1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of April 23, 2012 Minutes

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

4. BUSINESS MEETING
   a. No Business Meeting Items

5. REPORTS/PRESENTATION
   a. CAWG Report ........................................................................................................................ Pat Mosier

      This Report provides an update on CAWG activity, including recommendations made, and
      CAWG’s future schedule.

   b. Order 1000 Update .................................................................................................................. Paul Suskie

      Order 1000 ROFR Update (POTENTIAL VOTING ISSUE) ..................................................... Paul Suskie

      This report will update the RSC on the efforts of the SPCTF on Order 1000 and the Task
      Force’s Report recommendations on SPP compliance with Order 1000/1000-A on policy
      issues including the ROFR and possible impacts on the Highway/Byway cost allocation
      methodology.  SPP has asked the RSC for their input on SPP’s compliance filing as it
      relates to the impact Orders 1000 & 1000-A has on State regulators’ jurisdiction.

   CAWG’s Recommendation ROFR ..................................................................................... Pat Mosier

      The CAWG has a recommendation for the RSC on the ROFR as it relates to SPP’s Order
      1000 compliance filing.

   SPCTF on Order 1000 .............................................................................................................. Ricky Bittle

      This report will update the RSC on the efforts of the SPCTF on Order 1000 and the Task
      Force’s Report making recommendations on SPP’s compliance with Orders 1000/1000-A.

   Seams Steering Committee Update ................................................................................. Paul Malone

      This report will update the RSC on the efforts of the SSC on Order 1000 and the status of
      the SSC’s efforts to address the interregional planning requirements of Order 1000.

   Interregional Cost Allocation TF Update (VOTING ITEM) ............................................... Chairman Kevin Gunn
This report will update the RSC on the efforts of the task force on interregional cost allocation as part of Order 1000 compliance. The task force has developed general guidelines and principals as to how SPP should address cost allocation for Interregional Projects pursuant to Order 1000. The task force is asking the RSC to adopt these guidelines and principals.

c. Waiver Request (75196276) (VOTING ITEM) ................................................................. Lanny Nickell
   This report will provide a summary of the request by Oklahoma Municipal Power Authority waiver to base plan fund cost that exceed the safe harbor limit.

d. Waiver Request (76585958 & 76586012) (VOTING ITEM) ............................................ Lanny Nickell
   This report will provide a summary of the request by Arkansas Electric Cooperative Cooperation for two waivers to base plan fund cost that exceed the safe harbor limit.
   CAWG’s Recommendation on Waiver Requests ............................................................. Pat Mosier
   The CAWG has a recommendation for the RSC on the Waiver request.

e. Integrated Marketplace Update ......................................................................................... Bruce Rew
   This report will update the RSC on the SPP’s efforts in developing and implementing the Integrated Marketplace (IM).

6. FUTURE RSC MATTERS

   a. Officer Elections – October 2012
   
   B. Adoption of 2013 Budget

7. SCHEDULING OF NEXT REGULAR MEETING, SPECIAL MEETINGS OR EVENTS

   a. RSC Meetings:
       October 29, 2012 – Little Rock, AR
       January 28, 2012 – New Orleans, LA
Southwest Power Pool
REGIONAL STATE COMMITTEE
Renaissance Hotel, Oklahoma City, OK
April 23 2012

• M I N U T E S •

Administrative Items:
The following members were in attendance:

- Terry Jarrett, proxy for Kevin Gunn, Missouri Public Service Commission (MOPSC)
- 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)
- Mike Siedschlag, Nebraska Power Review Board (NPRB)
- Thomas Wright, Kansas Corporation Commission (KCC)

President Olan Reeves called the meeting to order at 1:05 p.m. with roll call and a quorum was declared. He then requested a round of introductions. There were 124 in attendance either in person or via phone (Attendance & Proxies – Attachment 1).

President Reeves asked for approval of the January 30, 2012 meeting minutes (RSC Minutes 1/30/12 - Attachment 2). Patrick Lyons moved to approve the minutes as presented; Tom Wright seconded the motion. The minutes were unanimously approved.

UPDATES

RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Suskie reported that the RSC is within budget. The seams cost allocation item is from 2011 and does not appear in the 2012 budget.

SPP Report
Mr. Nick Brown congratulated the RSC regarding the appeal on cost allocation, which has been dropped based largely to the great work and thinking of the Regional Allocation Review Task Force (RARTF). He commended the task force for great work.

Mr. Brown reported that following the January 2012 Board meeting, the Board of Directors and Officers met and discussed a strategic visioning initiative. Staff was asked to evaluate firms to conduct interviews with stakeholders, committees and the Economics Studies Working Group regarding ITP10 and ITP20 processes; conduct workshops to vet information regarding uncertainties/issues; and provide guidance selecting several scenarios and key issues. A recommendation will be made at the SPP Board of Directors meeting on April 24.
FERC
Mr. Patrick Clarey provided an update on recent FERC activities:

February
On February 3, 2012, President Barack Obama announced his intent to re-nominate John Norris as a FERC Commissioner. The Commission also opened a docket (AD12-12-000) as a repository for comments concerning gas-electric interdependence. Comments were due the end of March.

March
FERC approved the merger of Exelon Corporation and Constellation Energy Group, Inc. FERC also approved a Stipulation and Consent Agreement between the Commission’s Office of Enforcement and Constellation Energy Commodities Group related to findings of market manipulation. The Agreement directs Constellation to pay a civil penalty of $135 million and to disgorge unjust profits of $110 million or a total settlement amount of $245 million. This total reflects the largest penalty that the Commission has imposed under the expanded enforcement authority that Congress assigned in 2005.

Commissioner John R. Norris and Mr. Tony Clark testified before the Senate Committee on Energy & Natural Resources as part of the nominating process to be members of the Federal Energy Regulatory Commission.

FERC reaffirmed PJM’s region-wide, postage-stamp rate to allocate costs of new transmission lines operating at and above 500 kV.

April
FERC took steps to further promote efficient and nondiscriminatory operation of the nation’s electric system when it opened an inquiry into open access and priority rights for capacity on interconnection facilities. The Notice of Inquiry (NOI) asks whether FERC should revise its policy on access to interconnection facilities and, if so, offers alternate approaches for comment.

FERC conditionally accepted MISO and its transmission owners’ proposal to establish a transition for the integration of Entergy into MISO. The order finds the proposal to be just and reasonable and requires further explanation and tariff revisions on compliance, primarily to clarify the treatment of MVP projects.

BUSINESS MEETING
No business was reported.

REPORTS/PRESENTATIONS
RSC Consultant Report
Dr. Mike Proctor presented the Cost Allocation Working Group (CAWG) report (Hub & Spoke Presentations – Attachment 4). Dr. Proctor provided background and information regarding the hub and spoke cost allocation between load and generation including proposals made by the Area Generation Connection Task Force (AGCTF). The AGCTF was commissioned by the Markets and Operations Policy Committee (MOPC) to develop an approach to resolve potential difficulties from having a large number of individual generation connections along segments of 345 kV transmission lines. The CAWG requested that AGCTF provide a cost-effectiveness study of the Hub Design. After reviewing the AGCTF proposals, the CAWG made the following recommendation to the RSC:

CAWG recommends that the RSC accept a policy such that no generation interconnection costs associated with Hub and Spoke design be included in the regional transmission rates, and instead be assigned to generators.

Following discussion, Michael Siedschlag moved to approve the recommendation; Tom Wright seconded the motion. The motion passed with unanimous approval.
Dr. Proctor then provided background and information regarding the hub and spoke cost allocation among generators. He discussed cost allocation principles with the CAWG endorsing costs classifications as shared and assigned costs. Carl Huslig, AGCTF Chair, stated that there is a lack of cost allocation principles among generators and that the group is in need of direction. Mr. Huslig suggested sending hub and spoke policies to the Board of Directors for approval. Dr. Proctor then offered the following conclusions:

**The CAWG endorses the method for SPP allocation to generators of the Hub and Spoke interconnection costs described herein (see Attachment 4) and proposes that the RSC consider recommending this method to the SPP Board of Directors.**

After much discussion, the RSC decided not to act on this recommendation stating that it may be premature to make a recommendation, questioned if this was a regional cost and questioned if the RSC had authority to make decisions regarding generators.

**CAWG Report**
Pat Mosier provided the CAWG report (CAWG Report – Attachment 5). Ms. Mosier presented an update on CAWG activity, recommendations made and CAWG’s future schedule.

**Order 1000 Update (Order 1000 Presentations – Attachment 6)**

**Joint Task Force on Order 1000 Interregional Cost Allocation**
President Reeves stated that the RSC had begun working on seams issues prior to Order 1000 deciding to issue an RFP in January 2011 for a seams consultant. The Brattle Group was hired in July 2011 to analyze seams and provide a report to the RSC. President Reeves recommends that the RSC approve the formation of a Joint Task Force made up of: 3 RSC members, 3 SPP members and 1 SPP Board member. This task force is to be structured after the successful Regional Allocation Review Task Force (RARTF). Donna Nelson moved to approve this recommendation; Terry Jarrett seconded the motion. The motion passed with unanimous approval.

**Order 1000 Update**
Paul Suskie presented an update on Order 1000 providing RTO regional requirements and the current status of SPP compliance (Order 1000 Compliance Efforts – Attachment 6).

**SPCTF on Order 1000 Update**
Mel Perkins, SPCTF Chairman, provided eight recommendations as determined by the SPCTF regarding how SPP should comply with Order 1000 on regional policy issues such as ROFR and the consideration of public policy requirement in transmission planning. These recommendations are:

1. Recommendation as to the Transmission Upgrades for which SPP Should Seek to Retain the Federal ROFR.
2. Recommendation as to What Model SPP Should Use to Select Transmission Owners for Projects Without a ROFR.
3. Recommendation as to Transmission Owner Qualification Criteria.
4. Recommendation as to Changes to SPP’s Membership Agreement and OATT.
5. Recommendation as to Application of Order 1000 to Future SPP Projects.
6. Recommendation as to Consideration of Transmission Needs Driven by Public Policy
7. Recommendation as to Information and Data from Merchant Transmission Developers.
8. Timeline for Compliance Filing.
The Strategic Planning Committee (SPC) approved these recommendations unanimously with the exception of recommendation two, in which SPC approved the Competitive Solicitation Process model versus the Project Sponsorship Model to select builders for projects that do not have a Federal ROFR. These recommendations will be presented to the Board of Directors on April 24 at a policy level and hopefully with detailed language at the Board of Directors July meeting.

Seams Steering Committee (SSC) Update
Paul Malone reported that the SSC was tasked with ensuring compliance on the interregional transmission planning requirement of Order 1000. The SSC chartered the Seams FERC Order 1000 Task Force (SFOTF) to develop concepts and work on Joint Operating Agreement (JOA) language.

RSC Seams Cost Allocation Consultant (Brattle) Report
Johannes Pfeifenberger provided an update on the RSC seams cost allocation efforts. Mr. Pfeifenberger reviewed the seven building blocks previously identified, paying special attention to key seams cost allocation blocks 3 – 6. These building blocks are most closely related to seams allocation but are either missing or largely unspecified in the current JOAs. Brattle's final report and presentation is included in Attachment 6. Mr. Pfeifenberger concluded that the proposed framework strikes a balance between methodology that is actionable and also provides the flexibility needed for successful application of seams projects and seams entities. He believes it is imperative that there be significant coordination between SPP and the RSC.

Integrated Marketplace Update
Bruce Rew provided an Integrated Marketplace update (Integrated Marketplace Update – Attachment 7). He reviewed the Marketplace’s recent successes, the status of Tariff revisions, and a general program update. Mr. Rew stated that in February the decision was made to change the program status to yellow, which is defined as concerned about meeting a key milestone on the date assigned. This is precautionary as they are working through areas of concern. The Integrated Marketplace Scorecard is posted on the SPP website every month for reference. Following visits with all of the states coordinated by Heather Starnes (SPP), it is planned to have an Integrated Marketplace overview the morning prior to the RSC October meeting.

EPA Rules Update
Michael Desselle provided an EPA Rules update (EPA Rules – Attachment 8). Mr. Desselle discussed a contextual overview; the assessment process; and key data including MW, generation, and margin.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Reeves noted that the next regularly scheduled meeting is on July 30 in Kansas City, MO.

With no further business, the meeting adjourned at 4:45 p.m.

Respectfully Submitted,

Paul Suskie
Regional State Committee  
For the Six Months Ending June 30, 2012  
Budget vs. Actual

<table>
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<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<tr>
<td><strong>Income</strong></td>
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<td></td>
<td></td>
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<tr>
<td>Other Income</td>
<td>283,284</td>
<td>150,500</td>
<td>132,784</td>
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<td><strong>Total Income</strong></td>
<td>283,284</td>
<td>150,500</td>
<td>132,784</td>
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<tr>
<td><strong>Expense</strong></td>
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<td>Travel</td>
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<td>55,000</td>
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<td>Audit</td>
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<td>-</td>
<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>
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<td>(26,829)</td>
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<tr>
<td>Technical Conference</td>
<td>-</td>
<td>25,000</td>
<td>(25,000)</td>
</tr>
<tr>
<td>Seams Cost Allocation</td>
<td>168,406</td>
<td>-</td>
<td>168,406</td>
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<tr>
<td><strong>Total Expense</strong></td>
<td>283,284</td>
<td>150,500</td>
<td>132,784</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
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</table>
Report to the
Regional State Committee
July 30, 2012

COST ALLOCATION WORKING GROUP
(CAWG)

CAWG REPORT TO RSC

CAWG ACTIVITY - QUARTERLY UPDATE

- Updates To RSC - SPCTF on Order 1000
- Monitor SPP Working Groups / Task Forces
  * ESWG - Metrics Task Force
  * Seams Steering Committee
  * Regional Tariff Working Group
  * Project Cost Working Group
  * Market Working Group
  * Area Generation Connection Task Force
- Public Policy Requirements In Planning Survey
- Ongoing Consideration for Treatment of Cost Overruns
- Waiver Requests: OMPA & AECC
CAWG REPORT TO RSC

Updates To RSC - SPCTF on Order 1000

- Per RSC directive in January 2012, CAWG has approved ongoing updates for distribution to RSC members on activity of Task Force. (Most Current Updated Report is included as Attachment A to this Report.)

- The SPCTF voted to seek RSC support of its most current recommendation related to Order 1000’s directive on the elimination of Federal Rights of First Refusal (ROFR) on projects receiving regional cost allocation.

- The SPCTF currently recommends that SPP seek to retain ROFR for the following projects:
  - Byway Projects
  - Projects assigned entirely to Multi-TO zones
  - Short-term reliability Projects

- CAWG voted to recommend that the RSC support this SPCTF position.

CAWG REPORT TO RSC

Working Group/Task Force Updates(1) / General Overview

ESWG/Metrics Task Force

Most current CAWG Member Updates on Metrics Task Force activity reflects:

In addition to the four (4) metrics currently approved for measuring benefits in planning models, the Metrics Task Force has identified an additional ten (10) metrics which it will offer to the RARTF to be implemented in its first review.

The Metrics Task Force has also identified an additional eight (8) Metrics which are not yet ready for implementation but which the Task Force continues to address.

(1) All Working Group/Task Force Updates available in CAWG Meeting Minutes.
CAWG REPORT TO RSC

Working Group/Task Force Updates/General Overview
Seams Steering Committee (SSC)

Most current CAWG Member Updates on SSC activity reflects:

• SSC Task Force on Order 1000 continues to meet to make April 2013 FERC Filing Deadline

• And, related: New Interregional Cost Allocation Task Force (ICATF) had its first meeting.

• The SSC asked SPP to address options regarding better facilitation as to third party impacts, including a scheduled and recommended approach.

• SSC provided update on MISO activity, including MISO intervention in SPP/WAPA JOA filing and ongoing issues related to loop-flow and flow-gate coordination.

CAWG REPORT TO RSC

Working Group/Task Force Updates/General Overview
Regional Tariff Working Group (RTWG)

Most current CAWG Member Update on RTWG activity reflects:
RTWG approved (and sought and received approval at MOPC (2)) four tariff revisions:
1. Clarification as to time limits on billing corrections


3. Clarification that Balanced Portfolio Transfers over the 10 year period should capture the entire level of approved transfers, given the graduated transfers over the first five (5) years.

4. Per MOPC directive changed calculation of the Schedule 11 zonal component of through and out rates to be based on the regional average of all the Schedule 11 Zonal ATRR

(2) See RTWG presentation to MOPC 07/18-07/19)
CAWG REPORT TO RSC

Working Group/Task Force Updates/General Overview
Project Cost Working Group (PCWG)

Most current CAWG Member Update on PCWG activity reflects:

1. A selected group of members will review a sample of projects with NTCs, for which cost differences exceeding the +or- 20% levels are expected, to determine reason for difference. To that end, a report will be prepared for PCWG review for both differences and format of report.

2. A minor change to Business Practice to clarify that Designated Transmission Owner will provide cost estimates necessary to develop CPE was approved and will be presented to MOPC in October 2012.

3. Discussion continues on the impact of Order 1000’s required selection process on PCWG cost estimating process.

CAWG REPORT TO RSC

Working Group/Task Force Updates/General Overview
Market Working Group (MWG)

Most current CAWG Member Update on MWG activity reflects:

In general, MWG continues to address new markets, including current testing and very specific provisions of the expected operation of the markets.
CAWG REPORT TO RSC

Working Group/Task Force Updates/General Overview
Area Generation Connection Task Force (AGCTF)

Most current CAWG Member Update on AGCTF activity reflects:

The Hub & Spoke proposal (as endorsed by the RSC) which was approved at the April Board meeting is now with the RTWG. Because of time limitations caused by Order 1000, the RTWG has not yet taken up tariff language on its implementation.

In April 2012, FERC issued NOI “Open Access and Priority Rights on Interconnection Facilities” in which SPP has filed comments and may have future impact on current Hub/Spoke impacts.

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CAWG REPORT TO RSC

Public Policy Requirements In Planning Survey

CAWG supported differentiation of Public Policy Requirements in the current ITP20 Survey between those required by statute or regulation and those which were simply goals or targets. In June 2012, SPP provided the following update on the Survey results:

<table>
<thead>
<tr>
<th>2013 ITP20</th>
<th>Capacity (MW)</th>
<th>Energy (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2033 Targets</td>
<td>4,040</td>
<td>15,059,491</td>
</tr>
<tr>
<td>2033 Mandates</td>
<td>3,322</td>
<td>12,383,668</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>7,363</strong></td>
<td><strong>27,443,160</strong></td>
</tr>
</tbody>
</table>
CAWG REPORT TO RSC

Ongoing Consideration for Treatment of Cost Overruns

CAWG is considering options related to treatment of Cost Overruns, including an option proposed by RSC consultant, Mike Proctor. No CAWG recommendation is being made to RSC at this time.

CAWG REPORT TO RSC

Waiver Requests: OMPA & AECC

SPP presented for CAWG approval waiver requests by two TOs, OMPA and AECC; SPP will present these two TO requests for waiver to the RSC for its approval at this meeting. SPP will provide the information related to those requests.

CAWG voted to recommend approval of each of the requests subject to specific limitations based on the facts surrounding each TO’s request.
CAWG REPORT TO RSC

Future CAWG Meetings

• CAWG will continue to address proposals related to Cost Overruns in future meetings

• CAWG will continue to monitor pertinent Working Group/Task Force Activity in anticipation of future RSC action

• CAWG will continue to provide the RSC updates on FERC’s Order 1000 requirements for both ROFR issues and Interregional Cost Allocation and SPP’s compliance filings.

Questions:

Submitted by: Pat Mosier
Chairman, CAWG
July 30, 2012
The following represents the most currently known position of the SPP Board (as approved in April 2012) and the SPCTF on Order 1000 (SPCTF1000 or TF or Task Force) as finalized in July 2012. This Report to the RSC\(^1\) represents the positions that CAWG anticipates will be presented to the Board at its July meeting for approval. For background on issues covered previously, the Report should be read in conjunction with prior reports made available through the CAWG. This Report updates the Report approved by CAWG at its July 11, 2012.

Within this Report is a CAWG recommendation to be made to the RSC at its July 30, 2012 meeting.

*****

Background
Board Approved Provisions From April 2012 Meeting

**I. Projects for which SPP would seek to retain ROFR:**

SPP will seek retention of ROFR on all projects, except Base Plan projects of 300 kv and above (which are allocated 100% to the region).

**II. Model Used to Select Transmission Owners for Projects no longer subject to ROFR provisions.**

SPP will use the Competitive Solicitation Model under which all projects approved in the ITP process, irrespective of who proposed them, are subject to a bidding process.

**III. The timing as to which projects would be subject to the new Order 1000 ROFR requirements.**

Projects subject to Order 1000 requirements would be those approved in the first STEP Report that is issued after the first participant/developer approval process, with the date of the approval process dependent upon the date of FERC’s approval of SPP’s Compliance filing.

\(^1\) At its January 2012 meeting, the RSC directed the CAWG to provide it updated information regarding the issues addressed in this Report.
IV. The Timeline for Order 1000 Compliance

The original deadline for its compliance filing was October 11, 2012. On July 13, 2012, SPP was granted an extension on its filing until November 12, 2012 per original Board approval to seek extension.

V. The Order 1000 issues to be addressed by other Task Forces or Working Groups

A. RTWG – Compliance Changes to SPP’s Membership Agreement and OATT
B. RTWG/TWG/ESWG – Compliance with Public Policy Requirements;
C. RTWG – Information Requirements from Non-Participating Merchant Developers.

*****

UPDATE THROUGH JULY 30
POST-APRIL BOARD MEETING RECOMMENDATIONS
ORDER 1000 COMPLIANCE

I. Projects for which SPP would seek to retain the Right of First Refusal (ROFR):

A. Byway Projects

The Task Force continues to recommend that SPP make its compliance filing seeking to exclude Byway projects from Order 1000 ROFR requirements (thus, requesting that all Byway projects still retain Federal ROFR).

The Task Force also considered seeking changes to the current allocation method to address Order 1000 ROFR provisions related to Byway Projects but agreed to continue to support its original April 2012 recommendation to the Board and propose no changes to allocation at this time.

B. Multi-TO Zones

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2 It is anticipated that certain provisions approved by the Board in its July 2012 meeting will require further delineation prior to the November 2012 Compliance Filing and will be assigned to other Working Groups.

3 Order 1000-A, issued May 17, clarified that projects allocated entirely to any zone which included more than one TO would be considered regional for purposes of Order 1000 and ROFR would no longer apply. SPP has five (5) zones with more than one TO.
The TF voted to have SPP make its compliance filing maintaining ROFR for its five multi-TO zones. The TF recommended SPP argue that FERC’s ruling is not applicable to SPP, noting that, in SPP multi-TO zones, only one TO is the predominant provider of transmission service, without which no load in that zone could be served. Further, the ATRR impact to the other non-predominant TOs supports that finding.

C. Short-Term Reliability Projects

The TF also voted to have SPP make its compliance filing maintaining ROFR for any reliability project (assuming it would be subject to regional allocation) which required immediate attention and that the proposed bidding process time-line for non-ROFR projects would not accommodate that short-term need. The TF considered the option to have the incumbent be directed to build the project with all costs directly assigned. The TF rejected that proposed treatment, determining that the rate impact to the incumbent’s ratepayers would be unfair, given that, absent the timing of the need, these projects would have garnered Highway/Byway treatment and that such policy runs counter to the currently approved allocation method.

The Mobile-Sierra Doctrine Argument in Seeking Retention of ROFR:

The Task Force also recommended that SPP assert the applicability of the “Mobile-Sierra Doctrine” to current contracts (i.e. Membership Agreements) and that FERC has failed to make the requisite findings under that doctrine. FERC, in Order 1000-A, provided that the Mobile-Sierra argument could be made, but that it must be done in conjunction with a filing which, assuming the legal argument was not successful, complied with the provisions of Order 1000.

(A general explanation of that Doctrine is that:

The Mobile-Sierra Doctrine recognizes that in requiring that rates be “just and reasonable,” Congress did not intend to impose this standard on rates initially fixed by private contracts when later challenged by FERC or a third party. Rather, in such cases, the rates can be changed only if the entity seeking the change can show that the modification is required by the “public interest,” as opposed to showing simply that the rates are “unjust and unreasonable.”

(Taken from article in Electric Light & Power, POWERGRID International, and Utility Products: What’s Left of Mobile-Sierra by Larry Eisenstat and George Johnson)

4 Order 1000-A clarified that delineation of a project as “reliability” did not make that project not subject to the provisions of Order 1000.

5 The Task Force defined “near term system reliability needs” in its “Selection Process” as reliability needs for which; 1) non transmission based mitigation is not feasible; and 2) transmission based mitigation cannot be achieved considering the RFP timeline.
RSC Support:

The SPCTF1000 voted to request RSC support of SPP’s position that it will seek to retain ROFR on Byway projects, projects assigned entirely to Multi-TO zones, and reliability projects for which there is an immediate need.

CAWG RECOMMENDATION:

At its July 11, 2012, meeting, CAWG voted to recommend the following to the RSC:

CAWG recommends to the RSC that it support or endorse those provisions of SPP’s Order 1000 compliance filing\(^6\) in which SPP will seek exclusion from Order 1000 ROFR requirements of designated “Byway” projects, projects assigned entirely to Multi-TO zones and reliability projects which must be completed in a short time period.

*****

UPDATED PROVISIONS FOR WHICH NO RSC ACTION IS REQUESTED

II. Transmission Owner Qualification Criteria (Applicable to all Applicant Transmission Owners (ATOs), including incumbents. Once an ATO becomes a Qualified Transmission Owner, i.e. QTO, the QTO remains eligible for 5 years, with annual QTO affirmation of its QTO status.)

(A) Threshold Membership Criteria:

SPP Membership: An ATO must be a member of SPP or be willing to become a member if selected in Selection Process.

(B) Financial Qualification Criteria:

An ATO must show that it meets SPP’s financial criteria as established by SPP’s Finance Committee which it may help establish by submission to SPP that it has:

1. An investment Grade Rating; or
2. A Guaranty from a Parent with Investment Grade Rating; or
3. A Bank reference letter or bonding indication; or
4. A Direct rate-making or taxing authority.

\(^6\) While the CAWG supports retention of ROFR provisions for these projects, the CAWG makes no determination related to the Mobile-Sierra legal arguments which are to be incorporated into SPP’s compliance filing in support of ROFR retention.
(C) Management Criteria:

ATO must provide showing that it has:

1. Expertise in transmission (i.e. to build, own, operate, etc.),
2. Safety Qualifications (i.e. internal safety program, safety record, etc.),
3. Operations Expertise (i.e. control center operations, NERC compliance, etc.),
4. Maintenance Qualifications & Expertise (i.e. staffing, maintenance plans, NERC compliance process and history), and
5. Ability to Comply with Good Utility Practice, SPP criteria, industry standards, etc.

*****

III. Transmission Owner Qualification Process

Qualification Process

1. Application Reviewed By SPP, questions by SPP to ATO can be made;
2. Notification of Qualification Deficiency(ies);
3. Notification of Qualification as Qualified Transmission Owner (QTO);
4. Allow for Changes needed to ATO Applications or QTO Status by ATO/QTO, and
5. Application is Posted to SPP Website (Eliminated requirement to notify state commissions.)
6. Once qualified, a QTO remains such for five years unless there is a change in circumstance.
7. If there is a change in circumstances, QTO must notify SPP and SPP can
   (a) Determine that the change does not affect the QTO’s qualification to participate in SPP’s Competitive Solicitation Process;
   (b) Determine that the QTO no longer qualifies as a QTO;
   (c) Suspend the QTO’s eligibility to participate in SPP’s Competitive Solicitation Process until the QTO has cured any deficiency in its qualifications to SPP’s satisfaction; or
   (d) Allow the QTO to continue to participate in SPP’s Competitive Solicitation Process for a limited time period while the QTO cures the deficiency to SPP’s satisfaction.

*****

Page 5 of 9
IV. Proposal for Selection of QTO to Build Project – RFPs, RFP Administration, RFP Process & Timeline, and TO Selection Criteria & Scoring

A. RFPs

1. RFP Issuance (standard form):

   The RFP will list its purpose, deadlines, cost and financial information requirements, project engineering requirements, construction information requirements, operations and maintenance cost information requirements, information exchange requirements (i.e. NERC information), safety information requirements, and SPP RFP evaluation process, and will allow for attachments to standard form.

2. RFP Administration/Industry Expert Panel

   Industry Expert Panel (IEP)

   The SPP Oversight Committee (OC) shall establish a pool of candidates having expertise in Engineering Design, Project Management (i.e. Construction), Operations, Rate Analysis, and Finance/Credit from which a panel, i.e. the IEP, will be chosen to evaluate the annual proposals in response to the RFPs. That pool shall be subject to Board approval prior to Board approval of the ITP transmission projects.

   Upon BOD approval of a transmission expansion plan, SPP staff will solicit QTO responses to the RFP under the following process:

   a. SPP staff will notify the Chairman of the BOD and Chairman of the OC Projects subject to bid will be submitted to the Chairman of the Board and the Oversight Committee (OC).

   b. From the pool, the OC shall choose the IEP(s) which will be made up of 3 to 5 panelists (2 of which must be industry experts). That IEP’s recommendation shall be the primary source for BOD selection of the QTO for each project.

   c. Any subsequent affiliation of an IEP member with an SPP stakeholder must be disclosed for further OC evaluation. All panelists must sign a standard non-disclosure form.

   d. The IEP will evaluate all proposals and develop a single recommendation for the BOD.

3. RFP Process and Timeline:

   a. Issue RFP (to QTOs only) within 7 days of Board Approval of Project or no later than 18 months prior to expected first financial expenditure.

---

7 An Expert’s affiliation with any SPP stakeholder must be disclosed and will be reviewed by the OC in the selection process.
8 Staff, with BOD approval, may select more than one IEP if RFP responses are greater than expected.
b. QTO must respond to RFP within 90 days (Response Window).

c. SPP reviews QTO Responses for completeness (corrections must be completed within 90-day Response Window).

d. If no response to RFP, SPP assigns to incumbent TO.

e. At close of Response Window, QTO Responses are evaluated by IEPs and scored, with IEPs making final recommendation to Board within 60 days. QTO identities will be provided IEPs but not the Board.

f. All communications between the IEP and RFP respondents shall be documented, with IEP scoring done in a non-discriminatory manner and lobbying of the IEP is prohibited.

g. The IEP will compile an internal report detailing their deliberations which is provided to Staff. The report, excluding confidential information, will be published and provided to all QTOs and stakeholders and to the BOD 14 days prior to the BOD meeting in which a TO will be selected (i.e. Selected Transmission Owner, or STO. A backup QTO will also be selected.

h. By issuance of NTC (which is subject to project cost tracking), SPP shall notify STO it is Designated Transmission Owner (DTO) & DTO shall sign all necessary agreements.

i. Failure by STO to accept NTC within 7 days waives right to be DTO and NTC is delivered to backup QTO under same terms as provided originally.

j. Failure by backup QTO to accept NTC within 7 days waives right of backup QTO to be DTO and results in assignment of project to incumbent.

k. The Board may accelerate the RFP timeline to meet urgent reliability needs and directly assign the incumbent as the TO.

l. An estimate of the pro rata share of the cost of the RFP process will be assessed each responding QTO to the RFP, with a true up to actual cost.

m. DTOs chosen through the RFP process may not assign or novate the project.

n. Post-NTC funding proof must be provided by the DTO (e.g. Performance bond, letter of credit.)

o. A deposit of 2% of the estimated cost of the project must be provided by DTO (unless DTO is incumbent TO) to ensure completion of the project. Deposit is required irrespective of letter of credit or bond. Upon default the deposit will be credited to the project to offset the total project costs.

B. Transmission Owner Selection Criteria & Scoring
1. Respondents must meet minimum QTO requirements. The EIP will develop final scores in a non-discriminatory manner and give recommendation to BOD and may eliminate respondent because of low score in one category. Highest score may not necessarily be chosen.

2. **IEP Scoring:**

There are 1000 points available in Base Categories with an additional 100 points available in an incentive category to encourage innovation in planning process.

3. **Base Categories & Points:**

a. Engineering Design (Reliability/Quality/General Design): – 200 points:
   Measures the quality of the design, material, technology, and life expectancy of a transmission project and includes but is not limited to:
   - Type of construction (wood, steel, design loading, etc.)
   - Losses (design efficiency)
   - Estimated life of construction
   - Reliability/Quality Metrics

b. Construction (Project Management): – 200 points:
   Measures a QTO’s expertise in implanting construction projects similar in scope to the project that is subject of the RFP and includes but is not limited to:
   - Environmental
   - ROW Acquisition
   - Procurement
   - Project scope
   - Project development schedule (**including obtaining necessary regulatory approvals**)  
     - Construction
     - Commissioning
     - Timeframe to construct
     - Experience/Track Record

   Measures safety and capability of a QTO to operate, maintain, and restore a transmission project and includes but is not limited to:
   - Control center operations (staffing etc.)
   - Storm/Outage response plan
   - Reliability metrics
   - Restoration Experience/Performance
   - Maintenance Staffing/Training
   - Maintenance plans
   - Equipment
July 30, 2012
Report to RSC
SPCTF Order 1000

• Maintenance performance/expertise
• NERC compliance-process/history
• Internal safety program
• Contractor safety program
• Safety performance record (program execution)

d. Rate Analysis (Cost to Customer): – 225 points.
Measures over a 40 year period a QTO’s cost to construct, own, and operate the transmission project that is the subject of the RFP and includes but is not limited to:
• Estimated total cost of project
• Financing costs
• FERC Incentives
• Revenue Requirements
• Lifetime cost of the project to customers
• ROE
• Material on Hand, ROW approval, Assets on hand
• Cost certainty guarantee.

e. Finance (Financial Viability and Creditworthiness): - 125 points.
Measures a QTO’s ability to obtain financing for a transmission project that is the subject of the RFP and includes but is not be limited to:
• Evidence of financing
• Material conditions
• Financial/Business plan
• Pro forma financial statements
• Expected financial leverage
• Debt covenants
• Projected liquidity
• Dividend policy
• Cash flow analysis

4. **Incentive Points:**

Incentives (Project Proposal Submission): – 100 points.
Awards bonus points to QTOs that proposed the transmission project within the planning process that are selected and the subject of the RFP. The points are awarded to QTO on its proposed project upon which it bids. Staff gives notice of projects being studied in planning process and provides 30 day window for proposals, with proposals to be made reflecting specifics of the project. Staff will develop open-window process to determine proposals adopted.
Order 1000 Presentation

for the

SPP Regional State Committee

July - 2012
Order 1000 Requirements Analysis

- Analysis divides requirements into:
  
  1. Regional (RTO) Requirements
  2. Interregional Requirements
# Order 1000 Regional (RTO) Requirements

<table>
<thead>
<tr>
<th>No.</th>
<th>RTO Regional Requirements</th>
<th>Current Status of SPP Compliance</th>
<th>Leads on Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regional Planning</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1(a)</td>
<td>Participate in a regional transmission planning process that produces a regional transmission plan and complies with the Order No. 890 transmission planning principles. [¶ 6, 146]</td>
<td>SPP Complies with requirement.</td>
<td>N/A</td>
</tr>
<tr>
<td>1(b)</td>
<td>Amend OATT to explicitly provide for the consideration of transmission needs driven by Public Policy Requirements in both local and regional transmission planning processes. [¶ 203, 222]</td>
<td>Section III.6.k &amp;n of Attachment O to the SPP OATT considers Public Policy Requirements.</td>
<td>SPP Legal/Regulatory, Strategic Planning Committee, &amp; RTWG: Consider drafting amendments to Attachment O that more directly addressing Public Policy requirements in Order 1000.</td>
</tr>
<tr>
<td>1(c)</td>
<td>Regional Planning must evaluates transmission alternatives at the regional level that may resolve the transmission planning region’s needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. [¶ 6, 146]</td>
<td>SPP Complies with requirement.</td>
<td>N/A</td>
</tr>
<tr>
<td>1(d)</td>
<td>Regional Planning must consider proposed non-transmission alternatives on a comparable basis. [¶ 148]</td>
<td>SPP Complies with requirement</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Right of First Refusal</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.</td>
<td>Remove from FERC-jurisdictional tariffs and agreements any right of first refusal for an incumbent transmission provider to construct transmission facilities identified in the regional transmission plan for cost allocation. [¶ 313]</td>
<td>SPP’s OATT has ROFR language.</td>
<td>Strategic Planning Committee: Review and consider amendments to SPP Membership Agreement &amp; OATT that directly address “ROFR.”</td>
</tr>
</tbody>
</table>

## Cost Allocation

| 3. | Include in its OATT a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for cost allocation. [¶ 482] | SPP Complies with requirement. | N/A |
# Order 1000 Interregional Requirements

<table>
<thead>
<tr>
<th>No.</th>
<th>Interregional Requirements</th>
<th>Current Status of SPP Compliance</th>
<th>Leads on Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Engage in interregional coordination with each neighboring transmission planning region within the same interconnection to identify and jointly evaluate interregional transmission facilities that may more efficiently or cost-effectively address the individual needs of each respective local and regional transmission planning processes. [¶ 345, 393, 415]</td>
<td>Although SPP has Seams Agreements with neighboring regions, Order 1000 places additional requirements on Interregional planning</td>
<td><em>SPP Engineering &amp; SPP Seams Steering Committee:</em> Review Seams Agreements/Joint Operating Agreements. Develop procedures to comply with the interregional coordination requirements set forth in Order No. 1000 and to develop the same language to be included in each public utility transmission provider’s OATT that describes the procedures that a particular pair of transmission planning regions will use to engage in interregional coordination. OATT must still provide enough description so that stakeholders can follow how interregional transmission coordination will be conducted, and the OATT must contain links to the actual agreements</td>
</tr>
<tr>
<td>2.</td>
<td>Develop, working through its transmission planning region, a method or set of methods for allocating the costs of new interregional transmission facilities that two (or more) neighboring transmission planning regions determine resolve the individual needs of each region more efficiently and cost-effectively. [¶ 578]</td>
<td>SPP has no methods for allocating costs for interregional transmission facilities with neighboring regions</td>
<td><em>SPP Regulatory, SPP Seams Steering Committee &amp; SPP Regional State Committee:</em> SPP’s RSC has already engaged the Brattle Group to look at Seams Cost Allocation.</td>
</tr>
</tbody>
</table>
ORDER 1000 AND ROFR
“RIGHT OF FIRST REFUSAL”
Order 1000 - Elimination of ROFR

ROFR Removal - Public utility transmission providers must remove from their OATTs or other FERC-jurisdictional tariffs and agreements any provisions that grant a federal right of first refusal to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation. [P 313] The focus of this requirement is transmission facilities that are evaluated at the regional level and selected in the regional plan for purposes of cost allocation, as opposed to facilities that are planned exclusively in the public utility transmission provider’s local planning process and simply “rolled-up” and listed in the regional transmission plan for informational purposes and analysis. [P 318 and n.299]

Applicability - This requirement does not apply to the right of an incumbent utility to build, own, and recover costs for upgrades to its existing transmission facilities, and does not alter an incumbent transmission provider’s use and control of existing rights of way, even if such upgrades or facilities on existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation. [P 319]
ROFR’s 4 Limitations

• Rule removing ROFR from Commission approved tariffs and agreements is subject to four limitations:

(1) This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation;

(2) This does not apply to upgrades to transmission facilities, such as tower change outs or reconductoring;

(3) This allows, but does not require, the use of competitive bidding to solicit transmission projects or project developers; and

(4) Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
Order 1000-A; Paragraph 426.

“Petitioners request clarification about whether a transmission facility is a local transmission facility if it is selected in a regional transmission plan for purposes of cost allocation and the costs are allocated to a single pricing zone in which the proposed transmission facility is to be located, and that zone consists of more than one transmission provider. . . . In general, any regional allocation of the cost of a new transmission facility outside a single transmission provider’s retail distribution service territory or footprint, including an allocation to a “zone” consisting of more than one transmission provider, is an application of the regional cost allocation method and that new transmission facility is not a local transmission facility. “

* * * * *

“However, we recognize . . . that special consideration is needed when a small transmission provider is located within the footprint of another transmission provider. “

* * * * *

“Accordingly, we will address whether a cost allocation to a multi-transmission provider zone is regional on a case-by-case basis based on the specific facts presented. Specific situations may be included in a compliance filing along with the filed regional cost allocation method or methods.”
17 Transmission Owning Zones in SPP

<table>
<thead>
<tr>
<th>Zone No.</th>
<th>Zone Name</th>
<th>(3) Zonal ATRR (FROM Transmission Owner)</th>
<th>(4) Base Plan Zonal ATRR</th>
<th>(5) Base Plan Zonal ATRR after June 19, 2010</th>
<th>(6) ATRR Reallocated to Balanced Portfolio Region-wide ATRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>American Electric Power –West (Total)</td>
<td>$152,220,454</td>
<td>$25,784,103</td>
<td>$84,075</td>
<td>$0</td>
</tr>
<tr>
<td>2</td>
<td>Reserved for Future Use</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>City Utilities of Springfield, Missouri</td>
<td>$8,651,509</td>
<td>$73,326</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>4</td>
<td>Empire District Electric Company</td>
<td>$14,075,000</td>
<td>$229,436</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>5</td>
<td>Grand River Dam Authority</td>
<td>$21,196,230</td>
<td>$2,492,320</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>6</td>
<td>Kansas City Power &amp; Light Company</td>
<td>$30,440,539</td>
<td>$3,298,358</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>7</td>
<td>Oklahoma Gas and Electric (Total)</td>
<td>$82,534,685</td>
<td>$11,462,867</td>
<td>$492,086</td>
<td>$0</td>
</tr>
<tr>
<td>8</td>
<td>Midwest Energy, Inc.</td>
<td>$8,819,682</td>
<td>$152,259</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>9</td>
<td>KCP&amp;L Greater Missouri Operations Company</td>
<td>$36,405,920</td>
<td>$970,922</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>10</td>
<td>Southwestern Power Administration</td>
<td>$14,267,100</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>11</td>
<td>Southwestern Public Service Company (Total)</td>
<td>$112,447,746</td>
<td>$17,151,748</td>
<td>$331,789</td>
<td>$0</td>
</tr>
<tr>
<td>12</td>
<td>Sunflower Electric Power Corporation</td>
<td>$14,484,045</td>
<td>$1,144,163</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>13</td>
<td>Western Farmers Electric Cooperative</td>
<td>$20,719,639</td>
<td>$3,960,828</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>14</td>
<td>Westar Energy, Inc. (Kansas Gas &amp; Electric and Westar Energy)</td>
<td>$148,462,476</td>
<td>$24,218,556</td>
<td>$104,607</td>
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<tr>
<td>15</td>
<td>Mid-Kansas Electric Company (Total)</td>
<td>$16,897,799</td>
<td>$866,604</td>
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<td>$0</td>
</tr>
<tr>
<td>16</td>
<td>Lincoln Electric System</td>
<td>$21,433,977</td>
<td>$116,420</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>17</td>
<td>Nebraska Public Power District</td>
<td>$55,001,484</td>
<td>$16,892,471</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>18</td>
<td>Omaha Public Power District</td>
<td>$40,944,590</td>
<td>$3,314,125</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>19</td>
<td>Total</td>
<td>$799,002,875</td>
<td>$112,128,506</td>
<td>$1,012,557</td>
<td>$0</td>
</tr>
</tbody>
</table>

Source: April, 2012 Posting of “RRR” Files, SPP OATT Attachment H. Annual Transmission Revenue Requirement for Network Integration Transmission Service

http://www.spp.org/publications/For_Bills_2012-04-01_Revenue_Requirements_and_Rates_after%20Tri-County.xls
12 of 17 Zones have a Single TO

<table>
<thead>
<tr>
<th>(1) Zone No.</th>
<th>(2) Zone Name</th>
<th>% of ATRR in Zone</th>
<th>(3) Zonal ATRR (FROM Transmission Owner)</th>
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<td>100%</td>
<td>$8,619,682</td>
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<td>$0</td>
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<td>Southwestern Power Administration</td>
<td>100%</td>
<td>$14,267,100</td>
<td>$0</td>
<td>$0</td>
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<td>$0</td>
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<td>$0</td>
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</tr>
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<td>17</td>
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http://www.spp.org/publications/For_Bills_2012-04-01_Revenue_Requirements_and_Rates_after%20Tri-County.xls

Note: % ATRR in Zone added to Att. H Table 1, otherwise numbered columns are as they appear in the OATT
SPP has five pricing zones that contain transmission facilities owned by multiple entities:

<table>
<thead>
<tr>
<th>Zone No.</th>
<th>Zone Name</th>
<th>% of ATRR in Zone</th>
<th>(3) Zonal ATRR (FROM Transmission Owner)</th>
<th>(4) Base Plan Zonal ATRR</th>
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</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td><em>American Electric Power – West (Total)</em></td>
<td>96.79%</td>
<td>$152,220,454</td>
<td>$25,784,103</td>
<td>$84,075</td>
<td>$0</td>
</tr>
<tr>
<td>1a</td>
<td>American Electric Power (PSCO &amp; SWEPCO)</td>
<td></td>
<td>$147,332,963</td>
<td>$25,109,134</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1b</td>
<td>East Texas Electric Cooperative, Inc.</td>
<td>1.80%</td>
<td>$2,733,879</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>1c</td>
<td>Tex-La Electric Cooperative of Texas, Inc.</td>
<td>0.39%</td>
<td>$588,874</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>1d</td>
<td>Deep East Texas Electric Cooperative, Inc.</td>
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</tr>
<tr>
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<td>Oklahoma Municipal Power Authority</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>1f</td>
<td>AEP West Transmission Companies (AEP)</td>
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<td>$674,969</td>
<td>$84,075</td>
<td>$0</td>
</tr>
<tr>
<td>7</td>
<td><em>Oklahoma Gas and Electric (Total)</em></td>
<td></td>
<td>$82,534,685</td>
<td>$11,462,867</td>
<td>$492,086</td>
<td></td>
</tr>
<tr>
<td>7a</td>
<td>Oklahoma Gas and Electric</td>
<td>99.55%</td>
<td>$82,166,184</td>
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<td>$492,086</td>
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<tr>
<td>7b</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
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<td></td>
<td>$112,447,746</td>
<td>$17,151,748</td>
<td>$331,789</td>
<td>$0</td>
</tr>
<tr>
<td>11a</td>
<td>Southwestern Public Service Company</td>
<td>98.24%</td>
<td>$110,464,906</td>
<td>$17,151,748</td>
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<td>Tri-County Electric Cooperative</td>
<td>1.76%</td>
<td>$1,982,840</td>
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<td><em>Westar Energy, Inc. (Kansas Gas &amp; Electric and Westar Energy)</em></td>
<td>99.64%</td>
<td>$148,462,476</td>
<td>$24,218,555</td>
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<td>14b</td>
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<td>14c</td>
<td>Kansas Power Pool</td>
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<td>15</td>
<td><em>Mid-Kansas Electric Company (Total)</em></td>
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Source: SPP OATT Attachment H: Annual Transmission Revenue Requirement for Network Integration Transmission Service

http://www.spp.org/publications/For_Bills_2012-04-01_Revenue_Requirements_and_Rates_after%20Tri-County.xls
SPP Pricing Zones with More than One Transmission Owner

Pricing Zone Number

- Zone 1: AEPW
- Zone 7: OKGE
- Zone 11: SWPS
- Zone 14: WERE
- Zone 15: MKEC

- 161 kV
- 230 kV
- 345 kV

Southwest Power Pool

Entergy ICT
4 SIGNIFICANT CHANGES ON SPP BY ORDERS 1000 & 1000-A

Unanticipated Changes on SPP’s ITP Process and Cost Allocation Methodology
4 Significant Changes of Order 1000’s - ROFR

(1) That the RSC’s approval of regionalized funding for projects as low as 100 kV could result in the loss of a Right of First Refusal (ROFR) from FERC tariffs (currently in the SPP OATT) for projects 100 kV and above. See Order 1000-A, paragraph 430. (This has significant state jurisdictional issues)

(2) That five of SPP’s 17 zones, which include parts of six states and 63% of SPP’s load, could potentially lose ROFR, with the exception of FERC carve outs, because each of the five zones contain more than one transmission owner in a particular zonal rate. See Order 1000-A, paragraph 424.
4 Significant Changes of Order 1000’s - ROFR

(3) That FERC would, in effect, preclude Transmission Providers such as SPP from including a requirement that participants in SPP’s Transmission Owner Selection Process must obtain or be able to obtain state authority to construct, own, and operate transmission facilities under state law before participating in the SPP Transmission Owner Selection Process for projects with ROFR elimination.

(4) That FERC would prohibit the application of Highway/Byway funding to short-term reliability projects that were needed in a timeframe under which only the incumbent Transmission Owner could build within the necessary timeframe that would result in zonal cost assignment for projects built outside the Transmission Owner Selection Process. See Order 1000-A, paragraph 428.
Outreach to State Commissioners

(1) Inform State Commissioners in the SPP region of the impact of FERC’s Orders 1000 & 1000-A on State Retail Jurisdiction.

(2) Seek the RSC’s input RSC’s view on SPP’s compliance filing.
Outreach to State Commissioners

(1) Inform State Commissioners in the SPP region of the impact of FERC’s Orders 1000 & 1000-A on State Retail Jurisdiction.

• Under Orders 1000 & 1000-A SPP may be required to award transmission projects entities that have not been recognized by state commissions as a utility

• Projects being awarded to entities that are not utilities under state law raises state jurisdictional issues.

• Competitive Solicitation Process will delay SPP FERC approved ITP process.
Outreach to State Commissioners

(2) Seek the RSC’s input RSC’s view on SPP’s compliance filing on ROFR.

Three Questions:

1. Whether or not the RSC supports SPP’s compliance filing seeking to maintain a ROFR for projects (100 kV & below) in the five SPP zones with more than one transmission owner? (The five zones with multiple transmission owners are AEP, OG&E, SPS, Mid-Kansas, and Westar.)

2. Whether or not the RSC supports SPP’s compliance filing seeking to maintain a ROFR for SPP projects funded under the RSC’s Byway cost allocation methodology (100 kV to 300 kV upgrades)?

3. Whether or not the RSC supports SPP’s compliance filing seeking to maintain a ROFR for short-term reliability projects that are needed to be in-service before SPP can complete a Transmission Owner Selection Process and before a selected owner could obtain necessary state approvals for a project that is needed to maintain reliability?
## SPP Highway/Byway Upgrades & ROFR

<table>
<thead>
<tr>
<th>Voltage/Type of Facility</th>
<th>Allocation of Costs</th>
<th>Input from RSC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Zonal Upgrades:</strong> 100 kV &amp; below</td>
<td>100% Zonal</td>
<td><strong>100% Funded by the Zone:</strong> Under Order 1000-A [Para. 426], because SPP has 5 zones with more than 1 Transmission Owner SPP will need to provide case-by-case justification to retain ROFR. <em>RSC Input?</em></td>
</tr>
<tr>
<td><strong>Byway Upgrades:</strong> 100 – 300 kV</td>
<td>1/3 Regional &amp; 2/3 Zonal</td>
<td><strong>2/3 Regionally Funded:</strong> Under Orders 1000 &amp; 1000-A SPP will need to justify retaining ROFR. <em>RSC Input?</em></td>
</tr>
<tr>
<td><strong>Highway Upgrades:</strong> 300 kV &amp; above</td>
<td>100% Regional</td>
<td><strong>100% Regional Funding:</strong> SPP plans to file a compliance filing to remove ROFR.</td>
</tr>
</tbody>
</table>
**TOPIC:** Request for input from the SPP RSC on the removal of ROFR in the SPP footprint.

**SPPT**

In January 2009, SPP created the Synergistic Planning Project Team (SPPT). The SPPT was a high-level, multi-disciplinary policy team consisting of state regulators from SPP’s Regional State Committee and SPP member representatives. The SPPT focused on recommendations for creating a robust, flexible, and cost-effective transmission system for the region, large enough in both scale and geography to meet SPP’s future needs looking forward twenty to forty years.

In April 2009, the SPPT issued its Report which recommended (1) the development of an Integrated Transmission Planning process (ITP) that improves and integrates SPP's existing transmission planning processes and (2) the implementation of a new Highway/Byway cost allocation methodology (“Highway/Byway”) to pay for new transmission in the region.

In April 2009, SPP’s RSC and Members Committee unanimously supported the Report which was also approved by SPP’s Board of Directors.

**RSC HIGHWAY/BYWAY COST ALLOCATION METHODOLOGY and UNFORESEEN CONSEQUENCES CREATED BY FERC ORDERS 1000 and 1000-A**

**RSC’s Highway/Byway Cost Allocation Methodology**

The RSC led SPP’s effort on the development of the Highway/Byway per the RSC’s FERC-approved Section 205 responsibility over cost allocation in SPP. Between April and October of 2009, SPP’s RSC worked diligently to develop a Highway/Byway cost allocation methodology per the recommendation contained in the SPPT Report. The final Highway/Byway methodology included regionalizing 100% of costs for transmission upgrades of 300 kV and 33% of costs for facilities between 100 kV to 300 kV. The RSC approved this methodology in October 2009, and FERC approved this methodology with no changes in June 2010.

The SPP’s RSC development and approval of the Highway/Byway cost allocation methodology was historic in terms of regional-state cooperation in the United States. The development of the Highway/Byway and its implementation have received significant praise in the electric utility industry and has been called the “model” and “poster child” by FERC Commissioners.

The ability of the RSC to agree on this methodology was a result of years of hard work as well as trust and faith from SPP’s state regulators who were willing to support the regional funding of projects in SPP. This faith and trust was premised on the understanding and belief that SPP has and will continue to include and give great deference to SPP’s state regulators.
At the time SPP’s RSC approved the concept of regional funding for projects as small as 100 kV in SPP, the RSC could not have foreseen that FERC would change the SPP stakeholder process on transmission planning. Nor could the RSC have predicted how the assignment of projects in SPP would so significantly change with the adoption of Orders 1000 and 1000-A.

The significant, unanticipated changes that Orders 1000 and 1000-A placed upon SPP and the RSC’s approved cost allocation methodology include:

(1) That the RSC’s approval of regionalized funding for projects as low as 100 kV could result in the loss of a Right of First Refusal (ROFR) from FERC tariffs (currently in the SPP OATT) for projects 100 kV and above.\(^1\)

(2) That five of SPP’s 17 zones, which include parts of six states and 63% of SPP’s load, could potentially lose ROFR, with the exception of FERC carve outs, because each of the five zones contain more than one transmission owner in a particular zonal rate.\(^2\)

(3) That FERC would, in effect, preclude Transmission Providers such as SPP from including a requirement that participants in SPP’s Transmission Owner Selection Process must obtain or be able to obtain state authority to construct, own, and operate transmission facilities under state law before participating in the SPP Transmission Owner Selection Process for projects with ROFR elimination.\(^3\) In Order 1000-A, the Commission did note that, if a transmission facility is selected in the regional transmission plan for purposes of cost allocation, the Commission clarifies that the transmission developer of that transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals, necessary to develop and construct the transmission facility such that it meets the transmission needs of the region.

(4) That FERC would prohibit the application of Highway/Byway funding to short-term reliability projects that were needed in a time frame under which only the incumbent Transmission Owner could build within the necessary timeframe that would result in zonal cost assignment for projects built outside the Transmission Owner Selection

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\(^1\) Under language contained in Order 1000-A, SPP members would lose their federal ROFR for projects 100 kV and above. See Order 1000-A, paragraph 430.

\(^2\) Under language contained in Order 1000-A, as a general rule, SPP members in five of SPP’s 17 zones would also lose the federal ROFR even below 100 kV. See Order 1000-A, paragraph 424. It is important to note that the Commission in Order 1000-A specifically also provided the ability for regions to file in their compliance filing evidence demonstrating that a cost allocation to a multi-transmission zone should be considered local and the Commission to make a ruling based on the specific facts presented on a case-by-case basis.

\(^3\)
Process. This would include projects in which enough time does exist for SPP to complete its Transmission Owner Selection Process and for a selected owner could obtain necessary state approvals in the time frame that the project was needed to maintain reliability. This disadvantages the retail ratepayers of the incumbent Transmission Owner’s zone due to cost assignment to only that zone for such projects and runs counter to the policy approved by both the RSC and FERC with the adoption of SPP’s Highway/Byway.

Delays in SPP’s ITP Process

Additionally, SPP wishes to inform the RSC of the concern of timing delays caused by FERC’s requirement to remove ROFR. This is of particular concern with reliability projects needed in the short term.

The process being proposed by SPP to comply with Order 1000 is a Competitive Solicitation process. Under this process SPP will issue a Request for Proposals (RFP) for all projects that do not have a ROFR. It is through this Competitive Solicitation process that SPP will select the entity that will build an upgrade.

SPP anticipates that this additional amount of time will add at least six months to SPP’s transmission planning process. This six month delay estimate does not contain any estimated delays caused by litigation from a transmission owner that is not selected in the Competitive Solicitation process.

SPP RESPONSE TO ORDERS 1000 AND 1000-A AND REQUEST FOR RSC INPUT

As SPP Staff and stakeholders have worked through issues in order to comply with Orders 1000 and 1000-A, it has become apparent that there are concerns with the potential loss of ROFR whenever any project, regardless of voltage level, receives regional funding.  

4 Under language contained in Order 1000-A, because of the regional funding of projects in SPP, SPP could not use Highway/Byway funding for reliability projects needed on a schedule which requires only the incumbent to build. See Order 1000-A, paragraph 428.

5 SPP will assert Mobile-Sierra as a part of its Order 1000 compliance filing as it relates to the SPP Membership Agreement. FERC will first determine, based on a more complete record, whether the agreement is protected by Mobile-Sierra. In general, the Mobile-Sierra doctrine indicates that rates set by a freely negotiated wholesale energy contract are presumed to be just and reasonable. This presumption can only be overcome if FERC concludes that the contract “seriously harms the public interest.” Recent U.S. Supreme Court cases have indicated that the Mobile-Sierra doctrine applies both to FERC and third-parties, not just to the contracting parties. FERC determined to address such arguments on a case-by-case basis in the compliance filing proceedings. Additionally, in Order 1000-A FERC clarifies, that parties seeking
As a result, SPP is seeking the input of the RSC members as SPP begins to finalize its Order 1000 regional compliance filing. In particular, SPP seeks the RSC’s input on:

(1) Whether or not the RSC supports SPP’s compliance filing seeking to maintain a ROFR for projects (100 kV & below) in the five SPP zones with more than one transmission owner? (The five zones with multiple transmission owners are AEP, OG&E, SPS, Mid-Kansas, and Westar.)

(2) Whether or not the RSC supports SPP’s compliance filing seeking to maintain a ROFR for SPP projects funded under the RSC’s Byway cost allocation methodology (100 kV to 300 kV upgrades)?

(3) Whether or not the RSC supports SPP’s compliance filing seeking to maintain a ROFR for short-term reliability projects that are needed to be in-service before SPP can complete a Transmission Owner Selection Process and before a selected owner could obtain necessary state approvals for a project that is needed to maintain reliability?

As a result of the language in Order 1000-A, the SPCTF recommended that SPP include as a part of its compliance filing for Order 1000 arguments that the Right of First Refusal contained in SPP’s Membership Agreement is protected under the Mobile-Sierra Doctrine. The SPC and Board of Directors will provide further guidance in their SPP July meetings. However as noted above, SPP is required to submit tariff/agreement revisions in their compliance filings to comply with Orders 1000 and 1000-A. While SPP will file a Mobile-Sierra assertion, SPP has provided its proposed compliance filing position.
As approved at its last Board meeting, SPP will seek retention of ROFR on all projects except Base Plan projects of 300 kv and above (which are allocated 100% to the region).

According to Order 1000 and Order 1000-A, any project, for which regional funding is applicable, will no longer retain Federal ROFR.

Specifically, SPP will seek retention of ROFR on three sets of projects addressed under Orders 1000/1000-A.
Order 1000 Compliance Filing

A. Byway Projects

Although subject to 1/3 regional allocation treatment, the SPCTF seeks to exclude Byway projects from Order 1000 ROFR requirements and retain Federal ROFR. The Task Force considered seeking changes to the current allocation method to address Order 1000 ROFR provisions related to Byway Projects but agreed to continue to support its original April 2012 recommendation to the Board and propose no changes to allocation at this time.

CAWG considered the impact removal of ROFR would have, given the lower voltage lines contained within the Byway, on completion of transmission projects as well as possible proposals to change the currently approved Highway/Byway allocation method approved by the RSC. In this regard, the CAWG voted to support retention of ROFR for Byway Projects.

B. Multi-TO Zones

Order 1000-A, issued May 17, clarified that projects allocated entirely to any zone which included more than one TO would be considered regional for purposes of Order 1000 and ROFR would no longer apply. SPP has five (5) zones with more than one TO.

The SPCTF voted to have SPP make its compliance filing maintaining ROFR for these multi-TO zones and recommended SPP argue that FERC’s ruling is not applicable to SPP, given that, in SPP multi-TO zones, only one TO is the predominant provider of transmission service, without which no load in that zone could be served. Further, the ATRR impact to the other non-predominant TOs supports that finding.

CAWG considered the rationale upon which the SPCTF made its recommendation and voted to recommend the RSC support seeking retention of ROFR for Multi-TO Zones.
C. Short-Term Reliability Projects

Order 1000-A clarified that delineation of a project as reliability did exclude that project from the provisions of Order 1000 and, thus, Order 1000’s ROFR exclusion.

The SPCTF supports maintenance of ROFR for any reliability project, even subject to regional allocation, which required immediate attention and for which 1) non-transmission based mitigation is not feasible, and 2) transmission based mitigation cannot be achieved considering the RFP timeline. The SPCTF rejected the option of directly assigning costs to TOs directed to build immediate need projects as being unfair to incumbents ratepayers. The SPCT also determined the change in treatment runs counter to the currently approved allocation method.

The CAWG, having considered the rationale proffered by the SPCTF, voted to recommend the RSC support exclusion from Order 1000 ROFR requirements those Short-Term Reliability Projects as defined within the SPCTF’s recommendation to the SPC.

Order 1000 Compliance Filing

CAWG RECOMMENDATION TO THE RSC
ON ROFR ISSUES IN
SPP’s PROPOSED ORDER 1000 COMPLIANCE FILING

Pursuant to the majority vote of the CAWG, the CAWG makes the following recommendation to the RSC:

CAWG recommends to the RSC that it support or endorse those provisions of SPP’s Order 1000 compliance filing in which SPP will seek exclusion from Order 1000 ROFR requirements of designated “Byway” projects, projects assigned entirely to Multi-TO zones and reliability projects which must be completed in a short time period.

The CAWG does not address nor make any recommendations regarding the legal arguments SPP will make or the SPCTF’s final determinations on the processes and requirements it proposes be adopted in meeting Order 1000 ROFR requirements.
Order 1000 Compliance Filing

Questions:

Submitted by: Pat Mosier
On Behalf of the CAWG
July 30, 2012
SPCTF Recommendations on Order 1000

2nd Report

July - 2012

<table>
<thead>
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<th>SPCTF Members</th>
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<td>Mel Perkins, Chairman</td>
<td>Oklahoma Gas &amp; Electric, Co.</td>
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<tr>
<td>Noman Williams, Member</td>
<td>Sunflower Electric Power Corporation</td>
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<tr>
<td>Brian Thumm, Member</td>
<td>ITC Holdings</td>
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<td>Dennis Reed, Member</td>
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<td>Ricky Bittle, Member</td>
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<td>Todd Fridley, Member</td>
<td>Kansas City Power &amp; Light Company</td>
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<td>Paul Malone, Member</td>
<td>Nebraska Public Power District</td>
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<td>Terri Gallup, Member</td>
<td>America Electric Power</td>
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<td>Mitch Elmore, Member</td>
<td>Xcel Energy</td>
</tr>
<tr>
<td>Michael Desselle, SPP Staff</td>
<td>SPP Staff</td>
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COMPLIANCE DEADLINES OF ORDER 1000

• Regional Compliance Filing: Compliance filings addressing the Order No. 1000 regional transmission planning and cost allocation requirements must be submitted to FERC by October 11, 2012.
  – On July 13, 2012 FERC approved SPP’s request for a 30-day extension. New Compliance Date is Nov. 12, 2012

• Interregional Compliance Filing: Compliance filings addressing the interregional coordination and cost allocation requirements of Order No. 1000 are due by April 11, 2013.
8 Recommendations

I. Recommendation as to the Transmission Upgrades for which SPP Should Seek to Retain the Federal ROFR.

II. Recommendation as to What Model SPP Should Use to Select Transmission Owners for Projects Without a Federal ROFR.

III. Recommendation as to Transmission Owner Qualification Criteria.

IV. Recommendation as to Changes to SPP’s Membership Agreement and OATT to Remove the Federal ROFR.

V. Recommendation as to Application of Order 1000 to Future SPP Projects.

VI. Recommendation as to Consideration of Transmission Needs Driven by Public Policy.

VII. Recommendation as to Information and Data from Merchant Transmission Developers.

VIII. Timeline for Compliance Filing.

Regional Compliance Filing

OVERVIEW OF 2ND REPORT OF THE SPCTF ON ORDER 1000
6 RECOMMENDATIONS OF THE SPCTF

I. Recommendation of Transmission Owner Selection Criteria

II. Recommendation of Qualification Criteria for Applicant Transmission Owners.

III. Recommendation on the Mobile-Sierra Doctrine.

IV. Recommendation on the Retention of ROFR for Short-Term Reliability Projects.

V. Recommendation on Establishment of a Need by Date, Notice of Such Date, and Requirement to meet Deadlines.

VI. Recommendation of a required Deposit from the selected transmission owner

I. Recommendation - Owner Selection Criteria SPP Should Use.

1.1. Recommended Transmission Owner Selection Criteria

The SPCTF recommends that SPP use the Transmission Owner Selection Criteria in an SPP Competitive Solicitation Process as detailed in Attachment A to this Report.
I. RFP Process Timeline (Calendar Days)

1. BOD Approves Transmission Expansion Plan
2. SPP Issues RFP to QTOs
3. QTOs Respond; Window Closes; IEP Evaluations Begin
4. Evaluations Submitted to BOD
5. BOD Selects QTO for Project; SPP Notifies STO of NTC
6. If STO Doesn’t Respond or is Unwilling to Accept NTC, Backup QTO is Notified
7. If Backup QTO Doesn’t Respond or is Unwilling to Accept NTC, NTC issued to Incumbent TO

I. Request for Proposals (RFP) Contents

1) General Information
2) Proposal Submission Content Requirements and Procedures
3) Project Design Requirements
4) Cost and Financial Requirements
5) Engineering Design
6) Construction
7) Operations and Maintenance
8) Information Exchange
9) Safety Program/Current/past statistics
10) Evaluation Procedure
11) Attachments
I. IEP Selection Process and Criteria

- Oversight Committee (OC) establishes a pool of candidates to serve on an Industry Expert Panel (IEP) to evaluate transmission proposals.
- The OC designates an IEP from the pool of candidates with expertise in the following areas:
  - Engineering Design
  - Project Management (Construction)
  - Operations
  - Rate Analysis
  - Finance/Credit
- IEP consists of three (3) to five (5) panelists.
  - Upon BOD approval, the OC may designate additional IEPs to address larger than expected volumes of RFP responses.

I. TO Selection Criteria & Scoring

- IEPs will use “Reasonable Professional” standard in evaluation of proposals.
- Point allocations for scoring are as follows;
  - Engineering Design: – 200 points
  - Project Management: – 200 points
  - Operations: – 250 points
  - Rate Analysis: – 225 points
  - Finance/Credit: - 125 points
  - Incentive (Project Proposal Submission): – 100 points
- A QTO that has submitted a proposal and required supporting information to the ITP for a project that is approved by the BOD, shall eligible to receive the 100 incentive points.
II. Recommendation - Qualification Criteria for Applicant Transmission Owners.

• The entity must satisfy all Transmission Owner Qualification Criteria prior to being eligible to participate in the Transmission Owner Selection Process.

• Three Criteria Categories
  • (1) Membership Criteria:
  • (2) Financial Qualification Criteria:
  • (3) Managerial Qualification Criteria:

II. Recommendation - Qualification Criteria for Applicant Transmission Owners.

   Membership Criteria

• An Application must show that the ATO is a SPP Member
• Or be willing to sign the SPP Membership Agreement if the ATO is selected in the SPP’s Transmission Owner Selection Process.
II. Recommendation - Qualification Criteria for Applicant Transmission Owners.

Financial Qualification Criteria

- An Application from an ATO must provide a showing that the ATO meets SPP’s financial criteria:
  - a) An investment Grade Rating; or
  - b) a Guaranty from a Parent with Investment Grade Rating; or
  - c) a Bank reference letter or bonding indication; or
  - d) a Direct rate-making or taxing authority.

Managerial Qualification Criteria

- Expertise to construct, own, and operate electric transmission facilities includes:
  - Transmission Project Construction Expertise:
  - Safety Qualifications and Expertise:
  - Operations Expertise:
  - Maintenance Qualifications and Expertise:
  - Ability to comply with Good Utility Practice, SPP Criteria, industry standards, and applicable local, state, and federal requirements.

II. Recommendation - Qualification Criteria for Applicant Transmission Owners.  
ATO Application Notice

Posting an Application from an ATO and Notice: Applications from an ATO will be posted on the SPP website upon receipt by SPP, subject to any applicable confidentiality protections.

III. Recommendation - Mobile-Sierra Doctrine.

- The SPCTF recommends that SPP include as a part of its compliance filing for Order 1000 arguments that the federal Right of First Refusal contained in SPP’s Membership Agreement is protected under the Mobile-Sierra Doctrine.
IV. Recommendation - Retention of ROFR for Short-Term Reliability Projects.

- The SPCTF recommends that SPP seek to retain ROFR for short-term reliability projects that:
  - cannot be built in time to allow for the time delays associated with the implementation of a Transmission Owner Selection Process.
- The SPCTF further recommends that this category of projects be identified and approved by SPP’s BODs.

V. Recommendation - Establishment of a Need by Date, Notice and Requirement to meet Deadlines.

- The SPCTF recommends:
  - SPP staff identify a state approval need date as part of the ITP process;
  - Entities that respond to an RFP must include a development schedule that does not conflict with the state approval need date; and
  - If a DTO fails to or is unable to achieve all necessary state approvals by the state approval need date, SPP may reevaluate the transmission facility to seek an alternative solution or select a different DTO.
VI. Deposit Requirement

- Based on a Finance Committee Recommendation the SPC adopted a deposit requirement (2% of bid) for the selected TO:
  - Upon default the deposit will be credited to the project to offset the total project costs. This solution serves as a benefit to the ultimate rate payers.
  - Deposits will not be required of the Selected Transmission Owner if that entity is also the provider of last resort incumbent transmission owner.
  - Deposits will be required even if the Selected Transmission Owner utilizes a performance bond or letter of credit to secure their ultimate performance on the project.
SSC Order 1000
Update: Interregional Transmission Planning

Regional State Committee

July 30, 2012

ORDER 1000 OVERVIEW
Overview of Order 1000 Requirements

• Jointly evaluate with neighbors potential interregional planning solutions
  – Must evaluate whether an interregional solution is more cost effective than regional solutions
• Study must utilize jointly agreed upon assumptions, models, and criteria
• Projects must be approved by each region to qualify for interregional cost allocation
• Transparent stakeholder process
• Annual data sharing requirement
  – Will improve regional models as well

Challenges

• Currently planning for three seams entities: MAPPCOR, AECI, MISO
  – Requires new JOA with MAPPCOR
  – Independent process for each
  – Entergy informed SPP they plan to meet Order 1000 requirements through MISO
• Timeline for interregional joint evaluation
  – Timeline must work for SPP and the seams entity
• Coordination of interregional and regional processes
SPP PROCESS DEVELOPMENT

Seams FERC Order 1000 Task Force (SFOTF)

- 3 Members from Seams Steering Committee (SSC)
- 1 Member each from the Economic Studies Working Group (ESWG) and Transmission Working Group (TWG)
- Tasked with developing processes to address interregional planning requirements of Order 1000
- Reports to SSC
Development of SPP Proposal

- Options reviewed and updated by SFOTF and other stakeholder groups
- ESWG and TWG provided comments/suggestions
- SFOTF recommended Option 1 to the SSC
- SSC unanimously approved Option 1 as the SPP proposal to use in negotiating with each neighbor

HIGH LEVEL OVERVIEW OF PROPOSED PROCESS (OPTION 1)
Proposed Process Inputs

SPP Inputs

- ITP approved regional projects
  - Projects that have a reasonable chance of having a cost-effective interregional alternative
- ITP identified issues
  - Other issues around the seam that have not yet been assigned a solution
- Stakeholder identified needs
  - Projects to address stakeholder identified issues
Input Review & Stakeholder Guidance

Flowchart Segment 2 of 3

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Input Review

- Inputs are reviewed and decision made on the need for a transmission study
  - Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting
  - SSC currently working on how to populate the IPSAC and the role of the IPSAC
- Decision to not perform a study ends the interregional cycle for the year
- Include requirement that a study must be performed every 3 years
Joint Study Scope

- Scope created specifically for each Joint Study
- Specifics of scope may, and most likely will, change from one cycle to the next
  - Scope focused to address the identified needs
- Scope includes types of studies to be performed
- Cost Effective Analysis
- Jointly agreed upon criteria
- Solution development determines cost effective solution(s)

Approval Process

Flowchart
Segment 3 of 3
Joint Coordinated System Plan (JCSP) Report

- Includes all aspects of study and results
- Reviewed by IPSAC
- IPSAC will provide recommendation on report to the regions
- After JCSP report each entity will review in the respective regional process
  - Does not mean it must go through the ITP
  - Applicable stakeholder review
- Projects must be approved regionally to qualify for interregional cost allocation

SPP NEXT STEPS
Milestones & Additional Comments

- Majority of compliance met through Joint Operating Agreement (JOA) updates rather than OATT
- Initial draft JOA language for Joint SPP-MISO September 20 meeting
- Draft JOA language for MOPC on October 16
- Final JOA/OATT language for MOPC and SPP Board in January
- April 2013 filing deadline
- Currently having initial discussions with AECI & MAPPCOR
SPP Interregional Benefit and Cost Allocation Principles

July 30, 2012

SPP Interregional Cost Allocation TF

- The SPP RSC formed the IRCATF subsequent to the April meeting of the RSC.
- The IRCATF has three RSC members, three SPP members, and a member of the SPP BOD.
- The Chair of the IRCATF is Chairman Kevin Gunn (MoPSC) and the Vice-Chair is Paul Malone (NPPD).
- The IRCATF met on June 18 and agreed to a number of guidelines and principles for interregional cost allocation.
General Benefit Principles

• Recognize that interregional projects may offer combinations of different types of benefits and entirely different sets of benefits may accrue to each entity;

• Benefit metrics used for the evaluation of interregional projects by each entity will include all benefit and metrics considered in each entity’s internal (local and regional) transmission planning process;

• Each entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other entity;

General Benefit Principles (cont.)

• Seams entities will develop a common set of benefits and metrics for use in evaluating interregional projects;

• Interregional projects can offer unique benefits beyond those currently considered in either entity’s internal transmission planning process;

• Additional benefits can be developed and documented as more experience is gained;
General Benefit Principles (cont.)

- Interregional projects may avoid or delay the cost of:
  - Transmission projects in existing regional and local transmission plans;
  - Transmission upgrades that may be needed in the future to meet local or regional needs; and
  - Transmission upgrades needed to satisfy GI and TSRs.

Interregional Cost Allocation Principles

- Allocated costs should be at least roughly commensurate with total benefits to each entity; neither seams entity shall be allocated costs without receiving benefits (Order 1000);
- Cost allocation methodologies and identification of benefits must be transparent (Order 1000);
- Different cost allocation methods may be applied to different types or different portions of transmission facilities (e.g., transmission needed for different reasons) (Order 1000);
Interregional Cost Allocation Principles (cont.)

• Seams entities will quantify and, if possible, monetize benefits:
  – Non-monetized and non-quantified benefits may also be recognized in assessing overall reasonableness of proposed interregional cost allocations;

• Monetized reliability, load serving, or public policy benefits will be at least equal to the avoided cost of achieving the same benefit through local or regional upgrades;

Interregional Cost Allocation Principles (cont.)

• If minimum benefit-to-cost thresholds are utilized, they should not exceed 1.25 (Order 1000);

• The share of benefits to each seams entity should be sufficient to support the interregional projects’ approval through each entity’s internal planning process;

• The costs of an interregional project allocated to each seams entity will be recovered by use of the existing internal cost allocation process of each entity (Order 1000).
Recovery of Interregional Costs

- How should the costs of Interregional projects be recovered within SPP?
- Two options considered:
  - Utilize the Highway/Byway
    - Benefit – has been approved by FERC
  - Recover regionally through the Highway
    - Has not been approved by FERC
    - Supported by the SSC in its White Paper from 2011
- The Task Force supports either mechanism but prefers recovery only through the Highway

Next Steps

- If approved by the RSC, SPP will have adopted:
  - Internal cost recovery methodologies
  - Interregional cost allocation principles and benefit guidelines;
- Initiate discussions with neighboring planning regions (MISO, AECI, and MAPPCOR)
- Drive for developing tariff/JOA language by January 2013 for April 2013 FERC compliance filing.
Aggregate Study Waiver Requests

July 30, 2012

Lanny Nickell
Vice President, Engineering

Aggregate Study Waivers

- Review of Aggregate Study Waiver Process
- Research on Past Aggregate Study Waivers
- OMPA Waiver Request
- AECC Waiver Request
REVIEW OF AGGREGATE STUDY WAIVER PROCESS

Aggregate Study Waivers

- Attach. J Sec. III.C.
  - Base Plan funding of Directly Assigned Upgrade Costs for Designated Resources
  - Need arises when
    - Request does not meet requirements for Base Plan funding; or
    - Costs exceed the Safe Harbor Cost Limit
  - Decision to waive based on analysis of specific situation considering factors outlined in the tariff
Aggregate Study Upgrade Cost Allocation Under Attach. J

Conditions for Base Plan Funding for Designated Resources

- Commitment must be at least 5 years
- Designated Resources/Load Ratio ≤ 125%
- Designated Wind Resources/Load Ratio ≤ 20%

Safe Harbor Cost Limit (SHCL)

- Base Plan Funding up to $180,000/MW
- Costs greater than the SHCL are Directly Assigned

Customer can request waiver of the requirements and/or the SHCL

Review of Aggregate Study Waiver Process Under Attachment J

Within 15 days
SPP Posts Study with Directly Assigned Costs

Within 120 days
Customer submits waiver request
SPP reviews request
CAWG
SPP Board
RSC
MOPC
RESEARCH ON PAST AGGREGATE STUDY WAIVERS

Waiver Statistics

- As of the end of July 2012, there have been 29 waiver requests submitted and processed

<table>
<thead>
<tr>
<th>Final Waiver Disposition</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Granted Full Base Plan Funding by BOD (for SPP facilities)</td>
<td>12</td>
</tr>
<tr>
<td>Granted Partial Base Plan Funding by BOD</td>
<td>3</td>
</tr>
<tr>
<td>Granted Funding according to new tariff provisions for wind resources that were not yet effective(^1)</td>
<td>3</td>
</tr>
<tr>
<td>Withdrawn prior to BOD action</td>
<td>11</td>
</tr>
<tr>
<td>TOTAL</td>
<td>29</td>
</tr>
</tbody>
</table>

\(^1\)Safe Harbor Cost Limit calculated using requested transmission capacity instead of “net dependable capacity” for wind resources, and allocation of upgrade costs outside the POD zone at 1/3 Directly Assigned.
Waiver Statistics

Of the 18 waiver requests that were approved by SPP Board:

<table>
<thead>
<tr>
<th>Ultimate Use of Waiver</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waiver was not needed because final costs were less than Safe Harbor Cost Limit</td>
<td>4</td>
</tr>
<tr>
<td>Waiver was needed and used to provide base plan funding of upgrade costs</td>
<td>7</td>
</tr>
<tr>
<td>Waiver permitted new tariff provisions for wind resources to be applied to upgrade costs</td>
<td>3</td>
</tr>
<tr>
<td>Final costs not yet determined – study still in progress</td>
<td>4</td>
</tr>
<tr>
<td>TOTAL Approved</td>
<td>18</td>
</tr>
</tbody>
</table>
Past Methods

- Examination of the benefits of specific resources to multiple customers
  - Example: Turk’s benefits to AECC, OMPA, AEP, ETEC
- Consideration of the circumstances for cost allocation
  - Example: OMPA 3-MW resource in which the upgrade was driven by other requests that were not allocated costs because they did not meet the 3% impact threshold

Past Methods

- Upgrade costs substantially less than the Safe Harbor Cost Limit would have been had the request qualified for Base Plan funding
  - Example: OMPA 50-MW resource for a term <5 years had allocated costs that were a fraction of what a qualified request would have been allowed under the SHCL
CAWG 2.5% per year Example

- Attach. J Safe Harbor Cost Limit (SHCL) = $180,000/MW (Minimum term = 5 years)
- \( \text{SHCL}_{\text{new}} = 180,000/MW \times \left( \left( \text{Term} - 5 \right) \times 2.5\% \right) + 1 \times \text{MW} \)
- Example
  - Requested Term = 15 years
  - Requested MW = 10 MW
  - Initial SHCL = $180,000/MW \times 10 \text{ MW} = $1.8 million
  - \( \text{SHCL}_{\text{new}} = 180,000/MW \times \left( \left( 15 - 5 \right) \times 2.5\% \right) + 1 \times 10 \text{ MW} \)
    \( = 225,000/MW \times 10 \text{ MW} \)
    \( = $2.25 \text{ million} \)

WAIVER REQUESTS UNDER CONSIDERATION
Waiver Requests

• Two requests for consideration
  • OMPA
    • OASIS Request 75196276
      • Amount: 3 MW
      • Term: 15 years 10 months (3/1/2012 – 12/31/2027)
  • AECC
    • OASIS Request 76585985 and 76586012
      • Amount: 51 MW
      • Term: 5 years (10/1/2012 – 10/1/2017 and 7/1/2015 – 7/1/2020)
  • Staff recommends baseplan funding both waiver requests

Aggregate Study Waivers

OMPA
**Timeline**

- Waiver Request Received: 7/6/2012
  - CAWG Meetings: 7/11/2012 (next meeting 8/22/2012)
  - MOPC Meeting: 7/17/2012 (next meeting 10/16/2012)
  - BOD Meeting: 7/31/2012 (next meeting 10/30/2012)
- 120-Days after receipt: 11/3/2012

**OMPA Waiver Request Summary**

- OASIS Request 75196276
  - Aggregate Study: 2011-AGP1
  - Customer: Oklahoma Municipal Power Authority (OMPA)
  - Type: NITS, Designated Resource
  - Path: CSWS-OKGE
  - Amount: 3 MW
  - Term: 15 years 10 months (3/1/2012 – 12/31/2027)
- Allocated E&C Cost of SPP upgrades
  - $3,049,257 in AFS7
  - Safe Harbor Limit: $1,600,000 from previously-approved waiver
  - Directly Assigned Upgrade Cost: $1,449,257
Upgrade Impact

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Rating (MW)</th>
<th>Flow Increase (MW)</th>
<th>Flow Impact (%)</th>
<th>Cost Allocation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>36TH &amp; LEWIS - 52ND &amp; DELAWARE TAP 138KV</td>
<td>278</td>
<td>12</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OMPA Request with TDF &gt;3%</td>
<td>&lt;1</td>
<td>2%</td>
<td>100%</td>
<td></td>
</tr>
<tr>
<td>Other Requests with TDF &lt;3%</td>
<td>11</td>
<td>98%</td>
<td>0%</td>
<td></td>
</tr>
</tbody>
</table>

Background

- On July 26, 2011 the SPP Board passed the following motion:

  Approve OMPA’s waiver request #75196276 to establish the allocated E&C cost of **$1.6 million** as the Safe Harbor Limit.
Recommendations

• CAWG recommends the cost of this upgrade not be directly assigned to the customer.

• MOPC recommends that the cost of this upgrade not be allocated to OMPA’s request based on the increased flow being less than 1 MW.

• SPP Staff recommends that the cost of this upgrade not be allocated to OMPA’s request.

Aggregate Study Waivers

AECC
Timeline

- Waiver Request Received: 6/28/2012
- CAWG Meetings: 7/11/2012 (next meeting 8/22/2012)
- MOPC Meeting: 7/17/2012 (next meeting 10/16/2012)
- BOD Meeting: 7/31/2012 (next meeting 10/30/2012)
- 120-Days after receipt: 10/26/2012

AECC Waiver Request Summary

- OASIS Request 76585985 and 76586012
  - Aggregate Study: 2012-AG1
  - Customer: Arkansas Electric Cooperative Corporation (AECC)
  - Type: NITS, Designated Resource
  - Path: WR-CSWS and WR-OKGE
  - Amount: 51 MW
  - Term: 5 years (10/1/2012 – 10/1/2017 and 7/1/2015 – 7/1/2020)
- Allocated E&C Cost of SPP upgrades
  - $12,900,493 in AFS2
  - Safe Harbor Cost Limit: $9,180,000
  - Directly Assigned Upgrade Cost: $3,720,493
AECC Request for Waiver

- AECC requests full Base Plan funding based on Section III.C.2.ii of SPP OATT Attachment J:
  
  “...those costs that exceed the Safe Harbor Cost Limit may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation taking into account the extent to which the duration of the Transmission Customer’s commitment to the new or changed Designated Resource exceeds the five-year commitment period ....”

- Staff has additional information that warrants different consideration of justification for base plan funding

Upgrade Impact

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Rating (MW)</th>
<th>Flow Increase (MW)</th>
<th>Flow Impact (%)</th>
<th>Cost Allocation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MUSKOGEE - ROSS LAKE 161KV</td>
<td>223</td>
<td>17</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AECC Requests with TDF &gt;3%</td>
<td></td>
<td>&lt;1</td>
<td>6%</td>
<td>100%</td>
</tr>
<tr>
<td>Other Requests with TDF &lt;3%</td>
<td></td>
<td>16</td>
<td>94%</td>
<td>0%</td>
</tr>
</tbody>
</table>
Upgrade Impact

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Rating (MW)</th>
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</tr>
</thead>
<tbody>
<tr>
<td>PECAN CREEK 345/161 Xfrm</td>
<td>370</td>
<td>18</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AECC Requests with TDF &gt;3%</td>
<td>&lt;1</td>
<td>6%</td>
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<td>17</td>
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</tbody>
</table>

Recommendations

- CAWG recommends increase in Safe Harbor limit to $12,622,500.
- MOPC recommends the cost of the two upgrades not be allocated to AECC’s requests based on the increased flow being less than 1 MW.
- SPP Staff recommends that the cost of these two upgrades not be allocated to AECC’s requests.
CAWG Recommendations
to the
Regional State Committee
Waiver Request by OMPA
Waiver Request by AECC

July 30, 2012

Waiver Requests: OMPA & AECC

At CAWG’s July 2012 meeting, SPP recommended CAWG approval of waiver requests sought by OMPA and AECC under the Aggregate Study process. SPP recommended Base Plan Funding of the waiver requests. Those waiver requests were as follows:

OMPA:
OASIS Request 75196276  
Amount: 3 MW

AECC:
OASIS Request 76585985 and 76586012  
Amount: 51 MW
Waiver Requests: OMPA & AECC

OMP A REQUEST:

OMP A Request based on most current Aggregate Study:

Total E&C estimated costs of upgrades allocated to OMPA will be $3,049,257.

Previously approved waiver on Safe Harbor Limit is $1,600,000

Directly Assigned Estimated Upgrade Cost is thus $1,449,257

OMP A seeks waiver of all Final Directly Assigned Costs.

Waiver Requests: OMPA & AECC

SPP recommends approval of the waiver and base plan treatment of all final costs related to OMPA's waiver request for upgrades made to the 36th & Lewis – 52nd & Delaware Tap 138 kv.

SPP's presentation to CAWG illustrated that, under the current cost allocation process related to upgrades, while OMPA qualified to absorb all costs of this upgrade under current tariff provisions, OMPA's actual flow impact was only 2% of all requests as follows:
CAWG Considerations:

In coming to its proposed recommendation, CAWG considered the impact on OMPA ratepayers in relation to its cost causation reflected above and the inequities inherent in that relationship. (In this regard, CAWG recommended to SPP that it address these inequities under the current tariff provisions, which SPP advised it was currently working on.) CAWG, however, also had concerns related to the open-ended provisions of the waiver request, which were offset to an extent by the current level of certainty regarding expected final costs of the project at issue. Further, CAWG members expressed concern that such open-ended requests for Base Plan treatment were being regularly sought.

CAWG, therefore, determined that, while it supported the waiver given the inequitable impact to OMPA ratepayers, it would recommend RSC support, subject to limiting provisions.
CAWG Recommendation to RSC on OMPA request:

CAWG recommends to the RSC that, with regard to OMPA’s request for this particular waiver only and having no future policy implications with regard to the RSC’s vote on this waiver request,

1. The costs associated with improvements for the 36th and Lewis – 52nd and Delaware Tap 138 kV line not be directly assigned to the OMPA transmission request #75196276.

2. The cost for improvements for the 36th and Lewis – 52nd and Delaware Tap 138 kV line related to granting Aggregate Study 2011-AGP1 requests be granted Base Plan funding.

3. The Safe Harbor Limit for the OMPA transmission request is reaffirmed at $1.6 million based on the size and the term of the request.

AECC’S WAIVER:

AECC Request based on first rounds of Aggregate Study, OASIS Request 76585985 and 76586012.

Total E&C estimated costs of upgrades allocated to AECC will be $12,900,493 (which is an early estimate and will likely change).

Current Safe Harbor Limit Under Tariff is $9,180,000

Directly Assigned Estimated Upgrade Cost is thus $3,720,493

AECC seeks waiver of all Final Directly Assigned Costs.
Similar to its OMPA recommendation, SPP recommends approval of the waiver and base plan treatment of all final costs related to AECC’s waiver request for upgrades made to the Muskogee – Ross Lake 161 kv upgrade and the Pecan Creek 345/161 Xfm upgrade.

Again, SPP’s presentation to CAWG illustrated that, under the current cost allocation process related to upgrades, while AECC qualified to absorb all costs of the two upgrade under current tariff provisions, AECC’s actual flow impact was only 6% in relationship to all requests as follows:

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Rating (MW)</th>
<th>Flow Increase (MW)</th>
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<td></td>
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<tr>
<td>Other Requests with TDF &lt;3%</td>
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<td>100%</td>
<td></td>
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<td>94%</td>
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<td></td>
</tr>
</tbody>
</table>
CAWG Considerations:

Similar to its considerations related to OMPA’s request, CAWG considered the relative inequity to AECC’s ratepayers of the costs assigned in relation to the cost causation reflected above.

However, CAWG was also more concerned as to the relatively early stage of cost estimate coupled with the request that all costs in excess of the Safe Harbor Limit be approved.

Differentiating itself from OMPA’s request, AECC had originally noted in its waiver request that under provisions of the tariff and recently approved waivers, AECC’s would qualify for additional amounts based on the life of its production contract, which was 20 years, 15 years in excess of the 5 year assumption under the Tariff.

CAWG Considerations (cont):

In its request for full Base Plan funding, AECC cited Section III.C.2.ii of SPP OATT Attachment J in support of its request: “…those costs that exceed the Safe Harbor Cost Limit may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation taking into account the extent to which the duration of the Transmission Customer’s commitment to the new or changed Designated Resource exceeds the five-year commitment period ….”

Assuming approval of a waiver related to the additional 15 years of the contract, the additional Safe Harbor Limit would be $3,442,500 calculated under the method adopted in recently approved waiver requests.

Thus, CAWG, noting both the early stage of the estimate juxtaposed to the amount of additional Safe Harbor Limit giving consideration to the 20-year contract, made its recommendation setting a limit to reflect that known amount, but left it open for AECC to seek future waiver requests.
CAWG Recommendation to RSC on AECC request:

CAWG recommends to the RSC that, with regard to AECC’s request for this particular waiver only and having no future policy implications with regard to the RSC’s vote on this waiver request,

1. The costs associated with AECC’s requests numbered 76585985 and 76586012 and the related respective upgrades styled Muskogee – Ross Lake 161 kv and Pecan Creek 345/161 Xfrm be granted Base Plan funding up to the amount of $12,622,500 which represents $9,180,000 qualified as Safe Harbor under the tariff and an additional $3,442,500 calculated under the method adopted in recently approved waiver requests which allows additional Safe Harbor amounts related to contract length.

2. AECC is free to seek a waiver in the future of any additional costs in excess of the total approved Safe Harbor of $12,622,500 under future aggregate studies.

Questions:

Submitted by: Pat Mosier
On Behalf of the CAWG
July 30, 2012
Southwest Power Pool, Inc.

THIRD QUARTERLY PROJECT TRACKING REPORT

July 2012

I. Project Tracking, Current SPP Process:

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 Board of Directors or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

In this Third Quarterly Report of 2012, the reporting period is March 1, 2012 through May 31, 2012.

II. Project Summary:

Figure 1 represents the summary of active projects for this quarter. Figure 1 reflects all upgrades, including transmission lines, transformers, substations, and devices. The 2nd Quarter marked the first Notifications to Construct issued from the ITP10 process, as well as the first Notifications to Construct with Conditions under the newly approved Business Practices. There was seven new Notifications to Construct issued by the ITP10 process, with six of these being Notifications to Construct with Conditions. There were 11 Notifications to Construct approved by the Board for regional reliability projects within the ITPNT process, with one of those being a Notification to Construct with Conditions. Overall there were 73 upgrades, with almost 954 miles of new transmission at a cost of $1.43 billion, assigned to Transmission Owners this quarter.

Figure 2 shows the total miles of transmission lines currently planned within the portfolio, as well as miles by project voltage. Figure 3 reflects the percentage cost of each project type in the total active portfolio.
### 2nd Quarter 2012 Project Tracking Summary

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Number of Upgrades</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>237</td>
<td>$1,295,581,409</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>14</td>
<td>$46,612,000</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>10</td>
<td>$32,478,855</td>
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<tr>
<td>Transmission Service</td>
<td>55</td>
<td>$428,590,593</td>
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<tr>
<td>Generation Interconnect</td>
<td>21</td>
<td>$151,582,596</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>18</td>
<td>$855,339,021</td>
</tr>
<tr>
<td>High Priority</td>
<td>22</td>
<td>$1,446,090,589</td>
</tr>
<tr>
<td>ITP10</td>
<td>28</td>
<td>$1,153,991,209</td>
</tr>
<tr>
<td>Other Sponsored Upgrades</td>
<td>47</td>
<td>$288,067,341</td>
</tr>
<tr>
<td><strong>TOTALS</strong></td>
<td>452</td>
<td><strong>$4,402,752,204</strong></td>
</tr>
</tbody>
</table>

### 2nd Quarter Total Active Portfolio Transmission Miles

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>New Miles</th>
<th>Reconductor Miles</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>64</td>
<td>17.8</td>
<td>189.5</td>
<td>207.3</td>
</tr>
<tr>
<td>115</td>
<td>83</td>
<td>310.4</td>
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<td>138</td>
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<td>345</td>
<td>62</td>
<td>2,815.5</td>
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<td>2,815.5</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>316</strong></td>
<td><strong>3,448.5</strong></td>
<td><strong>518.8</strong></td>
<td><strong>3,967.4</strong></td>
</tr>
</tbody>
</table>

Figure 1: 2012 2nd Quarter Project Summary

Figure 2: Project Mileage within the Portfolio
III. Regional Reliability Project Summary:

Regional reliability projects include all tariff signatory projects identified in an SPP study to meet regional reliability criteria for which NTC letters have been issued. Figure 4 shows the breakdown of the regional reliability projects.

There were 13 upgrades, with latest Engineering and Construction (E&C) cost estimates at $154,357,681 completed in the timeframe of the 2nd Quarter of 2012. The largest completed project was Westar Energy’s section of the Rose Hill - Sooner project, which added 53 miles of the full 92 miles of 345kV transmission line to the SPP footprint. Western Farmers Electric Cooperative’s Snyder project also added four miles of new 138kV to the footprint.

There are 35 upgrades, with latest E&C cost estimates of $142.9 million, on schedule to be completed within the next four years. There are 40 upgrades with costs of $211.7 million waiting for acceptance by the Transmission Owners, which will occur during the next quarter. There are 22 upgrades that are in a delay status with no mitigation. SPP has been working directly with the transmission owners of these upgrades to determine and approve correct mitigation plans.
IV. Transmission Service/Generation Interconnection (TSR/GI) Project Summary:

This category contains upgrades identified as needed to support new Transmission Service (TSR) and Generation Interconnection (GI) service agreements. Figure 4 shows the details of the Transmission Service and Generation Interconnect projects.

Seven Transmission Service upgrades, with latest E&C cost estimates at $15.5 million were completed in the 2nd Quarter of 2012. American Electric Power’s South Texarkana line project added almost six miles of reconducted 69kV back into the footprint. Also, American Electric Power’s Generation Interconnect project for Turk-SE Texarkana line was completed in March, which added 34 miles of new 138kV line to the SPP footprint. There are nine Transmission Service upgrades, with estimated E&C costs of $179.6 million, on schedule to be completed within the next four years. There are two upgrades in a delay with no mitigation status. There are 11 Generation Interconnect upgrades, at an estimated E&C cost of $68.2 million, scheduled to be completed in the next four years.

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Total</th>
<th>Complete</th>
<th>On Schedule</th>
<th>On Schedule - Later in 10 yr Horizon (NTCs Issued)</th>
<th>Behind Schedule - With Mitigation</th>
<th>Behind Schedule - Without Mitigation</th>
<th>Within NTC Commitment Window</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>237</td>
<td>26</td>
<td>35</td>
<td>17</td>
<td>97</td>
<td>22</td>
<td>40</td>
</tr>
<tr>
<td></td>
<td>$1,295,581,409</td>
<td>$257,102,851</td>
<td>$142,939,235</td>
<td>$126,442,050</td>
<td>$433,463,580</td>
<td>$123,965,033</td>
<td>$211,666,660</td>
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<tr>
<td>Transmission Service</td>
<td>55</td>
<td>14</td>
<td>9</td>
<td>7</td>
<td>23</td>
<td>2</td>
<td>0</td>
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<tr>
<td></td>
<td>$428,590,593</td>
<td>$58,847,314</td>
<td>$179,624,522</td>
<td>$48,175,000</td>
<td>$139,793,757</td>
<td>$2,150,000</td>
<td>$0</td>
</tr>
<tr>
<td>Generation Interconnect</td>
<td>21</td>
<td>10</td>
<td>11</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$151,582,595</td>
<td>$83,336,545</td>
<td>$68,246,050</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>18</td>
<td>1</td>
<td>14</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>$855,339,021</td>
<td>$15,000,000</td>
<td>$764,638,114</td>
<td>$0</td>
<td>$14,900,907</td>
<td>$0</td>
<td>$60,800,000</td>
</tr>
<tr>
<td>High Priority</td>
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<td>0</td>
<td>19</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$1,446,090,589</td>
<td>$0</td>
<td>$1,042,053,923</td>
<td>$404,036,666</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
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<tr>
<td>ITP10</td>
<td>28</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tr>
<tr>
<td></td>
<td>$1,153,991,209</td>
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<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$1,153,991,209</td>
</tr>
</tbody>
</table>

Figure 4: Project Status
V. Completed Projects Summary:

Figure 5 shows the number and costs for the projects completed over the last 12 month period. The 2nd Quarter of 2012 produced 23 projects that were completed with a total estimated cost of $198.7 million. This is higher in number of projects completed and in total cost than the same period in 2011. The May-June 2012 time frame was projected to have a concentrated number of projects scheduled for completion, and that has stayed steady over this quarter. Over 16 projects have already been reported as complete in June, as is reflected in the Net Corrections column in Figure 5.

There were two zonal upgrades completed this quarter at a reported cost of $3.2 million. Lincoln Electric System completed 2.1 miles of an 115kV reconductor project.

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. Corrections are listed for those projects reported complete after the 2nd Quarter reporting period had ended.

<table>
<thead>
<tr>
<th>Projects Completed By Quarter</th>
</tr>
</thead>
<tbody>
<tr>
<td>3rd Q 2011</td>
</tr>
<tr>
<td>-----------------------------</td>
</tr>
<tr>
<td>Reliability</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Transmission Service</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Generation Interconnect</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Balanced Portfolio</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>High Priority</td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

Figure 5: Completed Project Summary through 2nd Quarter 2012
### 2\textsuperscript{nd} Quarter Total Transmission Miles Completed

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>New Miles</th>
<th>Reconductor Miles</th>
<th>Total Miles</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>8</td>
<td>0.0</td>
<td>23.1</td>
<td>23.1</td>
<td>$22,487,467</td>
</tr>
<tr>
<td>115</td>
<td>4</td>
<td>0.0</td>
<td>2.1</td>
<td>2.1</td>
<td>$7,132,576</td>
</tr>
<tr>
<td>138</td>
<td>6</td>
<td>38.0</td>
<td>0.0</td>
<td>38.0</td>
<td>$55,816,770</td>
</tr>
<tr>
<td>161</td>
<td>1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$866,122</td>
</tr>
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<td>230</td>
<td>2</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$24,193,424</td>
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<tr>
<td>345</td>
<td>2</td>
<td>53.0</td>
<td>0.0</td>
<td>53.0</td>
<td>$88,219,298</td>
</tr>
<tr>
<td>Totals</td>
<td>23</td>
<td>91.0</td>
<td>25.2</td>
<td>116.2</td>
<td>$198,715,657</td>
</tr>
</tbody>
</table>

Figure 6: Completed Transmission for 2nd Quarter 2012

### VI. Future Projections:

#### 3\textsuperscript{rd} Quarter 2012:

The 3\textsuperscript{rd} Quarter of 2012, ending August 31, 2012 is scheduled to have 44 projects completed across all project types at an estimated cost of $277 million. The ITC Great Plains and Oklahoma Gas & Electric’s Valiant-Hugo-Sunnyside 345 kV transmission service projects that were scheduled to complete in the 2\textsuperscript{nd} Quarter at a current estimated cost of $188.8 million should be reported complete in the next Quarter’s report as details of the project were delayed in reporting complete until June.

Figure 7 shows the 3\textsuperscript{rd} Quarter estimated completed projects broken out by Project Type.

#### June 2012 through May 2013:

The next 12 months are scheduled to have a total of 107 upgrades completed at an estimated cost of $698 million. This is lower than last quarter’s projections, as a large amount of projects completed this quarter. These numbers should increase as the Transmission Owners accept the newly issued Notifications to Construct. Also factored into the drop in the 12 month projection is the fact that June of 2013 projects a significantly higher number of projects completed (56) and that will be picked up with next quarter’s report. Figure 7 shows the next 12 months estimated completed projects broken out by Project Type.
There are scheduled to be 414 miles of new transmission added to the system during the next 12 month period. 231 miles of 345 kV transmission lines are still scheduled to be completed. There will also be 212 miles of reconducted transmission placed into the system, with 109 miles being 115 kV. Figure 9 shows the details of the estimated transmission miles to be completed over the next 12 months.

<table>
<thead>
<tr>
<th>Scheduled Complete</th>
<th>Last Day of Quarter</th>
<th>First day of Quarter</th>
<th>Last Day of Reporting Year</th>
<th>First day of Reporting Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>27</td>
<td>$117,845,939</td>
<td>Reliability</td>
<td>65</td>
</tr>
<tr>
<td>Reliability-Non OATT</td>
<td>7</td>
<td>$25,220,750</td>
<td>Reliability-Non OATT</td>
<td>8</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>0</td>
<td>$0</td>
<td>Zonal Reliability</td>
<td>4</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>7</td>
<td>$46,599,701</td>
<td>Transmission Service</td>
<td>17</td>
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<tr>
<td>Generation Interconnect</td>
<td>1</td>
<td>$150,000</td>
<td>Generation Interconnect</td>
<td>6</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>2</td>
<td>$88,000,000</td>
<td>Balanced Portfolio</td>
<td>7</td>
</tr>
<tr>
<td>Zonal Sponsored</td>
<td>9</td>
<td>$21,928,841</td>
<td>Zonal Sponsored</td>
<td>16</td>
</tr>
<tr>
<td>ITP10</td>
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<td>$0</td>
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<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>44</td>
<td>$277,816,390</td>
<td>Total</td>
<td>107</td>
</tr>
</tbody>
</table>

Figure 7: Upgrades Scheduled to Complete Next Quarter/Next 12 Months
### 3rd Quarter Projected Transmission Miles Complete

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>New Miles</th>
<th>Reconductor Miles</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>9</td>
<td>0.0</td>
<td>8.6</td>
<td>8.6</td>
</tr>
<tr>
<td>115</td>
<td>14</td>
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<td>138</td>
<td>13</td>
<td>12.5</td>
<td>25.0</td>
<td>37.5</td>
</tr>
<tr>
<td>161</td>
<td>3</td>
<td>5.0</td>
<td>22.0</td>
<td>27.0</td>
</tr>
<tr>
<td>230</td>
<td>1</td>
<td>62.0</td>
<td>0.0</td>
<td>62.0</td>
</tr>
<tr>
<td>345</td>
<td>4</td>
<td>162.0</td>
<td>0.0</td>
<td>162.0</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>44</strong></td>
<td><strong>241.5</strong></td>
<td><strong>83.0</strong></td>
<td><strong>324.5</strong></td>
</tr>
</tbody>
</table>

Figure 8: Transmission Miles Scheduled to Complete 3rd Quarter

### Projected Transmission Miles Complete Next 12 Months

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Number of Upgrades</th>
<th>New Miles</th>
<th>Reconductor Miles</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>16</td>
<td>3.0</td>
<td>54.8</td>
<td>57.8</td>
</tr>
<tr>
<td>115</td>
<td>25</td>
<td>13.7</td>
<td>108.7</td>
<td>122.4</td>
</tr>
<tr>
<td>138</td>
<td>23</td>
<td>26.9</td>
<td>26.8</td>
<td>53.7</td>
</tr>
<tr>
<td>161</td>
<td>10</td>
<td>21.6</td>
<td>22.0</td>
<td>43.6</td>
</tr>
<tr>
<td>230</td>
<td>6</td>
<td>118.0</td>
<td>0</td>
<td>118.0</td>
</tr>
<tr>
<td>345</td>
<td>13</td>
<td>231</td>
<td>0</td>
<td>231.0</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>93</strong></td>
<td><strong>414.2</strong></td>
<td><strong>212.26</strong></td>
<td><strong>626.5</strong></td>
</tr>
</tbody>
</table>

Figure 9: Transmission Miles Scheduled to Complete Next 12 Months
Project milestone increased

ON SCHEDULE < 4

12/31/14
Project milestone increased

ON SCHEDULE < 4

PW project delayed due to delay in obtaining substation steel

ON SCHEDULE < 4

DELAY - MITIGATION

3/31/14
DELAY - NO MITIGATION

4/30/14
10/29/11

Project lead time and cost estimated by SPP staff

3/31/14

Kansans for Life

4/30/14

Water quality

8/20/11

Cost increase due to route changes to utilize more existing right of way and live line construction requirements

4/30/14

On Schedule beyond 4 Year Horizon.

4/30/14

ON SCHEDULE < 4

ON SCHEDULE > 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE > 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4

ON SCHEDULE < 4
<table>
<thead>
<tr>
<th>Project Code</th>
<th>Project Name</th>
<th>Voltage</th>
<th>Reliability</th>
<th>Start Date</th>
<th>End Date</th>
<th>Cost (2014)</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>20000 10582 AEP</td>
<td>Multi - Pils Creek - Centerton 345 kV and Centerton- East Cntnt 161 kV</td>
<td>regional reliability</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$35,185,000</td>
<td>ON SCHEDULE &lt;</td>
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</tr>
<tr>
<td>20000 10583 AEP</td>
<td>Multi - Pils Creek - Centerton 345 kV and Centerton- East Cntnt 161 kV</td>
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<td>06/01/14</td>
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<tr>
<td>20000 10585 AEP</td>
<td>Multi - Pils Creek - Centerton 345 kV and Centerton- East Cntnt 161 kV</td>
<td>regional reliability</td>
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<td>06/01/14</td>
<td>$13,104,000</td>
<td>ON SCHEDULE &lt;</td>
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<tr>
<td>20007 10711 AEP</td>
<td>Line - Lone Star-Logan Grove 115 kV</td>
<td>regional reliability</td>
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<td>06/01/14</td>
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<tr>
<td>20017 11401 AEP</td>
<td>Line - Northwest Hendrison - Pigeon 69 kV</td>
<td>Regional Reliability</td>
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<td>06/01/14</td>
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</tr>
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<td>20017 11331 AEP</td>
<td>Line - Diana - Perdue 138 kV</td>
<td>Regional Reliability</td>
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<tr>
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<td>Line - Blackhill North South Tap - Chillico 138 kV Ckt 1</td>
<td>transmission service</td>
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<td>06/01/14</td>
<td>$4,400,000</td>
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<td>06/01/14</td>
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<tr>
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<td>Multi - Centeron - Osage Creek 345 kV</td>
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<td>06/01/14</td>
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<td></td>
</tr>
<tr>
<td>20183 10417 AEP</td>
<td>Multi - Elk City - Garland 345 kV</td>
<td>regional reliability</td>
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<td>06/01/15</td>
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<td>06/01/15</td>
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</tr>
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<td>06/01/15</td>
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</tr>
<tr>
<td>10722 CLEC</td>
<td>KFR - Conductive 230/138 kV</td>
<td>regional Reliability - Non OAT</td>
<td>06/01/12</td>
<td>06/01/12</td>
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<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>10373 DETEC</td>
<td>Line - Etoile - Chireno</td>
<td>zonal - sponsored</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>10849 DETEC</td>
<td>Line - Martinsville - Timpson 138 kV conversion</td>
<td>zonal - sponsored</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>10850 DETEC</td>
<td>Line - Martinsville - Timpson 138 kV conversion</td>
<td>zonal - sponsored</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>10851 DETEC</td>
<td>Line - Martinsville - Timpson 138 kV conversion</td>
<td>zonal - sponsored</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>10852 DETEC</td>
<td>Line - Martinsville - Timpson 138 kV conversion</td>
<td>zonal - sponsored</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>10834 DETEC</td>
<td>Line - Chireno-Martinville 138 kV</td>
<td>zonal - sponsored</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>ON SCHEDULE &lt;</td>
<td></td>
</tr>
<tr>
<td>20036 10547 EDE</td>
<td>Line - Sub 124 - Aurora H.T. - Sub 152 - Monett H.T. 69 kV</td>
<td>regional reliability</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$0</td>
<td>DELAY - MITIGATION</td>
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<td>04/01/12</td>
<td>01/16/09</td>
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</tbody>
</table>

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Network upgrade complete. Awaiting project close-out to determine final cost.

In-service delay due to material delivery.

Delay - Mitigation
Project delayed to Fall 2012 due to load forecast changes. Project need mitigated by delay in load increase at this location.

Complete
Post-contingency loading issues on this line would be managed through utilization of the short-term 30-minute emergency rating and generation re-dispatch. An interim facility rating upgrade on this line from 80 MVA to 113 MVA was completed by 6/11/12 as terminal equipment upgrades were completed. The conductor upgrade to 100 Degrees C is planned by 6/1/13 to complete the full scope of the project.

Complete
Project is on schedule according to the in-service date listed on the NTC issued by SPP. The NTC was issued to NPPD after the dates listed in the B2G Determined Need Date. The "CTO Determined Need Date" should be adjusted to 6/1/2014 to match the NTC. Short-term 30-minute emergency rating of 234 MVA available to address any post-contingency loading issues prior to the NTC requested in-service date of 6/1/2014.

Cancelled
Project on hold due to routing issues associated with Keystone XL pipeline and the delay in the project receiving its presidential permit.

Multi-upgrade project for new arc furnance near Arcublue (on upgrade in device tab - Cap bank at MAdl)

Final Cost Still being compiled

Full BPF - Scope of project was reduced - Rebuilt fewer miles - Portion of reported cost is distribution.

Full BPF - Handled on O&M

Original Costs included distribution

Cost estimated reduced due to lower material costs and no scheduling issues occurred with project.

In service delay due to material delivery.
20017 50169 OGE Multi - Hugo - Sunnyside 345 kV (OGE) transmission service 04/01/12 04/01/12 01/16/09 $75,000,000 $157,000,000 ON SCHEDULE < 4 $3,000,000 reduction due to better cost information

20017 50171 OGE Multi - Hugo - Sunnyside 345 kV (OGE) transmission service 04/01/12 04/01/12 01/16/09 $6,750,000 $2,050,000 04/09/12 Full BPF

20081 10300 OGE Line - Fort Smith - Coltoni 161 kV 2 regional reliability 06/01/13 06/01/13 02/06/10 $2,500,000 $2,100,000 ON SCHEDULE < 4

20081 10843 OGE Line - Kigore - VBI 161 kV reg. 06/01/13 06/01/13 02/07/09 $10,000 $10,000 ON SCHEDULE < 4

20081 11182 OGE Sub - Canadian River Substation regional reliability 02/15/13 06/01/10 02/08/10 $5,500,000 $7,100,000 DELAY - MITIGATION

11228 OGE Line - Cushing - Pumping Station 32 138 kV zonal - sponsored generation interconnect 03/01/13 $0 $6,700,000 ON SCHEDULE < 4

20029 10792 OGE Multi - Dover-Twin Lake-Crescent-Cottwood conversion 138 kV regional reliability 06/01/13 06/01/08 06/01/08 $5,404,260 $8,100,000 ON SCHEDULE < 4

20029 10850 OGE Line - HSC East - YEL West 69 kV regional reliability 06/01/13 06/01/08 05/20/11 $250,000 $220,000 ON SCHEDULE > 4

20137 11406 OGE KFM - Richland 345/138 kV Ckt 3 transmission service 06/01/17 06/01/17 06/27/11 $15,000,000 $15,000,000 ON SCHEDULE < 4

20017 50168 OGE KFM - Ft Smith 500/161 kV Ckt 3 transmission service 06/01/17 06/01/17 01/16/09 $11,000,000 $11,000,000 ON SCHEDULE < 4

20017 50172 OGE Line - VBI - VBI North 69 kV transmission service 06/01/17 06/01/17 01/16/09 $100,000 $100,000 ON SCHEDULE > 4

20001 50419 OGE Multi - EIC City - Graddon 345 kV transmission service 02/28/13 04/08/12 04/09/12 $7,428,000 $7,500,000 04/06/12 Full BPF - Reviewing metering CT - May be able to increase rating to 600 amps

20117 11052 OGE Line - Bryant - funciona 138 kV transmission service 06/01/19 06/01/19 06/25/10 $520,000 $225,000 ON SCHEDULE < 4

20117 11343 OGE Line - Arcadia - Redbud 345 kV Ckt 3 transmission service 06/01/19 06/01/19 06/25/10 $19,000,000 $18,000,000 ON SCHEDULE > 4

20018 50456 OGE Multi - Woodward EHV - Tatonga - Matthewson - Cimarron 345 kV transmission service 06/01/17 06/01/17 04/06/12 $71,876,622 $71,876,622 04/06/12 Full BPF - Project in Service, final financials are in progress.

20117 11554 OGE Multi - Woodward EHV - Tatonga - Matthewson - Cimarron 345 kV transmission service 06/01/17 06/01/17 04/06/12 $82,139,900 $82,139,900 04/06/12 Full BPF - Project in Service, final financials are in progress.

20029 10925 OPPD Multi - S1341 161 kV regional reliability 06/01/17 06/01/17 02/08/10 COMPLETE

20029 10926 OPPD Multi - S1341 161 kV regional reliability 06/01/17 06/01/17 02/08/10 COMPLETE

20029 10792 OPPD Multi - S1341 161 kV regional reliability 06/01/17 06/01/17 02/08/10 COMPLETE

20138 11195 SEPC Line - Holcomb - Pioneer Tap 115 kV regional reliability 06/01/12 06/01/12 06/27/11 $4,000,000 $6,025,790 DELAY - NO MITIGATION

20004 10800 SPS Multi - Wheeler County Project - Tap 230 kV line - Two new XFs regional reliability 06/01/08 06/01/08 02/13/08 $0 $2,000,000 DELAY - MITIGATION

20004 10407 SPS Line - Roosevelt County Interchange 115 kV - Curry County line regional reliability 06/01/13 06/01/13 01/01/13 $0 $200,000 ON SCHEDULE < 4

20004 10200 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 06/01/10 03/10/08 COMPLETE

20004 10201 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 06/01/09 03/10/08 COMPLETE

20004 10326 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 06/01/10 02/13/08 COMPLETE

20004 10327 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 04/01/10 02/13/08 COMPLETE

20004 10328 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 06/01/09 02/13/08 COMPLETE

20004 10330 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 06/01/09 02/13/08 COMPLETE

20004 10331 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/11 06/01/09 02/13/08 COMPLETE

20130 11389 SPS Multi - Hitchland - Texas Co. 230 kV and 115 kV regional reliability 06/01/12 06/01/11 02/14/11 COMPLETE

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### 20031 10822 SPS Multi: Legacy Interchange 69 kV Tap - 115/69 transformer - 2 new regional reliability 08/18/11 $4,646,250 $4,373,940 COMPLETE This project is the fix for the Gaines Co. Auto STEP project.

### 20031 10823 SPS Multi: Legacy Interchange 69 kV Tap - 115/69 transformer - 2 new regional reliability 07/28/11 $2,214,338 $2,214,338 COMPLETE This project is the fix for the Gaines Co. Auto STEP project.

### 20031 10824 SPS Multi: Legacy Interchange 69 kV Tap - 115/69 transformer - 2 new regional reliability 07/28/11 $2,214,338 $2,024,265 COMPLETE This project is the fix for the Gaines Co. Auto STEP project.

### 20031 10825 SPS Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new line regional reliability 06/22/11 $1,771,875 $1,771,875 COMPLETE Mitigation will not be needed. The 115 kV potion of this project is 100% complete. The new 115/69 kV transformer at Eagle Creek is carrying load. The new 69 kV lines out of Eagle Creek are not complete. However the existing 69 kV lines are terminated on the Eagle Creek Substation 69 kV bus. To address the overload of one Artesia Interchange 115/69 kV transformer during the outage of the other Artesia Interchange 115/69 kV transformer, the above latest model was used. The results of that contingency revealed a 49% load on the in service transformer in Artesia.

### 20031 10826 SPS Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new line regional reliability 06/16/11 $281,250 $1,221,673 $300,000 $335,413 COMPLETE Mitigation not required for 2011. Future TEMPORARY MITIGATION OPEN 8758 near Kress Rural; CLOSE 3811 Plainview; Shed load as necessary.

### 20031 10827 SPS Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new line regional reliability 06/16/11 $281,250 $1,221,673 $300,000 $335,413 COMPLETE Mitigation not required for 2011. Future TEMPORARY MITIGATION OPEN 8758 near Kress Rural; CLOSE 3811 Plainview; Shed load as necessary.

### 20130 11374 SPS Line - Eagle Creek - Seven RIVERS Interchange 115 kV Ckt 1 zonal - sponsored 07/31/11 $0 $12,462,188 10,594,373 $5,197,500 DELAY - MITIGATION Project is in-service but all associated costs are not yet final. Should have final cost in 2nd quarter report.

### 20130 11379 SPS Multi - Randall County Interchange - Palo Duro Sub 115 kV Ckt regional reliability 06/01/11 02/14/11 $50,000 $56,275 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project. This line goes from Channing to Potter and does not go in and out of Tascosa sub. Tascosa is served by a 34.5 kV line from Channing which is constructed as a double circuit with the 115 kV from Channing.

### 20130 11380 SPS Multi - Randall County Interchange - Palo Duro Sub 115 kV Ckt regional reliability 06/01/11 02/14/11 $50,000 $56,275 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project. This line goes from Channing to Potter and does not go in and out of Tascosa sub. Tascosa is served by a 34.5 kV line from Channing which is constructed as a double circuit with the 115 kV from Channing.

### 20130 11381 SPS Multi - Randall County Interchange - Palo Duro Sub 115 kV Ckt regional reliability 06/01/11 02/14/11 $50,000 $56,275 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project. This line goes from Channing to Potter and does not go in and out of Tascosa sub. Tascosa is served by a 34.5 kV line from Channing which is constructed as a double circuit with the 115 kV from Channing.

### 20031 10704 SPS Multi:  Dallam - Channing - Tascosa -Potter regional reliability 08/10/11 $0 $15,324,192 COMPLETE Project is in-service but all associated costs are not yet final. Should have final cost in 2nd quarter report.

### 20031 10705 SPS Multi:  Dallam - Channing - Tascosa -Potter regional reliability 06/01/12 $0 $15,324,192 COMPLETE Project is in-service but all associated costs are not yet final. Should have final cost in 2nd quarter report.

### 20130 11321 SPS Multi:  Dallam - Channing - Tascosa -Potter regional reliability 06/01/12 $0 $15,324,192 COMPLETE Project is in-service but all associated costs are not yet final. Should have final cost in 2nd quarter report.

### 20130 11322 SPS Multi:  Dallam - Channing - Tascosa -Potter regional reliability 06/01/12 $0 $15,324,192 COMPLETE Project is in-service but all associated costs are not yet final. Should have final cost in 2nd quarter report.

### 20130 10757 SPS Line - Ocotillo sub conversion 115 kV regional reliability 02/28/12 $0 $3,175,596 $1,102,202 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project.

### 20084 11029 SPS Line - Maddox - Swanning SW 115 kV regional reliability 05/31/12 $0 $3,175,596 $1,102,202 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project.

### 20084 11036 SPS Multi: Legacy Interchange 69 kV Tap - 115/69 transformer - 2 new regional reliability 05/31/12 $0 $3,175,596 $1,102,202 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project.

### 20084 11052 SPS Multi: Legacy Interchange 69 kV Tap - 115/69 transformer - 2 new regional reliability 05/31/12 $0 $3,175,596 $1,102,202 COMPLETE Mitigation plan has been provided to and accepted by SPP for this project.
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<th>Description</th>
<th>Start Date</th>
<th>End Date</th>
<th>Budget</th>
<th>Estimated Cost</th>
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**Notes:**
- **DELAY - MITIGATION:** Mitigation plan has been provided to and accepted by SPP for this project.
- **DELAY - NO MITIGATION:** Mitigation plan has been provided to and accepted by SPP for this project.
- **COMPLETE:** Project is complete.
- **SCHEDULE:** On schedule.
- **COMPETE:** Project is complete.

Additional text:
- Alternative 1: Swap Swisher Co-op load onto Kress Interchange, bus 525192, CLOSE N.O. REC (22) Claytonville and OPEN REC (16) Northcutt (total 8.5 MVA).
- Alternative 2: CLOSE switch 6745 LS, bus 526979 LG-LS Smith. OPEN SW 7797 bus 527777 Goodpasture; then CLOSE SW 6817 bus 526931 LG. Lakeview and OPEN switch 8913 bus 526238 LG. New Moore. Don't know what the current estimate of $100,000 entails, the SPS estimate to expand the 115 kV bus is $3,643,355.
- \(4\)
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**Notes:**
- The transmission service for WR Line - Neosho - Northeast Parsons 138 kV was replaced with built-up 266 ACSR wire rated at 192MV.
- The mitigation is to open the Halstead-Burton 69 kV line and close the Burton line to Yoder Junction and switch Burton load to be served from Hutchinson.
- Project costs are for Westar Energy portion only; Public hearing held; Technical hearing held; Project costs include rebuilding of 138 kV underground system on same ROW.
- Current cash estimate for WPL 1B00 is sufficient for both 230/115kV work. Additional dollars not required. The mitigation is to run Able Energy Center.
- The mitigation is to re-dispatch LEC generation and/or open Wakarusa Jct-Eudora 115 kV.
- Westar Energy portion only; Public hearing held; Technical hearing held; Project costs include rebuilding of 138 kV underground system on same ROW.
- Load will not be in service until June, 2014. No mitigation is needed. The RTO date needs to be changed according to an email that was sent to Steve Purdy.
- Load will not be in service until June, 2014. Load will not be in service until June, 2014. No mitigation is needed. The RTO date needs to be changed according to an email that was sent to Steve Purdy.
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Description</th>
<th>Voltage</th>
<th>Regional/Reliability</th>
<th>Timeline</th>
<th>Cost 1</th>
<th>Cost 2</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>200179</td>
<td>WR</td>
<td>XFR - Auburn Road 230/115 kV Transformer Ckt 1</td>
<td>Regional Reliability</td>
<td>06/01/14 04/05/12</td>
<td>$25,845,600</td>
<td>$25,845,600</td>
<td>COMMISSION WINDOW</td>
</tr>
<tr>
<td>200181</td>
<td>WR</td>
<td>XFR - Moundridge 138/115 kV</td>
<td>IPP15</td>
<td>12/01/14 04/05/12</td>
<td>$12,197,900</td>
<td>$12,197,900</td>
<td>COMMISSION WINDOW</td>
</tr>
<tr>
<td>200175</td>
<td>WR</td>
<td>Line - Fort Junction - West Junction City 115 kV</td>
<td>Regional Reliability</td>
<td>06/01/16 06/25/10</td>
<td>$62,110,152</td>
<td>$62,110,152</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20108</td>
<td>WR</td>
<td>Line - Halstead South - Sedgwick 138 kV</td>
<td>transmission service</td>
<td>06/01/16 06/25/10</td>
<td>$62,110,152</td>
<td>$62,110,152</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>200182</td>
<td>WR</td>
<td>Mult - Elm Creek - Summit 345 kV</td>
<td>IPP15</td>
<td>03/01/16 04/05/12</td>
<td>$62,110,152</td>
<td>$62,110,152</td>
<td>COMPLETE</td>
</tr>
<tr>
<td>20108</td>
<td>WR</td>
<td>Line - East Manhattan - NW Manhattan 230 kV Ckt 1</td>
<td>transmission service</td>
<td>03/19/12 06/25/16</td>
<td>$62,110,152</td>
<td>$62,110,152</td>
<td>COMPLETE</td>
</tr>
</tbody>
</table>
### SPP 3rd Quarter 2012 Project Tracking List - Device

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Project Owner</th>
<th>Project Name</th>
<th>Project Status</th>
<th>Status Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>GRDA</td>
<td>Device - Tahlequah West 69 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 7/15/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>MW</td>
<td>Device - Kinsley Capacitor 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 7/15/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Onell 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Plattsburgh North 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Clarks 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Ainsworth 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Oneill 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Valentine 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>NPPD</td>
<td>Device - Kearney 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>OGE</td>
<td>Device - Little Lake 69 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>OGE</td>
<td>Device - Kolache 69 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>SEPC</td>
<td>Device - Johnson Corner 115 kV</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>SEPC</td>
<td>Device - Johnson Corner 115 kV 2nd</td>
<td>On Schedule 4</td>
<td>Project placed in service 11/10/12. Costs finalized.</td>
</tr>
</tbody>
</table>

*Project types "zonal - sponsored" and "regional reliability - non OATT" do not receive NTCs and are not filed at FERC but are being tracked because they are expected to be built in the near term.*
<table>
<thead>
<tr>
<th>NTC_ID</th>
<th>UID</th>
<th>Project Owner</th>
<th>Project Name</th>
<th>Project Type</th>
<th>Project Owner Indicated In-Service Date</th>
<th>RTO Reliability Need Date</th>
<th>Letter of Notification to Contractor's Date</th>
<th>Cost Estimate</th>
<th>Final Cost</th>
<th>Project Status</th>
<th>Project Status Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>200166</td>
<td>50093</td>
<td>SPS Device - Bushland Interchange 230 kV Capacitor</td>
<td>Regional Reliability</td>
<td>06/01/12</td>
<td>04/09/12</td>
<td>$1,071,475</td>
<td>NTC - COMMITMENT WINDOW</td>
<td>Needs further analysis - this is a wind farm outlet bus - no capacitors were identified in TS or GI studies. Project deferred beyond the planning horizon as per 2007 Expansion Plan.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200166</td>
<td>50378</td>
<td>SPS Device - Dinkard 115 kV Capacitor</td>
<td>Regional Reliability</td>
<td>06/01/15</td>
<td>04/09/12</td>
<td>$1,349,807</td>
<td>NTC - COMMITMENT WINDOW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200166</td>
<td>50401</td>
<td>SPS Device - Crosby 115 kV Capacitor</td>
<td>Regional Reliability</td>
<td>03/30/14</td>
<td>04/09/12</td>
<td>$1,336,466</td>
<td>NTC - COMMITMENT WINDOW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50045</td>
<td>WFEC Device - Esquadale Cap 69 kV</td>
<td>regional reliability</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>01/27/09</td>
<td>$243,000</td>
<td>ON SCHEDULE &lt; 4</td>
<td>WFEC will move ahead line project: Cache to Grandfield to mitigate voltage problem. Short term mitigation until line can be built will be transferring load from Hulen Substation to Empire and Duncan Substations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>19985</td>
<td>50047</td>
<td>WFEC Device - Comanche</td>
<td>regional reliability</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>02/02/07</td>
<td>$350,000</td>
<td>ON SCHEDULE &lt; 4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25003</td>
<td>50085</td>
<td>WFEC Device - Oysmuth Cap 69 kV</td>
<td>regional reliability</td>
<td>06/01/11</td>
<td>04/01/08</td>
<td>02/13/08</td>
<td>$150,000</td>
<td>DELAY - MITIGATION</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50109</td>
<td>WFEC Device - Latia Cap 138 kV</td>
<td>regional reliability</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>02/13/08</td>
<td>$324,000</td>
<td>ON SCHEDULE &lt; 4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50116</td>
<td>WFEC Device - Eagle Grass 69 kV Capacitor</td>
<td>Regional Reliability</td>
<td>06/01/10</td>
<td>06/01/09</td>
<td>01/27/09</td>
<td>$260,000</td>
<td>DELAY - MITIGATION</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50116</td>
<td>WFEC Device - Elsloa 69 kV Capacitor</td>
<td>regional reliability</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>02/08/10</td>
<td>$240,000</td>
<td>DELAY - NO MITIGATION</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50129</td>
<td>WR Device - Allen 69 kV Capacitor</td>
<td>transmission service</td>
<td>05/31/12</td>
<td>06/01/12</td>
<td>09/18/09</td>
<td>$594,830</td>
<td>COMPLETE</td>
<td>Shed load at Loco Substation (up to 3.5MW in 2007 Summer Peak) Shed load at Empire Substation (up to 5MW in 2007 Summer Peak). MW values mentioned are typical for a Summer Peak case. Mitigation Plan under review by SPP staff.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50129</td>
<td>WR Device - Altogna East 69 kV Capacitor</td>
<td>transmission service</td>
<td>06/01/13</td>
<td>06/01/14</td>
<td>09/18/09</td>
<td>$1,040,000</td>
<td>ON SCHEDULE &lt; 4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50221</td>
<td>WR Device - Athens 69 kV Capacitor</td>
<td>transmission service</td>
<td>12/01/13</td>
<td>09/13/13</td>
<td>09/18/09</td>
<td>$1,026,734</td>
<td>DELAY - MITIGATION</td>
<td>Bring on cap banks at Allen and Roga. Dispatch Chautauqua/Elmsford generation.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50224</td>
<td>WR Device - Hoga 69 kV Capacitor</td>
<td>transmission service</td>
<td>07/06/11</td>
<td>06/01/11</td>
<td>09/18/09</td>
<td>$732,398</td>
<td>COMPLETE</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20030</td>
<td>50224</td>
<td>WR Device - Dalesing 138 kV Capacitor</td>
<td>transmission service</td>
<td>06/01/13</td>
<td>06/01/12</td>
<td>01/13/10</td>
<td>$1,215,000</td>
<td>DELAY - MITIGATION</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20140</td>
<td>50370</td>
<td>WR Device - Chapman Junction 115 kV Capacitor</td>
<td>Zonal Reliability</td>
<td>10/01/13</td>
<td>10/01/12</td>
<td>05/27/11</td>
<td>$873,461</td>
<td>DELAY - MITIGATION</td>
<td>Because North Manhattan 15 Mvar cap bank will be in-service in summer 2012, this project does not need a mitigation.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>200175</td>
<td>50382</td>
<td>WR Device - Benton Cap #2</td>
<td>zonal - sponsored</td>
<td>06/01/13</td>
<td>06/01/12</td>
<td>04/09/12</td>
<td>$2,072,000</td>
<td>ON SCHEDULE &lt; 4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200175</td>
<td>50383</td>
<td>WR Device - Northwest Manhattan 115 kV Capacitor</td>
<td>Zonal Reliability</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>04/09/12</td>
<td>$957,660</td>
<td>NTC - COMMITMENT WINDOW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200175</td>
<td>50388</td>
<td>WR Device - Elk River 69 kV Capacitor</td>
<td>Zonal Reliability</td>
<td>12/01/13</td>
<td>06/01/12</td>
<td>04/09/12</td>
<td>$1,657,160</td>
<td>NTC - COMMITMENT WINDOW</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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Project Tracking Update

- Projects with cost estimate > 20% since the last quarter
  - Cottonwood Creek – Crescent 138kV Conversion (OG&E)
  - Medicine Lodge Transformer 138/115 kV (MKEC)
  - Lynn Co. Substation 115 kV Load Conversion (SPS)
  - Alva Substation Upgrade 69 kV (OG&E)
2nd Quarter 2012 Cost Increases

*Cottonwood Creek – Crescent 138 kV Conversion (OG&E)*

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>1st Quarter 2012 Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q2-Q1)</th>
<th>Cost Change % (Q2/Q1)</th>
<th>Cost Change (Q2-NTC)</th>
<th>Cost Change % (Q2/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>regional reliability</td>
<td>1/27/2009</td>
<td>6/1/2014</td>
<td>$5,404,250</td>
<td>$5,404,250</td>
<td>$8,100,000</td>
<td>$2,695,750</td>
<td>49.88%</td>
<td>$2,695,750</td>
<td>49.88%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Original 2008 estimate assumed minimal substation upgrades needed at Crescent to reach 138 kV capability
    - New estimate includes additional costs to rebuild Crescent substation to meet required standards

**Staff Recommendation**

- **Cottonwood Creek – Crescent 138kV Conversion**
  - No NTC modification or re-evaluation
    - Project being constructed jointly with WFEC
      - 5 total upgrades in project, WFEC owns 4
      - 2 upgrades from WFEC’s portion projected in-service 12/31/2012
    - Actual expenditures are likely high for WFEC upgrades
2nd Quarter 2012 Cost Increases

**Medicine Lodge Transformer 138/115 kV (MKEC)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>1st Quarter 2012 Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q2-Q1)</th>
<th>Cost Change % (Q2/Q1)</th>
<th>Cost Change (Q2-NTC)</th>
<th>Cost Change % (Q2/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>transmission service</td>
<td>1/13/2010</td>
<td>2/1/2013</td>
<td>$5,625,000</td>
<td>$5,864,617</td>
<td>$8,627,726</td>
<td>$2,763,109</td>
<td>47.11%</td>
<td>$3,002,726</td>
<td>53.4%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Original estimate based on internal resource allocation with minimal substation upgrades
  - Due to significant increase in internal workload, new estimate calculated on turnkey basis

**Staff Recommendation**

- **Medicine Lodge Transformer 138/115 kV**
  - No NTC modification or re-evaluation
    - 2/1/2013 projected in-service
    - Insufficient time to re-evaluate relative to in-service date
2nd Quarter 2012 Cost Increases

**Alva Substation Upgrade 69 kV (OG&E)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>1st Quarter 2012 Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q2-Q1)</th>
<th>Cost Change % (Q2/Q1)</th>
<th>Cost Change (Q2-NTC)</th>
<th>Cost Change % (Q2/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>regional reliability</td>
<td>2/14/2011</td>
<td>7/15/2012</td>
<td>$112,500</td>
<td>$112,500</td>
<td>$344,000</td>
<td>$231,500</td>
<td>205.78%</td>
<td>$231,500</td>
<td>205.78%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Original estimate based on replacement of limiting relay at Alva interconnection substation
    - New estimate includes costs to replace 69 kV interconnect metering not previously identified

**Staff Recommendation**

- **Alva Substation Upgrade 69 kV**
  - No NTC modification or re-evaluation
    - Upgrade in-service 7/15/2012
### 2nd Quarter 2012 Cost Increases

**Lynn Co. Substation 115 kV Load Conversion (SPS)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>1st Quarter 2012 Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q2-Q1)</th>
<th>Cost Change % (Q2/Q1)</th>
<th>Cost Change (Q2-NTC)</th>
<th>Cost Change % (Q2/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>regional reliability</td>
<td>2/14/2011</td>
<td>12/31/2013</td>
<td>$100,000</td>
<td>$100,000</td>
<td>$4,489,314</td>
<td>$4,389,314</td>
<td>4389%</td>
<td>$4,389,314</td>
<td>4389%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Previous estimate did not include conversion of bus configuration at substation to breaker-and-a-half scheme
    - New configuration conforms to Study Estimate Design Guide

---

### Staff Recommendation

- **Lynn Co. Substation 115 kV Load Conversion**
  - Re-evaluate the NTC as part of 2013 ITP Near-Term
    - Actual expenditures are likely low
      - $300,000 to date
    - RTO Determined Need Date of 6/1/2012
      - Mitigation plan in place
    - 12-month lead time
      - 12/31/2013 projected in-service date
    - Re-evaluation complete 1/2013
Staff Recommendations

- **Cottonwood Creek – Crescent 138kV Conversion (OG&E)**
  - No NTC modification or re-evaluation
- **Medicine Lodge Transformer 138/115 kV (MKEC)**
  - No NTC modification or re-evaluation
- **Alva Substation Upgrade 69 kV (OG&E)**
  - No NTC modification or re-evaluation
- **Lynn Co. Substation 115 kV Load Conversion (SPS)**
  - Re-evaluate the NTC as part of 2013 ITP Near-Term

MOPC Recommendation

- **Lynn Co. Substation 115 kV Load Conversion (SPS)**
  - Suspend NTC
3rd Quarter 2012 Project Tracking Update

July 30, 2012
RSC

Project Tracking Update

- Projects with cost estimate > 20% since the last quarter
  - Sub 170 Nichols – Sub 80 Sedalia 69 kV (EDE)
  - Clay Center Switching Station – TC Riley 115 kV (WR)
  - Halstead South Transformer 138/69 kV (WR)
  - Altoona East 69 kV Capacitor (WR)
  - Athens 69 kV Capacitor (WR)
3rd Quarter 2012 Cost Increases

**Sub 170 Nichols – Sub 80 Sedalia 69 kV (EDE)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>3rd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q3-Q2)</th>
<th>Cost Change % (Q3/Q2)</th>
<th>Cost Change (Q3-NTC)</th>
<th>Cost Change % (Q3/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>regional reliability</td>
<td>2/8/2010</td>
<td>5/1/2012</td>
<td>$3,520,000</td>
<td>$3,520,000</td>
<td>$4,500,000</td>
<td>$980,000</td>
<td>27.8%</td>
<td>$980,000</td>
<td>27.8%</td>
</tr>
</tbody>
</table>

- Cost Increase Justification
  - More ROW required than originally expected
  - Structure types changed from H-frame to single pole for portion of line due to more restrictive ROW

**Staff Recommendation**

- **Sub 170 Nichols – Sub 80 Sedalia 69 kV**
  - No NTC modification or re-evaluation
    - Upgrade in-service 5/1/2012
3rd Quarter 2012 Cost Increases

**Clay Center Switching Station – TC Riley 115 kV (WR)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>3rd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q3-Q2)</th>
<th>Cost Change % (Q3/Q2)</th>
<th>Cost Change (Q3/NTC)</th>
<th>Cost Change % (Q3/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zonal Reliability</td>
<td>5/27/2011</td>
<td>6/1/2014</td>
<td>$4,549,942</td>
<td>$4,632,508</td>
<td>$7,472,511</td>
<td>$2,840,003</td>
<td>61.3%</td>
<td>$2,922,569</td>
<td>64.2%</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td></td>
<td><strong>$9,427,492</strong></td>
<td><strong>$9,510,058</strong></td>
<td><strong>$10,247,362</strong></td>
<td><strong>$737,304</strong></td>
<td><strong>7.8%</strong></td>
<td><strong>$819,870</strong></td>
<td><strong>9.1%</strong></td>
</tr>
</tbody>
</table>

Also part of this project: **Clay Center Switching Station Substation 115 kV (WR)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>3rd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q3-Q2)</th>
<th>Cost Change % (Q3/Q2)</th>
<th>Cost Change (Q3/NTC)</th>
<th>Cost Change % (Q3/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zonal Reliability</td>
<td>5/27/2011</td>
<td>11/1/2012</td>
<td>$4,877,550</td>
<td>$4,877,550</td>
<td>$2,774,851</td>
<td>($2,102,699)</td>
<td>-43.1%</td>
<td>($2,102,699)</td>
<td>-43.1%</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td></td>
<td><strong>$9,755,100</strong></td>
<td><strong>$9,755,100</strong></td>
<td><strong>$5,549,651</strong></td>
<td>($2,205,449)</td>
<td>-43.1%</td>
<td>($2,205,449)</td>
<td>-43.1%</td>
</tr>
</tbody>
</table>

**Cost Increase Justification**
- Cost reallocation among upgrades within the same project
- Total increase for both upgrades within project is 7.8%

**Staff Recommendation**

- **Clay Center Switching Station – TC Riley 115 kV**
  - No NTC modification or re-evaluation
    - Total project cost variance within 20% threshold
    - Much of the work is complete for the project
    - Actual expenditures are likely high
3rd Quarter 2012 Cost Increases

*Halstead South Transformer 138/69 kV (WR)*

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>3rd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q3-Q2)</th>
<th>Cost Change % (Q3-Q2)</th>
<th>Cost Change (Q3-NTC)</th>
<th>Cost Change % (Q3/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>regional reliability</td>
<td>2/10/2010</td>
<td>6/1/2014</td>
<td>$1,700,000</td>
<td>$1,875,000</td>
<td>$3,205,323</td>
<td>$1,330,323</td>
<td>71.0%</td>
<td>$1,505,323</td>
<td>88.5%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Detailed engineering review revealed additional needed substation work not included in original estimate

Staff Recommendation

- **Halstead South Transformer 138/69 kV**
  - Re-evaluate the NTC as part of 2013 ITP Near-Term
    - Actual expenditures are likely low
    - RTO Determined Need Date of 6/1/2011
      - Mitigation plan in place
    - 24-month lead
      - 6/1/2014 projected in-service date
    - Re-evaluation complete 1/2013
3rd Quarter 2012 Cost Increases

**Altoona East 69 kV Capacitor (WR)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>3rd Quarter 2012 Cost Estimate</th>
<th>Cost Change (Q3-Q2)</th>
<th>Cost Change % (Q3/Q2)</th>
<th>Cost Change (Q3-NTC)</th>
<th>Cost Change % (Q3/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>transmission service</td>
<td>9/18/2009</td>
<td>6/1/2014</td>
<td>$607,500</td>
<td>$607,500</td>
<td>$1,045,000</td>
<td>$437,500</td>
<td>72.0%</td>
<td>$437,500</td>
<td>72.0%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Detailed engineering review revealed additional needed substation work not included in original estimate

**Staff Recommendation**

- **Altoona East 69 kV Capacitor**
  - Re-evaluate the NTC in future Aggregate Study
    - Actual expenditures are likely low
    - RTO Determined Need Date of 6/1/2014
      - Mitigation plan in place
    - 18-month lead time
      - 6/1/2014 projected in-service date
    - Re-evaluation study duration – 30 days
3rd Quarter 2012 Cost Increases

**Athens 69 kV Capacitor (WR)**

<table>
<thead>
<tr>
<th>Project Type</th>
<th>NTC Issue Date</th>
<th>In-Service Date</th>
<th>NTC Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate</th>
<th>2nd Quarter 2012 Cost Estimate Change (Q3-Q2)</th>
<th>Cost Change % (Q3/Q2)</th>
<th>Cost Change % (Q3/NTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>transmission service</td>
<td>9/18/2009</td>
<td>12/1/2013</td>
<td>$607,500</td>
<td>$607,500</td>
<td>$1,026,734</td>
<td>$419,234</td>
<td>69.0%</td>
</tr>
</tbody>
</table>

- **Cost Increase Justification**
  - Detailed engineering review revealed additional needed substation work not included in original estimate

**Staff Recommendation**

- **Athens 69 kV Capacitor**
  - Re-evaluate the NTC in future Aggregate Study
    - Actual expenditures are likely low
    - RTO Determined Need Date of 6/1/2013
    - 12-month lead time
      - 6/1/2013 projected in-service date
    - Re-evaluation study duration – 30 days
Staff Recommendations

- **Sub 170 Nichols – Sub 80 Sedalia 69 kV (EDE)**
  - No NTC modifications or re-evaluation
- **Clay Center Switching Station – TC Riley 115 kV (WR)**
  - No NTC modifications or re-evaluation
- **Halstead South Transformer 138/69 kV (WR)**
  - Re-evaluate need for NTC
- **Altoona East 69 kV Capacitor (WR)**
  - Re-evaluate need for NTC
- **Athens 69 kV Capacitor (WR)**
  - Re-evaluate need for NTC

MOPC Recommendations

- **Halstead South Transformer 138/69 kV (WR)**
  - Suspend NTC for re-evaluation
- **Altoona East 69 kV Capacitor (WR)**
  - Suspend NTC for re-evaluation
## PROJECT TRACKING STATISTICS

### Cost Estimate Trending

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Original Cost Estimate</th>
<th>2011 Q3</th>
<th>2012 Q1</th>
<th>2012 Q3</th>
<th>% Diff From Original</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balanced Portfolio</td>
<td>$698,548,515</td>
<td>$870,712,596</td>
<td>$903,039,973</td>
<td>$855,339,021</td>
<td>22.45%</td>
</tr>
<tr>
<td>Generation Interconnect</td>
<td>$67,840,000</td>
<td>$84,588,000</td>
<td>$84,588,000</td>
<td>$84,588,000</td>
<td>24.69%</td>
</tr>
<tr>
<td>high priority</td>
<td>$1,144,856,481</td>
<td>$1,109,563,535</td>
<td>$1,439,712,179</td>
<td>$1,437,062,178</td>
<td>25.52%</td>
</tr>
<tr>
<td>regional reliability</td>
<td>$1,044,107,707</td>
<td>$1,255,565,444</td>
<td>$1,296,130,620</td>
<td>$1,343,280,714</td>
<td>28.65%</td>
</tr>
<tr>
<td>transmission service</td>
<td>$984,499,278</td>
<td>$513,686,923</td>
<td>$466,096,852</td>
<td>$460,626,033</td>
<td>15.59%</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>$2,815,000</td>
<td>$3,782,279</td>
<td>$3,782,279</td>
<td>$3,782,279</td>
<td>34.36%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$3,356,666,981</strong></td>
<td><strong>$3,837,898,777</strong></td>
<td><strong>$4,193,349,903</strong></td>
<td><strong>$4,184,678,225</strong></td>
<td><strong>24.67%</strong></td>
</tr>
</tbody>
</table>
**Cost Estimate Trending**

![Cost Estimate Trending Chart]

**Update Frequency Trending**

<table>
<thead>
<tr>
<th>Report Date</th>
<th>Overall # of Upgrades</th>
<th># of Upgrades Within Lead Time</th>
<th>% Cost Estimates Changed</th>
<th>% In-Service Dates Changed</th>
<th>% Upgrade Status Comments Changed</th>
<th>% Upgrades w/ Any Changes</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011 Q3</td>
<td>459</td>
<td>164</td>
<td>7.19%</td>
<td>8.06%</td>
<td>7.84%</td>
<td>20.48%</td>
</tr>
<tr>
<td>2011 Q4</td>
<td>473</td>
<td>204</td>
<td>10.78%</td>
<td>12.26%</td>
<td>8.88%</td>
<td>26.43%</td>
</tr>
<tr>
<td>2012 Q1</td>
<td>476</td>
<td>192</td>
<td>11.34%</td>
<td>11.34%</td>
<td>8.61%</td>
<td>24.37%</td>
</tr>
<tr>
<td>2012 Q2</td>
<td>394</td>
<td>210</td>
<td>13.96%</td>
<td>16.75%</td>
<td>10.66%</td>
<td>36.55%</td>
</tr>
<tr>
<td>2012 Q3</td>
<td>380</td>
<td>210</td>
<td>12.11%</td>
<td>20.53%</td>
<td>13.16%</td>
<td>45.26%</td>
</tr>
</tbody>
</table>