Southwest Power Pool  
REGIONAL STATE COMMITTEE  
Marriott Country Club Plaza, Kansas City, Missouri  
July 30, 2012

• M I N U T E S •

Administrative Items:
The following members were in attendance:

   Kevin Gunn, Missouri Public Service Commission (MOPSC)  
   Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)  
   Dana Murphy, Oklahoma Corporation Commission (OCC)  
   Dana Murphy, proxy for 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 1:00 p.m. with roll call and a quorum was declared. He then requested a round of introductions. There were 106 in attendance either in person or via phone (Attendance & Proxies – Attachment 1).

President Reeves asked for approval of the April 23, 2012 meeting minutes (RSC Minutes 4/23/12 - Attachment 2). Patrick Lyons moved to approve the minutes with one minor change; Tom Wright seconded the motion. The minutes were unanimously approved as amended.

UPDATES

RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Suskie reported that the RSC is over Budget due in part to travel expenses. Travel may need to be increased when drafting the 2013 Budget, which should also consider staff travel to the CAWG meetings. The final bill shown for the Seams Cost Allocation expense item was actually a 2011 Budget item. The 2013 Budget will be approved at the October 29 meeting.

SPP Report
Mr. Brown announced that SPP held a ribbon-cutting for the new facility on July 9, moving onto the campus on July 16. Discussion regarding a new facility began in 2008, the SPP campus was approved in 2009 and ground-breaking took place in 2010. The building was on schedule and slightly under budget. After 67 years in leased space, it is great to have a facility designed to meet SPP’s specific needs.

Mr. Brown stated that the Integrated Marketplace has been divided into three components with the systems status moving from yellow to green. A push on staffing helped with the change of status as well as relying more on staff than external consultants. Internal and external audits continue to be performed to assess project status. More information will be provided later in the meeting. Dana Murphy requested that members receive data in a timely fashion to allow time to adjust, that the time frame for integrating the system is shared with the members, and that the stakeholders are made aware of any additional costs with the system.
Mr. Brown was happy to announce that SPP received a senior unsecure rating of A from Fitch.

FERC
Mr. Patrick Clarey provided an update on recent FERC activities:

May
FERC upheld its Order No. 1000 reforms to transmission planning and cost allocation. FERC denied rehearing of the July 2011 final rule establishing minimum criteria that a transmission planning process must satisfy, including general principles for cost allocation methods.

The order also affirms the Commission’s actions in Order No. 1000 to promote competition in regional transmission planning by removing from Commission-approved tariffs and agreements any federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to certain limitations.

FERC recently approved SPP’s requested 32-day extension for a compliance filing for requirements of Order No. 1000.

FERC approved a policy statement outlining how it will advise the Environmental Protection Agency (EPA) on requests for extra time for electric generators to comply with the new mercury and air toxics standards rule. The Commission will vote on its comments before providing them to EPA, but this will not constitute a final determination that a reliability standard has or will be violated, nor will it be considered a final agency action that would trigger civil penalties or other enforcement actions.

June
Commissioners Tony Clark and John Norris were sworn in for their new terms.

FERC issued a proposal that would approve the North American Electric Reliability Corporation’s (NERC) revisions to the definition of the bulk electric system to provide greater clarity and ensure consistency in identifying system elements across the nation’s reliability regions.

July
FERC announced the dates and locations for five regional technical conferences on better coordination between natural gas and electricity markets. The conferences will explore gas-electric interdependence as well as ways to improve coordination and communication between the two industries. Discussion at each conference will focus on: (1) communications, coordination and information sharing; (2) scheduling; (3) market structures and rules; and (4) reliability concerns. The conferences will be open to the public, and Commission members will attend. SPP’s region will be included in an August 6th conference in St. Louis along with MISO and ERCOT.

At the July Open Meeting FERC proposed to clarify and refine its policies governing capacity allocation for new merchant transmission projects and new nonincumbent, cost-based, participant-funded transmission projects.

FERC upheld NERC’s assessment of a $19,500 penalty against the Southwestern Power Administration for violations of certain reliability standards. Over objections from DOE, FERC found that under the FPA, it has the authority to impose a monetary penalty against a federal agency for violation of a mandatory reliability standard.

BUSINESS MEETING
No business was reported.

REPORTS/PRESENTATIONS
Cost Allocation Working Group Report
Pat Mosier provided the CAWG report (CAWG Report – Attachment 4). Ms. Mosier presented a quarterly
overview of the group’s activities. Items addressed were:

- SPCTF on Order 1000
- SPP Working Groups/Task Forces
- Public Policy Requirements in Planning Survey
- Ongoing consideration for Treatment of Cost overruns
- Waiver Request: OMPA & AECC

Order 1000

Order 1000 ROFR

Paul Suskie updated the group on the efforts of the SPCTF on Order 1000 and the Task Force’s Report recommendations to comply with Order 1000/1000-A on policy issues including the Right of First Refusal (ROFR) and the possible impacts on the Highway/Byway cost allocation methodology (Order 1000 – Attachment 5). Mr. Suskie stated that the group seeks RSC’s input on SPP’s compliance filing on ROFR in three areas:

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?

Following discussion including that CAWG supports the SPCTF position, Tom Wright moved to support the areas outlined; Dana Murphy seconded the motion. The motion passed unanimously.

Patrick Lyons and Dana Murphy suggested that the RSC should draft a letter to be included in SPP’s Order 1000/1000-A compliance filing showing the RSC’s support to retain ROFR for certain projects. Following discussion, Dana Murphy moved to draft a letter to the SPP Board of Directors and Nick Brown and Paul Suskie showing support for the retention of ROFR; Patrick Lyons seconded the motion. The motion passed unanimously.

SPCTF on Order 1000

Ricky Bittle provided an update on SPCTF on Order 1000 (SPCTF Update – Attachment 6). Mr. Bittle stated that SPP had received a 30-day extension for compliance filings addressing the Order 1000 regional transmission planning and cost allocation requirements. The compliance filings addressing the interregional coordination and cost allocation requirements are due by April 11, 2013. Mr. Bittle reviewed eight recommendations to the SPP Board of Directors from the 1st SPCTF on Order 1000 Report:

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 Federal ROFR.
3. Recommendation as to Transmission Owner Qualification Criteria.
4. Recommendation as to Changes to SPP’s Membership Agreement and
OATT to Remove the Federal ROFR.
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.

He then presented the six recommendations to the SPP Board of Directors from the 2nd SPCTF on Order 1000 Report:

1. Recommendation of Transmission Owner Selection Criteria
3. Recommendation on the Mobile-Sierra Doctrine.
5. Recommendation on Establishment of a Need by Date, Notice of Such Date, and Requirement to meet Deadlines.
6. Recommendation of a required Deposit from the selected transmission owner

The SPCTF recommendations for SPP’s compliance with Orders 1000/1000-A will be presented to the SPP Board of Directors on July 31, 2012.

Seams Steering Committee (SSC)
Paul Malone presented an SSC update (SSC Report – Attachment 7). Mr. Malone provided an overview of Order 1000 interregional planning requirements and stated that currently SPP was planning for three seams entities: MAPPCOR, AECI and MISO. The SSC has formed a Seams FERC Order 1000 Task Force (SFOTF) to develop an SPP proposal to address these requirements. Mr. Malone then presented a high level overview of the proposed process (Option 1), which the SSC unanimously approved as the SPP proposal to use in negotiating with each neighbor (See Attachment 7).

Interregional Cost Allocation TF (IRCATF) Update
Chairman Kevin Gunn provided the IRCATF update (IRCATF Report – Attachment 8). Following a brief description of the group, Chairman Gunn presented General Benefit Principals and Interregional Cost Allocation Principles (as stated in the report). He then moved for adoption of these principles; Tom Wright seconded the motion. The motion passed unanimously.

OMPA Waiver Request (75196276)
Lanny Nickell reviewed the Aggregate Study Waiver Process under Attachment J and provided past history (Waiver Requests Report – Attachment 9). Mr. Nickell then presented OMPA Request 75196276 and offered the following 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.
CAWG also recommended that the cost for improvements be granted Base Plan funding. Dana Murphy moved to approve the OMPA Waiver Request as recommended by the CAWG; Kevin Gunn seconded the motion. The motion passed unanimously.

AECC Waiver Requests (76585958 & 76586012)
Lanny Nickell provided background for the AECC Waiver Requests 76585958 and 76586012. He then presented the following 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.

Tom Wright moved to approve AECC Waiver Requests as recommended by the CAWG; Michael Schiedschlag seconded the motion. The motion passed unanimously.

During discussion, the group asked if the waiver process needed to be reviewed. The group was informed that the MOPC has requested the Business Practices Working Group (BPWG) review this process and consider improvements regarding small waiver requests.

Integrated Marketplace Update

Future RSC Matters
Future RSC matters include the election of Officers in October 2012 and the adoption of the 2013 Budget.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Reeves noted that the next regularly scheduled meeting is on October 29 in Little Rock at the new SPP campus.

With no further business, the meeting adjourned at 4:35 p.m.

Respectfully Submitted,

Paul Suskie
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.*
   c. 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.
   d. 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.
   e. 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.
   f. 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 safeharbor 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 safeharbor 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
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<tbody>
<tr>
<td>Tom Dunn</td>
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<td>Todd Feidley</td>
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<td>Mary EI</td>
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<td>Terri Gallup</td>
<td>ABPSC - PS0185</td>
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<td>G. Richard Ross</td>
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<td>Brett Kruse</td>
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<td>David Linton</td>
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<tr>
<td>Walt Shumate</td>
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<td>LARRY ALTENBOAVER</td>
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<td>Josh Martin</td>
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<td>Ricky Bithe</td>
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<td>Barry Warren</td>
<td>Empire District Electric Co.</td>
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<td>Pat Mosier</td>
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<td>Mike Proctor</td>
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<tr>
<td>Stuart Solomon</td>
<td>AEP Companies (PSE/EPARC)</td>
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<td>Label Langthorn</td>
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<td>Phil Crissup</td>
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<td>Patrick Peters</td>
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<td>Patrick H. Lyon</td>
<td>N.M. PRC Comm</td>
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<td>Michael Siegenschug</td>
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<td>Dana Murphy</td>
<td>OK Corp. Comm.</td>
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<td>Phyllis Bernard</td>
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<td>Nick Brown</td>
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<td>Julian Ban</td>
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<td>Henry Skilton</td>
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# Southwest Power Pool

**SPP REGIONAL STATE COMMITTEE**  
*July 30, 2012*

## ATTENDANCE LIST

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SPP REGIONAL STATE COMMITTEE  
July 30, 2012  

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<td>Brenda Harris</td>
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Southwest Power Pool  
REGIONAL STATE COMMITTEE  
Renaissance Hotel, Oklahoma City, OK  
April 23 2012  

• MINUTES •

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>
<thead>
<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>283,284</td>
<td>150,500</td>
<td>132,784</td>
</tr>
<tr>
<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>55,000</td>
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<tr>
<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>
<td>(500)</td>
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<tr>
<td>RSC Consultant</td>
<td>30,671</td>
<td>57,500</td>
<td>(26,829)</td>
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<tr>
<td>Technical Conference</td>
<td>-</td>
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<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.

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>Total</td>
<td>7,363</td>
<td>27,443,160</td>
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</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.
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
ATTACHMENT A

CAWG REPORT TO RSC
SPCTF ORDER 1000 CURRENT DETERMINATIONS

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 project⁴ (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 need⁵. 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 Doctrine⁶

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.

⁶A 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)

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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.

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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\(^7\) 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)\(^8\) 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.

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\(^7\) 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
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>Regional Planning</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></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Right of First Refusal</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>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost Allocation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.</td>
<td>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])</td>
<td>SPP Complies with requirement.</td>
<td>N/A</td>
</tr>
</tbody>
</table>
# 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></td>
<td>Interregional Planning</td>
<td></td>
<td><strong>SPP Engineering &amp; SPP Seams Steering Committee:</strong> 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>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></td>
</tr>
<tr>
<td></td>
<td><strong>Interregional Cost Allocation</strong></td>
<td></td>
<td><strong>SPP Regulatory, SPP Seams Steering Committee &amp; SPP Regional State Committee:</strong> SPP’s RSC has already engaged the Brattle Group to look at Seams Cost Allocation.</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></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

### SPP OATT Att. H, Table 1, Zones

<table>
<thead>
<tr>
<th>(1) Zone No.</th>
<th>(2) 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>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</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>
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<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>
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<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>
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<td>14</td>
<td>Westar Energy, Inc. (Kansas Gas &amp; Electric and Westar Energy)</td>
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<td>15</td>
<td>Mid-Kansas Electric Company (Total)</td>
<td>$16,897,799</td>
<td>$866,604</td>
<td>$0</td>
<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>$18,892,471</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/Fer_Bills_2012-04-01_Revenue_Requirements_and_Rates_after%20Tri-County.xls](http://www.spp.org/publications/Fer_Bills_2012-04-01_Revenue_Requirements_and_Rates_after%20Tri-County.xls)
12 of 17 Zones have a Single TO

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<td>$0</td>
<td>$0</td>
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<td>Omaha Public Power District</td>
<td>100%</td>
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<td>$3,314,125</td>
<td>$0</td>
<td>$0</td>
</tr>
</tbody>
</table>

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

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>
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<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>96.79%</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>$25,109,134</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1c</td>
<td>Tex-La Electric Cooperative of Texas, Inc.</td>
<td>0.39%</td>
<td>$588,874</td>
<td>$25,109,134</td>
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<tr>
<td>1d</td>
<td>Deep East Texas Electric Cooperative, Inc.</td>
<td>0.28%</td>
<td>$428,131</td>
<td>$25,109,134</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1e</td>
<td>Oklahoma Municipal Power Authority</td>
<td>0.49%</td>
<td>$748,647</td>
<td>$25,109,134</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1f</td>
<td>AEP West Transmission Companies (AEP)</td>
<td>0.25%</td>
<td>$387,960</td>
<td>$674,969</td>
<td>$84,075</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>Oklahoma Gas and Electric (Total)</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>
<td>$11,462,867</td>
<td>$492,086</td>
<td></td>
</tr>
<tr>
<td>7b</td>
<td>Oklahoma Municipal Power Authority</td>
<td>0.45%</td>
<td>$368,501</td>
<td>$11,462,867</td>
<td>$492,086</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Southwestern Public Service Company (Total)</td>
<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>
<td>$331,789</td>
<td></td>
</tr>
<tr>
<td>11b</td>
<td>Tri-County Electric Cooperative</td>
<td>1.76%</td>
<td>$1,982,840</td>
<td>$17,151,748</td>
<td>$331,789</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Westar Energy, Inc. (Kansas Gas &amp; Electric and Westar Energy)</td>
<td>99.64%</td>
<td>$148,462,476</td>
<td>$24,218,555</td>
<td>$104,607</td>
<td>0</td>
</tr>
<tr>
<td>14a</td>
<td>Westar Energy, Inc. (Kansas Gas &amp; Electric)</td>
<td>99.64%</td>
<td>$147,933,559</td>
<td>$24,218,555</td>
<td>$104,607</td>
<td></td>
</tr>
<tr>
<td>14b</td>
<td>Prairie Wind Transmission, LLC.</td>
<td>0.00%</td>
<td>$0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>14c</td>
<td>Kansas Power Pool</td>
<td>0.36%</td>
<td>$258,917</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Mid-Kansas Electric Company (Total)</td>
<td></td>
<td>$16,897,799</td>
<td>$866,604</td>
<td>$0</td>
<td>0</td>
</tr>
<tr>
<td>15a</td>
<td>Mid-Kansas Electric Company</td>
<td>89.61%</td>
<td>$15,142,441</td>
<td>$866,604</td>
<td>$0</td>
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</tr>
<tr>
<td>15b</td>
<td>ITC Great Plains</td>
<td>11.39%</td>
<td>$1,755,358</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15c</td>
<td>Prairie Wind Transmission, LLC.</td>
<td>0.00%</td>
<td>$0</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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
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 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 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. <strong>RSC Input?</strong></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. <strong>RSC Input?</strong></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/BWAY 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.
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.\(^4\) 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.\(^5\)

\(^4\) 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?

to assert Mobile-Sierra must also submit tariff/agreement revisions in their compliance filings to comply with Orders 1000 and 1000-A, which FERC will review only after addressing the Mobile-Sierra arguments.

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.

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

## 2\textsuperscript{nd} Report

July - 2012

### SPCTF Members

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

OVERVIEW OF 1ST REPORT OF THE SPCTF ON ORDER 1000
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.

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)

- **BOD Approves Transmission Expansion Plan**
- **SPP Issues RFP to QTOs**
- **QTOs Respond; Window Closes; IEP Evaluations Begin**
- **Evaluations Submitted to BOD**
- **BOD Selects QTO for Project; SPP Notifies STO of NTC**
- **If STO Doesn’t Respond or is Unwilling to Accept NTC, Backup QTO is Notified**
- **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.

QUESTIONS???
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 ITP Input**
- **Other SPP Process Input**
- **Stakeholder Input**

**Flowchart Segment 1 of 3**

**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

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 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

78 of 133
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 effective¹</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>

¹Safe 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

• Formula to increase Safe Harbor Cost Limit for requests that exceed 5 years; adopted by CAWG
  - (Term in years - 5) x 2.5%/year x $180,000/MW
  - Example: OKGE waiver request in which the SPP Board approved the amount based on this formula

• Examination of the benefits of specific upgrades in comparison to alternatives
  - Example: Rose Hill- Sooner 345 kV that had greater benefits to the system than multiple, lower-voltage upgrades which would have been required otherwise
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 \text{ 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>&lt;1</td>
<td>6%</td>
<td>100%</td>
<td></td>
</tr>
<tr>
<td>Other Requests with TDF &lt;3%</td>
<td>16</td>
<td>94%</td>
<td>0%</td>
<td></td>
</tr>
</tbody>
</table>
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>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>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Other Requests with TDF &lt;3%</td>
<td>17</td>
<td>94</td>
<td>0</td>
<td></td>
</tr>
</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**

**OMPA REQUEST:**

OMPA 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**

OMPA 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:
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
Integrated Marketplace Update

July 30-31, 2012

Bruce Rew, P.E.
The Integrated Marketplace Successes

- Build-Test phase has begun
  - TCR’s iHedge, Settlements e-terrasettlements
  - Markets workstream closed out design
- FERC conditional order requested by July 31
- 34 of 36 eligible MPs registered for Marketplace
- TCR Mock Auction in second phase
- Engagement activities ramping up

Recovery Plan for Systems development

- Why Yellow in February?
  - Concern about meeting deliverable on date assigned
  - Detailed review of testing effort indicated Market Trials date (May 15, 2013) was in jeopardy
- Go-Live still March 1, 2014
- Integrated Marketplace Recovery Approach
Areas of concern

• Testing
  – Optimized testing and process
  – Addressed resource constraints
• POPS
  – Inadequate work plan
  – Lack of sufficient resources
• Interfaces
  – Underestimated number and revamped plan
  – Obtained needed expertise to implement

Risks Going Forward

• Testing
  – System readiness: 6 weeks to install, operationally test
    Market systems before Connectivity Testing
  – Parallel testing
  – Additional resources
• POPS
  – Large system with dependencies across the program
• Interfaces
  – Tight schedule; further delays could slip schedule
Market Participant Readiness

- CWG has primary responsibility
- Active engagement from Market Participants
- SPP Staff is highly involved and plays important role
- CWG met last week to review initial engagement report
- Program Concerns Expressed
  - Improved SPP staff coordination required
  - Staff assigned Jim Gunnell as lead over MP engagement
- Recommended Yellow status

Participant Engagement Report Activities

<table>
<thead>
<tr>
<th>Date</th>
<th>Participant Activity</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>April 30, 2012</td>
<td>Participant Design Underway</td>
<td>MP</td>
</tr>
<tr>
<td>June 1, 2012</td>
<td>Registration Packet Returned</td>
<td>SPP</td>
</tr>
<tr>
<td>June 29, 2012</td>
<td>Participant Interface Design Complete</td>
<td>SPP</td>
</tr>
<tr>
<td>Aug 1, 2012</td>
<td>Participant Interface Build Underway</td>
<td>MP</td>
</tr>
<tr>
<td>Aug 31, 2012</td>
<td>Complete Participation in TCR Mock Phase 2</td>
<td>SPP</td>
</tr>
<tr>
<td>Sept 28, 2012</td>
<td>Participant System Design Complete</td>
<td>SPP</td>
</tr>
<tr>
<td>Sept 30, 2012</td>
<td>MP Approach Completed for TCR Market Trials</td>
<td>MP</td>
</tr>
<tr>
<td>Oct 31, 2012</td>
<td>MP/TO Testing with the MCST tool</td>
<td>SPP</td>
</tr>
<tr>
<td>Nov 1, 2012</td>
<td>Participant System Build Underway</td>
<td>MP</td>
</tr>
<tr>
<td>Dec 28, 2012</td>
<td>Participant Interfaces (MP-SPP) Ready for Connectivity</td>
<td>MP</td>
</tr>
<tr>
<td>Dec 31, 2012</td>
<td>Begin using MCST for Model Change Submissions</td>
<td>SPP</td>
</tr>
</tbody>
</table>
**iDashboard’s Engagement Reports**

- Preparation of SPP Staff for Integrated Marketplace
- Staff coordination with Market Participant's a focus
- Initial status planned for October
- Substantial internal efforts underway already
  - Training
  - Operations
  - IT
  - Settlements and Credit
Integrated Marketplace

Market Participant Milestones

- May 2: SPP begins Marketplace software builds
- April 2: Participants develop market software/data and integrate it into plan
- May 16: Participants ready to begin TCR mock auctions
- June 1: Participants make appropriate regulatory filings
- January 2: Participants’ market systems ready for interface testing with SPP
- May 15, 2013: Participants ready for system integration
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>
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<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>
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<tr>
<td>Balanced Portfolio</td>
<td>18</td>
<td>$855,339,021</td>
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<tr>
<td>High Priority</td>
<td>22</td>
<td>$1,446,090,589</td>
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<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>$4,402,752,204</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>
<td>186.8</td>
<td>497.2</td>
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<td>138</td>
<td>68</td>
<td>109.3</td>
<td>108.4</td>
<td>217.7</td>
</tr>
<tr>
<td>161</td>
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<td>31.1</td>
<td>34.2</td>
<td>65.3</td>
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<td>230</td>
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<td>164.4</td>
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<td>345</td>
<td>62</td>
<td>2,815.5</td>
<td>0.0</td>
<td>2,815.5</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td><strong>316</strong></td>
<td><strong>3,448.5</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 projected 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 2\textsuperscript{nd} 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 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>Behind 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>
</tr>
<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>
</tr>
<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>$833,336,546</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>
<td>22</td>
<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>
</tr>
<tr>
<td>ITP10</td>
<td>28</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>28</td>
</tr>
<tr>
<td></td>
<td>$1,153,991,209</td>
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<td>$0</td>
<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>Reliability</td>
</tr>
<tr>
<td>3rd Q 2011</td>
</tr>
<tr>
<td>Reliability</td>
</tr>
<tr>
<td>14</td>
</tr>
<tr>
<td>$51,348,548</td>
</tr>
<tr>
<td>Transmission Service</td>
</tr>
<tr>
<td>13</td>
</tr>
<tr>
<td>$31,790,738</td>
</tr>
<tr>
<td>Generation Interconnect</td>
</tr>
<tr>
<td>0</td>
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<tr>
<td>$0</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
</tr>
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<td>0</td>
</tr>
<tr>
<td>$0</td>
</tr>
<tr>
<td>High Priority</td>
</tr>
<tr>
<td>1</td>
</tr>
<tr>
<td>$960,895</td>
</tr>
</tbody>
</table>

Figure 5: Completed Project Summary through 2nd Quarter 2012
### 2nd 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>
</tr>
<tr>
<td>345</td>
<td>2</td>
<td>53.0</td>
<td>0.0</td>
<td>53.0</td>
<td>$88,219,298</td>
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<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:

**3rd Quarter 2012:**

The 3rd 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 2nd 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 3rd 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>Complete</th>
<th>First day of Quarter</th>
<th>Last Day of Quarter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>27</td>
<td>6/1/2012</td>
<td>8/31/2012</td>
</tr>
<tr>
<td></td>
<td>$117,845,939</td>
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<tr>
<td>Reliability-Non OATT</td>
<td>7</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$25,220,750</td>
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<td></td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>0</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Service</td>
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</tr>
<tr>
<td></td>
<td>$46,599,701</td>
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</tr>
<tr>
<td>Generation Interconnect</td>
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</tr>
<tr>
<td></td>
<td>$150,000</td>
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<td></td>
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<tr>
<td>Balanced Portfolio</td>
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</tr>
<tr>
<td></td>
<td>$88,000,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zonal Sponsored</td>
<td>9</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$21,928,841</td>
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<td>ITP10</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
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<td></td>
<td>$277,816,390</td>
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</table>

<table>
<thead>
<tr>
<th>Scheduled Complete</th>
<th>Complete</th>
<th>First day of Reporting Year</th>
<th>Last Day of Reporting Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>65</td>
<td>6/1/2012</td>
<td>5/31/2013</td>
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<td></td>
<td>$329,844,892</td>
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<td>$329,844,892</td>
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<td>Reliability-Non OATT</td>
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</tr>
<tr>
<td></td>
<td>$29,158,250</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zonal Reliability</td>
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</tr>
<tr>
<td></td>
<td>$20,081,278</td>
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<tr>
<td>Transmission Service</td>
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</tr>
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<td></td>
<td>$124,657,607</td>
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<td>Generation Interconnect</td>
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<td>$30,896,528</td>
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</tr>
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<td>Balanced Portfolio</td>
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<tr>
<td>Zonal Sponsored</td>
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<td>$54,607,507</td>
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<tr>
<td>ITP10</td>
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<td></td>
<td>$0</td>
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<tr>
<td>Total</td>
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<tr>
<td></td>
<td>$698,645,462</td>
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</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>
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<td>27.4</td>
<td>27.4</td>
</tr>
<tr>
<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>
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<tr>
<td>Totals</td>
<td>44</td>
<td>241.5</td>
<td>83.0</td>
<td>324.5</td>
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</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>
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<td>118.0</td>
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<td>345</td>
<td>13</td>
<td>231</td>
<td>0</td>
<td>231.0</td>
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<tr>
<td>Totals</td>
<td>93</td>
<td>414.2</td>
<td>212.26</td>
<td>626.5</td>
</tr>
</tbody>
</table>

Figure 9: Transmission Miles Scheduled to Complete Next 12 Months
## SPP 3rd Quarter 2012 Project Tracking List - Branch_Xfr

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Project Owner Indicators</th>
<th>In Service Date</th>
<th>RTO Determined Need Date</th>
<th>Original Cost Estimate</th>
<th>Current Cost Estimate</th>
<th>Final Cost</th>
<th>Project Status</th>
<th>Project Lead Time and Cost Estimated by SPP Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>- Delay - Mitigation - NTC - COMMITMENT WINDOW</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Delayed beyond the RTO determined need date and no mitigation plan provided.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>DELAY - NO MITIGATION. Behind schedule, require re-evaluation due to anticipated cost forecast changes.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AEP Tulsa Power Station 138 kV reactor</td>
<td>high priority</td>
<td>06/10/11</td>
<td>06/30/10</td>
<td>$842,847</td>
<td>$900,895</td>
<td>COMPLETE</td>
<td>Complete 6/10/2011</td>
<td></td>
</tr>
<tr>
<td>SPS Multi - Hitchland - Woodward 345 kV (SPS)</td>
<td>high priority</td>
<td>06/01/17</td>
<td>07/22/11</td>
<td>$174,500</td>
<td>$231,600</td>
<td>COMPLETE</td>
<td>Currently in contract negotiations for line routing and siting.</td>
<td></td>
</tr>
<tr>
<td>SPS Multi - Hitchland - Woodward 345 kV (SPS)</td>
<td>high priority</td>
<td>06/01/17</td>
<td>07/22/11</td>
<td>$114,500</td>
<td>$152,600</td>
<td>COMPLETE</td>
<td>Currently in contract negotiations for line routing and siting.</td>
<td></td>
</tr>
<tr>
<td>SPS Multi - Hitchland - Woodward 345 kV (SPS)</td>
<td>high priority</td>
<td>06/01/17</td>
<td>06/30/10</td>
<td>$12,029,091</td>
<td>$19,796,666</td>
<td>COMPLETE</td>
<td>Cost already included in above two projects. Original SPS project.</td>
<td></td>
</tr>
<tr>
<td>OGE Line - Thistle - Woodward 345 kV dbl Ckt (OGE)</td>
<td>high priority</td>
<td>12/31/14</td>
<td>11/22/10</td>
<td>$97,427,500</td>
<td>$149,600,000</td>
<td>COMPLETE</td>
<td>Final cost still being compiled.</td>
<td></td>
</tr>
<tr>
<td>OGE Line - Sooner - Cleveland 345 kV</td>
<td>high priority</td>
<td>12/31/12</td>
<td>06/19/09</td>
<td>$17,000,000</td>
<td>$57,100,000</td>
<td>COMPLETE</td>
<td>Cost reduced to account for lower construction costs than expected.</td>
<td></td>
</tr>
<tr>
<td>KPCL Tap - Swisshole - Sill rail</td>
<td>high priority</td>
<td>12/31/12</td>
<td>06/19/09</td>
<td>$2,000,000</td>
<td>$2,000,000</td>
<td>COMPLETE</td>
<td>Project delayed due to delay in obtaining substation steel.</td>
<td></td>
</tr>
<tr>
<td>GMO Line - Nebraska City - Maryville 345 kV (GMO)</td>
<td>high priority</td>
<td>06/01/17</td>
<td>07/22/11</td>
<td>$114,500</td>
<td>$152,600</td>
<td>COMPLETE</td>
<td>Currently in contract negotiations for line routing and siting.</td>
<td></td>
</tr>
<tr>
<td>OPPD Line - Nebraska City - Maryville 345 kV (OPPD)</td>
<td>high priority</td>
<td>06/01/17</td>
<td>06/30/10</td>
<td>$12,029,091</td>
<td>$19,796,666</td>
<td>COMPLETE</td>
<td>Currently in contract negotiations for line routing and siting.</td>
<td></td>
</tr>
<tr>
<td>OGE Line - Sooner - Cleveland 345 kV</td>
<td>high priority</td>
<td>12/31/12</td>
<td>06/19/09</td>
<td>$17,000,000</td>
<td>$1,806,000</td>
<td>COMPLETE</td>
<td>Cost reduced to account for lower construction costs than expected.</td>
<td></td>
</tr>
<tr>
<td>OGE Line - Tuco - Woodward 345 kV (OGE)</td>
<td>high priority</td>
<td>05/19/14</td>
<td>06/01/14</td>
<td>$15,000,000</td>
<td>$167,100,000</td>
<td>COMPLETE</td>
<td>Build midpoint reactor station at interception point of Woodward to Tuco line. Cost already included in above two projects. Original SPS project.</td>
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<tr>
<td>SPS Multi - Tuco - Woodward 345 kV (SPS)</td>
<td>high priority</td>
<td>03/13/13</td>
<td>06/01/12</td>
<td>$11,250,000</td>
<td>$14,900,000</td>
<td>DELAY - MITIGATION</td>
<td>This cost is included in the total cost of project UID 10536 according to the NTC description.</td>
<td></td>
</tr>
<tr>
<td>ITCGP Line - Spearville - Clark Co - Thistle 345 kV dbl Ckt</td>
<td>high priority</td>
<td>12/31/14</td>
<td>07/29/11</td>
<td>$9,957,647</td>
<td>$12,029,091</td>
<td>COMPLETE</td>
<td>GMO will construct Iatan-Nashua transmission line; cost increase due to route changes to utilize more existing right of way and live line construction requirements.</td>
<td></td>
</tr>
<tr>
<td>ITCGP Line - Spearville - Clark Co - Thistle 345 kV dbl Ckt</td>
<td>high priority</td>
<td>12/31/14</td>
<td>07/29/11</td>
<td>$4,379,000</td>
<td>$4,379,000</td>
<td>COMPLETE</td>
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<td>ITCGP Line - Spearville - Clark Co - Thistle 345 kV dbl Ckt</td>
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<td>07/29/11</td>
<td>$4,379,000</td>
<td>$4,379,000</td>
<td>COMPLETE</td>
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<td>ITCGP Line - Spearville - Clark Co - Thistle 345 kV dbl Ckt</td>
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<td>ITCGP Line - Spearville - Clark Co - Thistle 345 kV dbl Ckt</td>
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<td>$4,379,000</td>
<td>$4,379,000</td>
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<tr>
<td>ITCGP Multi - Axtell - Post Rock - Spearville 345 kV Balanced Portfolio</td>
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<td>06/18/12</td>
<td>06/19/09</td>
<td>$96,000,000</td>
<td>$84,006,000</td>
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<tr>
<td>NPPD Line - NPPD - Axtell - Kansas Border 345 kV</td>
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<td>06/01/15</td>
<td>04/17/12</td>
<td>$50,643,091</td>
<td>$170,932,114</td>
<td>COMPLETE</td>
<td>GMO will construct Iatan-Nashua transmission line; cost increase due to route changes to utilize more existing right of way and live line construction requirements.</td>
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<tr>
<td>KCPL Multi - latan - Nashua 345 kV</td>
<td>high priority</td>
<td>06/01/15</td>
<td>04/17/12</td>
<td>$49,824,000</td>
<td>$10,156,809</td>
<td>COMPLETE</td>
<td>KCPL will construct line terminals and substations additions at latan &amp; Nashua</td>
<td></td>
</tr>
</tbody>
</table>
KCPL will construct transformer addition at Nashua.

Mitigation is redispatch.

Interim redispatch required.

Delayed.

Full BPF. SPP to provide revised NTC.

As of 05/11/12 Clearing approximately 100% complete.

Replacement not needed in 2009 due to re-rating, but replacement needed in 2011 due to voltage conversion associated with Turk.

Notification received from the SPP concurring with the new in-service date due to the delay of the Turk plant. 73% BPF. Completed 4/17/12.

Change PID and UID (old PID 349 and old UID 10453) Turk commercial operation date delayed until late 2012.

Completion 6/12/2011.

Delay - Mitigation.

Delay - Mitigation.

Delay - Mitigation.

Delay - Mitigation.

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Delay - Mitigation.
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<th>Project Number</th>
<th>Project Name</th>
<th>Line Type</th>
<th>Customer</th>
<th>Start Date</th>
<th>End Date</th>
<th>Cost</th>
<th>Status</th>
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<tr>
<td>20000</td>
<td>10582</td>
<td>AEP</td>
<td>Multi - Frist Creek – Centerton</td>
<td>345 kV and Centerton - East Centerton 161 kV</td>
<td>Regional Reliability</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$35,185,000</td>
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<td>20000</td>
<td>10655</td>
<td>AEP</td>
<td>Multi - Frist Creek – Centerton</td>
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<td>2007</td>
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<td>Line - Lone Star-Locust Grove</td>
<td>115 kV</td>
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<tr>
<td>20167</td>
<td>10415</td>
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<td>Line - Nolinwest Hendrixson – Poynter 69 kV</td>
<td>Regional Reliability</td>
<td>06/01/14</td>
<td>06/09/12</td>
<td>$7,214,837</td>
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<tr>
<td>20167</td>
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<td>Line - Dina - Perdue 138 kV</td>
<td>Reconstructor</td>
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<td>20104</td>
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<td>Line - Broken Arrow North South Tap - Oneta</td>
<td>138 kV Ckt 1</td>
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<td>06/01/15</td>
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<tr>
<td>200167</td>
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<td>Multi - Elk City - Gracemont</td>
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<tr>
<td>20123</td>
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<td>Multi - Nichols 170 - Republic 345 - Republic 451 - Republic 359</td>
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<td>Line - Nashua - Smithville 161 kV</td>
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<td>06/01/11</td>
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<tr>
<td>20004</td>
<td>10830</td>
<td>GMO</td>
<td>Multi - Loma Vista - Montrose 161 kV</td>
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<tr>
<td>20004</td>
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<td>Line - South Harper 161 kV cut-in to Stilwell-Anche Juntion 16</td>
<td>Regional Reliability</td>
<td>11/30/12</td>
<td>06/01/09</td>
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<td>Line - Cooke - Chilies 161 kV</td>
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<tr>
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<td>GMO</td>
<td>Multi - Toneyee - Stilwell City 161 kV</td>
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<td>GMO</td>
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<td>20072</td>
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<td>12/31/13</td>
<td>06/01/13</td>
<td>$0</td>
<td>COMPLETE</td>
<td>4</td>
</tr>
</tbody>
</table>

**Notes:**
- **ON SCHEDULE:** Project is on schedule.
- **COMPLETE:** Project is complete.
- **DELAY - MITIGATION:** Project is delayed due to mitigation strategies.
<table>
<thead>
<tr>
<th>Date</th>
<th>Description</th>
<th>Amount</th>
<th>Notes</th>
</tr>
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<td>11/16/14</td>
<td>$15,773,000</td>
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</tr>
</tbody>
</table>

**Notes:**
- GFR would could reduce generation at Kerr Hydro to relieve loading.
- GFR would could reduce generation at Kerr Hydro to relieve loading.
- Direct assigned to Network Customer. Transformer installation is currently complete by 6/16/12 and substation can be constructed by WPEC delayed due to lack of DCP for the substation.
- Project is delayed due to delay in obtaining substation steel.
- Project complete and in service, not finalized.
- Project complete and in service, not finalized.
- Project is completed and in service, not finalized.
- Project is complete and in service, not finalized.
- New ratings Rate A = 83 MVA, Rate B = 99 MVA.
- Project is complete and in service, not finalized.
- Project is complete and in service, not finalized.
- This is an Option to Build LGA. This cost is only for MKEC's part.
- Installation will occur after summer peak loads. Mitigation for transformer loading involves running City of Colby generation and transferring load away from Colby via 34.5 kV switching.
- This is an Option to Build LGA. This cost is only for MKEC's part.
- This is an Option to Build LGA. This cost is only for MKEC's part.
- This is an Option to Build LGA. This cost is only for MKEC's part.
- This is an Option to Build LGA. This cost is only for MKEC's part.
- This is an Option to Build LGA. This cost is only for MKEC's part.
- Construction underway. LTC adjustments and Great Bend generation will mitigate any 115 kV voltage problems through summer 2012.
Network upgrade complete. Awaiting project close-out to determine final cost.

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

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 6/1/12 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.

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

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

Final Cost Still being compiled

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 date listed on the NTC issued by SPP. The NTC was issued to NPPD.

NOTE: Initial costs include distribution

ARES Project was performed on holiday at customer's request

Final Cost Still being compiled

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

NOTE: Initial costs include distribution

NOTED: Initial costs include distribution

Original Costs included distribution

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

Full BPF - Handled on O&M

Transmission assets associated with project - Costs are still being compiled

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

In-service delay due to material delivery
Majority of project is removal only

Full BPF

regional reliability

Full BPF

regional reliability 10/01/10 06/01/15 $0 $200,000

The estimated ISD is 02/01/2013.

The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.

Complete - Project in Service, final financials are in progress.

CURRENT - COMMITMENT WINDOW

This line was formally V-30 and now reconfigured in & out of Hitchland and resulted in the construction of 10 miles of new double circuit 115 kV line on steel structures.

This line was formally circuit T-88 and now reconfigured in & out of Hitchland, approximately 2 miles of wreckout and rebuild.

This line from Dallam to Sherman is currently in-service. The current cost estimate amount was changed to the original cost of $7,787,000 for the new substation, 115 kV line, customer service, service hardware, and transmission line cost. Final cost is recorded in the 2012 3rd quarter report.

This project will be placed in-service the week of June 4, 2012.

This project is the final cost of the 230 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

This is the final cost of the 345 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

This project is scheduled to be completed by the end of the project's NTC commitments, which is 6/1/2010.

This line was formally circuit T-88 and now reconfigured in & out of Hitchland, approximately 2 miles of wreckout and rebuild.

This project will be placed in-service by the end of the project's NTC commitments, which is 6/1/2010. NTC should be modified to show the tap of the 230 kV line.

This is the final cost of the 345 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

This is the final cost of the 345 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

This project will be complete after the Summer of 2009. The estimated ISD is 9/1/2011.

This project is the final cost of the 230/115 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

This is the final cost of the 345 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

This project is the final cost of the 230/115 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

The line from Dalhart to Sherman is currently in-service. The current cost estimate amount was changed to the original NTC cost amount which included substation upgrades, right of way cost and transmission line cost. The total cost is the SPS cost including the Lasley switching station, right of way and transmission line cost. Final cost is recorded in the 2012 3rd quarter report.

The estimated ISD is 8/2/2011.

This is the final cost of the 345 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

The line from Dalhart to Sherman is currently in-service. The current cost estimate amount was changed to the original NTC cost amount which included substation upgrades, right of way cost and transmission line cost. The total cost is the SPS cost including the Lasley switching station, right of way and transmission line cost. Final cost is recorded in the 2012 3rd quarter report.

The estimated ISD is 8/2/2011.

This is the final cost of the 345 kV portion of the Hitchland substation. The total cost of the Hitchland substation was $15,548,925.

COMPLETE - Project in Service, final financials are in progress.

COMPLETE - Project in Service, final financials are in progress.

COMPLETE

COMPLETE

COMPLETE - Project in Service, final financials are in progress.

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COMPLETE - Project in Service, final financials are in progress.
This project is the fix for the Gaines Co. Auto STEP project.

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<table>
<thead>
<tr>
<th>Date</th>
<th>Project Description</th>
<th>Reliability</th>
<th>Start Date</th>
<th>End Date</th>
<th>Cost (Actual)</th>
<th>Cost (Estimated)</th>
<th>Notes</th>
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<tbody>
<tr>
<td>12/30/14</td>
<td>11053 Multi - Pleasant Hill- Potter 345 kV Ckt 1</td>
<td>Regional Reliability</td>
<td>06/01/11</td>
<td>02/08/10</td>
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<td>12/30/14</td>
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<td>03/31/13</td>
<td>11096 XFR - Kingsmill 115/69 kV Ckt 2</td>
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<td>06/01/13</td>
<td>11101 Line - Potrillo - Zodiak 69 kV to 115 kV Conversion</td>
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<td>04/30/13</td>
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<td>11177 Line - Randall - Amarillo S 230 kV Ckt 1</td>
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<td>06/30/13</td>
<td>11349 Ckt - HARRINGTON STATION EAST BUS 230kV Ckt 1</td>
<td>Transmission Service</td>
<td>06/30/13</td>
<td>12/06/10</td>
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<tr>
<td>12/31/13</td>
<td>11335 Convert Lynn load to 115 kV</td>
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<td>06/01/13</td>
<td>02/14/11</td>
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<td>$2,230,200</td>
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<tr>
<td>02/28/14</td>
<td>11107 Multi - Kress Interchange - Kiser - Cox 115 kV</td>
<td>Regional Reliability</td>
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<tr>
<td>02/28/14</td>
<td>11184 Line - North Plainview line tap - 115 kV</td>
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<td>02/14/11</td>
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<td>11007 XFR - Kiser - Eddy Co-op load onto Kress Interchange, bus 524091</td>
<td>Transformer Reliability</td>
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<td>04/09/12</td>
<td>$1,890,000</td>
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<td>06/01/14</td>
<td>11009 XFR - Happy County 115/69 kV Transformers</td>
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<td>11100 XFR - Northeast Hereford 115/69 kV Transformer Ckt 2</td>
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<td>04/09/12</td>
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<td>DELAY - MITIGATION</td>
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<td>12/31/14</td>
<td>04/09/12</td>
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<td>$6,900,000</td>
<td>DELAY - MITIGATION</td>
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<td>111172 XFR - Eddy Co-op load onto Kress Interchange, bus 524091</td>
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<td>04/09/12</td>
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<td>04/30/15</td>
<td>02/08/10</td>
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<td>$11,980,445</td>
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<tr>
<td>04/30/15</td>
<td>11045 Multi - New Hart Interchange 230/115 kV</td>
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<td>02/14/11</td>
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<td>06/01/15</td>
<td>11373 Line - Soccy convert load to 115 kV</td>
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<td>02/14/11</td>
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<tr>
<td>11/30/11</td>
<td>10941 XFR - Paragould 161/69 kV Auto 1 &amp; 2</td>
<td>Transformer Reliability</td>
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<td>12/01/11</td>
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<td>05/25/11</td>
<td>10944 Line - Dandanelle - Russellville South 161 kV</td>
<td>Regional Reliability</td>
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<td>06/01/10</td>
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<td>$165,000</td>
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</tbody>
</table>

Project complete. Xfmr 1 was replaced and put in service in 2011. Xfmr 2 was added at Center Hill and load transferred to Center Hill.
10819 SWPA  
Line - Ashville - Idalia 161 kV Reconstructor  
regional reliability - non OATT  
06/26/12 06/01/14 $0 $10,095,750  

10845 SWPA  
KFR - Springfield 161kV #3  
regional reliability - non OATT  
12/01/13 06/01/17 $0 $2,250,000  
ON SCHEDULE < 4  

10859 SWPA  
KFR - Calligua 161/69 kV Transformers 1 & 2  
regional reliability - non OATT  
03/01/14 02/13/08 $0 $4,500,000  
ON SCHEDULE < 4  

10576 SWPA  
Line - Nixa - Nixa DT Nabud  
regional reliability - non OATT  
03/01/15 02/13/08 $0 $660,000  
ON SCHEDULE < 4  

20030 WPEC  
Multi - Lindsay - Ulysses SW and Bradley-Mush Springs  
regional reliability  
01/27/09 06/01/10 02/13/08 $3,646,594 $2,065,000  
DELAY - Mitigation  
line converted but energized @ 69kV  

20030  
Multi - Ulysses - Canadian SW 138 kV  
regional reliability  
01/27/09 06/01/10 02/13/08 $2,250,000  
DELAY - Mitigation  
line converted but energized @ 69kV  

20030  
Multi - Ulysses - Canadian SW 138 kV  
regional reliability  
01/27/09 06/01/10 02/13/08 $2,250,000  
DELAY - Mitigation  
in construction  

20030 WPEC  
Multi: WFEC-Dover-Twin Lake_Crescent-Cottonwood conversion  
regional reliability  
01/27/09 06/01/10 02/13/08 $0 $5,765,600  
DELAY - Mitigation  
C line upgraded to 66 amp effective 1/10/11. No cost for this upgrade.  

20035 WPEC  
Line - Tipton 69 kV Ckt 1  
regional reliability  
06/01/11 $0 $225,000  
DELAY - NO MITIGATION  

50402 WPEC  
Line - Washita - Garman 138 kV Ckt 2  
Generation Interconnect  
02/17/09 06/01/10 06/01/07 $4,740,546 $4,740,546  
COMPLETE  

20039 WPEC  
Multi - Lindsay - Ulysses SW and Bradley-Mush Springs  
regional reliability  
06/01/10 02/13/08 $1,248,750  
COMPLETE  

19951 WPEC  
XFR - Anadarko 138/69 kV transmission service  
10/01/12 06/01/11 01/02/07 $2,000,000 $2,000,000  
DELAY - NO MITIGATION  

20030 WPEC  
Line - ACME - W Norman 69 kV  
regional reliability  
06/01/11 $0 $921,000  
DELAY - MITIGATION  
Mitigation Plan under review by SPP. Deferred in latest SPP Transmission Expansion Plan.  

20030 WPEC  
Line - Wakita - Hazelton 69 kV  
regional reliability  
04/01/10 02/13/08 $5,870,000 $8,000,000  
DELAY - MITIGATION  

20030 WPEC  
Line - Anadarko - Georgia Tap 138 kV  
regional reliability  
07/01/14 06/01/10 $750,000 $2,000,000  
DELAY - MITIGATION  

20030 WPEC  
Line - Richland - Rose Hill Junction 69 kV  
Zonal Reliability  
11/03/11 06/01/11 09/18/09 $2,815,000 $3,782,279  
COMPLETE  

19986 WPEC  
Caney River Wind Project Generation Interconnect  
09/13/11 $0 $625,000 $847,064  
COMPLETE  

20091 WR  
Line - Oswego - Rose Hill 69 kV  
regional reliability - non OATT  
02/27/11 06/01/10 $1,350,000 $2,676,185  
COMPLETE  

11445 WR  
Caney River Wind Project  
Generation Interconnect  
09/13/11 $0 $6,876,000 $276,558  
COMPLETE  
Costs to be incurred by wind farm owner.  

20091 WR  
Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV transmission service  
03/31/11 06/01/11 $9,555,588 $2,996,364  
COMPLETE  

20091 WR  
Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV transmission service  
03/31/11 06/01/11 $3,267,972 $2,777,239  
COMPLETE  

114 of 133
transmission service 12/01/12 06/01/12 03/31/10 $3,921,591 $4,352,345

transmission service 10/01/13 01/01/13 03/31/10 $2,614,395 $3,438,116

Redispatch TEC generation.

transmission service 03/29/12 11/01/13 03/31/10 $653,598 $1,693,501

The mitigation is to open the Halstead-Burrton 69 kV line and close the Burrton line to Yoder Junction and switch Burrton load to be served from Hutchison.

WR Line - Neosho - Northeast Parsons 138 kV transmission service 06/01/11 06/01/11 09/18/09 $250,000 $114,269 $ 114,269 COMPLETE

Jumper was replaced with builted 266 ACSR wire rated at

Transmission is application of existing Transmission Operating Directive 634

115 of 133

INTERIM MITIGATION is application of existing Transmission Operating Directive 634

Currently 230/115kV dollars are combined. Will break apart for Q3 report.

20105 10674 WR Sub - Clay Center Junction 115 kV Zonal Reliability 10/01/12 10/01/12 05/27/11 $2,849,367 $2,849,367 ON SCHEDULE < 4

Clay Center did not provide Westar with construction easement. This required redesign and will extend construction by one month. Mitigation is to serve the load at existing Delivery Point for an extra month.

20059 10231 WR Line - Chase - White Junction 69 kV regional reliability 06/01/13 06/01/10 09/18/09 $5,184,701 $6,066,000 DELAY - MITIGATION

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 Hutchison.

20059 10623 WR Line - Olathe - Dolphin 69 kV regional reliability 07/26/12 06/01/10 02/13/08 $483,000 $482,996 DELAY - MITIGATION

20059 10074 WR Line - Rose Hill - Sooner 345 kV Ckt 1 regional reliability 04/27/12 01/01/13 09/18/09 $84,669,696 $84,379,298 COMPLETE

Project costs are for Westar Energy portion only. Public hearing held; Technical hearing held. Project costs include rebuilding of 138 kV underlying system on same ROW

20033 10808 WR Multi - NW Manhattan regional reliability 03/18/12 06/01/10 01/27/09 $17,437,500 $ 3,650,576 COMPLETE

Current cost estimate for UID 10806 is sufficient for both 230/115kV work. Additional dollars not required. The mitigation is to run Abilene Energy Center.

20086 10700 WR Line - G&C West - Waaco 138 kV regional reliability 12/01/12 10/01/13 11/06/06 $1,000,000 $3,640,652 DELAY - MITIGATION

20086 11204 WR Line - Macfarlal - Calhoun 69 kV Ckt 1 transmission service 03/12/12 06/01/12 01/13/10 $40,000 $50,200 $ 20,522 COMPLETE

An external equipment meets minimum NTC requirement

20131 11344 Multi - Craig - 87th - Stranger 345 kV Ckt 1 regional reliability 12/25/12 06/01/11 02/14/11 $9,866,277 DELAY - MITIGATION

20131 11345 Multi - Craig - 87th - Stranger 345 kV Ckt 1 regional reliability 12/25/12 06/01/11 02/14/11 $26,825,000 $15,119,789 DELAY - MITIGATION

20131 11346 Multi - Craig - 87th - Stranger 345 kV Ckt 1 regional reliability 12/25/12 06/01/11 02/14/11 $12,047,385 DELAY - MITIGATION

20091 50228 WR Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf transmission service 12/01/12 06/01/12 03/31/10 $3,921,598 $4,352,345 DELAY - MITIGATION

Mitigation is to re-dispatch Gill and Evans in the Wichita area.

20029 50368 WR Sub - Chapman Junction 115 kV Zonal Reliability 11/01/12 10/01/12 05/27/11 $4,877,550 $4,787,550 ON SCHEDULE < 4

20140 50369 WR Sub - Clay Center Junction 115 kV Zonal Reliability 11/01/12 10/01/12 05/27/11 $4,877,550 $4,787,550 ON SCHEDULE < 4

200176 50465 WR Mutli - Rice - Circle 230Kv CONVERSION Generation Interconnect 11/15/12 01/16/12 $5,095,881 $5,095,881 ON SCHEDULE < 4

No NTC Please remove from tracking list SPP continues to want to track this project

20086 11082 WR Line - Gill Energy Center East - MacArthur 69 kV regional reliability 06/01/14 06/01/13 02/08/10 $2,200,000 $3,471,989 DELAY - MITIGATION

Due to uncertainty of Presidential Permit, TransCanada has extended their in-service date to 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.

Due to uncertainty of Presidential Permit, TransCanada has extended their in-service date to 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.

20131 11411 WR Multi - Mulberry - Franklin - Sheffield 161 kV regional reliability 06/01/14 06/01/13 02/14/11 $7,347,754 $4,981,988 COMPLETE

Distribution Capacitor banks are in-service to improve the PF on Marmon-Litchfield 69 kV.

20131 11412 WR Multi - Mulberry - Franklin - Sheffield 161 kV regional reliability 06/01/14 06/01/13 02/14/11 $4,981,988 COMPLETE

Distribution Capacitor banks are in-service to improve the PF on Marmon-Litchfield 69 kV.

20131 11413 WR Multi - Mulberry - Franklin - Sheffield 161 kV regional reliability 06/01/14 06/01/13 02/14/11 $8,750,767 $11,471,061 COMPLETE

Due to uncertainty of Presidential Permit, TransCanada has extended their in-service date to 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.

20131 11444 WR Multi - Mulberry - Franklin - Sheffield 161 kV regional reliability 06/01/14 06/01/13 02/14/11 $2,793,625 COMPLETE

20140 50372 WR - Line - Clay Center Switching Station - TC Riley 115 kV Ckt 1 Zonal Reliability 06/01/14 10/01/12 05/27/11 $4,549,942 $7,472,511 DELAY - MITIGATION

Due to uncertainty of Presidential Permit, TransCanada has extended their in-service date to 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.

20140 50374 WR Sub - TC Riley 115 kV regional reliability 06/01/14 10/01/12 05/27/11 $580,000 $580,000 DELAY - MITIGATION

Due to uncertainty of Presidential Permit, TransCanada has extended their in-service date to 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.

20059 50241 WR Line - Neosho - Northeast Parsons 138 kV transmission service 06/01/11 06/01/11 09/18/09 $250,000 $114,269 $ 114,269 COMPLETE

Jumper was replaced with builted 266 ACSR wire rated at
<table>
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<th>Project ID</th>
<th>Year</th>
<th>Description</th>
<th>Completion Date</th>
<th>Commitment</th>
<th>Total Cost</th>
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<td>Regional Reliability</td>
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<td>WR XFR - Moundridge 138/115 kV</td>
<td>200181 10425</td>
<td>Transmission</td>
<td>12/01/14</td>
<td>04/06/12</td>
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<td>200175 10812</td>
<td>Regional Reliability</td>
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<td>WR Line - Halstead South - Sedgwick 138 kV</td>
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<td>Transmission service</td>
<td>06/01/16</td>
<td>04/06/12</td>
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<td>WR Multi - Elm Creek - Summit 345 kV</td>
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ON SCHEDULE > +4
**SPP 3rd Quarter 2012 Project Tracking List - Device**

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<th>RTO Reliability by Need Date Date</th>
<th>Letters of Notification to Complete More Date</th>
<th>Cost Estimate</th>
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<td>Project under study. Distribution transformer taps to be adjusted accordingly to serve load adequately until the project can be implemented/energized.</td>
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<td>Project installation delayed until late Spring 2012. Current analysis using SPP MDWG 2012 B2 models shows no additional mitigation needed.</td>
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<td></td>
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</tr>
</tbody>
</table>

- **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.
- 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.
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>
</tr>
</thead>
<tbody>
<tr>
<td>regional reliability</td>
<td>6/27/2009</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>
</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
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>$4,632,308</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>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Zonal Reliability</th>
<th>5/27/2011</th>
<th>11/1/2012</th>
<th>$4,877,550</th>
<th>$2,774,851</th>
<th>$(2,102,699)</th>
<th>-43.1%</th>
<th>$(2,102,699)</th>
<th>-43.1%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Totals</td>
<td>$9,427,492</td>
<td>$9,510,058</td>
<td>$10,247,362</td>
<td>$737,304</td>
<td>7.8%</td>
<td>$819,870</td>
<td>9.1%</td>
<td></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>
</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>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>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>12/1/2013</td>
<td>$607,500</td>
<td>$607,500</td>
<td>$1,026,734</td>
<td>69.0%</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
### 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>$398,499,278</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

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>