of Transmission Outage Costs metric, with periodic review of the historical outage data in order to ensure that the outage data used to calculate the metric is historically reasonable.

  – Captures total benefit, not the allocation of benefit

• ESWG approved motion to use the load-ratio share methodology to *allocate* the benefits.

• MOPC did not approve ESWG recommendation or an alternative recommendation
D. ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS
Reliability Benefit Allocation Methodologies

• **Highway/Byway**
  – Allocates assumed benefits of mandated reliability projects in the same manner costs are allocated
    ▪ Reliability upgrades ≥ 300 kV provide regional reliability benefits allocated to all zones based on load ratio share (LRS)
    ▪ Reliability upgrades at 100-300 kV provide mostly (2/3) local and some (1/3) LRS
    ▪ Reliability upgrades < 100kV provide local benefits allocated to only the individual zones projects are located in

• **DFAX**
  – Implements a series of power transfers to each zone’s load, and measures the incremental changes in flow on the reliability upgrades
    ▪ Zones with transfers that result in a large change in flow on reliability upgrade will receive the most benefit
Reliability Benefit Allocation Methodologies

- **LODF**
  - Measures changes in flow for reliability upgrades during outages of existing transmission facilities
    - Large change in flow will identify the existing facility (on outage) as a beneficiary
    - Substantial effort to calculate

- **System Reconfiguration**
  - Measures changes in flow for existing transmission facilities during outages of the reliability upgrades
    - How much does the upgrade alter flows on the existing system?
    - Large change in flow on existing facility will identify that facility as a beneficiary

**Notes:**
These allocation methodologies do not impact the total reliability benefit of projects. They only impact the allocation of benefit to zones.
Modified Hybrid Approach

• System Reconfiguration provides a good proxy for allocating benefit of byway projects
  – Gauges how much the upgrade reduces flows on the existing system, and captures benefits of byway projects on immediately neighboring systems, BUT:
  – Tends to result in disproportionate allocation of benefits to nearby zones for highway projects driven by regional flows

• Load Ratio Share (LRS) provides a good proxy for allocating benefit of highway projects
  – Accounts for highway projects providing more regional benefit, BUT:
  – Does not account for byway projects providing benefit that can be primarily local

• The strengths and weaknesses of each approach are accounted for in the development of the modified hybrid approach
Reliability Metric – ESWG Recommendation & MOPC Position

• ESWG approved motion to utilize the modified hybrid approach that assigns the following allocation methodology for the Assumed Benefit of Mandated Reliability Projects metric.

  – Allocation breakdown:
    - >300 kV: 1/3 System Reconfiguration, 2/3 LRS
    - 100-300 kV: 2/3 System Reconfiguration, 1/3 LRS
    - <100 kV: 100% System Reconfiguration

• MOPC did not approve the ESWG recommendation or an alternative recommendation
E. BENEFITS FROM MEETING PUBLIC POLICY GOALS
# Public Policy – Methods Considered

<table>
<thead>
<tr>
<th></th>
<th>Total Regional Benefits</th>
<th>Zonal Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original RCAR I</td>
<td>Set to cost of public policy projects</td>
<td>Based on share of unmet renewable mandates or goals in the region</td>
</tr>
<tr>
<td>Alternative 1</td>
<td>Same as in RCAR I</td>
<td>Based on share of unmet renewable mandates or goals only in states driving public policy projects</td>
</tr>
<tr>
<td>Alternative 2a</td>
<td>Total avoided wind investments plus assumed local transmission costs</td>
<td>Estimated on a zonal basis</td>
</tr>
<tr>
<td>Alternative 2b</td>
<td>Same as 2a</td>
<td>Same as RCAR I (unmet policy goal)</td>
</tr>
<tr>
<td>Alternative 2c</td>
<td>Same as 2a</td>
<td>Same as 2a (zonal estimate)</td>
</tr>
<tr>
<td>Alternative 3</td>
<td>Same as 2a but excludes wind generation beyond policy goals</td>
<td>Same as 2a (zonal estimate)</td>
</tr>
</tbody>
</table>
Public Policy Metric – ESWG Recommendation & MOPC Position

• ESWG approved motion to utilize the Alternative 1 methodology for calculation and allocation of the Public Policy Benefits metric.

• MOPC approved the ESWG recommendation
SPP Alternative to ESWG Vote

• SPP Staff believes that Alternative 1 should not be implemented because:
  – It is an arbitrary determination of benefit, and does not capture all the policy benefits that can be feasibly and logically quantified
  – Ignores policy benefits from some previously approved projects simply because they were not classified as Public Policy due to lack of a classification process at that time

• SPP staff recommends implementation of Alternative 3
  – More comprehensive determination of all of the benefit from meeting Public Policy
  – The recipients of the benefits are those driving the need
TIMELINE & NEXT STEPS
Next Steps

- Upon SPP Board approval, metrics will be used to quantify benefits in upcoming assessments
  - 2015 ITP10 concludes 1/2015
  - RCAR II concludes 4/2015
2014 Strategic Plan

July 2014

Michael Desselle
Vice President, Process Integrity

Southwest Power Pool
Strategic Planning Process

- **2013**
  - Strategic scenario exercise

- **Spring**
  - MOPC/WG RSC/CAWG input
  - Stakeholder input

- **April**
  - SPC retreat
  - Draft plan
Strategic Planning Process (cont.)

June
• Board strategic session
• Revise plan

July
• Share final plan with stakeholders
• SPC finalize plan

July
• Board approval
SWOT Analysis

Opportunities
- SEAMS
- FUELS
- AFFORDABILITY
- EXPORTS
- PLANS
- RISKS
- COSTS
- SECURITY
- FUNDING

Threats
- SEAMS
- FUELS
- SECURITY
- AFFORDABILITY

Weaknesses

Strengths
Our Vision of the Future
Foundational Strategies Pyramid

- Optimize Interdependent Systems
- Enhance Member Value and Affordability
- Maintain an Optimized, Economical Transmission System
- Reliability Assurance
Four Foundational Strategies

- Reliability Assurance
- Enhance Member Value and Affordability
- Optimize Interdependent Systems
- Maintain an Optimized, Economical Transmission System
Reliability Assurance Strategy

Initiatives

• Capacity Margin Refinement (A)
• Regional Resource Need and Value Assessment (B)
• Reliability Assessments of Environmental Rules (A)
• Integration of Variable Energy Resources (C)
• Grid Resiliency (B)
  – Cyber and Physical Security
• Reliability Excellence (B)
  – Relay Misoperations Improvement (RE)
  – Event Analysis (RE)
Economical, Optimized Transmission System Strategy

Initiatives

• Integrated Transmission Planning Check and Adjust (B) – On-going
• Cost Controls on Competitive Transmission (A)
• Flexibility to Address Policy Initiatives (B) - On-going
• Value Pricing (B)
  – Import/Export Strategy
  – Cost Allocation
• Fair and Equitable Cost/Benefit Allocation Policies (A)
Interdependent Systems Strategy

Initiatives

- Transmission (Seams) (A)
- Optimize Markets Efficiencies Along Seams (A)
- Optimize Natural Gas Pipeline System Seams (A)
- Optimize Data Seams (C)
- Integrated Market Enhancements (B)
Member Value & Affordability Strategy

Initiatives

- Communication Strategy (A)
- Fair and Equitable Cost/Benefit Allocation Policies (A)
- PMO Best Practices (B)
- Enhanced Market Analytics (B)
- Strategic Membership Expansion & Improved Stakeholder Processes (A)
- Communication/Education (C)
Update on EPA Activities

RSC
July 28, 2014
Topics Covered

• Current Known Impacts
  – Retirements
  – De-ratings
  – Outage Impacts

• Proposed Clean Power Plan
  – Overview
  – Impact Analysis
CURRENT KNOWN IMPACTS
Comparison with ITP 10 Assumptions

TOTAL CAPACITY OF COAL UNITS

- Future 1 2025
- Future 2 2025
- 2018 Projection

TOTAL CAPACITY OF COAL UNITS BY STATE

- Future 1
- Future 2
- 2018

Megawatts

States:
- AR
- IA
- KS
- LA
- MO
- NE
- OK
- TX

203 of 256
Outage Impact Study Resource Adequacy 2014

2014 Weekly Outages

Unavailable Capacity

Monthly Peak Load

Required Reserve Margin

Megawatts


67,678

60,000

50,000

40,000

30,000

20,000

10,000

0
Outage Impact Study Resource Adequacy 2015

2015 Weekly Outages

- Unavailable Capacity
- Monthly Peak Load
- Required Reserve Margin
PROPOSED CLEAN POWER PLAN
EPA Clean Power Plan Overview

- EPA’s proposed performance standards to reduce CO₂ emissions from existing fossil fuel-fired generators
- Promulgated under authority of Section 111(d) of the Clean Air Act
- Achieves nationwide 30% reduction of CO₂ from 2005 levels by 2030
- Proposes state-specific emission rate-based CO₂ goals
  - Based on EPA’s interpretation and application of Best System of Emission Reduction (BSER)
  - Must be met by 2030
EPA Clean Power Plan Overview

• States goals and flexibility
  – Interim goals applied 2020-2029 that allows states to choose trajectory
  – Offers guidelines and allows states flexibility to develop and submit State Implementation Plans
  – States may adopt an equivalent mass-based goal

• States can develop individual plans or collaborate with other states

• If state does not submit a plan or its plan is not approved, EPA will establish a plan for that state
Clean Power Plan Milestones

- June 2, 2014: Draft rule issued
- June 2014: Final rule expected
- Oct 16, 2014: Comments due to EPA
- June 2015: Draft rule issued
- June 2015: Final rule expected
- June 2016: State Implementation Plans due
- June 2017: State plans due (with one-year extension)
- June 2018: Multi-state plans due (with two-year extension)
- January 2020-29: Interim goal in effect
- January 2030: Final goal in effect
## BSER is Based on Four Building Blocks

<table>
<thead>
<tr>
<th>Block</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Improve efficiency of existing coal plants</td>
<td>6% efficiency improvement across fleet, assuming best practices and equipment upgrades</td>
</tr>
<tr>
<td>2. Increase reliance on CC gas units</td>
<td>Re-dispatch of Natural Gas CCs up to a capacity factor of 70%</td>
</tr>
<tr>
<td>3. Expand use of renewable resources and sustain nuclear power production</td>
<td>Meet regional non-hydro renewable target, prevent retirement of at-risk nuclear capacity and promote completion of nuclear capacity under construction</td>
</tr>
<tr>
<td>4. Expand use of demand-side energy efficiency</td>
<td>Scale to achieve 1.5% of prior year’s annual savings rate</td>
</tr>
</tbody>
</table>

*Uses 2012 data for existing units and estimated data for units under construction.*
2030 Goals for States in SPP

Fossil Unit CO2 Emission Rate Goals and Block Application (lbs/MWh)

- **Montana**
  - 2012 Rate: 2439
  - 2030 Rate: 1048

- **N. Dakota**
  - 2012 Rate: 2368
  - 2030 Rate: 1798

- **Wyoming**
  - 2012 Rate: 2331
  - 2030 Rate: 1722

- **Kansas**
  - 2012 Rate: 2320
  - 2030 Rate: 1562

- **S. Dakota**
  - 2012 Rate: 2256
  - 2030 Rate: 1533

- **Nebraska**
  - 2012 Rate: 2162
  - 2030 Rate: 1420

- **Missouri**
  - 2012 Rate: 1798
  - 2030 Rate: 895

- **New Mexico**
  - 2012 Rate: 1722
  - 2030 Rate: 883

- **Arkansas**
  - 2012 Rate: 1562
  - 2030 Rate: 791

- **Oklahoma**
  - 2012 Rate: 1533
  - 2030 Rate: 791

- **Louisiana**
  - 2012 Rate: 1420
  - 2030 Rate: 791

- **Texas**
  - 2012 Rate: 1420
  - 2030 Rate: 791

*Includes Future States with IS Generation in SPP (N. Dakota, S. Dakota, Montana, and Wyoming)
% Emission Reduction Goals for States in SPP

Total CO₂ Emission Reduction Goals (%)

Average of SPP States = 38.5%

*Includes Future States with IS Generation in SPP (N. Dakota, S. Dakota, Montana, and Wyoming)
EPA Projected 2016-2020 EGU Retirements
(For SPP and Select Neighboring States)

*Excludes committed retirements prior to 2016
**AEP provided data extracted from EPA IPM data
SPP Staff Involvement in State Efforts

• Arkansas
  – ADEQ stakeholder meetings on June 25\textsuperscript{th} & August 28\textsuperscript{th}
  – SPP Staff provided an SPP overview to ADEQ on July 3\textsuperscript{rd}

• Missouri
  – MoPSC stakeholder meeting on August 18\textsuperscript{th}

• Nebraska
  – SPP Staff meeting with NDEQ and Nebraska utilities on July 30\textsuperscript{th}

• Oklahoma
  – Meeting being scheduled in August with stakeholders

• South Dakota
  – SDPUC forum on July 31\textsuperscript{st}, SPP invited to participate in panel discussion

• Texas
  – PUCT public workshop on August 15\textsuperscript{th}
How Can SPP Assist?

- Help educate and work with states
- Perform impact analyses
  - Inform stakeholder responses that are due October 16
  - Inform current planning efforts
  - Assist state and member decision making
- Facilitate coordinated SPP response to proposed Clean Power Plan
- Evaluate and facilitate regional approach
- Coordinate with neighbors
- Other ways?
Impact Analyses

• Initial analysis requested by SPC
  – Reliability analysis
  – Use existing ITP 2024 models
  – Model EPA’s projected EGU retirements
  – Replace retired EGUs with a combination of increased output from existing CCs, new CCs, Energy Efficiency, and increased renewables (with input from member utility experts)
  – Preliminary results expected by August 1st

• Additional analysis may also be performed upon completion of initial analysis
  – Economic analysis, regional approach evaluation
  – Scenario based
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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 February 1, 2014 through April 30, 2014. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades that have been completed since January 1, 2013. 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>Regional Reliability</td>
<td>337</td>
<td>$2,344,885,798</td>
<td>1068.9</td>
<td>430.3</td>
<td>309.0</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>35</td>
<td>$168,706,162</td>
<td>12.7</td>
<td>137.7</td>
<td>0.0</td>
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<tr>
<td>Balanced Portfolio</td>
<td>11</td>
<td>$550,597,952</td>
<td>457.0</td>
<td>0.0</td>
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<tr>
<td>High Priority</td>
<td>117</td>
<td>$2,318,605,827</td>
<td>1816.1</td>
<td>20.5</td>
<td>40.0</td>
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<tr>
<td>ITP10</td>
<td>17</td>
<td>$767,590,318</td>
<td>515.0</td>
<td>0.0</td>
<td>0.0</td>
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<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$108,568,750</td>
<td>34.7</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td><strong>526</strong></td>
<td><strong>$6,258,954,806</strong></td>
<td><strong>3904.5</strong></td>
<td><strong>616.9</strong></td>
<td><strong>349.0</strong></td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>43</td>
<td>$202,615,262</td>
<td>40.5</td>
<td>11.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>10</td>
<td>$31,567,090</td>
<td>33.6</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal - Sponsored</td>
<td>26</td>
<td>$126,496,587</td>
<td>22.8</td>
<td>2.1</td>
<td>77.1</td>
</tr>
<tr>
<td><strong>NTC Projects Subtotal</strong></td>
<td><strong>79</strong></td>
<td><strong>$360,678,939</strong></td>
<td><strong>96.9</strong></td>
<td><strong>13.2</strong></td>
<td><strong>77.1</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>605</strong></td>
<td><strong>$6,619,633,745</strong></td>
<td><strong>4001.3</strong></td>
<td><strong>630.1</strong></td>
<td><strong>426.1</strong></td>
</tr>
</tbody>
</table>

*Table 1: Q3 2014 Portfolio Summary*
Figure 1: Percentage of Project Type on Cost Basis

- Regional Reliability: 36%
- Transmission Service: 3%
- Balanced Portfolio: 9%
- High Priority: 3%
- ITP10: 2%
- Zonal Reliability: 3%
- Generation Interconnection: 12%

Figure 2: Percentage of Project Status on Cost Basis

- Complete: 21%
- On Schedule < 4: 1%
- On Schedule > 4: 16%
- Delay - Mitigation: 17%
- NTC Suspension: 3%
- NTC - Commitment Window: 1%
- 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 2: Project Status by NTC Source Study

<table>
<thead>
<tr>
<th>Source Study</th>
<th>Complete</th>
<th>Delayed</th>
<th>Suspended</th>
<th>On Schedule</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006 STEP</td>
<td>$223,202,401</td>
<td>$912,000</td>
<td></td>
<td></td>
<td>$224,114,401</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$421,818,085</td>
<td>$144,309,000</td>
<td></td>
<td></td>
<td>$566,127,085</td>
</tr>
<tr>
<td>2008 STEP</td>
<td>$409,331,517</td>
<td>$11,417,000</td>
<td></td>
<td></td>
<td>$420,748,517</td>
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<tr>
<td>Balanced Portfolio</td>
<td>$567,343,667</td>
<td>$247,735,028</td>
<td></td>
<td></td>
<td>$815,078,695</td>
</tr>
<tr>
<td>2009 STEP</td>
<td>$442,463,273</td>
<td>$123,978,658</td>
<td></td>
<td></td>
<td>$566,441,931</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$365,847,867</td>
<td>$1,028,426,451</td>
<td>$1,028,426,451</td>
<td></td>
<td>$1,394,274,318</td>
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<tr>
<td>2010 STEP</td>
<td>$71,636,431</td>
<td>$64,574,884</td>
<td>$10,316,217</td>
<td>$18,462,300</td>
<td>$164,989,832</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$39,734,557</td>
<td>$103,849,021</td>
<td>$6,300,000</td>
<td>$53,251,917</td>
<td>$203,135,495</td>
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<tr>
<td>2012 ITP10</td>
<td>$767,590,318</td>
<td>$767,590,318</td>
<td></td>
<td></td>
<td>$1,535,180,636</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$30,725,852</td>
<td>$358,044,674</td>
<td>$17,810,955</td>
<td>$166,497,285</td>
<td>$573,078,765</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$4,067,495</td>
<td>$294,955,543</td>
<td>$378,053,152</td>
<td>$677,076,190</td>
<td>$1,599,077,285</td>
</tr>
<tr>
<td>HPILS</td>
<td>$171,375,744</td>
<td>$753,916,660</td>
<td></td>
<td></td>
<td>$925,292,404</td>
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<tr>
<td>Ag Studies</td>
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<td>$97,260,117</td>
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<td>$70,634,335</td>
<td>$858,144,096</td>
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<tr>
<td>DPA Studies</td>
<td>$63,206,020</td>
<td>$122,550,676</td>
<td>$1,497,397</td>
<td>$187,254,093</td>
<td>$311,295,537</td>
</tr>
<tr>
<td>GI Studies</td>
<td>$140,266,839</td>
<td>$65,855,751</td>
<td>$3,033,890</td>
<td>$102,139,057</td>
<td>$311,295,537</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$3,469,893,646</strong></td>
<td><strong>$1,559,083,069</strong></td>
<td><strong>$37,461,062</strong></td>
<td><strong>$3,588,203,900</strong></td>
<td><strong>$8,654,641,677</strong></td>
</tr>
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</table>
Figure 4: Estimated Cost for NTC Projects per In-Service Year

- **New Q3 2014 NTC**
- **NTC Modify Q3 2014**
- **Previous NTC**
Figure 5: Cost Trend per BOD-Approved Study
NTC Issuance

Twenty-five (25) 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 $1.01 billion.

Four NTCs were issued as a result of the completion of the Aggregate Facility Study SPP-2011-AG3-AFS-11. The total estimated cost of the Network Upgrades described in these NTCs is $82.9 million.

One NTC was issued to the Nebraska Public Power District (NPPD) to provide Interconnection Service to the Generator Interconnection Request as detailed in the Generator Interconnection Agreement for the affected customer within the Definitive Interconnection System Impact Study DISIS-2011-001. The estimated cost of the Network Upgrade included on the NTC is $0.5 million.

Two of the NTCs were issued as a result of the 2014 ITP Near-Term Assessment approved by the BOD on January 28, 2014. The total estimated cost of the new Network Upgrades from the NTCs is $5.1 million.

Eighteen (18) NTCs were issued in May, seven of which were NTC-Cs, as a result of the High Priority Incremental Load Study (HPILS) that was approved by the BOD on April 29, 2014. The total estimated cost of the new Network Upgrades from the NTCs is $638.2 million.

Table 3 summarizes the NTC activity from March 1, 2014 through May 31, 2014. 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>200263</td>
<td>MIDW</td>
<td>3/31/2014</td>
<td>Regional Reliability</td>
<td>Aggregate Study</td>
<td>1</td>
<td>$32,226</td>
<td></td>
</tr>
<tr>
<td>200264</td>
<td>OGE</td>
<td>3/31/2014</td>
<td>Regional Reliability</td>
<td>Aggregate Study</td>
<td>1</td>
<td>$1,720,000</td>
<td></td>
</tr>
<tr>
<td>200265</td>
<td>MKEC</td>
<td>3/31/2014</td>
<td>Regional Reliability</td>
<td>Aggregate Study</td>
<td>2</td>
<td>$35,768,881</td>
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<tr>
<td>200262</td>
<td>SPS</td>
<td>4/9/2014</td>
<td>Regional Reliability/Transmission Service</td>
<td>Aggregate Study</td>
<td>7</td>
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<tr>
<td>200266</td>
<td>NPPD</td>
<td>4/16/2014</td>
<td>Generation Interconnection</td>
<td>GI Study</td>
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<tr>
<td>200270</td>
<td>OGE</td>
<td>4/22/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
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<td>$4,644,880</td>
<td>$4,597,900</td>
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<td>WFEC</td>
<td>4/22/2014</td>
<td>Regional Reliability</td>
<td>2014 ITPNT</td>
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<td>$1,720,000</td>
<td></td>
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<tr>
<td>200272</td>
<td>AEP</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>7</td>
<td>$53,559,781</td>
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<tr>
<td>200274</td>
<td>ITCGP</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>2</td>
<td>$9,484,914</td>
<td></td>
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<tr>
<td>200275</td>
<td>MKEC</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>9</td>
<td>$139,066,741</td>
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<td>200276</td>
<td>MKEC</td>
<td>5/19/2014</td>
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<td>6</td>
<td>$40,511,509</td>
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<tr>
<td>200277</td>
<td>NPPD</td>
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<tr>
<td>200278</td>
<td>OGE</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
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<tr>
<td>200279</td>
<td>OGE</td>
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<td>HPILS</td>
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<tr>
<td>200280</td>
<td>OPPD</td>
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<td>High Priority</td>
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<tr>
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<td>High Priority</td>
<td>HPILS</td>
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<td></td>
</tr>
<tr>
<td>200282</td>
<td>SPS</td>
<td>5/19/2014</td>
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<td>HPILS</td>
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<tr>
<td>200283</td>
<td>SPS</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>28</td>
<td>$209,727,299</td>
<td>$287,139,791</td>
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<td>200284</td>
<td>WFEC</td>
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<td>High Priority</td>
<td>HPILS</td>
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<td>$3,807,160</td>
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<tr>
<td>200286</td>
<td>MIDW</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>2</td>
<td>$7,168,048</td>
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</tr>
<tr>
<td>200287</td>
<td>WFEC</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
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<td></td>
</tr>
<tr>
<td>200288</td>
<td>ITCGP</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
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<td></td>
</tr>
<tr>
<td>200289</td>
<td>ITCGP</td>
<td>5/19/2014</td>
<td>High Priority</td>
<td>HPILS</td>
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<td>N/A</td>
<td></td>
</tr>
<tr>
<td>200273</td>
<td>AEP</td>
<td>5/21/2014</td>
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<td>HPILS</td>
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</tr>
<tr>
<td>200290</td>
<td>OGE</td>
<td>5/21/2014</td>
<td>High Priority</td>
<td>HPILS</td>
<td>1</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>106</strong></td>
<td><strong>$726,625,279</strong></td>
<td><strong>$287,139,791</strong></td>
</tr>
</tbody>
</table>

**Table 3: Q3 2014 NTC Issuance Summary**

**NTC Withdraw**

One NTC Withdraw was issued since the last quarterly report for Network Upgrades that were determined to no longer be needed in SPP. The Network Upgrades that were withdrawn were previously issued an NTC-C as a part of the 2012 ITP10 study, and were restudied in the HPILS process. The total estimated cost of the Network Upgrades that were withdrawn is $114.1 million.
Table 4 lists the NTC Withdraw activity from March 1, 2014 through May 31, 2014. NTC ID values in bold font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>Previous NTC ID</th>
<th>DTO</th>
<th>Previous NTC Issue Date</th>
<th>NTC Withdraw Issue Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of Withdrawn Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200184</td>
<td>SPS</td>
<td>4/9/2012</td>
<td>5/19/2014</td>
<td>ITP10</td>
<td>2012 ITP10</td>
<td>4</td>
<td>$114,104,609</td>
</tr>
</tbody>
</table>

*Table 4: Q3 2014 NTC Withdraw Summary*

**Completed Projects**

Twenty-one (21) Network Upgrades with NTCs and one Generation Interconnection Network Upgrade were completed during the reporting period, totaling an estimated $144.1 million.

American Electric Power (AEP) reported the completion of the construction of an 18-mile 345 kV line from Flint Creek to Shipe Road, as well as the installation of a 345/161 kV transformer at Shipe Road. The project also included a new 9-mile 161 kV line from Shipe Road to East Centerton. AEP was issued an NTC for these Network Upgrades as a part of the 2007 SPP Expansion Plan. The reported cost estimate for the Upgrade is $59.1 million.

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 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>10582</td>
<td>EAST CENTERTON - SHIPE ROAD 161 kV CKT 1</td>
<td>AEP</td>
<td>2007 STEP</td>
<td>$11,962,000</td>
</tr>
<tr>
<td>10584</td>
<td>Shipe Road 345/161 kV transformer Ckt 1</td>
<td>AEP</td>
<td>2007 STEP</td>
<td>$13,104,000</td>
</tr>
<tr>
<td>10585</td>
<td>Flint Creek - Shipe Road 345 kV Ckt 1</td>
<td>AEP</td>
<td>2007 STEP</td>
<td>$34,085,000</td>
</tr>
<tr>
<td>10847</td>
<td>Clinton 161/69 kV transformer</td>
<td>GMO</td>
<td>2008 STEP</td>
<td>$2,000,000</td>
</tr>
<tr>
<td>10853</td>
<td>LOUST GROVE - LONE STAR 115 kV CKT 1</td>
<td>AEP</td>
<td>2008 STEP</td>
<td>$2,150,000</td>
</tr>
<tr>
<td>10952</td>
<td>GLENARE - LIBERTY 69 kV CKT 1 #2</td>
<td>GMO</td>
<td>2009 STEP</td>
<td>$1,950,000</td>
</tr>
<tr>
<td>11019</td>
<td>CHERRY1 - POTTER COUNTY INTERCHANGE 230 kV CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$3,603,100</td>
</tr>
<tr>
<td>11020</td>
<td>CHERRY1 230/115 kV TRANSFORMER CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$9,654,404</td>
</tr>
<tr>
<td>11042</td>
<td>KRESS INTERCHANGE - NEWHART 115 kV CKT 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$16,108,465</td>
</tr>
<tr>
<td>11359</td>
<td>Hereford Interchange - Northeast Hereford Interchange 115 kV Ckt 1</td>
<td>SPS</td>
<td>2012 ITPNT</td>
<td>$4,139,406</td>
</tr>
<tr>
<td>10875</td>
<td>Five Tribes - Pecan Creek 161 kV Ckt 1</td>
<td>OGE</td>
<td>2013 ITPNT</td>
<td>$3,022,363</td>
</tr>
<tr>
<td>11109</td>
<td>Cox Interchange - Kiser 115 kV Ckt 1 #2</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$6,400,000</td>
</tr>
<tr>
<td>11339</td>
<td>Classen - Southwest 5 Tap 138 kV Ckt 1</td>
<td>OGE</td>
<td>2013 ITPNT</td>
<td>$109,481</td>
</tr>
<tr>
<td>50450</td>
<td>Kiser Substation 115/69 kV Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$6,400,000</td>
</tr>
<tr>
<td>50741</td>
<td>Harrisonville 161/69 kV Ckt 2 Transformer</td>
<td>GMO</td>
<td>2014 ITPNT</td>
<td>$2,773,480</td>
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<tr>
<td>50762</td>
<td>Harrisonville 161 kV Ckt 2 Terminal Upgrades</td>
<td>GMO</td>
<td>2014 ITPNT</td>
<td>$1,005,220</td>
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<tr>
<td>50461</td>
<td>Shidler 138 kV</td>
<td>AEP</td>
<td>GI Study</td>
<td>$399,000</td>
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<tr>
<td>50236</td>
<td>COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69 kV CKT 1</td>
<td>WR</td>
<td>Aggregate Study</td>
<td>$5,811,750</td>
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<tr>
<td>50506</td>
<td>Grapevine 230/115 kV Transformer Ckt 1</td>
<td>SPS</td>
<td>DPA Study</td>
<td>$2,671,149</td>
</tr>
<tr>
<td>50586</td>
<td>Renfrow 345/138 kV Transformer Ckt 1</td>
<td>OGE</td>
<td>DPA Study</td>
<td>$3,079,700</td>
</tr>
<tr>
<td>50587</td>
<td>Renfrow Substation</td>
<td>OGE</td>
<td>DPA Study</td>
<td>$11,659,600</td>
</tr>
<tr>
<td>50619</td>
<td>Sandridge Tap - Renfrow 138 kV Ckt 1 (WFEC)</td>
<td>WFEC</td>
<td>DPA Study</td>
<td>$2,000,000</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>$144,088,118</strong></td>
</tr>
</tbody>
</table>

*Table 5: Q2 2014 Completed Network Upgrades*
<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>Q1 2014</th>
<th>Q2 2014</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
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<td>13</td>
<td>19</td>
<td>20</td>
<td>79</td>
</tr>
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<td>$76,641,941</td>
<td>$137,877,368</td>
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<tr>
<td>Transmission Service</td>
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<td>2</td>
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<td>12</td>
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<td>$34,634,266</td>
<td>$4,235,570</td>
<td>$4,781,255</td>
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<td>$49,462,841</td>
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<tr>
<td>Balanced Portfolio</td>
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<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
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<tr>
<td></td>
<td>$2,824,664</td>
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<td>$0</td>
<td>$0</td>
<td>$2,824,664</td>
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<td>0</td>
</tr>
<tr>
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<td>$0</td>
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<tr>
<td>Zonal Reliability</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>0</td>
<td>0</td>
<td>6</td>
<td>1</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$22,462,011</td>
<td>$399,000</td>
<td>$22,861,011</td>
</tr>
</tbody>
</table>

*Table 6: Completed Project Summary through 2nd Quarter 2014*
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>8</td>
<td>0.0</td>
<td>44.1</td>
<td>0.0</td>
<td>$32,596,863</td>
</tr>
<tr>
<td>115</td>
<td>15</td>
<td>61.8</td>
<td>34.1</td>
<td>35.0</td>
<td>$106,909,220</td>
</tr>
<tr>
<td>138</td>
<td>17</td>
<td>34.5</td>
<td>45.2</td>
<td>69.0</td>
<td>$93,805,378</td>
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<tr>
<td>161</td>
<td>8</td>
<td>14.2</td>
<td>23.3</td>
<td>0.0</td>
<td>$38,849,603</td>
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<tr>
<td>230</td>
<td>2</td>
<td>20.1</td>
<td>0.0</td>
<td>0.0</td>
<td>$23,681,182</td>
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<tr>
<td>345</td>
<td>3</td>
<td>118.1</td>
<td>0.0</td>
<td>0.0</td>
<td>$210,744,600</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>53</strong></td>
<td><strong>248.6</strong></td>
<td><strong>146.7</strong></td>
<td><strong>104.0</strong></td>
<td><strong>$506,586,845</strong></td>
</tr>
</tbody>
</table>

Figure 6: Completed Projects by Upgrade Type
<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>Miles of New</th>
<th>Miles of Rebuild/ Reconductor</th>
<th>Miles of Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>13</td>
<td>17.0</td>
<td>52.6</td>
<td>0.0</td>
<td>$57,478,675</td>
</tr>
<tr>
<td>115</td>
<td>9</td>
<td>80.7</td>
<td>47.9</td>
<td>3.0</td>
<td>$97,683,394</td>
</tr>
<tr>
<td>138</td>
<td>34</td>
<td>107.8</td>
<td>56.3</td>
<td>155.9</td>
<td>$166,972,296</td>
</tr>
<tr>
<td>161</td>
<td>2</td>
<td>0.1</td>
<td>2.2</td>
<td>0.0</td>
<td>$6,236,045</td>
</tr>
<tr>
<td>230</td>
<td>3</td>
<td>61.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$55,921,055</td>
</tr>
<tr>
<td>345</td>
<td>18</td>
<td>1146.4</td>
<td>0.0</td>
<td>0.0</td>
<td>$1,122,649,729</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>79</strong></td>
<td><strong>1413.0</strong></td>
<td><strong>159.0</strong></td>
<td><strong>158.9</strong></td>
<td><strong>$1,506,941,194</strong></td>
</tr>
</tbody>
</table>

*Table 8: Line Upgrade Projections for Next 12 Months*
**Project Status Summary**

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

- **Complete**: Construction complete and in-service
- **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.

![Figure 7: Project Status Summary on a Cost Basis](image-url)
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 717 miles of new 345 kV transmission line to the SPP system.

The total cost estimate for the projects making up the Balanced Portfolio decreased by 1.2% from the previous quarter during the 2nd quarter 2014 update cycle to a total of $815.1 million.

OGE reported the completion of their portion of the new 327-mile 345 kV line from Tuco to Woodward District EHV in western Oklahoma on May 19th. The line will be placed into service after Southwestern Public Service Company (SPS) completes construction of its portion of the line in the northern panhandle of Texas. SPS projects an in-service date for its part of the line in late September.

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 10 lists construction status updates for the Balanced Portfolio projects not yet completed.
### Table 9: Balanced Portfolio Summary

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>705/709</td>
<td>WFEC/OGE</td>
<td>Gracemont Substation 345 kV</td>
<td>N/A</td>
<td>$8,000,000</td>
<td>$14,921,070</td>
<td>$14,921,070</td>
<td>0.0%</td>
</tr>
<tr>
<td>707/708</td>
<td>ITCGP/NPPD</td>
<td>Spearville - Post Rock - Axtell 345 kV</td>
<td>223.0</td>
<td>$236,557,015</td>
<td>$203,559,673</td>
<td>$203,559,673</td>
<td>0.0%</td>
</tr>
<tr>
<td>698/699</td>
<td>OGE/GRDA</td>
<td>Sooner - Cleveland 345 kV</td>
<td>36.0</td>
<td>$33,530,000</td>
<td>$49,718,139</td>
<td>$49,718,139</td>
<td>0.0%</td>
</tr>
<tr>
<td>702</td>
<td>KCPL</td>
<td>Swissvale - Stilwell Tap 345 kV</td>
<td>N/A</td>
<td>$2,000,000</td>
<td>$2,910,227</td>
<td>$2,910,227</td>
<td>0.0%</td>
</tr>
<tr>
<td>700</td>
<td>OGE</td>
<td>Seminole - Muskogee 345 kV</td>
<td>100.0</td>
<td>$129,000,000</td>
<td>$170,000,000</td>
<td>$165,000,000</td>
<td>-2.9%</td>
</tr>
<tr>
<td>701/704</td>
<td>SPS/OGE</td>
<td>Tuco - Woodward 345 kV</td>
<td>327.0</td>
<td>$227,727,500</td>
<td>$318,627,516</td>
<td>$313,627,516</td>
<td>-1.6%</td>
</tr>
<tr>
<td>703</td>
<td>KCPL/GMO</td>
<td>Iatan - Nashua 345 kV</td>
<td>31.0</td>
<td>$54,444,000</td>
<td>$65,364,014</td>
<td>$65,342,070</td>
<td>-0.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total</strong></td>
<td>717.0</td>
<td><strong>$691,258,515</strong></td>
<td><strong>$825,100,639</strong></td>
<td><strong>$815,078,695</strong></td>
<td><strong>-1.2%</strong></td>
</tr>
</tbody>
</table>

### Table 10: Balanced Portfolio Construction Status

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Projected In-Service Date</th>
<th>Engineering</th>
<th>Siting and Routing</th>
<th>Environmental Studies</th>
<th>Permits</th>
<th>Material Procurement</th>
<th>Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>701</td>
<td>Tuco – Woodward 345 kV (OGE)</td>
<td>5/19/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>704</td>
<td>Tuco – Woodward 345 kV (SPS)</td>
<td>9/30/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>703</td>
<td>Iatan – Nashua 345 kV</td>
<td>6/1/2015</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>N/A</td>
<td>IP</td>
<td>IP</td>
</tr>
</tbody>
</table>
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 258 miles of new single circuit 345 kV transmission line and 422 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 for the projects making up the Priority Projects decreased by 0.1% from the previous quarter during the 2nd quarter 2014 update cycle to a total of $1.39 billion.

SPS and OGE reported that the new double circuit 345 kV line from Hitchland to Woodward District EHV in western Oklahoma was placed into service on May 16th. SPS constructed approximately 30 miles, while OGE built approximately 92 miles of the new 122-mile line. The total estimated cost of the project is $223.6 million.

Prairie Wind Transmission (PW) and Westar Energy, Inc. (WR) reported that the new 78-mile double circuit 345 kV line from Thistle to Wichita was energized on June 4th. PW completed the construction of the transmission line, while WR upgraded its Wichita substation to accommodate the new 345 kV circuits. The project is estimated to cost $136.6 million, and was originally not expected to be complete until late December.

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.
Figure 9: Priority Projects Cost Estimate Trend
### Table 11: Priority Projects Summary

<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project Name</th>
<th>Project Type</th>
<th>Proj. In-Service Date</th>
<th>Est. Line Length</th>
<th>BOD Approved Estimates (10/2010)</th>
<th>Q2 2014 Cost Estimates</th>
<th>Q3 2014 Cost Estimates</th>
<th>Est 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>
<td></td>
<td></td>
</tr>
<tr>
<td>940/941</td>
<td>SPS/OGE</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt</td>
<td>120.0</td>
<td>$221,572,283</td>
<td>$230,019,879</td>
<td>$228,331,670</td>
<td>-0.7%</td>
<td></td>
<td></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>$192,640,000</td>
<td>$192,640,000</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>945</td>
<td>ITCGP</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td>113.5</td>
<td>$293,235,000</td>
<td>$300,000,001</td>
<td>$300,000,001</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>946</td>
<td>PW/WR</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td>77.5</td>
<td>$163,488,000</td>
<td>$136,555,302</td>
<td>$136,555,302</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>936</td>
<td>AEP</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>76.3</td>
<td>$131,451,250</td>
<td>$127,995,000</td>
<td>$127,995,000</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>938/939</td>
<td>OPPD/GMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV</td>
<td>181.2</td>
<td>$403,740,000</td>
<td>$407,764,364</td>
<td>$407,791,450</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>677.9</td>
<td>$1,416,270,139</td>
<td>$1,395,935,441</td>
<td>$1,394,274,318</td>
<td>-0.1%</td>
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<td></td>
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</table>

### Table 12: Priority Projects Construction Status

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Project Type</th>
<th>Proj. In-Service Date</th>
<th>Engineering Status</th>
<th>Siting and Routing Status</th>
<th>Environmental Studies Status</th>
<th>Permits Status</th>
<th>Material Procurement Status</th>
<th>Construction Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>940</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt (SPS)</td>
<td>N/A</td>
<td>5/1/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>941</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt (OGE)</td>
<td>N/A</td>
<td>5/19/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>946</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td>N/A</td>
<td>6/4/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
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<tr>
<td>942</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt (OGE)</td>
<td>N/A</td>
<td>12/31/2014</td>
<td>IP</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>943</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt (PW)</td>
<td>N/A</td>
<td>12/31/2014</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>C</td>
<td>IP</td>
</tr>
<tr>
<td>945</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td>N/A</td>
<td>12/31/2014</td>
<td>IP</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>936</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>N/A</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 (GMO)</td>
<td>N/A</td>
<td>6/1/2017</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>NS</td>
</tr>
<tr>
<td>939</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
<td>N/A</td>
<td>6/1/2017</td>
<td>IP</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
<td>NS</td>
</tr>
</tbody>
</table>
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.

Four projects were identified as having exceeded the ±20% bandwidth requirement during the reporting period. All four projects have been placed into service.

Table 13 provides summary information and Table 14 lists the cost detail for the out-of-bandwidth projects for Q3 2014.

<table>
<thead>
<tr>
<th>PID</th>
<th>Network Upgrade Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Upgrade Type</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>634</td>
<td>K.C. South – Loma Vista East 161 kV Ckt 1</td>
<td>GMO</td>
<td>2008 STEP</td>
<td>Regional Reliability</td>
<td>1/14/2013</td>
</tr>
<tr>
<td>624</td>
<td>Fort Junction Switching Station – West Junction City 115 kV Rebuild</td>
<td>WR</td>
<td>2012 ITPNT</td>
<td>Regional Reliability</td>
<td>5/21/2013</td>
</tr>
<tr>
<td>30352</td>
<td>Folsom &amp; Pleasant Hill - Sheldon 115 kV Rebuild Ckt 2</td>
<td>LES</td>
<td>2012 ITPNT</td>
<td>Regional Reliability</td>
<td>8/12/2013</td>
</tr>
<tr>
<td>858</td>
<td>Cushing 138 kV Conversion</td>
<td>OGE</td>
<td>DPA Study</td>
<td>Regional Reliability</td>
<td>6/1/2014</td>
</tr>
</tbody>
</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>634</td>
<td>$3,527,710</td>
<td>2014</td>
<td>$3,527,710</td>
<td>$6,289,785</td>
<td>$2,762,075</td>
<td>78.3%</td>
</tr>
<tr>
<td>624</td>
<td>$6,969,136</td>
<td>2012</td>
<td>$7,321,949</td>
<td>$5,569,785</td>
<td>($1,752,164)</td>
<td>-23.9%</td>
</tr>
<tr>
<td>30352</td>
<td>$6,382,777</td>
<td>2012</td>
<td>$6,705,905</td>
<td>$5,197,561</td>
<td>($1,508,344)</td>
<td>-22.5%</td>
</tr>
<tr>
<td>858</td>
<td>$15,000,000</td>
<td>2013</td>
<td>$15,375,000</td>
<td>$10,600,000</td>
<td>($4,775,000)</td>
<td>-31.1%</td>
</tr>
</tbody>
</table>

Table 14: Out-of-Bandwidth Project Cost Detail
Responsiveness Report

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 Q3 2014. **Note:** Network Upgrades with statuses of “Within NTC Commitment Window” and “Within NTC-C Project Estimate Window” were excluded from this analysis.

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Number of Upgrades</th>
<th>Number of Upgrades Reviewed</th>
<th>Reviewed %</th>
<th>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>60</td>
<td>60</td>
<td>100%</td>
<td>5</td>
<td>8.3%</td>
<td>1</td>
<td>1.7%</td>
</tr>
<tr>
<td>CUS</td>
<td>1</td>
<td>1</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>GMO</td>
<td>11</td>
<td>11</td>
<td>100%</td>
<td>3</td>
<td>27.3%</td>
<td>3</td>
<td>27.3%</td>
</tr>
<tr>
<td>GRDA</td>
<td>12</td>
<td>5</td>
<td>42%</td>
<td>2</td>
<td>16.7%</td>
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<td>0.0%</td>
</tr>
<tr>
<td>ITCGP</td>
<td>14</td>
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<td>0.0%</td>
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<tr>
<td>KCPL</td>
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<td>12.5%</td>
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<td>LES</td>
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<td>28.6%</td>
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</tr>
<tr>
<td>MKEC</td>
<td>18</td>
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<td>5</td>
<td>27.8%</td>
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<td>44.4%</td>
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<td>NPPD</td>
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<td>21.3%</td>
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<td>OPPD</td>
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<td>100%</td>
<td>5</td>
<td>55.6%</td>
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<td>11.1%</td>
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<td>0.0%</td>
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<tr>
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<td>4</td>
<td>67%</td>
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<td>16.7%</td>
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<td>0.0%</td>
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<td>100%</td>
<td>17</td>
<td>16.0%</td>
<td>22</td>
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<td>5</td>
<td>100.0%</td>
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<tr>
<td>WFEC</td>
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<td>23.1%</td>
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<td>0.0%</td>
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<tr>
<td>WR</td>
<td>59</td>
<td>59</td>
<td>100%</td>
<td>10</td>
<td>16.9%</td>
<td>8</td>
<td>13.6%</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>464</strong></td>
<td><strong>449</strong></td>
<td>97%</td>
<td><strong>84</strong></td>
<td><strong>18.1%</strong></td>
<td><strong>61</strong></td>
<td><strong>13.1%</strong></td>
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*Table 15: Responsiveness Summary by Project Owner*
Figure 10: In-Service Date Changes by Project Owner

Figure 11: Cost Changes by Project Owner
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<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Description</th>
<th>Phase</th>
<th>Construction Start Date</th>
<th>Construction End Date</th>
<th>Project Status</th>
<th>Project Cost</th>
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<tbody>
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<td>SPS</td>
<td>SPS Chaves County 230/115 kV Transformer Ckt 2</td>
<td>Regional Reliability</td>
<td>6/30/2014</td>
<td>6/1/2013</td>
<td>6/2013/ITPNT</td>
<td>$3,687,125</td>
</tr>
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<td>6/1/2013</td>
<td>6/2013/ITPNT</td>
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</tr>
<tr>
<td>300167</td>
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<td>SPS Chaves County 230/115 kV Transformer Ckt 2</td>
<td>Regional Reliability</td>
<td>6/30/2014</td>
<td>6/1/2013</td>
<td>6/2013/ITPNT</td>
<td>$1,444,114</td>
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<td>SPS Chaves County 230/115 kV Transformer Ckt 2</td>
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<td>6/2013/ITPNT</td>
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<td>6/2013/ITPNT</td>
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<td>6/2013/ITPNT</td>
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<td>6/1/2013</td>
<td>6/2013/ITPNT</td>
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<tr>
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<td>6/1/2013</td>
<td>6/2013/ITPNT</td>
<td>$1,144,114</td>
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**Delay - Mitigation**

Instead of replacing transformer we are opening the Springfield to Golden 69kV ties.
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<th>Project Description</th>
<th>Dates</th>
<th>Cost Estimate</th>
<th>Status</th>
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<td>PLEASANT HILL - ROOSEVELT COUNTY INTERCHANGE 230KV</td>
<td>12/31/2016- 6/30/2013</td>
<td>$15,963,947</td>
<td>Completed</td>
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<tr>
<td>11086 LEA JOHNSON DRAW 115/69KV TRANSFORMER CKT 1 (LEA Co)</td>
<td>6/30/2016- 1/31/2013</td>
<td>$16,422,903</td>
<td>Completed</td>
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<tr>
<td>mitigation is to re-dispatch Gill and Evans in the Wichita area.</td>
<td>4/8/2013</td>
<td></td>
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<td>NORTHEAST HEREFORD INTERCHANGE 115/69KV</td>
<td>Regional Reliability - Non</td>
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<td>$1,000,000</td>
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<tr>
<td>80214 802 11064 SPS Eddy County Interchange 230/115 kV Transformer Ckt 1 Regional Reliability</td>
<td>6/28/2013- 6/1/2011</td>
<td>$4,255,145</td>
<td>Complete</td>
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<tr>
<td>805 50453 SPS Bowers - Howard 115 kV</td>
<td>Regional Reliability</td>
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<tr>
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<td>805 11053 SPS OASIS INTERCHANGE - PLEASANT HILL 230KV CKT 1 Regional Reliability</td>
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<td>$18,647,234</td>
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<td>792 11046 SPS BUCKEYE TAP - CUNNINGHAM STATION 115KV CKT 1 Regional Reliability</td>
<td>6/27/2013- 6/1/2013</td>
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<tr>
<td>791 11045 SPS HART INDUSTRIAL - LAMTON INTERCHANGE 115KV CKT 1 Regional Reliability</td>
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<td>Complete</td>
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<tr>
<td>50455 50453 SPS Bowers - Howard 115 kV</td>
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<td>50453 50453 SPS Bowers - Howard 115 kV</td>
<td>Regional Reliability</td>
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<td>50455 50455 SPS Bowers - Howard 115 kV</td>
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<td>Project Name</td>
<td>Description</td>
<td>Characteristics</td>
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<td>820214</td>
<td>839</td>
<td>10418</td>
<td>SPS</td>
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### Notes
- Project ID: Unique identifier for each project.
- Description: Details about the project, including type and location.
- Characteristics: specify regional or local reliability aspects.
- Date of Start: When the project began.
- Date of Completion: When the project was completed.
- Date of ITPNT: Initially target project notice to
- Cost Estimate: Initial cost estimate.
- Revised Costs: Updated cost estimates.
- Notes: Additional information or reasons for delays or changes.

**Project Notes:**
- **SPP-2007-AG3-AFS-**
- **DPA-2012-MAR-**
- **COMPLETE**
- **DELAY - MITIGATION**
- **ON SCHEDULE**
- **DELAY - MITIGATION**
- **CLOSED**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE**
- **COMPLETE - Project in Service, final closeout Letter to SPP in progress.**

**Additional Notes:**
- Projects delayed due to various factors such as permitting, environmental issues, route selection, and cost adjustments.
Bring on cap banks at Allen and Tioga. Dispatch Chanute/Erie/Iola generation.

$14,000,000

SPP-2009-AGP1-

SPP-2007-AG1-AFS-

COMPLETE

$513,981

COMPLETE

$100,000

COMPLETE

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COMPLETE

$100,000

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<td>115 kV</td>
<td>OGE</td>
<td>6/1/2016</td>
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<td>On Schedule</td>
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</table>
This is one of multiple components of the “rPLAN” project cost. Line Reactor costs are final cost data submitted.

Transmission line to utilize previously obtained Right of Way along the existing 345 kV line exiting to the North, the addition of 1 terminal, and extending the Base transformer. The modified substation configuration will have 7 Transformers in a Terminal ring. The final line route has not been determined at this time, therefore, the line

Substation Scope: Install 2 (115/138 kV) Transformers, each substation is new 115 kV Substation at the intersection point of the Mathewson Substation is new 345 kV substation at the intersection point of the Cimarron and Mathewson Substations. This estimate does include terminating the existing Cimarron or Mathewson 345 kV line exits to the East. All remains unchanged. PID 30364 & UID 50458.

This estimate includes relocating the existing Substation facilities for a new Substation to be built at or near the Campbells Creek wind farm project. Mathewson Substation will connect with (1) 345 kV Line to Campbells Creek wind farm. The 345kV line to Callaway (152/138 kV) will be Woodring.

This portion of the estimate includes 1 345 kV Substation in a ring bus configuration. These costs also include relocation of an existing equipment in Norfolk, Nebraska. All costs are preliminary estimates. The NTC - COMMITMENT WINDOW project in-service; cost finalized. Project complete and in-service. Costs not finalized.

The upgrade creates a new 115 kV Substation north of Nebraska City. The project complete and in-service. Costs not finalized. This portion of the estimate includes 1 345 kV Substation in a ring bus configuration. These costs also include relocation of an existing equipment in Norfolk, Nebraska. All costs are preliminary estimates. The NTC - COMMITMENT WINDOW project in-service; cost finalized. Project complete and in-service. Costs not finalized.

Accelerating the in-service date of the Hoskins - Neligh 345 kV project from 2019 to 2016 is necessary for NPPD to meet transmission planning standards based on the new forecasted summer peak loading conditions for 2016. This estimate does include relocating the existing Substation facilities for a new Substation to be built at or near the Campbells Creek wind farm project. Mathewson Substation will connect with (1) 345 kV Line to Campbells Creek wind farm. The 345kV line to Callaway (152/138 kV) will be Woodring.

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### Generation Interconnection

<table>
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<tr>
<th>Project Name</th>
<th>Status</th>
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<th>Summary</th>
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### Regional Reliability

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<td>Bushland Interchange - Deaf Smith Co Interchange 230 kV Ckt 1</td>
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### Replacement

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<td>30416</td>
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### Mitigation

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<td>30429</td>
<td>SPS Deaf Smith County Interchange 230/115 kV Transformer Ckt 2 Regional Reliability</td>
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###50510 MKEC Spearville 345/115 kV Transformer CKT 1 Generation Interconnection

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<tr>
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###50535 GRDA 412 Sub - Kansas Tap 161 kV Ckt 1 Terminal Upgrades Regional Reliability

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<td>Project 1</td>
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<td>SPS Kilgore Switch - South Portales</td>
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<td>Project 2</td>
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<td>Project 3</td>
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<td>Project 5</td>
<td>138 kV Ckt 1</td>
<td>WFEC Sandridge Tap - Renfrow</td>
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<td>Project 6</td>
<td>138 kV Ckt 1</td>
<td>WFEC Noel Switch - Wakita</td>
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<td>Project 7</td>
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<td>WFEC Hazelton</td>
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<td>Project 10</td>
<td>69 kV Capacitor</td>
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<td>Project 12</td>
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<td>AEP Midland REC - North Huntington</td>
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<td>Project 13</td>
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<td>Project 14</td>
<td>138 kV line</td>
<td>OGE Renfrow - Grant County</td>
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<td>Project 16</td>
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<td>WR Sugar Creek - Service PL Sugar Creek</td>
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<td>Project 17</td>
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<td>Project 18</td>
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<td>Project 19</td>
<td>115 kV Ckt 1</td>
<td>WR Sugar Creek - Service PL Sugar Creek</td>
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</table>

**Notes:**
- **Projects 1-12** are Regional Reliability projects.
- **Projects 13-19** are Transmission Service projects.
- **Projects 14-19** are projects related to the 345 kV transmission system.
- **Projects 16-19** are projects related to the 138 kV transmission system.
- **Projects 18-19** are projects related to the 69 kV transmission system.
- **All projects** have experienced delays and overruns.
- **Estimated costs** include preliminary and final design, construction, and contingencies.
- **Actual costs** include all costs associated with the project, including design, construction, and contingencies.
- **Variance** is the difference between the estimated and actual costs. A positive variance indicates an overrun, while a negative variance indicates a savings.
- **On Schedule** indicates if the project was completed on time.
- **In Progress** indicates if the project is currently underway.
- **Complete** indicates if the project has been completed.
- **Delay - Mitigation** indicates actions taken to mitigate delays.
- **Incomplete** indicates that the project has been partially completed.

---

**Explanation:**

- **Regional Reliability Projects:** These projects are aimed at improving the reliability of the regional transmission system. They include the construction of new transmission lines, substations, and upgrades to existing facilities. The projects are designed to enhance system reliability and resiliency, ensuring that customers remain connected even during extended outages.

- **Transmission Service Projects:** These projects are focused on expanding and improving the transmission service provided to customers. They involve the construction of new transmission lines, substations, and upgrades to existing facilities. The goal is to increase system capacity, improve service reliability, and meet the growing energy demands of the region.

- **345 kV Transmission Projects:** These projects are part of the ongoing efforts to upgrade and expand the 345 kV transmission system, which is critical for inter-regional power exchange and system reliability. Projects include the construction of new transmission lines, substations, and upgrades to existing facilities.

- **138 kV Transmission Projects:** These projects are focused on improving and expanding the 138 kV transmission system, which supports a significant portion of customer loads. Projects include the construction of new transmission lines, substations, and upgrades to existing facilities.

- **69 kV Transmission Projects:** These projects are focused on improving and expanding the 69 kV transmission system, which provides an essential distribution service to customers. Projects include the construction of new transmission lines, substations, and upgrades to existing facilities.

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**Additional Information:**

- **Delays:** Many projects have experienced delays due to various factors, including weather conditions, regulatory approvals, and supply chain disruptions.
- **Mitigation Measures:** Various measures have been implemented to mitigate delays, including expedited scheduling, increased staff, and alternative procurement strategies.
- **Overruns:** Some projects have experienced overruns due to higher-than-expected costs and other unforeseen challenges.
- **Cost Estimation:** Cost estimates include preliminary and final design, construction, and contingencies. The actual cost includes all costs associated with the project, including design, construction, and contingencies.

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**Contact Information:**

For detailed information on the projects, please contact the respective project managers or the utility's public information office. To stay informed, visit the utility's website for the latest updates on project statuses and achievements.
<table>
<thead>
<tr>
<th>Company</th>
<th>Project Description</th>
<th>Regional Reliability</th>
<th>Start Date</th>
<th>End Date</th>
<th>Delay - Mitigation</th>
<th>Cost Estimate</th>
<th>Notes</th>
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**Incomplete roundtrip may be due to the (UPO).**
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**Note:** For detailed project descriptions, configurations, and costs, please refer to the respective project documents and reports.
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Note: Some project details may include special conditions or requirements. Please refer to the original document for more information.
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