Southwest Power Pool
REGIONAL STATE COMMITTEE
Renaissance Hotel, Oklahoma City, OK
April 23 2012

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
Monday, April 23, 2012
1:00 - 5:00 p.m.
Renaissance Oklahoma City – Meeting Room 9 & 10
Oklahoma City, Oklahoma

1. CALL TO ORDER
2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of January 30, 2012 Minutes
3. UPDATES
   a. RSC Financial Report
   b. SPP
   c. FERC
4. BUSINESS MEETING
   a. No Business Meeting Items
5. REPORTS/PRESENTATION
   a. RSC Consultant Report ............................................................................................. Dr. Mike Proctor
      CAWG Recommendation on Cost Allocation for HUBs (VOTING ISSUE)
      The CAWG has reviewed cost allocation proposals related to funding of Hub and Spoke generation interconnection costs and makes a recommendation to the RSC. In view of that recommendation, the CAWG reviewed possible methods SPP may wish to use in allocating those Hub/Spoke Interconnection costs among the generators and endorses a method it presents to the RSC. The CAWG asks the RSC to consider recommending that method to the RSC Board.
   b. CAWG Report.............................................................................................................. Pat Mosier
      This Report provides an update on CAWG activity, including recommendations made, and CAWG's future schedule.
   c. Order 1000 Update ........................................................................................................................... Paul Suskie
      Update SPCTF on Order 1000 .......................................................................................... Mel Perkins
      This report will update the RSC on the efforts of the SPCTF on Order 1000 and the status of the Task Force's Report on recommendation as to how SPP should comply with Order 1000 on regional policy issues such as ROFR and the consideration of public policy requirements in transmission planning.
      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.
RSC Seams Cost Allocation Consultant (Brattle) Report .......................... Johannes Pfeifenberger

As directed by the RSC, this is the Brattle Group’s Final Report related to Interregional Seams Cost Allocation.

Joint Task Force on Order 1000 Interregional Cost Allocation (VOTING ISSUE).......Olan Reeves

This is President Reeve’s recommendation that the RSC approve the formation of a Joint Task Force between RSC members and SPP appropriate committee members to consider how SPP can comply with Order 1000’s interregional cost allocation requirements. The recommended Joint Task Force is structured after the successful RARTF.

d. Integrated Marketplace Update .......................................................................................... Bruce Rew

This report will update the RSC on the SPP’s efforts in developing and implementing the IM.

e. EPA Rules Update ........................................................................................................... Michael Desselle

This report will update the RSC on the SPP efforts related to new EPA regulations.

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

a. RSC Meetings:

July 30, 2012 – Kansas City, MO

October 29, 2012 – Little Rock, AR
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<thead>
<tr>
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<tbody>
<tr>
<td>Bruce Rew</td>
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<td>Johannes Fichtenberger</td>
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<td>David Vora</td>
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## Attendance List

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<td>Alan McQueen</td>
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<td>Ben Bright</td>
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<td>Brian Thompson</td>
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Southwest Power Pool
SPP REGIONAL STATE COMMITTEE MEETING
April 23, 2012

ATTENDANCE LIST

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<td>Walt Cecil</td>
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<td>Gerald Beaver</td>
<td>SPS</td>
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<td>Mark Watson</td>
<td>Platts</td>
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Phone:
Cheryl- Commissioner Terry Jarrett has my proxy on all issues to be discussed and/or voted on for the RSC meeting in Oklahoma. I apologize for not formally notifying you earlier.

Kevin Gunn
Administraive 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)
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 110 in attendance either in person or via phone (Attendance – Attachment 1).

President Reeves asked for approval of the October 24, 2011 meeting minutes (RSC Minutes 10/24/11 - Attachment 2). Tom Wright moved to approve the minutes as presented; Patrick Lyons seconded the motion. The minutes were unanimously approved.

UPDATES

RSC Financial Report
Paul Suskie provided the RSC Financial Report (Financial Report and Audit – Attachment 3). Mr. Suskie reported that the group was under budget overall in 2011. The RSC was within budget in all categories with the exception of travel expenses and auditor fees. The seams cost allocation item will carry over until April 2012.

SPP Report
Nick Brown provided the SPP report. Mr. Brown reported that the new SPP facility is on schedule and on budget. The operations center was completed in December 2011 and the administration building is due for completion on May 15. Mr. Brown extended an invitation to all for a ribbon-cutting in Little Rock on July 9. SPP will move into the new facility on July 15. The October series of meetings are scheduled to be held in the new facility.

Mr. Brown reported that the Integrated Marketplace Project is on schedule consisting of four towers and twenty-three workstreams. Thanks to Trip Doggett (ERCOT) and his sharing lessons learned, SPP has a very detailed project plan with an ongoing internal audit. According to the first audit report, SPP rated a C+. This shows that the Integrated Marketplace is succeeding but that there is room for improvement.

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

November
FERC Enforcement staff presented its 2011 report on enforcement activities. The report noted that the Commission approved 9 settlement orders between Enforcement and regulated entities last fiscal year, resulting in over $2.9 million in civil penalties and over $2.75 million in disgorgement of unjust profits. Staff closed another 10 investigations with no enforcement action. Staff opened 12 investigations, 8 of which concern allegations of market manipulation or false statements to the Commission or RTOs and ISOs. Enforcement staff completed 72 audits last year.

FERC held a Commissioner-led Reliability Technical Conference to explore issues involving EPA Regulations and the bulk power system. As a follow-up to this, Federal and State energy regulators launched a forum to further explore these reliability issues. The forum, will consist of FERC and NARUC members and will coincide with NARUC’s three yearly meetings.

December
Commissioner Marc Spitzer resigned from FERC effective December 14, 2011.

FERC rejected Duke Energy Corp. and Progress Energy, Inc.’s proposed mitigation plan to remedy their merger’s harmful effects on competition, saying it cannot unconditionally approve the merger until the applicants remedy the harmful effects on competition previously identified by FERC.

January
Last week, North Dakota Chair Tony Clark was nominated by the President to fill Marc Spitzer’s seat at FERC. FERC also denied rehearing of its interpretation of the JOA between MISO and SPP.

On January 30, FERC staff issued a White Paper and request for comments on a proposal to provide a fair, timely and transparent process for the Commission to advise the Environmental Protection Agency (EPA) on requests for extension of time to comply with its Mercury and Air Toxics Standards rule. Comments are due 30 days after publication in the Federal Register.

FERC continues a series of informational conferences to aid stakeholders in the Order No. 1000 compliance process.

BUSINESS MEETING

Approval of RARTF Report
Mr. Paul Suskie presented the Regional Allocation Review Task Force report (RARTF Report – Attachment 4). Mr. Suskie stated that the Tariff requires a review of the regional allocation methodology and the zonal allocation methodology at least once every three years. He reviewed the four-step review process, presented the RARTF Charter and provided an overview of the RARTF Report unanimously adopted by the task force. Mr. Michael Siedschlag presented a chart to illustrate RARTF’s vision of how this process would look in the future (RARTF Chart – Attachment 8). Mr. Suskie then requested that the Board of Directors approve the following recommendation:

The MOPC, RSC & Board of Directors approve the RARTF’s Report and direct SPP staff to implement the recommendations and review SPP’s Highway/Byway Cost Allocation methodology per SPP OATT.

Tom Wright moved to approve the RARTF Report; Kevin Gunn seconded the motion. The motion passed unanimously. President Reeves thanked the group for a job well done and the numerous hours invested in the process.

Approval of Patricia Salman as 2011 Auditor & Preparation
Pat Mosier (APSC) provided background and the recommendation to retain Patricia Salman & Associates to conduct the annual examination of the financial accounts of the RSC for 2011 as required by Section 9, Audits of the Regional State Committee Bylaws and to prepare the related tax returns (RSC Auditor – Attachment 5). Patricia Salman has provided this service since 2006. Tom Wright moved to approve; Mike Siedschlag seconded the motion. The motion passed unanimously.
REPORTS/PRESENTATIONS

CAWG Report

Dr. Mike Proctor provided the Cost Allocation Working Group report (CAWG Report – Attachment 6). Dr. Proctor stated that the CAWG has had three recurring items on its agenda: 1) Area Generation Connection Task Force (AGCTF) Hub & Spoke Design and associated cost allocation; 2) Timing of transfers for the Balanced Portfolio; and 3) obstacles to transmission construction. Dr. Proctor provided a Hub & Spoke update stating that AGCTF is considering two alternative designs for generation interconnection: Hub only and Hub & Spoke. The CAWG is considering alternative cost allocations, one of which could include regional funding.

Dr. Proctor provided Balanced Portfolio history on cost allocation, upgrades, and implementation. He then provided information regarding the transfer mechanism, which would transfer cost from the zonal rate of those having less benefits than allocated costs (“deficient zones”) and place those costs in a region-wide rate. There are two interpretations of the Tariff:

- Interpretation 1 is the total amount of the transfers limited to what is calculated on a present value basis over the 10-year period analyzed
- Interpretation 2 is the total amount of the transfers limited to what is calculated on a per-year basis over the 10-year period analyzed

After analyzing these interpretations the CAWG recommends:

**The RSC approve that Balanced Portfolio Transfer Payments are determined by the Tariff being implemented over a 10 year period calculated on a present value basis.**

Tom Wright moved to approve: Mike Siedschlag seconded the motion. The motion passed unanimously. Dr. Proctor added that the expected SPP filing would be in early April.

Pat Mosier provided a report on the obstacles to transmission construction (Obstacles – Attachment 7). The RSC requested that it be provided with a list of obstacles to construction which could significantly increase cost of construction. The CAWG sent a Request for Information to all SPP Transmission Owners (TOs) to provide obstacles both current and expected. The responses are included in the background and have been shared with the Project Cost Working Group (PCWG) who is also pursuing a compilation of data.

Order 1000

**SPCTF on Order 1000**

Paul Suskie provided an overview of SPP compliance requirements for FERC Order 1000 including both regional and interregional areas (Order 1000 Compliance Requirements – Attachment 8). Ricky Bittle (AECC) provided a status report on SPCTF on Order 1000 (Order 1000 SPCTF Report – Attachment 9). Mr. Bittle stated that the group made the decision that the Right of First Refusal (ROFR) should apply in cases of less than 300 kV. Other decisions needing to be addressed are builder selection, project selection and models for process. The group also needs to build a rational for RPFR<300kV. The group’s timeline includes receiving a policy level approval from the Board of Directors in April, Tariff changes and associated Membership Agreement modifications approval in July 2012 and hopefully file with FERC in October 2012. Mr. Bittle asked the RSC to provide guidance or approval that the group is continuing in the right direction. During discussion, the RSC decided that they had not had time to view this material and did not feel prepared to address it at this time. Nick Brown stated that Staff would prepare a White Paper for the RSC regarding compliance with FERC Order 1000.

President Reeves stated that he planned to review the distribution and format of materials going forward so as to aid participants in meeting preparation.
RSC Seams Cost Allocation Consultant (Brattle) Report

Johannes Pfeifenberger provided an update on the RSC seams cost allocation efforts (Brattle Report – Attachment 10). Mr. Pfeifenberger reviewed his October 2011 report to the RSC and the seven building blocks that had been identified. Since then the Brattle Group has worked with SPP staff, the Seams Steering Committee, and stakeholders to achieve buy-in and develop language integrating the seven building blocks as well as start applying (conceptually) the framework to candidate seams projects. Following feedback from stakeholders, the final report will be prepared and presented to the RSC in April.

ITP10/ITPNT

Lanny Nickell presented a report on the SPP Transmission Expansion Plan: ITPNT, ITP10 and 2012 STEP (ITPNT, ITP10 and STEP – Attachment 11). Mr. Paul Suskie presented information on the rate impact of ITP10/NT using the Rate Impact Task Force method. After discussion, the following recommendation was presented for approval:

MOPC recommends the BOD endorse the “2012 SPP Transmission Expansion Plan” report as the documentation of SPP Staff completing the SPP OATT processes including the Attachment O transmission planning process and approve the ITPNT and ITP10 projects and issue NTCs/ATPs conditioned on completion of the NTC/ATP business practices.

Kevin Gunn (MOPSC) suggested two suggestions when endorsing ITP10:

1. Request that SPP perform a Stability Analysis for SW Missouri, which they did not do this cycle, for the next ITP10
2. Ask for the projects receiving a Notification to Construct with conditions instead receive consideration for an Authorization to Plan, as this is the first ITP10 and first time issuing an ATP.

Kevin Gunn moved to approve the motion with the two suggestions; Mike Siebeschlag seconded the motion. The motion passed unanimously.

Integrated Marketplace Update

Bruce Rew provided an Integrated Marketplace update (Integrated Marketplace Update – Attachment 12). He reviewed the Marketplace’s processes, the program structure, program milestones and participant milestones. Mr. Rew stated that the Integrated Marketplace Scorecard is posted on the SPP website every month for reference.

EPA Rules Update

Michael Desselle provided an EPA Rules update. He reminded the RSC that Nick Brown sent a letter to the EPA in September expressing concerns that using the EPA’s own models and analysis reliability in the SPP footprint would be compromised and that members were being placed in the untenable position of choosing which agency’s Rules to violate (FERC of EPA). Mr. Desselle then provided a status report of activities since that letter. The SPC met in October and in January approved the ITP20 Futures. He noted that Future 1 (Business As Usual) incorporated the provisions for the EPA regulations (CSAPR, MATS, 316b (water), and regional haze). Mr. Desselle noted that FERC conducted a technical workshop on the EPA Rules in November and that in December the EPA finalized its Mercury and Air Toxins Standards Rule (MATS). The Cross State Air Pollution Rule (CSAPR) was to become effective January 1, but the courts have stayed its implementation pending court proceedings in April. The SPP Staff is currently conducting a survey regarding how members plan to comply with both the MATS and CSAPR Rules. From the survey results, analysis will be conducted to assess regional reliability and resource adequacy in the SPP footprint. That effort is to be completed by April. Member compliance plans will form the modeling basis to determine transmission expansion changes for a “High Priority” re-evaluation of the 2012 ITP10. That effort is to be completed by April 2013 in synchronization with the regular ITP Planning schedule.
ATRR Update
Paul Suskie provided an update on the Annual Transmission Revenue Requirements (ATTRs) per SPP OATT, Attachment H, as requested at the October 2011 RSC meeting (ATTRs – Attachment 13). Mr. Suskie reviewed the current Highway/Byway Cost Allocation method and provided current data as well as summaries of upgrades receiving NTCs prior to and after June 2010, Balanced Portfolio with zonal transfers and ITP Near Term upgrades. He also provided ten year ATRR projections by zone.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Reeves noted that the next regularly scheduled meeting is on April 23 in Oklahoma City, OK.

With no further business, the meeting adjourned at 5:00 p.m.

Respectfully Submitted,

Paul Suskie
Regional State Committee  
For the Three Months Ending March 31, 2012  
Budget vs. Actual

<table>
<thead>
<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>139,046</td>
<td>62,750</td>
<td>76,296</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>139,046</td>
<td>62,750</td>
<td>76,296</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Travel</td>
<td>33,136</td>
<td>27,500</td>
<td>5,636</td>
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<tr>
<td>Meetings</td>
<td>4,925</td>
<td>6,250</td>
<td>(1,325)</td>
</tr>
<tr>
<td>Audit</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Administrative Costs</td>
<td>-</td>
<td>250</td>
<td>(250)</td>
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<tr>
<td>RSC Consultant</td>
<td>17,905</td>
<td>28,750</td>
<td>(10,845)</td>
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<tr>
<td>Technical Conference</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Seams Cost Allocation</td>
<td>83,080</td>
<td>-</td>
<td>83,080</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td>139,046</td>
<td>62,750</td>
<td>76,296</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>


HUB & SPOKE COST ALLOCATION BETWEEN LOAD AND GENERATION
Hub & Spoke Issue: Because of potential difficulties from having a large number of individual generation connections along segments of 345 kV transmission lines the MOPC commissioned the Area Generation Connection Task Force (AGCTF) to develop an approach to resolve these difficulties.

The approach developed by the AGCTF is detailed in their Hub & Spoke White Paper and Principles Paper (see attached AGCTF slides at MOPC for details). A brief overview of the AGCTF proposals is presented in these slides.
Background - Definitions

- Interconnection Facilities: Includes both attachment facilities and generator leads.
- Attachment Facilities: Also called substations, are the facilities required to connect a generator to SPP transmission lines that are directly attached to the transmission line.
  - Stand-Alone: attachment facilities required for an individual generation to connect to the SPP transmission lines (e.g., land, 3 ring-bus plus a reactor costing $16 M).
  - Hubs: attachment facilities that allow multiple generators to connect to the SPP transmission lines at a single location (e.g., land, multiple buses plus a reactor, starting at $18 M and increasing with decreasing cost per added connection).

- Generator Leads
  - Stand-Alone: the power lines that run from the generator to the SPP transmission lines.
  - Spokes: As defined by the AGCTF, a single 345 kV power line that extends out from a single interconnection at the hub and to which multiple generators are attached.
Background – Why Hub Design

Engineering:

- Each point of interconnection may require a reactor and each added reactor reduces the capacity of the 345 kV transmission lines.
- Allowing a large number of individual interconnections could result in the need to add additional 345 kV lines to accommodate the deliverability of energy from wind farms required to meet renewable energy targets.
- To eliminate this problem, since a hub requires only one reactor, the AGCTF recommends hubs on all 345 kV Transmission lines and these hubs to be located at least 23 miles apart.
  - Existing interconnection substations on 345 kV lines may be designated as hubs.

Economics:

- Having multiple generators interconnect at a hub results in reduced costs associated with a reduced number of reactors and breakers compared to individual interconnections.
- Assuming individual, stand-alone interconnections are located closer to the generators, the distances from the generators to the hub will be greater than for the sum of the individual interconnections.
CAWG requested that the AGCTF provide a cost-effectiveness study of the Hub Design. The results of this study are summarized below (details are in the Appendix).

- **Attachment Cost Savings**
  - Total = $262 M
  - Per Generator = $7.9

- **Generator Lead Cost Increases**
  - Total = $136 M
  - Per Generator = $4.1 M

- **Net Savings**
  - Total = $126 M
  - Per Generator = $3.8 M
Graphic Illustration of Cost Effectiveness

Stand-Alone
Attachment $ = 16*3 = $48 M
Leads = 11+12+9 = 32 miles
Lead $ = 0.75*32 = $24 M
Total $ = $72 M

Hub Design
Attachment $ = 21 M
Leads = 16.5+17.5+18.5 = 52.5 miles
Lead $ = 0.75*52.5 = $39.375 M
Total $ = $60.375 M

Over 3 Generator gives average savings of $3.9 M per generator.
AGCTF Question to CAWG

- AGCTF recommended to the CAWG that $13 million of the cost of each Hub built by SPP be rolled into a region-wide rate.

- CAWG rejected this proposal because:
  - Having generation interconnection costs paid for by load via a region-wide rate reflects neither cost causation nor beneficiary pays ratemaking principles. Specific examples:
    - SPP loads taking greater amounts of renewable energy would be subsidized by loads taking lesser amounts of renewable energy.
    - Exports of generation (e.g., renewable energy) would not have to pay their fair share of these uplifted costs.
    - Market-based generation would not have to pay these uplifted costs.
Additional AGCTF Recommendation for CAWG Considerations

- The AGCTF also recommended that the CAWG to consider temporary funding of a portion of generation interconnection costs until those costs fall from added interconnections.
  - Such funding would most likely be accomplished via a region-wide rate and would include payback when costs subsequently decreased.
- CAWG rejected temporary funding of generation interconnection cost because of the financial risk that ratepayers may not receive the payback if:
  - Additional generators ultimately don’t attach at a hub to reduce costs; or
  - Existing generators default on any payback owed to ratepayers.
CAWG Recommendation to RSC

- CAWG recommends that the RSC accept a policy such that no generation interconnection costs associated with hub & spoke design be included in the regional transmission rates, and instead be assigned to generators.
Details of Cost Effectiveness Study
## Hub Costs

<table>
<thead>
<tr>
<th>Hub Location</th>
<th># Gen</th>
<th>MW</th>
<th>345 kV Trans</th>
<th>Total Hub Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hub #1 - Beaver County, OK</td>
<td>3</td>
<td>900</td>
<td>2 Circuit</td>
<td>$21,000,000</td>
</tr>
<tr>
<td>Hub #2 - Texas County, OK</td>
<td>3</td>
<td>900</td>
<td>2 Circuit</td>
<td>$27,000,000</td>
</tr>
<tr>
<td>Hub #3 - Woodward County, OK</td>
<td>3</td>
<td>900</td>
<td>2 Circuit</td>
<td>$27,000,000</td>
</tr>
<tr>
<td>Hub #4 - Ford County, KS</td>
<td>5</td>
<td>1500</td>
<td>2 Circuit</td>
<td>$32,000,000</td>
</tr>
<tr>
<td>Hub #11 - Antelope County, NE</td>
<td>3</td>
<td>900</td>
<td>2 Circuit</td>
<td>$27,000,000</td>
</tr>
<tr>
<td>Hub #5 - Sherman County, TX</td>
<td>2</td>
<td>500</td>
<td>1 Circuit</td>
<td>$21,000,000</td>
</tr>
<tr>
<td>Hub #6 - Gray County, KS</td>
<td>3</td>
<td>565</td>
<td>1 Circuit</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>Hub #7 - Rush County, KS</td>
<td>2</td>
<td>400</td>
<td>1 Circuit</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>Hub #8 - Kingfisher, OK</td>
<td>2</td>
<td>550</td>
<td>1 Circuit</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>Hub #9 - Roger Mills county, OK</td>
<td>2</td>
<td>500</td>
<td>1 Circuit</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>Hub #10 - Cherry County, NE</td>
<td>2</td>
<td>500</td>
<td>1 Circuit</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>Hub #12 - Nodaway County, MO</td>
<td>3</td>
<td>800</td>
<td>1 Circuit</td>
<td>$21,000,000</td>
</tr>
<tr>
<td>Total All Hubs</td>
<td>33</td>
<td>8915</td>
<td>Combined</td>
<td>$266,000,000</td>
</tr>
</tbody>
</table>
$528 \text{ M} - $266 \text{ M} = $262 \text{ M}$ is an estimate of Attachment Cost Savings. Dividing this by 33 generators results in an average savings of $7.9$ million.
$136,000,000 is a rough estimate of Shared Spoke Costs. Dividing this by 33 generators results in an average added shared spoke cost of $4.1 million.
HUB & SPOKE COST ALLOCATION AMONG GENERATORS

Mike Proctor

Presentation to RSC, April 23, 2012
Cost Allocation Principles

- Generators should not be competitively disadvantaged relative to one another based on either:
  - the location of the hub or
  - the relative timing of the interconnections at a hub.

- At a specific hub, when the overall cost of the hub & spoke design is less than the sum of the stand alone costs for the same number of interconnections at that hub,
  - A cost allocation among generators at that hub should not result in a higher cost to interconnect for any generator than the cost of its stand-alone interconnection.
Current Cost Allocation for GIs Does Not Meet These Principles

- Attachment (Substation) Costs: Currently, the first GI pays for all of the substation costs required for its interconnection.
  - If an additional generator connects at the same substation, it is only required to pay the incremental costs associated with its interconnection.
  - In this case, the first generator will be competitively disadvantaged and may end up paying more than its stand-alone costs.

- Generator Lead Costs: Currently, each generator arranges and pays for the line going from its generator to the substation.
  - Because of increased distance to a single substation, generator lead costs are higher than from attaching to the nearest point on the 345 kV line. The location of the hub would result in larger cost increases for generators whose nearest point on the 345 kV line are furthest from the hub.
  - This will result in a competitive disadvantage to those generators who are paying larger cost increases for generator leads and may result in them paying more than their stand-alone costs.
To accomplish these cost allocation principles, the CAWG endorses the following cost classification:

- **Shared Cost**: Hub and Generator Lead Cost that are shared on a per connection basis among generator interconnections.

- **Assigned Costs**: Generator Lead Costs that are directly assigned to each generator based on the nearest distance of that generator to the 345 kV line to which the generator is attaching.
Hub: Shared Costs

- **Shared Cost Allocation:** The cost of the hub will be shared equally by the generators connecting to a specific hub.

- **Hub Examples:**

<table>
<thead>
<tr>
<th># Gen</th>
<th>Hub Costs</th>
<th>Cost per Gen</th>
<th>Savings per Gen</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$16.0</td>
<td>$16.0</td>
<td>$0.0</td>
</tr>
<tr>
<td>2</td>
<td>$18.0</td>
<td>$9.0</td>
<td>$7.0</td>
</tr>
<tr>
<td>3</td>
<td>$24.0</td>
<td>$8.0</td>
<td>$8.0</td>
</tr>
<tr>
<td>4</td>
<td>$29.0</td>
<td>$7.3</td>
<td>$8.8</td>
</tr>
<tr>
<td>5</td>
<td>$32.0</td>
<td>$6.4</td>
<td>$9.6</td>
</tr>
</tbody>
</table>
Cost estimates for power lines estimate miles of lines as the distance between two points as the sum of the height and base of a right triangle.

The estimated miles of a generator lead is therefore the sum of the distance from the nearest point on the 345 kV Transmission line to the generator plus the distance from that point to the hub.

- Assigned Cost — costs of the generator lead from the generator to the nearest point on the 345 kV Transmission line.
- Shared Cost — costs from the nearest point on the 345 kV Transmission line to the hub.
Shared & Assigned Costs for Generator Leads: Suggested Definitions

- **Only 345 kV generator leads are included in cost allocation**
  - Each generator interconnection to a 345 kV line must provide its own 345 kV transformer.
  - Any lower voltage lines from the generator to the 345 kV transformer are also provided by the generator.

- **Shared Generator Lead Costs:**
  - Contribution to Shared Cost equals the distance from the nearest point to the generator’s 345 kV transformer on the 345 kV Transmission line times the average cost per mile over all 345 kV generator leads (a Miles * (Total Line Costs ÷ Total Miles)).
  - Shared Costs are allocated equally to each generator.

- **Assigned Generator Lead Costs:**
  - Difference between each generators actual generator lead costs and each generators contribution to shared costs.
  - Assigned Costs are directly assigned to each generator.
Example of Cost Allocation for 345 kV Generator Leads

<table>
<thead>
<tr>
<th>Generators</th>
<th>b Miles</th>
<th>a Miles</th>
<th>Actual Miles</th>
<th>Costs $M</th>
<th>Shared Line Costs</th>
<th>Assigned Costs $M</th>
<th>Gen Lead Charges $M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Actual Cost $M</td>
<td>Cost per Mile $M</td>
<td>Contribution to Shared $</td>
<td>Allocation of Shared $</td>
</tr>
<tr>
<td>G₁</td>
<td>12</td>
<td>6</td>
<td>18.5</td>
<td>$13.857</td>
<td>$0.749</td>
<td>$4.530</td>
<td>$5.033</td>
</tr>
<tr>
<td>G₂</td>
<td>9</td>
<td>9</td>
<td>17.5</td>
<td>$13.143</td>
<td>$0.751</td>
<td>$6.795</td>
<td>$5.033</td>
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<tr>
<td>G₃</td>
<td>11</td>
<td>5</td>
<td>16.5</td>
<td>$12.458</td>
<td>$0.755</td>
<td>$3.775</td>
<td>$5.033</td>
</tr>
<tr>
<td>Totals</td>
<td>32</td>
<td>20</td>
<td>52.5</td>
<td>$39.457</td>
<td>$0.752</td>
<td>$15.100</td>
<td>$15.100</td>
</tr>
</tbody>
</table>

The above table illustrates the application of shared and assigned costs for generator leads to a hub.

- The average cost per mile of $752,000 is multiplied by the miles from the nearest point on the 345 kV to the hub (a miles) for all three generators to get their contributions to shared line costs.
- This total is then allocated equally to each GI customer.
- The contribution to shared cost is subtracted from actual costs for each generator to determine the assigned costs.
- The generator lead charges are the sum of the allocated shared costs and the assigned costs.
What Is A Spoke?

- The AGCTF has defined a spoke as a 345 kV line extending out from the hub to which multiple generators are attached.

- The AGCTF has determined that attachments to a spoke will require 3 ring bus attachment facilities.

This graphic shows the first generator ($G_1$) attaching to the hub via a 345 kV generator lead.

Subsequently generators 2 and 3 attach to the initial 345 kV generator lead, and it then becomes a spoke.
Is the CAWG Endorsed Cost Allocation Applicable to Interconnections with Spokes?

- Yes, with a few minor modifications.
- First, the costs of all the 345 kV generator leads, including the spoke are pooled for generator lead costs for a given hub.
- Second, the definition of the shared cost
  - for the generator leads remains the same using the average costs per mile for the pooled generator lead costs; and
  - includes the costs of the added 3 ring buses.
- Third, the assigned generator lead cost are the pooled generator lead costs minus the shared generator lead cost.
  - Assigned costs are allocated in proportion to the nearest distance to the 345 kV Transmission line from the 345 kV transformers for each generator.
Example of Cost Allocation for 345 kV Generator Leads Involving A Spoke

The above table illustrates the application of shared and assigned costs to a hub involving a spoke as illustrated in the diagram on slide 19.

- $30 M is the pooled cost for all the 345 kV generator leads including the spoke. The average cost per mile is $750,000 per mile.

- This is multiplied by the miles from the nearest point on the 345 kV to the hub (a miles) for each of the three generators to get their contributions to shared line costs. This total is then allocated equally to each GI customer.

- The remaining line costs are assigned to each generator in proportion to the distance from their 345 kV transformers to the nearest point on the 345 kV transmission line.
When Will SPP Use A Spoke Design?

- **Economic:** Whenever it is most cost-effective to add a spoke.
  - Added costs from 3 ring buses attaching to a spoke
  - Reduced costs from fewer connections at the hub
  - Reduced costs from shorter generator leads

- **Land Use Congestion at a Hub:** Whenever it is determined that there would otherwise be too many generator leads connecting to a single hub.
How Do Shared Costs Work?

- The first generator interconnecting pays SPP the full cost for the attachment facilities and generator lead.
- The next generator that attaches pays SPP its assigned costs plus one half of the shared costs, which in total are more than the incremental costs.
  - SPP pays back to the first generator the difference between what the second generator pays and the incremental costs.
  - This payback will make the second generators net payment equal to its assigned and shared costs.
  - Interest cost may be added to the assigned cost for the second generator.
- As additional generators are added to a hub, the above process is reapplied.
Conclusions

- The CAWG endorses the method for SPP allocation to generators of the Hub & Spoke interconnection costs described herein and proposes that the RSC consider recommending this method to the SPP Board of Directors.
AGCTF Update to MOPC

April 11, 2012

Area Generation Connection Task Force

• AGCTF Charter from the MOPC:
  • The Area Generation Connection Task Force (AGCTF) is responsible for developing and recommending policy to guide SPP Staff and/or recommendations for Tariff modifications or business practices to determine the optimum methods and locations for interconnecting generation to the transmission system given the complex situations generally prevalent.
  • AGCTF has developed a number of Whitepapers and Principle documents describing many of these issues and proposed solutions.
The Generation Interconnection Issue

- Current practice is that each GI customer independently interconnects, and directly pays for all costs, associated with its request for interconnection
- SPP has received multiple requests for interconnection in the same geographical area on the same line
  - May result in multiple substations in very close proximity to each other
  - May result in operational issues on the power line
  - Increase impedance on a line if line reactors are required
  - Increased capital and operations and maintenance cost associated with multiple substations

The Generation Interconnection Issue

- Currently GI customers appear to be reluctant to jointly share the same interconnection facilities
  - Ownership issues and lease agreements can make this difficult
Definitions

- Generation Hub (Hub) shall mean the interconnection substation designated by the Transmission Provider for interconnecting generation in a given area.
- Generation Collector Spoke (Spoke) shall mean the transmission line that ultimately connects multiple generators to the Hub.
- Spoke Collector Station shall mean the substation built on a Spoke to accommodate the interconnection of a Generating Facility to the Transmission System.

AGCTF Recommendation on Generation Hubs (Previously Approved by MOPC in April 2011)

- May be established in areas where multiple generators wish to interconnect on the same line
  - Generators would be required to interconnect at Hub
  - This will minimize the number of interconnections on the same line
- Existing Substations may qualify as a Hub
  - Minimize costs
  - Consistent with current Tariff (Attachment V. Section 4.2.3).
Generation Hubs

- Hubs can be identified by:
  - ITP process by identifying significant areas of generation potential
  - GI Cluster Study process when multiple generators request interconnection in the same geographical area
- Designation of Hubs must be approved by MOPC and Board of Directors
Generation Hubs

• Criteria for proposing new Hubs
  – Only on lines operating at 300kV or greater
  – Must have at least two GI Customers in close proximity to each other (or one additional generator to an existing substation that interconnects generation).
  – No Hub should be proposed within 23 miles of another Hub or existing or planned substation capable of being designated as a Hub.
  – Two different analysis go into decisions to site Hubs
    ▪ Switching Transients – determine if switching transients need to be controlled
    ▪ Economic – if switching transients are not an issue, determine the additional cost of adding substation

Generation Hubs

• Existing substations may be designated as Hubs if proposed through the process and approved by the BOD
• No NTC’s will be issued to build a new Hub until SPP has an executed an approved GIA
  – The “in service date” of the Hub will coincide with the in service date of the first generator interconnecting at the Hub
• Hubs preferably located and spaced for future transmission expansion
Requirements to Interconnect to a Hub

- When a Hub is approved, a GI customer must connect to the Hub if directed to do so through the GI process
- GI customer may ask for an exception
  - Reasons for Granting: Access to Hub, costs, etc.
  - Customer request lies in a “gray area” – can Hub be built 20 miles from another?
  - Must independently fund all related studies
  - May have its GI request delayed to complete the studies
  - If granted, the GI customer is responsible for all interconnection costs pursuant to Attachment V

Cost Allocation for Generation Hubs

- Being examined by CAWG and RSC
Collector System - Spokes

- To ease potential land pressures at a Hub, a Spoke that terminates at the Hub and extends to multiple generator facilities may be built at the discretion of SPP.

AGCTF Motion from February 24th

- AGCTF approved the following motion at its February 24th meeting
- “The AGCTF is supportive of moving forward with policy development for the development of Spokes. Such policy would apply for the interconnection (300kV +) of multiple generators assuming that the SPP region would support the cost of the Spoke development until such time that generator developers complete their connection through a subscription process. This policy assumes that SPP would be the entity to identify the need for and specifications of the Spoke and that generation developers would provide some level of initial financial support.”
Collector System - Spokes

- Spokes may be requested by Generator needing to interconnect to an existing or planned Hub.
- If approved, SPP will direct Transmission Owner to build the Spoke.
- Spokes are radial lines
- Spokes to be built with “minimum” 345kV construction (approx 800-1000MVA)
  - Allows spoke to not be “overbuilt”. Construction would be the same for either a 100MW or a 1000MW generator.
  - Additional Generators may request to interconnect into the Spoke.

Collector System - Spokes

- To accomplish an interconnection on a Spoke, a substation, minimum of 3 breaker ring bus or Transmission Owner minimum configuration, must be built on the Spoke. (Station @ D)
Collector System – Spoke Configurations

- Daisy Chain Configuration – Allows multiple interconnections on Spoke (less of concern on radial line)

Collector System – Spoke Configuration

- Common Collector Station – Station connects multiple generators
Spokes – Additional Principles

• Number of Spoke Collector Stations will be self-limiting due to Spokes being built for 800-1000MW.

• Number of Spokes per Hub will be self limiting in accordance with how much interconnection capacity is available on the interconnecting transmission line

• Connecting one Spoke to another Spoke (Closing the Loop) is considered by the AGCTF to be an exception to normal practice. If a situation should occur, the issue to be handled by SPP Staff on a case by case basis.

Spokes – Cost Allocation

• Being examined by CAWG and RSC
AGCTF Recommendation – Voting Item

• AGCTF recommends that MOPC approve AGCTF Principles for Hubs and Spokes as Policy.
  – CAWG and RSC will address cost allocation in their April meeting cycle.
• AGCTF recommends for MOPC to request RTWG to draft appropriate Tariff language and BPWG to develop any necessary Business Practice.
Report to the
Regional State Committee
April 23, 2012

COST ALLOCATION WORKING GROUP
(CAWG)

CAWG REPORT TO RSC

CAWG ACTIVITY - QUARTERLY UPDATE

☐ Cost Allocation - Hub & Spoke Proposal
☐ Report on Seams Cost Allocation/Planning
☐ Public Policy Requirements In Planning Survey
☐ Updates To RSC - SPCTF on Order 1000
CAWG REPORT TO RSC

Cost Allocation - Hub & Spoke Design
Mike Proctor Presentation

CAWG has considered the following on Hub/Spoke Cost Allocation:

- A Portion of Hub/Spoke Interconnection Costs be included in Regional Tariff
- Interconnection Charge be used for Hub/Spoke with temporary funding of Costs through Regional Tariff
- Assignment of all Hub/Spoke Interconnection Costs charged to Generators

CAWG chose to recommend Assignment of Interconnection Costs to generators as more appropriately reflecting cost causation and beneficiary pays ratemaking principles.

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Seams Cost Allocation/Planning
Brattle Presentation

CAWG has reviewed and provided input into the Brattle Report:

*Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*

CAWG supported RSC acceptance of the Brattle Report as the framework to use in determinations as to appropriate Cost Allocation for Seams Projects.
CAWG REPORT TO RSC

Public Policy Requirements in Planning Survey

CAWG recommended to the ESWG that its ITP10 Planning Survey require differentiation between mandated (i.e., required by statute or regulation) and goal-driven Public Policy Requirements and that the Survey participants provide an explanation of any such mandate each participant asserts is in effect.

The Policy Survey distributed reflected a request for that differentiation.

CAWG will continue to monitor the Survey Results and the application of those results within the ITP10 Planning Process.

CAWG REPORT TO RSC

Updates To RSC - SPCTF on Order 1000

Pursuant to the RSC’s request, CAWG has approved on-going reports for concurrent distribution to RSC member-Commissioners on the activity of the Strategic Planning Committee’s Task Force on Order 1000 (SPCTF-Order 1000 or TF).

In the RSC January meeting, the SPC sought RSC support of the TF’s then-current approach to meet Order 1000 directives to remove Right of First Refusal Provisions (ROFR) from SPP Tariffs & Agreements. The RSC declined to take a position but directed CAWG to provide it information on the issues presented.

The most current CAWG Report distributed to the RSC reflects the currently-approved SPC approach to meet the Order 1000 directives and for which SPC\(^{(1)}\) will seek Board approval.

(1) CAWG understands that the SPC will make a presentation to the RSC on its approved approach at the April meeting.
CAWG REPORT TO RSC

CAWG SCHEDULED

☐ Any RSC-Directed Hub & Spoke Considerations

☐ On-going: Seams Cost Allocation/Order 1000 Requirements

☐ Public Policy Issues/ITP10 Planning

☐ Updated Order 1000 ROFR Reports

☐ ESWG Metrics for RARTF

☐ Possible Cost Allocation Recommendations on Project Cost Overruns

Questions:

Submitted by: Pat Mosier
Chairman, CAWG
April 23, 2012
**Order 1000**

**RSC Efforts**

April 23, 2012
Commissioner Olan Reeves

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**Order 1000: Interregional Requirements**

<table>
<thead>
<tr>
<th>RSC TIMELINE</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>January 2011</strong></td>
</tr>
<tr>
<td><strong>June 2011</strong></td>
</tr>
<tr>
<td><strong>October 2011</strong></td>
</tr>
<tr>
<td><strong>January 2012</strong></td>
</tr>
<tr>
<td><strong>April 2012</strong></td>
</tr>
</tbody>
</table>
RSC Task Force on Order 1000

The purpose of the RSC Task Force on Order 1000 is to explore SPP’s compliance options related to Order 1000’s Interregional Cost Allocation Requirements. The RSC has engaged the Brattle Group as a consultant on these issues with a report expected in April, 2012. The Brattle Group report can serve as a foundation to explore interregional cost allocation options. Due the April, 2013 compliance filing deadline for SPP, completion of the task forces’ work will be critical by the end of 2012. This will allow the task force’s recommended option to be presented to the RSC and SPP Board of Directors in January, 2013 for the April filing at FERC.
RSC Task Force on Order 1000

- Membership
  - 3 RSC Members
  - 3 SPP Members
  - 1 SPP BOD Member

Questions?
Southwest Power Pool - Regional State Committee
Task Force on Order 1000 Cost Allocation Requirements
DRAFT Charter
April XX, 2012

PURPOSE
Under Southwest Power Pool’s (SPP) governance structure the Regional State Committee (RSC) has primarily responsibility for cost allocation of transmission upgrades. As a result, the RSC is forming a Task Force on FERC’s Order 1000 Interregional Cost Allocation Requirements. Order 1000 requires RTOs to submit compliance filings on the Interregional aspects of Order 1000 by April 2013.

The purpose of the RSC Task Force on Order 1000 is to explore SPP’s compliance options related to Order 1000’s Interregional Cost Allocation Requirements. The RSC has engaged the Brattle Group as a consultant on Interregional Cost Allocation issues with a report expected in April 2012. The Brattle Report can serve as a foundation to explore Interregional Cost Allocation options. Due to the April 2013 compliance filing deadline for SPP, completion of the task forces work will be critical by the end of 2012. This will allow the task force’s recommended option to be presented to the RSC and SPP Board of Directors in January 2013 for an April filing at FERC.

REPRESENTATION
The RSC Task force on Order 1000 (“RSCTF on Order 1000”) Interregional Cost Allocation Requirements will be a seven (7) member task force composed of three (3) representatives of the RSC, three (3) SPP Members and one (1) member of the SPP Board of Directors.

A RSC Member shall serve as Chair and a SPP Member shall serve as Vice-Chair. The RSC and SPP Members representatives shall be appointed by the RSC President and MOPC Chairman and shall represent diverse members. Selection of such representatives shall consider, among other factors, geography, member type and expertise. The Board of Directors Member of the Task Force will be appointed by the SPP Board of Directors.

DURATION
The RSCTF on Order 1000 will be a temporary task force. It is anticipated that its work will be completed by December 31, 2012, though the task force will continue its work until it is completed.

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

REPORTING
The RSCTF on Order 1000 will provide status reports to the RSC and the BOD at least on a quarterly basis at the regularly scheduled meetings. The task force may make additional status reports as it deems necessary or as requested by the RSC, the MOPC or the BOD.
The RSCTF on Order 1000 will make final recommendations to the RSC and the SPP BOD on what SPP should submit in SPP’s compliance filing in on FERC Order 1000’s Interregional Cost Allocation requirements.

The Task Force shall prepare and issue the report by December 31, 2012.
Order 1000
SPP Compliance Efforts

April 23, 2012
psuskie@spp.org
<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>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 to the SPP OATT 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>
</tbody>
</table>

### Right of First Refusal

2. 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]  
SPP’s OATT has ROFR language.  
Strategic Planning Committee, Corporate Governance: Review and consider amendments to SPP Membership Agreement & OATT that directly address “ROFR.”

### Cost Allocation

3. Include in its OATT a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for cost allocation. [¶ 482]  
SPP Complies with requirement.  
N/A
<table>
<thead>
<tr>
<th>No.</th>
<th>Interregional Requirements</th>
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<tbody>
<tr>
<td>1.</td>
<td>Engage in interregional coordination with each neighboring transmission planning region within the same interconnection to identify and jointly evaluate interregional transmission facilities that may more efficiently or cost-effectively address the individual needs of each respective local and regional transmission planning processes. [¶ 345, 393, 415]</td>
<td>Although SPP has Seams Agreements with neighboring regions, Order 1000 places additional requirements on Interregional planning</td>
<td>SPP Engineering &amp; SPP Seams Steering Committee: Review Seams Agreements/Joint Operating Agreements. Develop procedures to comply with the interregional coordination requirements set forth in Order No. 1000 and to develop the same language to be included in each public utility transmission provider’s OATT that describes the procedures that a particular pair of transmission planning regions will use to engage in interregional coordination. OATT must still provide enough description so that stakeholders can follow how interregional transmission coordination will be conducted, and the OATT must contain links to the actual agreements</td>
</tr>
<tr>
<td>2.</td>
<td>Develop, working through its transmission planning region, a method or set of methods for allocating the costs of new interregional transmission facilities that two (or more) neighboring transmission planning regions determine resolve the individual needs of each region more efficiently and cost-effectively. [¶ 578]</td>
<td>SPP has no methods for allocating costs for interregional transmission facilities with neighboring regions</td>
<td>SPP Regulatory, SPP Seams Steering Committee &amp; SPP Regional State Committee: SPP’s RSC has already engaged the Brattle Group to look at Seams Cost Allocation.</td>
</tr>
</tbody>
</table>
Order 1000: Organizations on Regional Issues

The SPP BOD:
• Designated the SPC to address Regional Policy Issues related to Order 1000

The SPC:
• Established a SPCTF on Order 1000
Order 1000: Organizations on Interregional Issues

The SPP RSC:

• has authority on Interregional Cost Allocation
• has established a staff Working Group called Seams Cost Allocation Task Force

The SPP Membership:

• have developed the Seams Steering Committee
Questions?
SPCTF on Order 1000
Report Summary

April 23, 2012
Mel Perkins
# SPCTF on Order 1000

<table>
<thead>
<tr>
<th>SPCTF Order 1000 Member</th>
<th>Organization</th>
</tr>
</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>
</tr>
<tr>
<td>Ricky Bittle, Member</td>
<td>Arkansas Electric Cooperatives</td>
</tr>
<tr>
<td>Todd Fridley, Member</td>
<td>Kansas City Power &amp; Light Company</td>
</tr>
<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, Staff Secretary</td>
<td>SPP Staff</td>
</tr>
</tbody>
</table>
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.
I. Recommendation as to the Transmission Upgrades for which SPP Should Seek to Retain the Federal ROFR.

<table>
<thead>
<tr>
<th>Voltage/Type of Facility/Exclusion</th>
<th>Should SPP Seek to Retain ROFR?</th>
<th>Justification of Maintaining Federal ROFR?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zonal Upgrades: 100 kV &amp; below</td>
<td>Yes</td>
<td>Funded by the Zone: Under SPP’s Highway/Byway Cost Allocation Methodology ITP projects that are 100 kV and below are funded exclusively by the zone in which they are located. In this manner, they are akin to “local transmission facilities” as defined in Order 1000 and therefore are not subject to the requirement to eliminate Federal ROFR.</td>
</tr>
<tr>
<td>Byway Upgrades: 100 kV – 300 kV</td>
<td>Yes</td>
<td>Multiple Reasons: (1) 2/3 of these upgrades are funded by zone; (2) SPP is the only RTO in which all load serving entities are vertically integrated, thus there is a close nexus between load and a duty to serve; and (3) the reliability nature of upgrades.</td>
</tr>
<tr>
<td>Highway Upgrades: 300 kV &amp; above</td>
<td>No</td>
<td>Federal ROFR to be Eliminated</td>
</tr>
</tbody>
</table>
I. Recommendation as to the Transmission Upgrades for which SPP Should Seek to Retain the Federal ROFR.

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<td>Generation Interconnection Upgrades</td>
<td>Yes</td>
<td>Order 1000 expressly excludes Generation interconnection upgrades: Order 1000 indicates that “issues related to the generator interconnection process and to interconnection cost recovery are outside the scope of this rulemaking. . . . This Final Rule does not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities.” See Order 1000 at P. 760.</td>
</tr>
<tr>
<td>Sponsored Upgrades</td>
<td>Yes, with modifications as discussed below in § 1.2</td>
<td>Order 1000 appears to exclude SPP’s Sponsored Upgrades: Sponsored Upgrades do not fall within the definition of “transmission facilities selected in a regional transmission plan for purposes of cost allocation” and therefore, the requirement to eliminate the Federal ROFR does not apply. First, Sponsored Upgrades are not in the STEP for cost allocation, because the costs associated with Sponsored Upgrades are paid by the Project Sponsor. Thus, at the time that a Sponsored Project is included in the STEP, it is not included for purposes of cost allocation. Additionally, Sponsored Upgrades are built at the request of a Project Sponsor; they are not “selected pursuant to a transmission planning region’s Commission-approved regional transmission process for inclusion in a regional transmission plan for purposes of cost allocation because they are more efficient or cost-effective solutions to regional transmission needs.” The Order 1000 Federal ROFR mandate, therefore, should not apply. See Order 1000 at P. 63.</td>
</tr>
<tr>
<td>Transmission Service Upgrades</td>
<td>Yes</td>
<td>Order 1000 appears to exclude Transmission Service Upgrades: Service Upgrades identified through the SPP Aggregate Transmission Service Study process do not appear to be subject to the requirement to eliminate the Federal ROFR. While Service Upgrades are included in the STEP, and all or a portion of the costs of some Service Upgrades may be eligible for allocation under SPP’s Base Plan funding (i.e., Service Upgrades associated with a Designated Resource that meet the conditions in Section III.B of Attachment J or have obtained a waiver of the requirements), such upgrades do not appear to fall within the description of “transmission facilities selected in a regional transmission plan for purposes of cost allocation.” See SPP OATT at Attachment O § III.7.a. and Attachment J §§ III.B – III.C.</td>
</tr>
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I. Recommendation as to the Transmission Upgrades for which SPP Should Seek to Retain the Federal ROFR.

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<th>Justification of Maintaining Federal ROFR?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrades to Existing Transmission Facilities (Tower Change outs; Re-conductoring)</td>
<td>Yes</td>
<td><strong>FERC limitation on Federal ROFR Removal Requirement:</strong> “This Final Rule does not remove or limit any right an incumbent may have to build, own and recover costs for upgrades to the facilities owned by an incumbent . . .” <em>See Order 1000 at P. 319.</em></td>
</tr>
<tr>
<td>Upgrades when state or local laws or regulations limit who can site or be permitted to build transmission facilities</td>
<td>Yes</td>
<td><strong>FERC limitation on Federal ROFR Removal Requirement:</strong> “Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.” <em>See Order 1000 at P. 227 &amp; Footnote 231.</em></td>
</tr>
<tr>
<td>Upgrades along existing incumbent Transmission Owner Rights-of-Way</td>
<td>Yes</td>
<td><strong>FERC limitation on Federal ROFR Removal Requirement:</strong> “Nor does this Final Rule grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation.”</td>
</tr>
</tbody>
</table>
II. Recommendation as to What Model SPP Should Use to Select Transmission Owners for Projects Without a Federal ROFR.

2.3 Recommended Competitive Solicitation Process to Select Transmission Owners

The SPCTF recommends that SPP propose to FERC a Competitive Solicitation Model to select Transmission Owners to construct, own and operate projects that do not have a Federal ROFR. The SPCTF recommends that SPP use a process similar to the process outlined in the Draft Transmission Owner Selection Process which is attached hereto as “Attachment A”. Additionally, a flow chart of the Competitive Solicitation Process recommended by the SPCTF is attached hereto as “Attachment B”.

2.4 Recommendation on Development of Detailed Transmission Owner Selection Criteria

The SPCTF recommends the SPCTF develop in detail the evaluation criteria and associated scoring needed to evaluate/compare Qualified Transmission Owners (“QTOs”) that are competing to build transmission projects within SPP’s footprint. The general process, criteria and scoring is found in Attachment A and B which the SPCTF recommends be further vetted and developed by the SPCTF by June 2012.
II. Recommendation as to What Model SPP Should Use to Select Transmission Owners for Projects Without a Federal ROFR.

2.5 Majority/Minority Position

Proponents of the Competitive Solicitation Process, while acknowledging some weaknesses, believe the proposal: preserves the current ITP process recently approved by FERC maintaining the open, transparent and collaborative planning process; keeps the “need” component separated from the “construction” component thereby facilitating that the most cost-effective solutions are built; establishes only one competitive process for SPP staff to manage; and, has the least amount of Tariff work of all the options considered by the Task Force.

Opponents believe that the Competitive Solicitation approach is complex and potentially creates unintended drivers; relies on SPP planning staff and incumbent transmission owner for ideas and solutions to problems consequently not incenting stakeholders solutions and providing an unfair advantage for incumbents; imposes construction bidding expertise on SPP staff and processes contributing to increased SPP staffing and to delays in construction; and is incompatible with current NTC-C process.

For the comprehensive comparisons, see the following link: http://www.spp.org/publications/SPCTFOOrder1000-030812.pdf.
III. Recommendation as to Transmission Owner Qualification Criteria.

3.1 Recommended Transmission Owner Qualification Criteria

The SPCTF recommends that SPP’s compliance filing for Order 1000 contain Transmission Owner qualification criteria that must be met before a potential transmission owner can participate in SPP’s Competitive Solicitation Process described in Sections 2.2 and 2.3 above. The Transmission Owner qualification criteria would apply only to those entities seeking to construct, own, and operate transmission projects that are subject to the SPP Competitive Solicitation Process. The general basis upon which the SPCTF make its recommendation for Transmission Owner qualification criteria is the existing process outlined in Attachment O § VI.6 of the SPP OATT. These are:

1. Threshold eligibility criteria: The recommended threshold eligibility criteria would include, at a minimum, some level of proof by an Applicant Transmission Owner (“ATO”) that the ATO has the legal authority under state law to construct facilities within a state in which a project will be built and some level of assurance that the ATO is or will be a member of SPP.

2. Financial criteria: The recommended financial eligibility criteria would include certain creditworthiness requirements.

3. Managerial criteria: The recommended managerial eligibility criteria would require an ATO to demonstrate certain managerial expertise.
IV. Recommendation as to Changes to SPP’s Membership Agreement and OATT to Remove the Federal ROFR.

4.2 Recommended Change to SPP’s OATT

The SPCTF recommends that the following sections of SPP’s OATT be amended to remove the Federal ROFR as stated below.

A. SPP OATT, Attachment O – Section VI(1) & (4)

* * * **

As a result, the SPCTF recommends that SPP modify these sections to comply with Order 1000 in a manner that is consistent with this Report.

The SPCTF recommends that the RTWG draft the specific language for approval by the SPP Board of Directors during SPP’s current meeting cycle by June 30, 2012.
V. Recommendation as to Application of Order 1000 to Future SPP Projects.

5.1 Recommendation as to Which Facilities Will Be Subject to Order 1000 Requirements

The SPCTF recommends that SPP propose that the effective date of its Order 1000 compliance filing be the date FERC issues an order accepting the compliance filing, with the first developer qualification process beginning in the summer (June) thereafter. The SPCTF therefore recommends that the requirements of Order 1000 apply to all transmission facilities subject to Federal ROFR elimination that are approved for construction in the first STEP Report that is issued following the first developer qualification process, and for all facilities approved thereafter for which Federal ROFR has been eliminated.
VI. Recommendation as to Consideration of Transmission Needs Driven by Public Policy.

6.3 Recommendation as to How SPP Should Handle Public Policy under Order 1000.

The SPCTF recommends that SPP rely primarily on its existing OATT language regarding transmission needs driven by public policy requirements as discussed above. Rather than revising the OATT to provide explicitly for the consideration of transmission needs driven by public policy goals, the SPCTF recommends that SPP remain open to considering public policy goals through the language in Attachment O that allows for “Other input requirements identified during the stakeholder process” (see Attachment O § III.6.o).

The SPCTF recommends that the RTWG, in consultation with the TWG and the Economic Studies Working Group (“ESWG”), examine the existing OATT language to determine if any minor revisions are required to ensure that SPP complies with the requirements in paragraphs 205-211 of Order 1000 to establish procedures to: (1) identify transmission needs driven by public policy; (2) identify potential solutions to meet those needs; and (3) post information on the SPP website relating to public policy transmission planning.
VII. Recommendation as to Information and Data from Merchant Transmission Developers.

7.1 Recommended Information and Data that Merchant Transmission Developers that Do Not Participate in SPP Planning and Cost Allocation Should Be Required to Provide to SPP.

The SPCTF recommends that SPP seek FERC’s approval to require that merchant developers provide certain information and data to SPP. While Order 1000 does not expressly define "merchant developers", the Order states that merchant facilities are facilities that are not subject to the evaluation and selection processes that apply to transmission facilities for which regional cost allocation is sought and that merchant transmission developers assume all financial risk for developing and constructing the transmission project. [PP. 163-165] The SPCTF recommends that SPP consider any transmission facility within and/or interconnecting to the SPP Region that the builder does not intend to place under SPP's control under the SPP OATT to be "merchant facilities" for the purposes of the information and data requirements. While the language of Order 1000 could be read to include Sponsored Upgrades as defined in the SPP OATT (i.e., sponsor assumes financial risk and is not part of the evaluation process), because “Sponsored Upgrades” will be placed under SPP’s control under the SPP OATT, the SPCTF recommends that entities proposing to construct "Sponsored Upgrades" as defined in the SPP OATT will be subject to all of the requirements applicable to other Transmission Owners participating in the SPP transmission planning process. The SPCTF recommends that SPP’s TWG review existing SPP practices and policies in order to recommend the specific information and data SPP should require merchant transmission developers to provide to SPP.
<table>
<thead>
<tr>
<th></th>
<th>SPCTF Report Implementation Requirement</th>
<th>Responsible Stakeholder Group(s)</th>
<th>Deadline</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Endorsement of SPCTF on Order 1000 Report</td>
<td>SPC &amp; BOD</td>
<td>April 2012</td>
</tr>
<tr>
<td>2</td>
<td>Development of Transmission Owner Selection Criteria for a Competitive Solicitation Process</td>
<td>SPCTF</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See §§ 2.3 &amp; 2.4)</td>
<td></td>
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</tr>
<tr>
<td>3</td>
<td>Development of Transmission Owner Qualification Criteria &amp; TO Managerial Experience Criteria</td>
<td>SPCTF</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See §§ 3.1 &amp; 3.2)</td>
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</tr>
<tr>
<td>4</td>
<td>Development of Transmission Owner Creditworthiness Criteria</td>
<td>Finance Committee</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See § 3.1)</td>
<td></td>
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</tr>
<tr>
<td>5</td>
<td>Drafting &amp; Approval of Language to Remove ROFR in Membership Agreement</td>
<td>SPCTF, CGC, MOPC, &amp; BOD</td>
<td>SPCTF – April 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See § 4.1)</td>
<td></td>
<td>CGC – May 2012</td>
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<tr>
<td></td>
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<td>MOPC &amp; BOD - July 2012</td>
</tr>
<tr>
<td>6</td>
<td>Drafting &amp; Approval of Language to Remove ROFR in OATT</td>
<td>RTWG, MOPC, &amp; SPP BOD</td>
<td>RTWG – June 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See § 4.2)</td>
<td></td>
<td>MOPC &amp; BOD - July 2012</td>
</tr>
<tr>
<td>7</td>
<td>Review and Drafting of Recommended Language on Public Policy Requirements of Order 1000</td>
<td>RTWG, MOPC, &amp; SPP BOD</td>
<td>RTWG – June 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See § 6.3)</td>
<td></td>
<td>MOPC &amp; BOD - July 2012</td>
</tr>
<tr>
<td>8</td>
<td>Review and Draft Information and Data SPP Will Propose to Require Merchant Transmission Developers to Provide to SPP</td>
<td>TWG</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td></td>
<td>(See § 7.1)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Drafting and Endorsement/Approval of Tariff Language for SPP’s Order 1000 Regional Compliance Filing</td>
<td>RTWG</td>
<td>RTWG – August 31, 2012</td>
</tr>
<tr>
<td>10</td>
<td>Review and Approval of RTWG’s Language for SPP’s Order 1000 Regional Compliance Filing</td>
<td>MOPC &amp; BOD</td>
<td>September 31, 2012</td>
</tr>
<tr>
<td>11</td>
<td>Parallel Work of Drafting SPP’s Order 1000 Compliance Filing Letter for Regional Requirements</td>
<td>SPP Staff</td>
<td>October 11, 2012</td>
</tr>
</tbody>
</table>
Questions?
SPC Task Force on Order 1000

FINAL
REPORT

4/03/12
INTRODUCTION:

On July 21, 2011, the Federal Energy Regulatory Commission (“FERC”) issued Order 1000. Per the Order, public utility transmission providers\(^1\) must either amend their open access transmission tariffs (“OATT”) to comply with the requirements of Order 1000 or demonstrate how their existing OATT provisions already comply.\(^2\)

In response to Order 1000, the Southwest Power Pool, Inc. (“SPP”) Board of Directors tasked SPP’s Strategic Planning Committee (“SPC”) with leading SPP’s response to the regional policy requirements contained in Order 1000. After initial meetings of the SPC to discuss the requirements of Order 1000, the SPC formed the SPC Task Force on Order 1000 (“SPCTF”) to examine SPP’s existing OATT to determine whether SPP’s current transmission planning and cost allocation provisions comply with the Order 1000 requirements and whether additional revisions will be necessary. Further, the SPCTF was tasked with proposing how SPP should respond in its compliance filing with FERC.

The following are the members of the SPCTF:

<table>
<thead>
<tr>
<th>SPCTF Member</th>
<th>Organization</th>
</tr>
</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>
</tr>
<tr>
<td>Ricky Bittle, Member</td>
<td>Arkansas Electric Cooperatives</td>
</tr>
<tr>
<td>Todd Fridley, Member</td>
<td>Kansas City Power &amp; Light Company</td>
</tr>
<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, Staff Secretary</td>
<td>SPP Staff</td>
</tr>
</tbody>
</table>

\(^1\) SPP is a public utility transmission provider.
\(^2\) Order No. 1000 at P 795.
AREAS IN WHICH SPP DOES NOT COMPLY

A review of SPP’s existing practices and the regional requirements contained in Order 1000 shows that SPP largely complies with Order 1000’s regional requirements. This Report of the SPCTF contains the SPCTF’s recommendation on how to comply with the requirements of Order 1000 with which SPP currently does not comply or partially complies.

COMPLIANCE DEADLINES OF ORDER 1000

FERC Order 1000 has different filing deadlines for Order 1000’s regional and interregional requirements:

Regional Compliance Filing: Compliance filings addressing the Order 1000 regional transmission planning and cost allocation requirements must be submitted to FERC by October 11, 2012.

Interregional Compliance Filing: Compliance filings addressing the interregional coordination and cost allocation requirements of Order 1000 are due by April 11, 2013.

Therefore, if SPP is to maintain its regular planning cycle of quarterly meetings to meet FERC’s Order 1000 filing deadlines, SPP must approve the regional compliance filing at the SPP Board of Directors’ July 2012 meeting and interregional compliance filing at the SPP Board of Directors’ January 2012 meeting.²

³ The SPCTF recommends that SPP seek a 60-day extension for FERC Order 1000’s regional filing compliance deadline. See § 8.1
EXECUTIVE SUMMARY

SPP evaluated Order 1000 to determine SPP’s level of compliance with the new requirements. Through collaborative stakeholder meetings, SPP and the SPCTF worked to develop the SPCTF policy recommendations on how SPP should comply with the Order 1000 requirements with which SPP currently does not comply or partially complies. The SPCTF identified seven specific areas where decisions were needed. These recommendations are intended to be the product of a broader SPC recommendation to the SPP Board of Directors for its consent and approval.

The first topic for decision by the SPCTF relates to Order 1000’s General Requirement to Eliminate Rights of First Refusal from FERC-jurisdictional Tariffs and Agreements. 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. SPP reviewed the requirements of Order 1000 relating to a Federal Right of First Refusal (“ROFR”) and evaluated SPP’s existing methods of assigning construction and ownership responsibilities for transmission upgrades under SPP’s Membership Agreement and SPP’s OATT. The SPCTF unanimously recommends that SPP seek to retain the Federal ROFR for every category of transmission facility upgrades except “Highway Upgrades” (300 kV and above, regionally-funded transmission facilities).

The second topic for decision by the SPCTF relates to Order 1000’s: General Requirement to Eliminate Rights of First Refusal from FERC-jurisdictional Tariffs and Agreements. Order 1000 requires that the selection of a Transmission Owner to construct, own, and maintain an upgrade must provide comparable and nondiscriminatory treatment to incumbent transmission owners and non-incumbent transmission developers. The SPCTF has identified essentially three potential options for transmission owner selection: 1) a project sponsorship model; 2) a competitive solicitation model; and 3) a model that was not defined in Order 1000. The SPCTF invited stakeholders to submit potential builder selection models to the SPCTF for consideration. After reviewing each proposal and conducting extensive discussions on the proposed models over the course of several meetings, the SPCTF recommends that SPP use a Competitive Solicitation Process to select builders for projects that do not have a Federal ROFR. The SPCTF’s decision was not unanimous, with two entities not supporting the majority decision and instead supporting a “planning-only” sponsorship model.

The third topic for decision by the SPCTF relates to Order 1000’s requirement for Transmission Owner Qualification Criteria. Order 1000 requires each public utility...
transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity’s eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a non-incumbent transmission developer. The SPCTF unanimously recommends that SPP’s compliance filing contain Transmission Owner qualification requirements that must be met before a potential Transmission Owner can participate in SPP’s Competitive Solicitation Process. Recommended Transmission Owner qualification criteria include:

1. Threshold eligibility criteria that will be developed by the SPCTF;
2. Financial criteria that will be developed by SPP’s Finance Committee; and
3. Managerial criteria that will be developed by the SPCTF demonstrating ability to site, construct, own and operate transmission projects.

The fourth topic for decision by the SPCTF relates to Order 1000’s Changes to SPP’s Membership Agreement and OATT. The SPCTF unanimously recommends that Section 3.3(b) and (c) of SPP’s Membership Agreement be amended to remove the Federal ROFR. Additionally the SPCTF unanimously recommends that Attachment O to SPP’s OATT, referencing SPP’s Transmission Expansion Plan (“STEP”) and Integrated Transmission Plan (“ITP”) processes, be amended to remove the Federal ROFR.

The fifth topic for decision by the SPCTF relates to Order 1000’s Requirement to Determine the Application of Order 1000 to Future SPP Projects. The requirements of Order 1000 are intended to apply to new transmission facilities. Each public utility transmission provider must explain in its regional compliance filing how it will determine which facilities in its local and regional planning processes will be subject to Order 1000. The SPCTF unanimously recommends that Order 1000 requirements would become effective on the date that FERC issues an order accepting SPP’s compliance filing, with the first Transmission Owner qualification process beginning in the summer (June) thereafter. Further, the SPCTF unanimously recommends that the applicability of Order 1000 is to all transmission facilities for which Federal ROFR has been eliminated that are approved for construction in the first STEP Report issued following the first Transmission Owner qualification process, and for all facilities approved thereafter for which Federal ROFR has been eliminated.

The sixth topic for decision by the SPCTF relates to Order 1000’s Requirement to Consider Transmission Needs Driven by Public Policy. Transmission providers are required to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in their local
and regional transmission planning processes or to demonstrate how existing OATT provisions comply. The SPCTF unanimously recommends that SPP’s currently effective OATT generally complies with the requirement through the language in Attachment O that requires consideration of “Renewable energy standards,” (see Attachment O § III.6.k), “Other relevant environmental or government mandates,” (see Attachment O § III.6.n), and “Other input requirements identified during the stakeholder process” (see Attachment O § III.6.o). Further, the SPCTF recommends that the Regional Tariff Working Group (“RTWG”) examine the existing SPP OATT language to determine if any minor revisions might be required to comply with Order 1000.

The seventh and final topic for decision by the SPCTF relates to Order 1000’s Requirement for Information and Data from non-participating Merchant Transmission Developers. Order 1000 requires that public utility transmission providers include in their compliance filings the type of information and data that merchant transmission developers must provide to the regional planning process when the merchant developer does not intend to participate in the planning process or seek to recover costs through the regional cost allocation mechanism(s). The SPCTF unanimously recommends that SPP seek FERC’s approval to require merchant developers provide certain information and data to SPP. Therefore, the SPCTF recommends that the SPP Transmission Working Group (“TWG”) should develop a recommendation of information that merchant transmission developers should be required to provide SPP.
RECOMMENDATION OF THE SPCTF

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.
SECTION I:

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

ORDER 1000 REQUIREMENT: General Requirement to Eliminate Federal ROFR from FERC-jurisdictional Tariffs and Agreements: Public utility transmission providers must remove from their OATTs or other FERC-jurisdictional tariffs and agreements any provisions that grant a federal ROFR for Incumbent transmission providers with respect to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation. 4 [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] 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]

SPCTF Recommendation on Federal ROFR

1.1 Recommendation on the Upgrades for which SPP Should Seek to Retain the Federal ROFR.

After reviewing the requirements of Order 1000 relating to a Federal ROFR and evaluating SPP’s existing methods of assigning construction and ownership responsibilities for allocating costs for transmission upgrades under SPP’s Membership Agreement and OATT, the SPCTF recommends that SPP provide justification for the Federal ROFR as described below:

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4 Order 1000 continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not included in the regional transmission plan for cost allocation. [P. 262]
<table>
<thead>
<tr>
<th>Voltage/Type of Facility/Exclusion</th>
<th>Should SPP Seek to Retain ROFR?</th>
<th>Justification of Maintaining Federal ROFR?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zonal Upgrades: 100 kV &amp; below</td>
<td>Yes</td>
<td><strong>Funded by the Zone:</strong> Under SPP’s Highway/Byway Cost Allocation Methodology ITP projects that are 100 kV and below are funded exclusively by the zone in which they are located. In this manner, they are akin to “local transmission facilities” as defined in Order 1000 and therefore are not subject to the requirement to eliminate Federal ROFR.</td>
</tr>
<tr>
<td>Byway Upgrades: 100 kV – 300 kV</td>
<td>Yes</td>
<td><strong>Multiple Reasons:</strong> (1) 2/3 of these upgrades are funded by zone; (2) SPP is the only RTO in which all load serving entities are vertically integrated, thus there is a close nexus between load and a duty to serve; and (3) the reliability nature of upgrades.</td>
</tr>
<tr>
<td>Highway Upgrades: 300 kV &amp; above</td>
<td>No</td>
<td><strong>Federal ROFR to be Eliminated</strong></td>
</tr>
<tr>
<td>Generation Interconnection Upgrades</td>
<td>Yes</td>
<td><strong>Order 1000 expressly excludes Generation interconnection upgrades:</strong> Order 1000 indicates that “issues related to the generator interconnection process and to interconnection cost recovery are outside the scope of this rulemaking . . . . This Final Rule does not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities.” See Order 1000 at P. 760.</td>
</tr>
<tr>
<td>Sponsored Upgrades</td>
<td>Yes, with modifications as discussed below in § 1.2</td>
<td><strong>Order 1000 appears to exclude SPP’s Sponsored Upgrades:</strong> Sponsored Upgrades do not fall within the definition of “transmission facilities selected in a regional transmission plan for purposes of cost allocation” and therefore, the requirement to eliminate the Federal ROFR does not apply. First, Sponsored Upgrades are not in the STEP for cost allocation, because the costs associated with Sponsored Upgrades are paid by the Project Sponsor. Thus, at the time that a Sponsored Project is included in the STEP, it is not included for purposes of cost allocation. Additionally, Sponsored Upgrades are built at the request of a Project Sponsor; they are not “selected pursuant to a transmission planning region’s Commission-approved regional transmission process for inclusion in a regional transmission plan for purposes of cost allocation because they are more efficient or cost-effective solutions to regional transmission needs.” The Order 1000 Federal ROFR mandate, therefore, should not apply. See Order 1000 at P. 63.</td>
</tr>
<tr>
<td>Transmission Service Upgrades</td>
<td>Yes</td>
<td><strong>Order 1000 appears to exclude Transmission Service Upgrades:</strong> Service Upgrades identified through the SPP Aggregate</td>
</tr>
</tbody>
</table>
Transmission Service Study process do not appear to be subject to the requirement to eliminate the Federal ROFR. While Service Upgrades are included in the STEP, and all or a portion of the costs of some Service Upgrades may be eligible for allocation under SPP’s Base Plan funding (i.e., Service Upgrades associated with a Designated Resource that meet the conditions in Section III.B of Attachment J or have obtained a waiver of the requirements), such upgrades do not appear to fall within the description of “transmission facilities selected in a regional transmission plan for purposes of cost allocation.” See SPP OATT at Attachment O § III.7.a. and Attachment J §§ III.B – III.C.

### FERC limitation on Federal ROFR Removal Requirement:

**Upgrades to Existing Transmission Facilities (Tower Change outs; Reconductoring)**

| Yes |

**Upgrades when state or local laws or regulations limit who can site or be permitted to build transmission facilities**

| Yes |

**Upgrades along existing incumbent Transmission Owner Rights-of-Way**

| Yes |

1.2 **RECOMMENDED ADDITIONS TO SPONSORED UPGRADES**

With respect to Sponsored Upgrades as defined in the SPP OATT, the SPCTF recommends that SPP establish in its OATT three categories of “Sponsored Upgrades” that are funded directly by a SPP stakeholder. These categories are: (1) a Transmission Owner proposes to fund (sponsor) an upgrade on its own system that the Transmission Owner/sponsor will construct, own, and operate; (2) a Transmission

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5 For purpose of clarification, the term “Sponsored Upgrade” in the context herein, is describing SPP’s existing OATT provision that allows a stakeholder to build a transmission upgrade that the stakeholder will fund. This type of upgrade is not to be confused with the “sponsorship model” suggested in Order 1000.
Owner or other stakeholder proposes to fund (sponsor) an upgrade on another Transmission Owner’s system that the sponsor will construct, own, fund, and operate; and (3) a Transmission Owner or other stakeholder proposes to fund (sponsor) an upgrade on facilities not owned by the sponsor, and not construct, own and operate the upgrade. The SPCTF recommends that these categories of upgrades be addressed in SPP’s compliance filing as follows:

<table>
<thead>
<tr>
<th>Category</th>
<th>Summary</th>
<th>Who Builds</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) a Transmission Owner proposes to fund (sponsor) an upgrade on its own system that the proposing sponsor will fund, construct, own, and operate.</td>
<td>This is the same process that is currently in SPP’s OATT. This process has been used by SPP members.</td>
<td>Sponsor Builds.</td>
</tr>
<tr>
<td>(2) a Transmission Owner or other stakeholder proposes to fund (sponsor) an upgrade on another Transmission Owner’s system that the proposing sponsor will fund, construct, own, and operate.</td>
<td>This would be a process in which a stakeholder proposes to fund (sponsor) and construct, own, fund, and operate a new transmission facility on another Transmission Owner’s system.</td>
<td>Sponsor Builds.</td>
</tr>
<tr>
<td>(3) a Transmission Owner or other stakeholder proposes to fund (sponsor) an upgrade on facilities not owned by the sponsor, and not construct, own and operate the upgrade.</td>
<td>This would be a process in which a stakeholder proposes to fund but NOT construct, own, and operate an upgrade on another Transmission Owner’s facilities.</td>
<td>Use existing SPP processes.</td>
</tr>
</tbody>
</table>

The SPCTF notes that these recommended changes do not change the obligations Transmission Owners have to meet other SPP requirements.
Recommendation as to What Model SPP Should Use to Select Transmission Owners for Projects Without a Federal ROFR.

ORDER 1000 REQUIREMENT: General Requirement to Eliminate Federal Rights of First Refusal from FERC-jurisdictional Tariffs and Agreements: Upon the elimination of a federal ROFR, Order 1000 requires that public utility transmission providers provide comparable and nondiscriminatory treatment to incumbent transmission owners and non-incumbent transmission developers in the selection of transmission facilities and identification of developers to build those facilities. Order 1000 suggests at least two options under which this requirement can be met – a sponsorship model and a competitive solicitation model.

Sponsorship Model - In the Notice of Proposed Rulemaking that resulted in Order 1000, FERC expressly proposed that an entity that proposes or “sponsors” a project in the regional planning process would be granted the right to build the project if it is selected in the regional transmission plan. In Order 1000, FERC decided not to adopt its proposal that would give a project sponsor the federal right to construct and own a transmission facility it sponsored in the regional planning process. However, while Order 1000 did not mandate a sponsorship model, neither did it prohibit such an approach to determining which entity will construct a project in the regional transmission plan for purposes of cost allocation. Order 1000 arguably contemplates that an appropriately designed, nondiscriminatory sponsorship model may satisfy the mandate to eliminate federal ROFR and facilitate non-incumbent transmission developer participation in the regional transmission planning process.

Competitive Solicitation Model - Throughout Order 1000, FERC indicated that transmission planning regions may adopt a competitive solicitation process to identify transmission projects and developers to build those projects. While Order 1000 provided very little guidance on the design of a competitive solicitation process for selecting transmission projects and developers, such a process can be developed to comply with Order 1000.

2.1 Background Information on Transmission Owner Selection Model Options

The SPCTF has identified three potential options for Transmission Owner selection, as discussed in more detail below:
(1) **Project Sponsorship Model**: Projects for which Federal ROFR has been eliminated will be assigned to the entity that proposed or “sponsored” the project in the SPP planning process;

(2) **Competitive Solicitation Model**: Each project selected in the SPP planning process for which Federal ROFR has been eliminated will be subject to competitive bidding by qualified entities, with the winner to be selected by SPP on the basis of criteria set forth in the SPP OATT and Business Practices; or

(3) **Other**: SPP and its stakeholders develop a different process for selecting which entity will construct each project selected in the SPP planning process.

(1) **Project Sponsorship Model**

Throughout Order 1000, FERC repeatedly refers to project “sponsors,” suggesting that a nondiscriminatory sponsorship model may satisfy the requirements of Order 1000.

Under a sponsorship model, an entity seeking to construct transmission projects in the SPP planning process would first need to demonstrate its eligibility to participate in the SPP planning process by satisfying a series of qualification criteria set forth in the SPP OATT. [See Section III below.] Order 1000 requires each regional planning process to develop qualification criteria “for determining an entity’s eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a non-incumbent transmission developer.” SPP can tailor the qualification criteria to ensure that only qualified entities are permitted to propose projects and be designated as the designated Transmission Owner if the project is selected in the SPP planning process.

If SPP opts for a sponsorship approach, its process would need to accommodate changes such as if a selected project is modified from its original proposal; two sponsored projects are combined into a single project; or SPP selects a project that does not have a sponsor in the planning process.

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7 See, e.g., Order 1000 at P. 267 (“The Commission recognizes that there may be circumstances when an incumbent transmission provider may be called upon to complete a transmission project that it did not sponsor. . . . There also may be situations in which an incumbent transmission provider has an obligation to build a project that is selected in the regional transmission plan for purposes of cost allocation but has not been sponsored by another transmission developer.”); Id. at P. 332 (“The Commission also requires that a nonincumbent transmission developer must have the same eligibility as an incumbent transmission developer to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation.”)

8 Id. at P. 323.
(2) Competitive Solicitation Model

Order 1000 provided very little guidance on the design of a competitive solicitation process for selecting transmission owners to construct projects. However, SPP could use as a basis for a competitive solicitation model its current process for selecting an alternate entity to build a transmission facility if the designated Transmission Owner is unable or unwilling to construct an assigned transmission facility set forth in Section VI.6 of Attachment O to SPP OATT and SPP Business Practice 7150. Any entity seeking to bid on a project in the SPP planning process would be required to satisfy the qualification criteria required by Order 1000.

(3) Other

The two options identified above are not the only potential options to address the issue of transmission construction and ownership assignment in the SPP planning process. It is possible that SPP and its stakeholders could establish a process that combines elements of the sponsorship and competitive solicitation models or some different process altogether. In any event, whichever option SPP selects will need to provide comparable and nondiscriminatory treatment to incumbent transmission owners and non-incumbent transmission developers.

SPCTF on Order 1000 Recommendation on a Transmission Owner Selection Model

2.2 Recommendation on Transmission Owner Selection Model

The SPTC invited stakeholders to submit potential Transmission Owner selection models to the SPCTF for consideration. After reviewing each proposal and after conducting extensive discussion over the course of several meetings, the SPCTF recommends that SPP use a Competitive Solicitation Process to select Transmission Owners to construct, own, and operate projects that do not have a Federal ROFR.

2.3 Recommended Competitive Solicitation Process to Select Transmission Owners

The SPCTF recommends that SPP propose to FERC a Competitive Solicitation Model to select Transmission Owners to construct, own and operate projects that do not have a Federal ROFR. The SPCTF recommends that SPP use a process similar to the process outlined in the Draft Transmission Owner Selection Process which is attached hereto as “Attachment A”. Additionally, a flow chart of the Competitive Solicitation Process recommended by the SPCTF is attached hereto as “Attachment B”.

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2.4 Recommendation on Development of Detailed Transmission Owner Selection Criteria

The SPCTF recommends the SPCTF develop in detail the evaluation criteria and associated scoring needed to evaluate/compare Qualified Transmission Owners ("QTOs") that are competing to build transmission projects within SPP’s footprint. The general process, criteria and scoring is found in Attachment A and B which the SPCTF recommends be further vetted and developed by the SPCTF by June 2012.

2.5 Majority/Minority Position

Proponents of the Competitive Solicitation Process, while acknowledging some weaknesses, believe the proposal: preserves the current ITP process recently approved by FERC maintaining the open, transparent and collaborative planning process; keeps the “need” component separated from the “construction” component thereby facilitating that the most cost-effective solutions are built; establishes only one competitive process for SPP staff to manage; and, has the least amount of Tariff work of all the options considered by the Task Force.

Opponents believe that the Competitive Solicitation approach is complex and potentially creates unintended drivers; relies on SPP planning staff and incumbent transmission owner for ideas and solutions to problems consequently not incenting stakeholders solutions and providing an unfair advantage for incumbents; imposes construction bidding expertise on SPP staff and processes contributing to increased SPP staffing and to delays in construction; and is incompatible with current NTC-C process.

For the comprehensive comparisons, see the following link: http://www.spp.org/publications/SPCTFOrder1000-030812.pdf.
SECTION III:

Recommendation as to Transmission Owner Qualification Criteria

ORDER 1000 REQUIREMENT: Transmission Owner Qualification Criteria: Order 1000 requires each public utility transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity’s eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a non-incumbent transmission developer. These criteria must not be unduly discriminatory or preferential. [P. 323] The qualification criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate and maintain transmission facilities. [P. 323] Within these general parameters, FERC leaves it to each region to develop qualification criteria that are workable for the region, including procedures for timely notifying transmission developers of whether they satisfy the region’s qualification criteria and opportunities to mitigate any deficiencies. [P. 324]

SPCTF on Order 1000 Recommendation on Transmission Owner Qualifications

3.1 Recommended Transmission Owner Qualification Criteria

The SPCTF recommends that SPP’s compliance filing for Order 1000 contain Transmission Owner qualification criteria that must be met before a potential transmission owner can participate in SPP’s Competitive Solicitation Process described in Sections 2.2 and 2.3 above. The Transmission Owner qualification criteria would apply only to those entities seeking to construct, own, and operate transmission projects that are subject to the SPP Competitive Solicitation Process. The general basis upon which the SPCTF make its recommendation for Transmission Owner qualification

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9 The qualification criteria should allow for the possibility that an existing public utility transmission provider already satisfies the criteria and should allow any transmission developer the opportunity to remedy any deficiency. [P. 324]

10 The criteria are intended to apply only to entities that propose transmission projects and intend to develop the proposed transmission project if selected. Stakeholders that do not intend to develop transmission projects may continue to propose transmission projects for consideration in the regional transmission plan without being required to demonstrate compliance with the criteria. [n.304]

11 Nothing in the qualifications criteria requirement of Order 1000 is intended to change any existing RTO procedure or practice regarding the operation of existing transmission facilities. [n.303]
criteria is the existing process outlined in Attachment O § VI.6 of the SPP OATT. These are:

(1) **Threshold eligibility criteria:** The recommended threshold eligibility criteria would include, at a minimum, some level of proof by an Applicant Transmission Owner (“ATO”) that the ATO has the legal authority under state law to construct facilities within a state in which a project will be built and some level of assurance that the ATO is or will be a member of SPP.

The SPCTF recommends that the SPCTF develop the threshold criteria by June 30, 2012.

(2) **Financial criteria:** The recommended financial eligibility criteria would include certain creditworthiness requirements.

The SPCTF recommends that the SPP Finance Committee develop the financial eligibility criteria by June 30, 2012.

(3) **Managerial criteria:** The recommended managerial eligibility criteria would require an ATO to demonstrate certain managerial expertise.

The SPCTF recommends that the SPCTF develop the managerial expertise criteria by June 30, 2012.

3.2 **Recommended Process for Incumbent/Non-incumbent Transmission Developers to Submit the Information Necessary for SPP to Evaluate Whether They Satisfy the Transmission Owner Qualification Criteria.**

The SPCTF recommends the following process under which incumbent/non-incumbent transmission developers must submit the information necessary for SPP to evaluate whether they satisfy the qualification criteria discussed in Section 3.1 above.

1) **Application to become a Qualified Transmission Owner:** Prior to being eligible to participate in SPP’s Competitive Solicitation Process stated in Sections 2.2 and 2.3 above, an ATO must submit an Application to SPP demonstrating satisfaction of the Transmission Owner qualification criteria to be designated as a QTO.

The Application can be submitted at any time, but must be submitted by at least June 30th of the year prior to the year in which the developer plans to participate in SPP’s Competitive Solicitation process for one or more projects.

2) **Application Review by SPP:** Upon receiving an Application to become a QTO, SPP will review the Application to determine whether it satisfies the Transmission Owner qualification criteria and inform the ATO of its determination. SPP must notify each
ATO of its determination no later than September 30th of the year prior to the year in which the ATO desires to participate in SPP’s Competitive Solicitation Process.

3) Notification of Qualification Deficiency(ies): If SPP determines that the ATO fails to meet one or more of the qualification criteria, SPP will inform the ATO of such deficiency(ies) and the ATO will have 30 days to cure the deficiency(ies). Once SPP receives information from the ATO that the ATO believes cures each deficiency, SPP will inform the ATO within 45 days whether the deficiency(ies) have been cured. SPP will post the list of all QTOs by December 31 of each year for the Competitive Solicitation Process that will occur the following spring after approval of the STEP.

4) Notification of Qualification: Once SPP determines that an ATO satisfies the qualification criteria, the ATO will be deemed a QTO to participate in SPP’s Competitive Solicitation Process as described in Sections 2.2 and 2.3 above. Additionally, once qualified, the QTO will not be required to demonstrate its qualifications in any subsequent SPP planning process cycles or with respect to any subsequent SPP Competitive Solicitation Processes unless the QTO experiences a change in circumstances as discussed below.

5) Changes in Transmission Developer Application: All QTOs will be required to inform SPP if, at any time, there is any change to the information provided in their application, so that SPP may determine whether the QTO continues to satisfy the Transmission Owner qualification criteria. Upon notification of any such change, SPP will have the option to:

(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.
SECTION IV: Changes to SPP’s Membership Agreement and OATT.

Recommended Changes to SPP’s Membership Agreement and OATT to Remove the Federal ROFR

ORDER 1000 REQUIREMENT: General Requirement to Eliminate Rights of First Refusal from FERC-jurisdictional Tariffs and Agreements: Public utility transmission providers must remove from their OATTs or other FERC-jurisdictional tariffs and agreements any provisions that grant a federal ROFR to incumbent transmission providers for transmission facilities that are selected in a regional transmission plan for purposes of cost allocation.\(^{12}\) [P. 313]

SPCTF Recommendation on Changes to SPP’s Membership Agreement and OATT

4.1 Recommended Change to SPP’s Membership Agreement

The SPCTF recommends that the following sections of SPP’s Membership Agreement be amended to remove the Federal ROFR, as stated below.

Section 3.3 of the SPP Membership Agreement, which governs construction of transmission facilities in SPP, contains Federal ROFR language that will need to be modified to comply with Order 1000. Specifically, Section 3.3(b) of the SPP Membership Agreement indicates:

After a new transmission project has received the required approvals and been approved by SPP, \textit{SPP will direct the appropriate Transmission Owner(s)} to begin implementation of the project. If the project forms a connection between the facilities of a single Transmission Owner, \textit{that Transmission Owner will be designated} to provide the new facilities. If the project forms a connection between facilities owned by multiple parties, \textit{all parties will be designated} to provide the respective new facilities. The parties will agree among themselves as to how much of the project will be provided by each entity. If agreement cannot be reached, SPP will facilitate the ownership determination process.

\(^{12}\) Order 1000 continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not included in the regional transmission plan or submitted for regional cost allocation. [P. 262]
Thus, under the language of Section 3.3(b), SPP is obligated to designate an incumbent Transmission Owner to construct new transmission facilities (i.e., the owner of existing facilities to which the new facility will connect).

Furthermore, Section 3.3(c) of the SPP Membership Agreement states:

A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place. If the designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

This language provides an option for the designated Transmission Owner to assign the project to another entity or to decline to “implement the project” (i.e., “refuse” to build the project).

When read together, Sections 3.3(b) and 3.3(c) provide incumbent Transmission Owners a Federal ROFR over transmission projects approved for construction by SPP. SPP is required to assign the construction obligations for new transmission facilities to incumbent Transmission Owners that own the existing facilities to which a new transmission facility will interconnect. Once a new transmission facility is assigned, the designated Transmission Owner(s) have the option either to construct the project, assign the project to another entity, or decline to construct the project. As a result, the SPCTF recommends that SPP modify these sections to comply with Order 1000 in a manner that is consistent with this Report.

The SPCTF will provide language to the Corporate Governance Committee (“CGC”) by April 30, 2012.

4.2 Recommended Change to SPP’s OATT

The SPCTF recommends that the following sections of SPP’s OATT be amended to remove the Federal ROFR as stated below.

A. SPP OATT, Attachment O

SPP’s STEP and ITP processes set forth in Attachment O of the SPP OATT contain similar provisions to the Membership Agreement related to assignment of construction obligations and Federal ROFR. Specifically, Section VI of Attachment O, which governs the construction of transmission facilities, contains several provisions that address the manner in which SPP assigns the responsibility to construct transmission facilities in the STEP:
Section VI(1): The Transmission Provider, with input from the Transmission Owners and other stakeholders, shall designate in a timely manner within the SPP Transmission Expansion Plan (“STEP”) one or more Transmission Owners to construct, own, and/or finance each project in the plan.

Section VI(4): After a new transmission project is (i) approved under the SPP Transmission Expansion Plan or (ii) required pursuant to a Service Agreement or (iii) required by a generation interconnection agreement to be constructed by a Transmission Owner(s) other than the Transmission Owner that is a party to the generation interconnection agreement, the Transmission Provider shall direct the appropriate Transmission Owner(s) to begin implementation of the project for which financial commitment is required prior to the approval of the next update of the SPP Transmission Expansion Plan. . . . If the project forms a connection with facilities of a single Transmission Owner, that Transmission Owner shall be designated to construct the project. If the project forms a connection with facilities owned by multiple Transmission Owners, the applicable Transmission Owners will be designated to provide their respective new facilities. If there is more than one Transmission Owner designated to construct a project, the Designated Transmission Owners will agree among themselves which part of the project will be provided by each entity. If the Designated Transmission Owners cannot come to a mutual agreement regarding the assignment and ownership of the project the Transmission Provider will facilitate their discussion. . .

Like Section 3.3(b) of the SPP Membership Agreement, Section VI of Attachment O requires SPP to assign construction and ownership responsibilities for transmission facilities to the incumbent Transmission Owner(s) to whose existing facilities a new transmission facility will interconnect.

Section VI of Attachment O also contains language permitting the designated Transmission Owner to assign its construction responsibilities to another entity or to decline to construct a transmission facility. Specifically, Section VI(6) indicates:

In order to maintain its right to construct the project, the Designated Transmission Owner shall respond within ninety (90) days after the receipt of the Notification to Construct with a written commitment to construct the project as specified in the Notification to Construct or a proposal for a different project schedule and/or alternative specifications in its written commitment to construct (“Designated Transmission Owner’s proposal”). . . . If a Designated
Transmission Owner does not provide an acceptable written commitment to construct within the ninety (90) day period, the Transmission Provider shall solicit and evaluate proposals for the project from other entities and select a replacement designated provider. (emphasis added)

Therefore, by not providing “an acceptable written commitment to construct,” a designated Transmission Owner (i.e., the incumbent Transmission Owner(s) that own(s) facilities to which the new transmission facility will connect) has the option of declining to construct a facility. Read together, these provisions of Section VI of Attachment O to the SPP OATT create a Federal ROFR for incumbent Transmission Owners. As a result, the SPCTF recommends that SPP modify these sections to comply with Order 1000 in a manner that is consistent with this Report.

The SPCTF recommends that the RTWG draft the specific language for approval by the SPP Board of Directors during SPP’s current meeting cycle by June 30, 2012.
SECTION V: Application of Order 1000 to Future SPP Projects

ORDER 1000 REQUIREMENT: Determination as to Which Facilities Will Be Subject to Order 1000 Requirements: The requirements of Order 1000 are intended to apply to new transmission facilities, which are facilities that are no longer subject to evaluation or reevaluation in the transmission planning process after the effective date of the public utility transmission provider’s regional compliance filing. [PP. 65, 162] Each public utility transmission provider must explain in its regional compliance filing how it will determine which facilities in its local and regional planning processes will be subject to the Order 1000 requirements. [PP. 65, 162]

SPCTF on Order 1000 Recommendation as to the applicability of Order 1000.

5.1 Recommendation as to Which Facilities Will Be Subject to Order 1000 Requirements

The SPCTF recommends that SPP propose that the effective date of its Order 1000 compliance filing be the date FERC issues an order accepting the compliance filing, with the first developer qualification process beginning in the summer (June) thereafter. The SPCTF therefore recommends that the requirements of Order 1000 apply to all transmission facilities subject to Federal ROFR elimination that are approved for construction in the first STEP Report that is issued following the first developer qualification process, and for all facilities approved thereafter for which Federal ROFR has been eliminated.
SECTION VI: Consideration of Transmission Needs Driven by Public Policy

ORDER 1000 REQUIREMENT: Consideration of Transmission Needs Driven by Public Policy: Under Order 1000, public utility transmission providers are required to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in their local\(^{13}\) and regional transmission planning processes or to demonstrate how existing OATT provisions already comply. [P 203, 222] Public policy requirements include, at a minimum, needs driven by state or federal laws or regulations;\(^{14}\) however, the public utility transmission providers in a region can agree to consider needs driven by additional public policy objectives not specifically required by state or federal laws or regulations.\(^{15}\) [P. 214-216]

SPCTF on Order 1000 Recommendation on Consideration of Public Policy

6.1 Background Information on Order 1000 “Public Policy” Requirements

FERC’s requirement that public utility transmission providers consider transmission needs driven by public policy requirements means:

1. **The identification of transmission needs driven by public policy requirements**: Public utility transmission providers must establish, in consultation with stakeholders, procedures under which public utility transmission providers and stakeholders\(^{16}\) will identify those transmission needs driven by public policy requirements for which potential transmission solutions will be evaluated. [PP. 205-206]; and

2. **The evaluation of potential solutions to meet those needs**: Public utility transmission providers are required to amend their OATTs to describe the procedures by which transmission needs driven by public policy requirements will be identified in the local and regional transmission

\(^{13}\) To the extent public utility transmission providers within a region do not engage in local transmission planning, such as in some RTO regions, the public policy requirements of Order 1000 apply only to the regional transmission planning process. [n.185]

\(^{14}\) “State or federal laws or regulations” mean enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level. [P. 2]

\(^{15}\) For example, a public utility transmission provider and its stakeholders are not precluded from choosing to plan for state public policy goals that have not yet been codified into state law, which they nonetheless consider to be important long-term planning considerations. [n.193]

\(^{16}\) All stakeholders must have an opportunity to provide input and offer proposals regarding the transmission needs they believe should be identified. [P. 209]
planning processes and how potential solutions to the identified transmission needs will be evaluated in the local and regional transmission planning processes.\textsuperscript{17} [PP. 205, 211]

Public utility transmission providers are required to post on their websites an explanation of which transmission needs driven by public policy requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated. [P. 209]

Order 1000 also clarifies that the allocation of costs associated with transmission facilities associated with public policy requirements must be at least roughly commensurate with estimated benefits, meaning that those that receive no benefit, either at present or in a likely future scenario, must not be involuntarily allocated costs of the facility. [P. 219] Additionally, Order 1000 permits, but does not require, the creation of a separate class of public policy transmission facilities and separate cost allocation for such facilities. [P. 220]

6.2 Current SPP OATT Relating to Public Policies

Currently, the SPP OATT contains requirements relating to the consideration of public policy in SPP’s planning process. These requirements are contained in Attachment O to the SPP OATT as cited below:

Sections III.6.k, n & o of Attachment O to the SPP OATT states:

\textbf{III. The Integrated Transmission Planning Process}

The ITP process is an iterative three-year process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies the transmission projects, generally above 300 kV, and provides a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet the system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses the system upgrades, at all applicable voltage levels, required in the near term planning horizon.

* * * * *

\textsuperscript{17} Order 1000 leaves it to public utility transmission providers and their stakeholders to determine the procedures for evaluating potential transmission solutions to address identified public policy needs. The evaluation must include, at a minimum, proposals by stakeholders for transmission facilities proposed to satisfy an identified transmission need driven by public policy requirements. [P. 211]
6) Policy, Reliability, and Economic Input Requirements to Planning Studies

The Transmission Provider shall incorporate, as appropriate for the assessment being performed, the following into its planning studies:

* * * * *

k) Renewable energy standards;

* * * * *

n) Other relevant environmental or government mandates; and

o) Other input requirements identified during the stakeholder process.

6.3 Recommendation as to How SPP Should Handle Public Policy under Order 1000.

The SPCTF recommends that SPP rely primarily on its existing OATT language regarding transmission needs driven by public policy requirements as discussed above. Rather than revising the OATT to provide explicitly for the consideration of transmission needs driven by public policy goals, the SPCTF recommends that SPP remain open to considering public policy goals through the language in Attachment O that allows for “Other input requirements identified during the stakeholder process” (see Attachment O § III.6.o).

The SPCTF recommends that the RTWG, in consultation with the TWG and the Economic Studies Working Group (“ESWG”), examine the existing OATT language to determine if any minor revisions are required to ensure that SPP complies with the requirements in paragraphs 205-211 of Order 1000 to establish procedures to: (1) identify transmission needs driven by public policy; (2) identify potential solutions to meet those needs; and (3) post information on the SPP website relating to public policy transmission planning.

The SPCTF recommends that the RTWG draft any specific OATT language needed to comply with the public policy provisions of Order 1000 by June 30, 2012.
SECTION VII: Information and Data from Merchant Transmission Developers

ORDER 1000 REQUIREMENT: Information and Data from Merchant Transmission Developers: Order 1000 requires that public utility transmission providers include in their compliance filings the type of information and data that merchant transmission developers must provide to the regional planning process when the merchant developer does not intend to participate in the planning process or seek to recover costs through the regional cost allocation mechanism(s). [P. 164] The purpose of this requirement is to provide transmission providers in the regional planning process with adequate information and data to assess the potential reliability and operational impacts of the merchant transmission developer’s proposed transmission facilities on other systems in the region.

SPCTF Recommendation on Merchant Developer Information and Data

7.1 Recommended Information and Data that Merchant Transmission Developers that Do Not Participate in SPP Planning and Cost Allocation Should Be Required to Provide to SPP.

The SPCTF recommends that SPP seek FERC’s approval to require that merchant developers provide certain information and data to SPP. While Order 1000 does not expressly define "merchant developers", the Order states that merchant facilities are facilities that are not subject to the evaluation and selection processes that apply to transmission facilities for which regional cost allocation is sought and that merchant transmission developers assume all financial risk for developing and constructing the transmission project. [PP. 163-165] The SPCTF recommends that SPP consider any transmission facility within and/or interconnecting to the SPP Region that the builder does not intend to place under SPP’s control under the SPP OATT to be "merchant facilities" for the purposes of the information and data requirements. While the language of Order 1000 could be read to include Sponsored Upgrades as defined in the SPP OATT (i.e., sponsor assumes financial risk and is not part of the evaluation process), because “Sponsored Upgrades” will be placed under SPP’s control under the SPP OATT, the SPCTF recommends that entities proposing to construct "Sponsored Upgrades" as defined in the SPP OATT will be subject to all of the requirements applicable to other Transmission Owners participating in the SPP transmission planning process. The SPCTF recommends that SPP’s TWG review existing SPP practices and policies in order to recommend the specific information and data SPP should require merchant transmission developers to provide to SPP.

Further, the SPCTF recommends that the TWG provide their recommendation to the Markets and Operations Policy Committee by June 30, 2012.
SECTION VIII: Timeline for Compliance Filing

ORDER 1000 REQUIREMENT: Deadline to File Regional Compliance Filing: Compliance filings addressing the Order 1000 regional transmission planning and cost allocation requirements must be submitted to FERC by October 11, 2012.

SPCTF Recommendation on Compliance Filing Timeline

8.1 Recommended Compliance Filing Timeline for SPP.

The SPCTF recommends that the SPP Board of Directors direct SPP to seek a sixty (60) day extension from FERC for SPP to make its regional compliance filing under Order 1000. This will enable SPP to use its October 30, 2012 quarterly BOD meeting to finalize SPP’s compliance filing for Order 1000’s regional requirements.

The SPCTF recommends that the following timeline\textsuperscript{18} be used by SPP stakeholders to meet the FERC compliance filing deadline for the regional requirements of Order 1000:

<table>
<thead>
<tr>
<th>SPCTF Report Implementation Requirement</th>
<th>Responsible Stakeholder Group(s)</th>
<th>Deadline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Endorsement of SPCTF on Order 1000 Report</td>
<td>SPC &amp; BOD</td>
<td>April 2012</td>
</tr>
<tr>
<td>Development of Transmission Owner Selection Criteria for a Competitive Solicitation Process (See §§ 2.3 &amp; 2.4)</td>
<td>SPCTF</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td>Development of Transmission Owner Qualification Criteria &amp; TO Managerial Experience Criteria (See §§ 3.1 &amp; 3.2)</td>
<td>SPCTF</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td>Development of Transmission Owner Creditworthiness Criteria (See § 3.1)</td>
<td>Finance Committee</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td>Drafting &amp; Approval of Language to Remove</td>
<td>SPCTF, CGC</td>
<td>SPCTF – April 30, 2012</td>
</tr>
</tbody>
</table>

\textsuperscript{18} The SPCTF makes this recommended timeline without considering SPP’s request for an extension of time to make SPP’s regional compliance filing on Order 1000 at FERC. This recommendation will change if such an extension is granted.
<table>
<thead>
<tr>
<th></th>
<th>Activity Description</th>
<th>Participants</th>
<th>Dates</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>Drafting &amp; Approval of Language to Remove ROFR in OATT</td>
<td>RTWG, MOPC, &amp; SPP BOD</td>
<td>RTWG – June 30, 2012 MOPC &amp; BOD - July 2012</td>
</tr>
<tr>
<td>7</td>
<td>Review and Drafting of Recommended Language on Public Policy Requirements of Order 1000</td>
<td>RTWG, MOPC, &amp; SPP BOD</td>
<td>RTWG – June 30, 2012 MOPC &amp; BOD - July 2012</td>
</tr>
<tr>
<td>8</td>
<td>Review and Draft Information and Data SPP Will Propose to Require Merchant Transmission Developers to Provide to SPP</td>
<td>TWG</td>
<td>June 30, 2012</td>
</tr>
<tr>
<td>9</td>
<td>Drafting and Endorsement/Approval of Tariff Language for SPP’s Order 1000 Regional Compliance Filing</td>
<td>RTWG</td>
<td>RTWG – August 31, 2012</td>
</tr>
<tr>
<td>10</td>
<td>Review and Approval of RTWG’s Language for SPP’s Order 1000 Regional Compliance Filing</td>
<td>MOPC &amp; BOD</td>
<td>September 31, 2012</td>
</tr>
<tr>
<td>11</td>
<td>Parallel Work of Drafting SPP’s Order 1000 Compliance Filing Letter for Regional Requirements</td>
<td>SPP Staff</td>
<td>October 11, 2012</td>
</tr>
</tbody>
</table>
ATTACHMENT A

DRAFT TRANSMISSION OWNER SELECTION PROCESS
Competitive Solicitation Process

- **Policy, Reliability and Economic Inputs (Section III.6)**
- **Study Scope Including Policy, Reliability & Econ Inputs, and TSR and GI upgrades (Attach O III.7)**
- **Spring Planning Forums**
- **Analyse Alternatives**
  - (incl. zonal upgrades)
  - Broader Regional Upgrades and non-wire upgrades (Attach. O III.8)
- **ITP Studies (20/10 and Near Term) and other Studies Endorsed by Stakeholder Working Groups**
- **ITP Upgrades Approved or Endorsed by SPP BOD**
- **Fall Planning Forum**
  - Present potential Solutions to stakeholders
- **Annual SPP Transmission Expansion Plan (Section V)**

Integrated Transmission Planning Process

(Does not include upgrades related to TSRs, GI, or Sponsored Upgrades)

- **Incumbent TO builds**
- **Does ROFR Apply?**
  - **Yes**
  - **No**

Note: * ROFR applies to any project that is either
  1. < 300 kV,
  2. an upgrade to an existing facility,
  3. Or an addition or expansion of an existing facility which is on existing right-of-way.

4/3/2012
Transmission Owner Selection Process

1. SPP develops RFP (45 days)
2. Did SPP receive any responses?
   - Yes
     - TOs develop Proposal and cost estimate (+/- 20%) (60 days)
   - No
     - SPP issues RFP to TOs that responded to RFI and qualified. If only one TO responds then a shorter procedure may be used.
     - Incumbent TO builds (builder of last resort)

3. SPP issues RFI [Develop list of Interested TOs] (30 days)
4. SPP reviews Responses (15 days)
   - Yes
     - SPP issues RFP to TOs that responded to RFI and qualified. If only one TO responds then a shorter procedure may be used.
     - Incumbent TO builds (builder of last resort)
   - No
     - TOs develop Proposal and cost estimate (+/- 20%) (60 days)

5. Incumbent TO builds (builder of last resort)
6. Recommendation goes to SPP BOD

7. Revise Project Specifications?
   - Yes
     - SPP issues RFP to TOs that responded to RFI and qualified. If only one TO responds then a shorter procedure may be used.
     - Incumbent TO builds (builder of last resort)
   - No
     - SPP BOD selects TO?
       - Yes
         - NTC issued to TO
       - No
         - Project is re-evaluated

8. Project is re-evaluated
   - Yes
     - NTC issued to TO
   - No
     - Project is cancelled

4/3/2012
ATTACHMENT B

COMPETITIVE SOLICITATION PROCESS FLOWCHART
Attachment B – Competitive Solicitation Process Flowchart

BOD approves applicable transmission projects for construction as a result of the regional planning process

The Oversight Committee shall designate an IEP (15 Days)

SPP staff develops and issues an RFP. (30 days)

QEs respond to RFP (60-75 days)

SPP staff reviews RFP responses and provides the responses to the IEP for evaluation

IEP Evaluates RFPs and makes recommendation to the OC (30-60 days)

OC reviews IEP recommendation and makes recommendation to the BOD (15 Days)

BOD selects Transmission Developers (15 Days)

Selected QE does not sign agreements

SPP Contacts STO

No QE- Obligation to Construct remains with DTO

Selected QE executes agreements to become the DTO (10 Days)
SSC Order 1000 Activities

- SSC tasked with ensuring compliance on the interregional transmission planning requirements of Order 1000
- SSC chartered the Seams FERC Order 1000 Task Force (SFOTF)
  - Develop Order 1000 interregional planning concepts and work with staff on JOA language
  - Includes a member from the ESWG and TWG
- Developed concepts to be incorporated into SPP’s JOAs
SSC Order 1000 Interregional Planning Concepts

- Developed and reviewed by SPP stakeholders
- Received comments from MISO staff
- Joint Meeting April 12 with SPP stakeholders and neighboring entities
  - Presented concepts to stakeholders from multiple regions
  - MISO presented their concepts
- Concepts document available on SFOTF section of SPP website

Next Steps

- Work on JOA language started after April 12 meeting
- Additional joint coordination meetings
- Plan to present the MOPC with draft JOA language in October
  - Request MOPC comment and suggestions
- Final language is planned to be presented in January 2013
Seams Cost Allocation:
A Flexible Framework to Support Interregional Transmission Planning

April 2012

Johannes P. Pfeifenberger
Delphine Hou

Prepared for

Regional State Committee
EXECUTIVE SUMMARY

The Brattle Group was engaged by the Southwest Power Pool (“SPP”) Regional State Committee (“RSC”) to develop a general approach to seams cost allocation so that SPP could utilize a consistent set of principles and guidelines to assess the needs, benefits, and cost allocation of transmission projects at each of its seams with its diverse set of neighbors.

Seams cost allocation is especially challenging given the number of barriers related to the planning and analysis of interregional transmission projects. Planning-related challenges often start with limited staff resources to evaluate and consider seams projects, which can be exacerbated by a lack of sufficiently-detailed and current multi-region planning data and models to conduct joint system analyses. Uncertainty as to how or when neighboring systems will evaluate and consider seams projects as part of their regular planning processes can cause significant delays in the development of seams project. Also a “gap” between top-down and bottom-up planning studies can lead to an inability to identify beneficial seams projects. Qualification criteria for a seams project often differ between neighbors, and transmission benefits and metrics are not articulated with enough detail to allow for cost allocation based on identified benefits to each entity. Moreover, individual seams projects may offer a very different mix of benefits (e.g., reliability, market efficiency, and public policy) to each of the neighboring regions and its transmission owners, which complicates cost allocation efforts. Finally, the lack of sufficiently detailed, actionable but flexible cost allocation principles and guidelines creates yet another major barrier to the planning and cost allocation of seams projects. This barrier is magnified if cost allocation is not aligned with ownership interests and transmission rights.

Regional planning entities have been pursuing various efforts to address these barriers. SPP, for example, in collaboration with the SPP RSC, developed a draft whitepaper on seams cost allocation principles and has addressed interregional planning in joint operating agreements (“JOAs”) with several seams neighbors. The Federal Energy Regulatory Commission (“FERC”) recently released Order 1000, requiring regional transmission planning entities under its jurisdiction to develop interregional cost allocation methodologies based on FERC-approved principles.

As part of our engagement to develop a general approach to seams cost allocation, we collaborated with SPP and SPP RSC staff to pursue five major tasks: 1) review SPP’s draft whitepaper; 2) evaluate cost allocation frameworks used elsewhere; 3) develop a general framework for the cost allocation of seams projects; 4) test the framework with case studies of seams projects; and 5) draft and present a final report with our recommendations and proposed framework to the SPP RSC. A “Joint Project Team” was formed with key RSC- and SPP-assigned staff to facilitate project flow and coordination.
We provide in this report comments on SPP’s draft whitepaper and a review of seams cost allocation efforts in other markets to identify successful practices that may be considered by SPP and its seams neighbors. This survey of cost allocation approaches spanned both RTO and non-RTO regions in the U.S. and Europe and focused on cost allocation principles, seams planning, and benefit metrics as applied to a variety of seams project types to address reliability, market efficiency, and public policy objectives.

The framework we developed is based on clearly-identified cost allocation principles and a comprehensive set of benefit metrics, while also allowing for the flexibility needed to consider a wide range of different projects types and seams entities. Our review of relevant experience from other markets also strongly suggests that seams cost allocation needs to be designed as an integral part of the interregional planning process. In this context, SPP’s existing JOAs with neighboring transmission entities serve as the logical starting point for developing a more comprehensive and actionable interregional planning and cost allocation framework.

We identified seven “building blocks” needed to support interregional planning and cost allocation as shown in Figure 1 below. The first two building blocks already exist in SPP’s JOAs but would need to be expanded to incorporate best practices. For example, with regard to building block No. 1, the JOAs already require a commitment to *regular interregional planning meetings* of the seams entities as well as coordination with state, federal, and multi-state entities. We recommend, however, more direct participation of regulatory commission staff from states affected by the particular seam in the planning and cost allocation discussions under the JOAs. Such involvement by state regulatory staff in the evaluation of proposed seams projects would likely facilitate the development of seams projects and cost allocations that will be acceptable to each of the involved state commissions in the permitting and (where applicable) retail rate recovery of the selected projects. In addition, while the JOAs may specify bilateral meetings between entities, they should be flexible enough to *allow for participation by multiple seams entities* if doing so can more effectively address challenges along seams between multiple transmission planning entities.

Building block No. 2 requires the timely *exchange of planning data* (as is already provided for in the JOAs). In addition, to facilitate planning of seams projects, we recommend that seams neighbors develop jointly-validated and endorsed load-flow cases and planning models for the combined footprint and planning horizon. This would allow each seams entity to accurately analyze the system of its neighbor to prepare credible initial cost-benefit evaluations of potential seams projects.

The third through sixth building blocks are most directly related to seams cost allocation. They are also largely missing from or underspecified in the existing JOAs. Building block No. 3
serves to define the parameters of a seams project and requires the specification of a **process to propose and analyze seams projects**. The JOAs currently largely rely on the Joint Coordinated System Plan (“JCSP”) process to identify seams projects. We propose to establish additional options under which seams entities could unilaterally or jointly propose seams projects outside the JCSP process. SPP will also need to specify how their transmission owners and other market participants can propose seams projects to SPP.

**Figure 1**

**Building Blocks of Proposed Interregional Planning and Cost Allocation Framework**

1. Regular interregional planning meetings
2. Regular exchange of planning data
3. Process to propose and analyze seams projects
4. Evaluation criteria and benefit metrics
5. Seams cost allocation principles and guidelines
6. Payment mechanisms and transmission rights
7. Integration with internal planning and cost allocation

**Optional**: Pre-specified formulaic evaluation and cost allocation methodology

Building block No. 4 requires each seams entity to specify the **evaluation criteria and benefit metrics** that they will use for seams project evaluation. These criteria and metrics would not need to be identical across seams entities but would, *at a minimum*, need to include *all* the benefits and metrics each entity uses in its internal transmission planning process. In addition, we recommend the consideration of additional benefits and metrics, including some that are
unique to seams projects, such as increases in wheeling through and out revenues that can offset a portion of project costs.

Building block No. 5 consists of pre-specified **seams cost allocation principles and guidelines**. Rather than resolve seams cost allocation on a case-by-case approach (as is provided for under the current JOAs), we recommend the inclusion of agreed-upon principles and guidelines to serve as the overarching framework for developing transmission cost allocation for seams projects. We specify a number of recommended principles and guidelines and provide case studies of how cost allocation shares might be derived for specific types of projects, consistent with the evaluation criteria and benefit metrics outlined in building block No. 4.

Building block No. 6 specifies **payment mechanisms** that allow for the actual sharing of project costs across the seam. Given the different characteristics of seams projects and limitations that certain entities may have in paying for transmission upgrades they do not own, we propose that seams agreements specify several options for payment mechanisms—such as shared ownership and financial transfers—that can be used to implement the agreed-upon cost allocations. We additionally recommend that physical or financial **transmission rights** are provided to each seams entity in exchange for their seams-related payments or investments.

Building block No. 7 addresses the **integration of the interregional planning and seams cost allocation with each entity’s internal planning and cost allocation processes**. This includes adding to the JOAs specific provisions that address who can propose a seams project, who can build and operate it, how planning analyses for seams projects are initiated, and how seams projects are integrated with internal planning processes and cost recovery, including planning in response to generation interconnection and transmission service requests, which can impact the overall benefits of seams projects.

Finally, we recommend that an optional building block allow for the inclusion of **pre-specified formulaic evaluation and cost allocation methodologies for specific project types**. Several seams cost allocation methodologies in other markets include such pre-specified formulaic approaches, such as those for interregional reliability and economic projects between the MISO and PJM. However, while such formulaic approaches can greatly streamline the evaluation and cost allocation of seams projects, many seams projects will not “fit” the pre-specified qualifications criteria. We thus recommend that seams projects that do not fit such pre-specified options still be evaluated under the general cost allocation framework as summarized above.

Stakeholders suggested five candidate seams projects that could be used as “test cases” for our proposed approach. We have developed case studies for three of these projects to illustrate the application of our proposed framework. We also developed “straw man” tariff language.
(provided in Appendix C) to illustrate how the proposed framework might be implemented in the context of the existing JOAs.

SPP staff is actively working towards the Order 1000 compliance deadline, which is April 11, 2013 for interregional planning and cost allocation. We believe it is imperative that there be significant coordination between SPP and the RSC and hope that SPP and the RSC will be able to build on our proposed framework, including the straw man JOA language provided in Appendix C, to fully develop a robust interregional planning and cost allocation methodology that can be implemented through SPP’s ongoing coordination efforts with its neighbors. We hope that this report can be used as the basis for this coordinated work to meet the Order 1000 mandate.
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APPENDICES

Appendix A: SPP RSC Draft Cost Allocation Principles for Seams Transmission Expansion Projects (Draft Seams Cost Allocation Whitepaper)

Appendix B: Key Documents on Interregional Cost Allocation and Seams Issues Outside of SPP
   1. PJM-MISO Seams Cost Allocation for Reliability and Market Efficiency Projects
   2. Northern Tier Cost Allocation Process and Principles
   4. ISO-NE, NYISO, and PJM’s Northeastern ISO/RTO Planning Coordination Protocol
   5. UMTDI Cost Allocation Principles
   6. NESCOE Draft Framework for Public Policy Projects and Associated Cost Allocation
   7. Seams Cost Allocation for Michigan PARs to Address Lake Erie Loop Flows
   8. European ITC Mechanism for Seams Cost Allocation
   9. Europe-Wide Transmission System Planning

Appendix C: Possible Additions to Interregional Planning and Cost allocation Provisions in SPP’s Existing JOAs
   1. Draft Redlined Section VII of JOA Straw Man
   2. Draft Metrics and Cost Allocation Inserts for JOA
Appendix D: Summary of Candidate Seams Projects

- Entergy/Cleco/LUS – Acadiana Load Pocket (“ALP”) Project
- SPP/AECI – Proposed Branson Area Project
- SPP (AEPW)/Entergy – Proposed Quarry Project (Western Region)
- SPP (OGE)/Entergy – Proposed Danville Area EHV Station
- SPP (AEPW)/Entergy – Proposed Murfreesboro

About the Authors

Johannes Pfeifenberger is a Principal and Delphine Hou is an Associate of The Brattle Group, an economic consulting firm with offices in Cambridge (Massachusetts), Washington D.C., San Francisco, London, Rome, and Madrid. They can be contacted at www.brattle.com.

Acknowledgements and Disclaimers

The authors would like to thank SPP staff, SPP RSC staff, and stakeholders from SPP and neighboring seams entities for their input, cooperation, and responsiveness to questions and requests. Opinions expressed in this report, as well as any errors or omissions, are the authors’ alone. The examples, facts, and requirements summarized in this report represent our interpretations of them. The authors are economic consultants and nothing herein is intended to provide a legal opinion in any form or fashion.
I. BACKGROUND

Southwest Power Pool (“SPP”) established the Seams Steering Committee (“SSC”) in early 2010 to identify and address seams-related issues, provide guidance on operational and planning coordination, and suggest improvements. In the SSC’s review of existing agreements, it noted that a variety of agreements exist between SPP and its neighbors ranging from basic NERC reliability coordination agreements which are focused on operations, to more sophisticated joint operating agreements which discuss long-term planning. However, most existing documents did not adequately address or provide enough guidance on cost allocation for seams projects leaving the decision to be addressed on a case-by-case basis.

In an attempt to establish a more systematic approach to cost allocation, the SSC began developing a whitepaper, Draft Cost Allocation Principles for Seams Transmission Expansion Projects (“Draft Seams Cost Allocation Whitepaper” as provided in Appendix A and discussed in Section III below), in collaboration with the SPP Regional State Committee (“SPP RSC”). The whitepaper seeks to articulate a consistent set of overarching seams cost allocation principles and methodologies that could be applied to SPP and each of its neighbors. It could then be used by SPP as a starting point to discuss seams cost allocation, an especially challenging task as SPP’s neighbors include market-based (MISO), non-market private (Entergy, AECI, CLECO), and non-market public power (Western, SWPA) transmission entities.

On June 17, 2010, the Federal Energy Regulatory Commission (“FERC”) released its Notice of Proposed Rulemaking (“NOPR”) on “Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities” (“FERC NOPR”). With regard to interregional planning and cost allocation, the FERC NOPR proposed six principles cost allocation, which are discussed in greater detail in Section V.

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3 The SPP RSC is comprised of the retail regulatory commissioners in the SPP member states of Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The SPP RSC provides state regulatory agency input on matters of regional importance related to the development and operation of the bulk electric transmission within SPP. In addition, the SPP RSC is charged with developing cost allocation methodologies for transmission upgrades within SPP.
Though the FERC NOPR had not been finalized into a rulemaking and several of SPP’s neighbors are non-FERC-jurisdictional, the Draft Seams Cost Allocation Whitepaper proactively included several aspects of the FERC NOPR. To assist SPP and the SPP RSC with further development of a seams cost allocation methodology, the SPP RSC issued a request for proposal (“RFP”) in February 2011, seeking a qualified consulting firm to assist SPP, the SPP RSC, and SPP stakeholders in the area of cost allocation for seams transmission projects. The Brattle Group was engaged in June 2011 to provide our expertise and analysis on the matter. On July 21, 2011, the FERC issued its Order 1000, which retained the cost allocation principles that had been proposed in the NOPR.\(^6\)

### A. PROJECT ASSIGNMENT AND PURPOSE

The Brattle Group was engaged to undertake two phases of analyses as described in the RFP. The focus of the first phase was to develop a general approach to seams cost allocation so that SPP can use it to assess the needs and benefits at each of its seams with its neighbors. In doing so, we reviewed, documented, and reported to the SPP RSC and SPP SSC the benefit measurements that have been proposed and those that have been accepted for use by other jurisdictions to be applied to various types of transmission upgrades. We also reviewed the Draft Seams Cost Allocation Whitepaper to assess whether its proposed cost allocation principles were complete and consistent, whether the proposed cost allocations met those principles, and to recommend alternatives.

The second phase of this assignment, as originally specified in the RFP, was focused on leveraging the results and findings from the first phase to create a detailed recommendation report addressing SPP’s seams.

### B. APPROACH

After discussions with RSC and SPP staff, the two phases of this assignment as originally specified in the RFP were combined into five major tasks as summarized in Table 1 below.

---

Table 1
Combined Phase One and Two Task List

<table>
<thead>
<tr>
<th>Task</th>
<th>Description</th>
<th>Report Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Review of Draft Seams Cost Allocation Whitepaper</td>
<td>In-depth review of Draft Seams Cost Allocation Whitepaper</td>
<td>Section III</td>
</tr>
<tr>
<td>2. Evaluate Cost Allocation Frameworks Used Elsewhere</td>
<td>Identify and review proposed and/or accepted seams cost allocation and benefit measurements used elsewhere to see whether they are compatible with the principles outlines in the Draft Seams Cost Allocation Whitepaper</td>
<td>Section IV</td>
</tr>
<tr>
<td>3. Develop General Approach</td>
<td>Develop general approach and seams cost allocation framework with principles and methodologies and benefit measurements</td>
<td>Sections VI through XI</td>
</tr>
<tr>
<td>4. Test Approach Developed in Task 3</td>
<td>Test and demonstrate the robustness of the principles, framework, and methodologies developed in Task 3, and fine-tune or revise as necessary. Ideally the analysis would be based on specific transmission projects, involving the individual seams entities that are evaluated within the SPP transmission planning process to “troubleshoot” or “stress test” the considered approaches</td>
<td>Section XII</td>
</tr>
<tr>
<td>5. Draft and Present Report</td>
<td>Report and outline to be reviewed by RSC, SPP staff, other “Joint Project Team” members, and stakeholders. Deliver draft of detailed recommendations report to CAWG by March 2012, and a final report and presentation to the RSC by April 2012</td>
<td>Section I.C</td>
</tr>
</tbody>
</table>

As required by the RFP, Task 1 was an in-depth review of the Draft Seams Cost Allocation Whitepaper to check for completeness and consistency. This assessment is presented in Section III with the whitepaper included as Appendix A. We then researched and analyzed cost allocation frameworks used elsewhere (Task 2) as discussed in Section IV with key supporting documents provided in Appendix B. Based on the information gathered in Task 1 and Task 2 and discussions with SPP and RSC staff and stakeholders, we developed a general seams cost allocation methodology (Task 3), which included the cost allocation principles and methodologies as well as benefit metrics.
Throughout this process we worked closely with the RSC staff, SPP staff, and SPP stakeholder groups to leverage existing resources and work already completed on seams cost allocation. Tasks 1 through 3 largely address the requirements of the first phase described in the RFP. When developing a general framework, however, it is important to test and demonstrate its robustness or otherwise run the risk of developing methodology that cannot accommodate “real world” seams projects and complications. Therefore, Task 4 was designed specifically to “stress test” the proposed framework by applying it to existing or proposed seams projects. This allowed us to refine our proposed framework and present more concrete recommendations. As we discuss in Section XII, we received recommendations for specific candidate seams projects from SPP staff, RSC staff, and stakeholders, to which we could apply our proposed cost allocation framework. Lastly, Task 5 provides the presentations and reports required in both phases of the RFP and includes feedback from the RSC, SPP staff, stakeholders.

C. JOINT PROJECT TEAM AND STAKEHOLDER PROCESS

A Joint Project Team was formed to facilitate project flow and coordination. The Joint Project Team included key RSC- and SPP-assigned staff (e.g., from the Seams Cost Allocation Task Force or “SCATF” and the Cost Allocation Working Group or “CAWG”) and the Brattle project team. Team members participated in bi-weekly conference calls to discuss project status, data availability and needs, and coordination of logistical matters. For example, the Joint Project Team was responsible for reorganizing the project into the previously-discussed five tasks, developing a work plan, and agreeing on deadlines and deliverables. The SPP and RSC SCATF members of the Joint Project Team also provided introductions to access existing RSC- and SPP-internal experience, research, and data. The Joint Project Team further reviewed and provided feedback on draft research results, work products, and report drafts. Finally, the Joint Project Team provided guidance about the need and agenda for conference calls and meetings with other groups, such as the SPP SSC, the full RSC CAWG, the quarterly RSC meetings, and meetings adjacent seams entities. Table 2 summarizes the major meetings and conference calls with various groups and stakeholders to discuss the progress and present findings of the project.
<table>
<thead>
<tr>
<th>Date</th>
<th>Event</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 19, 2011</td>
<td>Kick-off meeting (TX)</td>
<td>Kick-off meeting with RSC SCATF and SPP staff to revise schedule, scope, identify concerns, and discuss SPP Draft Seams Cost Allocation Whitepaper. Continued Joint Project Team discussions in bi-weekly status calls and ad-hoc calls.</td>
</tr>
<tr>
<td>August 11, 2011</td>
<td>SSC Monthly Meeting (KS)</td>
<td>Attended meeting to discuss the ongoing effort, interregional cost allocation examples, candidate seams projects on which to test framework, and examples from other markets.</td>
</tr>
<tr>
<td>September 30, 2011</td>
<td>SSC conference call</td>
<td>Conference call to discuss Brattle’s first draft of a generic interregional planning and cost allocation framework and candidate seams projects.</td>
</tr>
<tr>
<td>October 21, 2011</td>
<td>SSC conference call</td>
<td>Follow-up conference call after receiving feedback on draft generic framework via email.</td>
</tr>
<tr>
<td>October 24, 2011</td>
<td>RSC Quarterly Meeting (NM)</td>
<td>Attended meeting to provide a progress update and presentation of draft framework and cost allocation principles</td>
</tr>
<tr>
<td>January 9, 2012</td>
<td>SSC Monthly Meeting</td>
<td>Participated in meeting via conference call to discuss cost allocation principles and methodologies, cost allocation guidelines based on illustrative examples, benefits, and metrics, and redlined joint operating agreements</td>
</tr>
<tr>
<td>January 26, 2012</td>
<td>Midwest ISO RECBTF Meeting</td>
<td>Participated via conference call to present draft framework to the Midwest ISO’s Regional Expansion Criteria and Benefits Task Force (“RECBTF”)</td>
</tr>
<tr>
<td>January 30, 2012</td>
<td>RSC Quarterly Meeting (TX)</td>
<td>Attended meeting to provide a progress update and presentation of cost allocation principles and methodologies, cost allocation guidelines based on illustrative examples, benefits, and metrics, and redlined joint operating agreement</td>
</tr>
<tr>
<td>February 3-28, 2012</td>
<td>Stakeholder Feedback</td>
<td>Individual conference calls with AEPW, Midwest ISO, Entergy, and AECI to discuss and receive feedback on draft framework and illustrative JOA inserts to implement framework</td>
</tr>
<tr>
<td>February 7, 2012</td>
<td>FERC Presentation</td>
<td>Presentation of draft framework to FERC staff members, including FERC’s office of the general counsel</td>
</tr>
<tr>
<td>April 4, 2012</td>
<td>CAWG Monthly Meeting</td>
<td>Participated in meeting via conference call to present and discuss draft of the final report provided on 3/28</td>
</tr>
<tr>
<td>April 12, 2012</td>
<td>Order 1000 Interregional Coordination Meeting</td>
<td>Participated via conference call in SPP-MISO meeting to review the RTO’s current thoughts on complying with the interregional aspects of Order 1000, incorporate stakeholder comments and develop consensus on concepts. Presented the proposed cost allocation framework.</td>
</tr>
<tr>
<td>April 23, 2012</td>
<td>RSC Quarterly Meeting (OK)</td>
<td>Attend meeting to present final report</td>
</tr>
</tbody>
</table>
D. REPORT STRUCTURE

The remainder of this report is structured as follows. Section II describes the barriers to interregional planning and cost allocation, which our proposed framework seeks to address. Section III includes our comments and feedback on the SPP RSC’s whitepaper, “Draft Cost Allocation Principles for Seams Transmission Expansion.” Section IV summarizes our survey of seams cost allocation efforts and issues outside of SPP, and Section V provides an overview of the FERC Order 1000 requirements for interregional cost allocation.

Sections VI through XI present our proposed interregional planning and cost allocation framework. In Section VI, we first present a case study of a seams project currently under construction, which we use to present our proposed framework for interregional planning and cost allocation and explain why cost allocation is an integral part of the overall planning process. We also introduce in this section our “building blocks,” which serve as the foundation of our proposed framework. While some portions or versions of the building blocks already exist in SPP’s processes and agreements with seams neighbors, others are insufficiently developed or missing entirely. We dedicate a section to each of these insufficiently-developed or missing building blocks.

The first of these insufficiently-developed or missing building blocks, presented in Section VII, defines a process to propose and analyze seams projects, including a process for unilaterally or jointly proposed projects and the responsibilities of each seams entity. Section VIII then discusses principles and examples for evaluation criteria and benefit metrics. Section IX presents our recommended seams cost allocation principles and guidelines that should be included in each interregional planning and cost allocation agreement. Section X discusses payment mechanisms that may be utilized by the neighboring entities to implement seams cost allocation. Lastly, Section XI presents an optional building block that allows for the development of pre-specified formulaic evaluation and cost allocation methodologies.

Section XII presents three case studies in which we apply and “stress test” the proposed approach. And, finally, a summary of our conclusions and next steps are presented in Section XIII.
II. BARRIERS TO INTERREGIONAL PLANNING AND COST ALLOCATION

To facilitate development of an effective seams cost allocation framework, we reviewed existing planning processes and obtained stakeholder input in an attempt to identify barriers to the development and cost allocation of seams projects. Interregional transmission planning is particularly challenging given a number of barriers in three broad categories: (1) interregional planning processes; (2) seams project evaluation and benefits; and (3) cost allocation.

Planning-related challenges often start with limited staff resources to evaluate and consider seams projects given the high work load of internal planning processes and operational seams efforts. Even if additional resources could be dedicated to seams planning, we found that there often is limited exchange of sufficiently current data and inadequate joint planning models. The emphasis here is not the sheer volume of data exchanged but the extent to which the available data and planning models would allow one seams entity to accurately model the impact of a proposed seams project on its neighbor’s system. For example, jointly-developed and validated interregional power flow cases are not generally available for the combined footprint such that one seams entity would be in a position to credibly model the neighboring system. We also found that there is considerable uncertainty as to how or when neighboring systems will evaluate and consider seams projects as part of their regular planning processes. This creates mismatched timelines and missed opportunities to evaluate seams projects in a timely fashion. Finally, we identified a “gap” between top-down and bottom-up transmission studies, which can lead to an inability to identify beneficial seams projects. For example, SPP’s “top-down” regional planning study, the Integrated Transmission Plan 10 (“ITP10”), identifies proposed transmission buildouts based on benefits provided by each configuration without fully considering projects that could be built and partially paid for in response to long-term transmission service requests (“TSRs”). At the same time, bottom-up planning efforts, like the evaluation of TSRs, only consider firmly-planned projects that already have a notice to construct but not other transmission projects that have been approved within the context of the ITP process. The disconnect is created because individual TSRs may benefit from the larger upgrades proposed in the ITP process but would not be able to fund such upgrades on an individual basis. Similarly, to the extent that an ITP project could address TSRs, payments received from TSRs would not be captured as a benefit in the ITP10 analysis.

When considering seams projects, we found that the qualification criteria for a seams project often differ between neighbors. These differences can create a gap that eliminates beneficial solutions even before a detailed analysis can be undertaken. This may be due to a requirement that a seams project that offers market efficiency benefits to one seams entity also needs to qualify as a market efficiency project in the neighboring seams entity. Other potentially beneficial seams projects may be eliminated by minimum voltage or project cost requirements or
the requirement that seams projects need to be physically located in both entities’ footprint. The latter eliminates from consideration as a seams project any upgrades to flow gates that are entirely within one entity’s footprint but constrain transactions within the neighboring seams entity.

Overall we also found that **many transmission-related benefits are not considered or lack specified metrics that could quantify or describe those benefits for seams projects.** There is also uncertainty about which types of transmission benefits are considered in the planning process of the neighboring seams entity. This can be a significant barrier to project selection and cost allocation, since costs can realistically be allocated to individual seams entities only based on benefits that are recognized by those entities. For example, would a seams neighbor consider a reduction in transmission loading relief (“TLR”) events to be a reliability benefit? How would this benefit be monetized or what portion of a seams project’s costs could be allocated to a neighbor who benefits from a reduction of TLR events? Moreover, **individual seams projects may offer very different types of benefits to each of the neighboring regions and transmission owners.** For example, a seams project that addresses a reliability concern within one seams entity may offer mostly market efficiency or economic benefits to the neighboring seams entity. As a result, a requirement that individual seams projects provide the same type of benefit (*i.e.*, reliability, economic, or public policy) to both seams neighbors will eliminate many potentially beneficial seams projects.

While robust planning and benefit considerations are essential to seams cost allocation, the **lack of sufficiently detailed, actionable, but flexible cost allocation principles and guidelines** makes it difficult to resolve seams cost allocation challenges. For example, FERC’s requirement that costs be allocated so they are “roughly commensurate” with benefits is a good starting point, but does not provide quite enough guidance to be actionable by itself. On the other hand, while entities have attempted to develop detailed interregional evaluation frameworks for certain types of seams projects (*e.g.*, reliability or market efficiency projects), we found that such frameworks often are based on the “lowest common denominator” of the neighboring entities’ planning processes and are insufficiently flexible to address many potentially attractive seams projects.

Finally, barriers to seams projects are created if cost allocation is not aligned with **ownership interests and transmission rights.** Transmission owners in non-market regions and non-jurisdictional transmission owners will be unable or hesitant to pay for seams projects without obtaining transmission rights (*e.g.*, a share of the upgrade’s incremental flowgate capacity) in return for their payments.

To mitigate the identified barriers, a successful approach to cost allocation will need to be flexible enough to accommodate different types of seams projects (*e.g.*, reliability, economic, and public policy projects) for different types of neighboring regions and entities (*e.g.*, market
and non-market areas, FERC jurisdictional, and non-jurisdictional entities). Furthermore, the approach should recognize that a project may provide different types of benefits to each of the neighboring seams entities. To balance this flexibility, an effective framework also needs to be specific enough to be actionable without being overly restrictive and formulaic. In this regard, our proposed framework requires the joint development and validation of planning assumptions and models, comprehensive identification and explanations of all quantitative and qualitative benefits considered in each entity’s transmission planning process, the identification of any additional benefits specific to seams projects (such as increased wheeling revenues), and specification of metrics by which to measure the identified benefits. Lastly, to address implementation-related barriers, assignment of transmission rights and specification of acceptable payment mechanisms to implement cost allocations will be necessary. The proposed framework for interregional planning and seams cost allocation presented in Sections VI through XI specifically builds on these considerations.

III. REVIEW OF SPP’S DRAFT SEAMS COST ALLOCATION WHITEPAPER

As noted earlier, in an attempt to establish a more systematic approach to cost allocation, the SPP’s Seams Steering Committee developed a draft whitepaper—the Draft Cost Allocation Principles for Seams Transmission Expansion Projects (“Draft Seams Cost Allocation Whitepaper,” provided in Appendix A)—in collaboration with the SPP Regional State Committee (“SPP RSC”). This Draft Seams Cost Allocation Whitepaper seeks to articulate a consistent set of overarching seams cost allocation principles and methodologies that could be applied to SPP and each of its neighbors. It begins with the recognition that SPP’s seams agreements with its various neighbors “lack systemic requirements describing how costs for upgrades identified in these coordinated plans should be allocated between SPP and its neighbors.” The draft whitepaper also acknowledges that effective cost allocation will “promote improved transmission planning coordination at SPP’s seams and facilitate more cost effective and efficient interregional solutions.” In order to develop a consistent approach to cost allocation, the Draft Seams Cost Allocation Whitepaper proposes principles to be considered in

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7 The SPP RSC is comprised of the retail regulatory commissioners in the SPP member states of Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The SPP RSC provides state regulatory agency input on matters of regional importance related to the development and operation of the bulk electric transmission within SPP. In addition, the SPP RSC is charged with developing cost allocation methodologies for transmission upgrades within SPP.
9 Ibid., p. 1.
five interrelated areas: (1) seams projects classification and applicability; (2) seams project designation criteria and OATT compatibility; (3) models and modeling assumptions; (4) metrics and criteria; and (5) cost allocation. This section of the report discusses these areas and provides our thoughts on the completeness and consistency of the specified principles.

A. **SEAMS PROJECTS CLASSIFICATION AND APPLICABILITY AND SEAMS PROJECT DESIGNATION CRITERIA AND OATT COMPATIBILITY**

The first two topic areas are closely interrelated and will therefore be discussed together. The Draft Seams Cost Allocation Whitepaper notes that seams projects, or so-called interregional transmission projects ("IRTPs"), are generally identified as part of a coordinated system planning and modeling effort between SPP and the neighboring seams entity. It also acknowledges that IRTPs may be unilaterally identified but are still considered for seams cost allocation.

**Observations:** We agree that this approach allows for some flexibility in how seams projects are identified and necessarily sets cost allocation within the context of interregional planning.

The draft whitepaper also specifies that an IRTP may physically cross a seams boundary or be wholly located within one seams entity. To qualify as an IRTP, a project should be a minimum of 100 kV and have a total engineering and construction cost of at least $20 million. While it is possible to consider lower voltages or costs, these minimum thresholds have been established so that time and resources are dedicated to projects that would be more likely to produce sufficient benefits to both seams entities.

**Observations:** We agree that IRTPs that provide benefits to both seams neighbors may or may not physically cross the seams boundary. We also agree that the availability of time and resources are significant constraints, but it does not necessarily follow that smaller or lower-voltage projects would not produce sufficient benefits to both parties in relation to allocated costs. In fact, smaller projects with significant benefits to both parties may be easier to validate and approve.

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11 “Seams” and “interregional” are used interchangeably in the Draft Seams Cost Allocation Whitepaper.
The draft whitepaper classifies IRTPs based on three major drivers: 1) reliability needs (“IRTP-R”); 2) economic improvements (“IRTP-E”); and 3) public policy requirements (“IRTP-P”).

To be considered an IRTP-R, the general principle notes that both seams entities should contribute to the need for a project by a “significant” amount so that there are sufficient benefits accruing to each party based on allocated costs. The seams entity not constructing the IRTP-R facility should contribute at least 5% of the loading on the constrained facility. This approach is similar to the one used between PJM and the MISO for reliability-driven seams projects (see discussion in Section IV.A). For IRTP-Es, the main principle is that each seams entity should receive benefits from reduced congestion equal to or exceeding its allocated costs. In addition, at least one generator in a seams entity’s dispatch footprint should have a generation to load distribution factor of 5% or greater on one or more of the constraints being addressed. This approach is also similar to the one used between PJM and the MISO for economically-driven seams projects (see Section IV.A). Public policy requirements are not specifically defined in the draft whitepaper but may include state or federal renewable energy standards or carbon caps. To qualify as an IRTP-P, the project should be identified through the seams entities’ coordinated system planning process, and determined necessary to meet the policy needs of at least one of the seams entities. IRTP-Ps are not upgrades required to meet transmission service or a request for generation interconnection.

**Observations:** We noted a potential inconsistency or at least a need for clarification in the consideration of project drivers. While it is helpful to classify projects based on reliability, economic, and public-policy drivers, few of SPP’s neighbors consider each of these drivers in the same way as defined in the draft whitepaper. For example, economic benefits may be considered by a neighbor but are not necessarily quantified in terms of adjusted production costs or other metrics used by SPP. Importantly, other seams entities may not distinguish between reliability, economic, and public policy projects as is suggested in the whitepaper. In fact, SPP’s own internal planning process does not categorize transmission projects based on these three drivers. Furthermore, it is not clear that seams entities will benefit from the project in the same way. This is recognized in the final section of the draft whitepaper, which notes that a project may provide benefits to a seams entity based on one driver but also provide benefits to its seams neighbor via a

16 Ibid., pp. 2-3.
17 Ibid., p. 3.
18 Ibid., p. 3.
19 Ibid., p. 2.
20 Ibid., p. 3.
different driver.\textsuperscript{21} For example, a reliability project in one entity’s footprint may provide economic benefits to the other seams entity. While this section notes that cost allocation of IRTPs should consider whether there are multiple benefits or drivers, it does not provide any guidance on how to do so. Furthermore, it is not clear if a project can qualify as an IRTP-R, IRTP-E, or IRTP-P (and thus be eligible for cost allocation) if the neighboring seams entity does not receive the same types of benefits. One approach may be to define an IRTP by a \textit{major driver} but recognize that it can produce different or multiple benefits to each seams entity.

The Draft Seams Cost Allocation Whitepaper makes special mention of OATT compatibility for cost sharing and recovery. It notes that IRTP’s should be identified via coordinated system planning and that each seams entity should have the appropriate cost recovery provisions to allocate the cost of IRTP’s.\textsuperscript{22} The draft whitepaper also notes that costs allocated for approved IRTP’s will be recovered using SPP’s then current regional cost allocation methodology, regardless of the IRTP’s voltage.\textsuperscript{23}

\textbf{Observations:} We agree with this provision and generally note that the allocated costs of IRTPs should be recovered by each seams entity in the same way as costs of other internal (regional or local) projects are recovered. It will, however, be important to specify the mechanisms defining how cost allocations are implemented (\textit{i.e.}, payment methodologies) and to make sure that these mechanisms are acceptable to each entity.

\textbf{B. MODELS AND MODELING ASSUMPTIONS}

In terms of models and modeling assumptions, the Draft Seams Cost Allocation Whitepaper requires the use of the same tools and assumptions as those used in the coordinated planning efforts between seams entities.\textsuperscript{24} The draft whitepaper notes that formulating similar assumptions within mutually accepted planning horizons will be essential to IRTP-R and IRTP-E screening, selection, and cost allocation solutions.\textsuperscript{25}

\textbf{Observations:} Relying on consistent data inputs and models will foster a better understanding of the seams and seams-related needs between neighboring entities. However, the exchange of data in itself, even if consistent with existing coordinated

\begin{footnotesize}
\begin{itemize}
  \item \textsuperscript{21} Draft Seams Cost Allocation Whitepaper, p. 5.
  \item \textsuperscript{22} \textit{Ibid.}, p. 2.
  \item \textsuperscript{23} \textit{Ibid.}, p. 2, footnote 2.
  \item \textsuperscript{24} \textit{Ibid.}, p. 3.
  \item \textsuperscript{25} \textit{Ibid.}, p. 3.
\end{itemize}
\end{footnotesize}
planning efforts, may still not produce agreeable results. We recommend that planning models are developed jointly for the combined footprint and validated by both seams entities. We also recommend that each pair of seams entities agree upon an explicit schedule for exchanging data, developing joint planning models, and validating the models. While the draft whitepaper does not go into much detail, a formal agreement between the seams entities should explicitly list the types of data, scenarios, and models used or developed for the analysis of seams projects.

C. METRICS AND CRITERIA

Metrics and criteria are not discussed in detail for IRTP-Rs or IRTP-Ps. Instead, the Draft Seams Cost Allocation Whitepaper offers seams entities the option to use metrics established by the SPP Economic Studies Working Group that represent reliability-, public policy-, and regulatory-driven needs.\(^\text{26}\) For IRTP-Es, the Draft Seams Whitepaper lists three metrics that, at the minimum, should be used for benefits calculations: (1) adjusted production cost (“APC”) savings; (2) project deferrals and/or displacements; and (3) reduced system losses. Additional metrics may be considered with the agreement of the seams entities. The Draft Seams Whitepaper also notes that IRTPs developed as a result of specific transmission service requests should allocate the costs to the transmission customers who submitted the request.

**Observations:** SPP has included in the draft whitepaper three metrics for IRTP-Es that it already considers in its own regional planning process. This is helpful because it recognizes that IRTPs will be considered in a manner consistent with SPP-internal projects. Though the three metrics for IRTP-Es are a useful starting point, non-market regions and non-jurisdictional transmission owners may not recognize or actively consider APC savings in their planning processes. In that case, it would be difficult to adopt the metric for seams planning as it would create an inconsistency with the entities’ internal planning processes. Furthermore, the APC metric will understate the benefits of seams projects as it does not consider the potential that a portion of a seams project’s costs could be offset by increased wheeling through and out revenues. The second IRTP-E metric, project deferrals and/or displacements, can be applied more broadly to all types of seams projects. In other words, any type of seams project can efficiently defer and/or displace any type of internal projects, including reliability and public policy-driven projects. As for system losses, it is not entirely clear if all of SPP’s neighbors currently consider this benefit in their planning efforts, which would cause inconsistencies with their internal planning framework. Lastly, the draft whitepaper

\(^{26}\) Draft Seams Cost Allocation Whitepaper, p. 4.
makes special mention of transmission service requests for energy transferred across a seams boundary. We propose to consider this a benefit that is specifically related to seams projects because increasing transmission capacity to accommodate service requests will generate revenues, which will offset a portion of the IRTP’s costs.

The proposal to use specific metrics and criteria for IRTP-Es suggests that both seams entities would need to agree to use the same metrics and criteria. This may be difficult for some entities, as discussed above, and may result in much time spent on efforts to develop a common set of metrics, which may only reflect a “least-common-denominator” outcome. Such an outcome would not be able to recognize many potentially beneficial seams projects.

D. COST ALLOCATION

The draft whitepaper’s final section on cost allocation establishes principles for each type of IRTPs. For IRTP-Rs, the proposed cost allocation principle is to reflect cost causation as measured by each entity’s loading contribution to the constrained facility.27 For IRTP-Es, the costs allocated to each entity are recommended to be based on the net present value of total quantifiable benefits for each entity. The Draft Seams Cost Allocation Whitepaper also notes that seams entities should be allowed to consider other arrangements, such as allocating costs based on allocation of physical transmission capacity rights if mutually agreeable to both entities.28 For IRTP-Ps, the cost allocation principle simply notes that the project should cost-effectively meet each entity’s public policy goals as compared to other options.29 Therefore, cost allocation should follow the level to which public policy objectives are met with the new IRTP-P. The final paragraph of the Draft Seams Cost Allocation Whitepaper then notes that other drivers should be considered under each classification of IRTPs for the purposes of cost allocation.

Observations: We generally agree with assigning costs to “cost causers” but point out that the cost of IRTP-Rs (or any other type of IRTP) could be allocated either to the cost causers or beneficiaries. In fact, the entities may “cause” transmission investment needs differently than they receive benefits from an upgrade. Thus, we recommend that benefits also be considered to determine cost allocation for IRTP-Rs. For IRTP-Es, we assume the cost allocation principle (read consistently with the first two areas discussed.

27 Draft Seams Cost Allocation Whitepaper, p. 4.
28 Ibid., p. 5.
29 Ibid., p. 5.
above) means that the costs allocated to each entity should be in proportion (but equal to or less than) the present value of quantifiable benefits calculated for each entity. An exclusive focus on the present value of benefits does not recognize non-monetized benefits that an IRTP-E may provide, such as additional reliability or public policy benefits. While the quantifiable and monetized benefits that a project may provide can serve as the foundation for cost allocation, other benefits should not be overlooked entirely even if they have not been monetized. Since transmission service across both RTO and non-RTO seams is still based on physical transmission rights, allocating costs in proportion to physical transmission capacity (and associated rights) may be a pragmatic and attractive option for many seams projects. Lastly, suggesting that IRTP-P costs should be allocated to each entity based on the “level” to which each entity is able to meet public policy goals is inconsistent with the proposed IRTP-P qualification criteria that requires only that an IRTP-P meet at a minimum one entity’s public policy goals. This would not allow seams entities to consider needs different from its neighbors and poses particular problems for IRTP-Ps if state mandates vary or projects provide public policy benefit to only one of the seams entities, even though other benefits may accrue to the other neighbor.

IV. EFFORTS AT INTERREGIONAL PLANNING AND SEAMS COST ALLOCATION ELSEWHERE

This section of the report summarizes efforts to address interregional cost allocation and planning efforts in other markets. We identify successful or promising practices that may be considered by SPP and its seams neighbors. Our survey covered nine examples from RTO and non-RTO regions in the U.S. and Europe, which include cost allocation principles, seams planning processes, and benefit measurements as applied to a variety of project types such as reliability, economic, and public policy upgrades.

A. PJM-MISO SEAMS COST ALLOCATION FOR RELIABILITY AND MARKET EFFICIENCY PROJECTS

The PJM Interconnection, L.L.C. (“PJM”) and Midwest ISO (“MISO”) are the only two RTOs with pre-specified, FERC-approved interregional cost allocation methodologies. PJM and MISO offer such cost allocation methodologies for two types of projects: reliability driven and market efficiency (i.e., economic) driven transmission upgrades (see Appendix B.1 for original tariff language). Both cost allocation methodologies rely on pre-specified qualification criteria (such as a minimum cost threshold) and pre-specified cost allocation formulas that are applied for projects that pass the qualification criteria.
For a transmission upgrade to qualify as a “cross-border baseline reliability project,” the following criteria are applied: (1) the joint RTO planning committee must agree that the project meets applicable reliability criteria; (2) the project needs to meet the definition of a reliability project under at least one of the RTO’s tariffs; (3) at least $10 million of the total project cost must be allocated to the RTO in which the project is not constructed; and (4) the neighboring RTO must contribute at least 5% to the total loading on the constrained facility. Costs are then allocated based on each RTO’s relative contribution to the combined flow on the constrained facilities or defined interface. The costs allocated to each RTO will then be recovered according to the internal cost-allocation framework under each of the RTOs’ respective tariffs.

“Cross border market efficiency projects” must meet a slightly different set of criteria: (1) the project must be evaluated as part of the RTOs’ coordinated system planning process; (2) the project must quality as a market efficiency upgrade under both RTOs’ tariffs; (3) total project costs must exceed $20 million; (4) the project must meet minimum benefit-cost ratios with benefits calculated based on 70% adjusted production cost savings and 30% load LMP savings to both RTOs; (5) the project must also meet each of the RTOs’ individual cost-benefit criteria; and (6) the project must address at least one constraint that carries at least 5% of power flows from one generator in the adjacent market serving load in the adjacent market. Costs are then allocated based on the net present value of the total benefits calculated for each RTO. Allocated costs are then recovered through each of the RTOs’ existing tariffs.

These cost allocation methodologies reflect an RTO-centric approach. For example, the evaluation criteria and benefit metrics used for seams cost allocation are based on the overlapping set of the two RTOs’ existing benefits metrics. Furthermore, the approach assumes recovery of allocated costs via the RTO’s existing internal cost allocation methodologies. And, consistent with the joint and common market principles shared between PJM and MISO, the methodologies do not include any physical rights to new or expanded transmission paths.

**Observations:** This is a valuable example because of the similarities between SPP’s relationship to MISO. As is the case for PJM and MISO, SPP and MISO use similar metrics to estimate benefits. While this approach based on a fairly narrowly-defined, formulaic approach could similarly be applied to reliability and market efficiency projects between SPP and MISO, it would not be able to address many types of seams projects. The approach would also not be helpful as a seams cost allocation framework with SPP’s non-RTO neighbors because many of these neighbors do not currently use similar benefit metrics. Though this approach provides significant clarity up front, it would be difficult to implement between market and non-market regions. Furthermore, neither of these two formulaic approaches would “fit” the types of candidate seams projects that have been identified by SPP staff and market participants. Even within MISO and PJM, no major cross border reliability or market efficiency projects have been
approved by the RTOs through this methodology—despite the fact that these options have now been available for several years.\textsuperscript{30}

\textbf{B. \hspace{1em} NORTHERN TIER COST ALLOCATION PROCESS AND PRINCIPLES}

The Northern Tier Transmission Group (“NTTG”) is a voluntary organization that coordinates transmission systems operations, products, business practices, and planning for its member utilities in the Pacific Northwest and Mountain states, serving customers in Oregon, Washington, California, Idaho, Montana, Wyoming, and Utah.\textsuperscript{31} The utility members include Deseret Power Electric Cooperative, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, and Utah Associated Municipal Power Systems. They collectively serve 2.7 million customers and maintain over 27,000 miles of high-voltage transmission.\textsuperscript{32}

Since NTTG is not an RTO, the boundary between each vertically-integrated utility member represents a seam similar to those of SPP and its neighbors. NTTG’s Steering Committee oversees and directs initiatives undertaken by members and is comprised of representatives from regulatory utility commissions of the states where NTTG members operate, utility members, and state consumer advocacy groups.\textsuperscript{33} NTTG has a set of cost allocation principles which it applies to proposed projects in its members’ service territories (see NTTG cost allocation principles attached as Appendix B.2).

As part of FERC Order 890 compliance, the NTTG formed a Cost Allocation Committee (“CAC”), which includes staff from regulatory utility commissions, its utility members, and state consumer advocacy groups. The CAC developed four broad cost allocation principles based on the “beneficiaries pay” concept with an emphasis on consensus building and equity.\textsuperscript{34} For example, costs cannot be allocated involuntarily and benefits received may include physical or financial transmission service rights.\textsuperscript{35} These cost allocation principles are applied to a wide variety of transmission projects (not defined by a \textit{de minimis} threshold), which include any

\begin{flushleft}


\textsuperscript{32} \textit{Ibid.}

\textsuperscript{33} \textit{Ibid.}


\textsuperscript{35} \textit{Ibid.}, p. 7.
\end{flushleft}
project that impacts one or more load serving entities in terms of supporting load growth, providing economic benefits, or meeting public policy goals.\textsuperscript{36}

During the transmission planning process, market participants within NTTG will submit an application with details about their projects, including a proposed cost allocation methodology. The CAC will review these submitted materials and analyses of costs and benefits, check for consistency against NTTG’s cost allocation principles, and provide a non-binding recommendation for cost allocation.\textsuperscript{37} The CAC will first provide a preliminary cost allocation recommendation during the transmission study plan development and then a final written recommendation to be included in the annual or biennial transmission planning reports submitted to the Steering Committee for approval.\textsuperscript{38} However, each project still needs approval from its applicable state commission.

Within the 2008-2009 planning cycle, for example, the CAC reviewed over $9 billion in proposed transmission projects and recommended (\textit{i.e.}, reaffirmed) the cost allocation methodologies as proposed by project sponsors for over $7 billion of the projects.\textsuperscript{39} One of these recommended projects, the “Energy Gateway” project, accounts for $6 billion and consists of nine segments.\textsuperscript{40} Each of the nine segments is allocated differently to one or two transmission owners, with ownership or joint ownership of individual segments used as the tool to implement cost allocation. For example, five segments are wholly owned by each of the individual utilities, with costs recovered through their respective transmission tariffs from native load and wheeling customers. The remaining four segments are jointly-owned and cost allocation is aligned with ownership shares.

\textbf{Observations:} This is a helpful example because cost allocation is explicitly linked to the transmission planning process and is based on concrete cost allocation principles without being overly prescriptive. Project sponsors are encouraged to develop a cost allocation methodology for review by the CAC (which includes utility, state commission, and consumer advocate staff) to ensure adherence to the pre-specified NTTG cost allocation principles. The principles also

\textsuperscript{36} \textit{Ibid.}, pp. 4-5.

\textsuperscript{37} Northern Tier Transmission Group, “Cost Allocation Committee Charter,” October 21, 2009, pp. 4-5.


\textsuperscript{40} The Energy Gateway project is comprised of 11 segments in total for a cost of over $7 billion. The sponsors for two of the segments did not provide enough information for the CAC to recommend a cost allocation.
provide for enough flexibility to allow for seams projects that benefit sponsors differently (e.g., provide reliability benefits to one utility, provide market efficiency benefits to a second utility, and provide a combination of benefits to a third utility).

C. **ColumbiaGrid Expansion Planning Process and Cost Allocation Guidelines**

ColumbiaGrid is a voluntary organization, which coordinates transmission systems operations and transmission planning, administers an OASIS portal, and provides corporate services for its member utilities in the Pacific Northwest and Mountain states serving customers in Oregon, Washington, Idaho, Montana, California, Wyoming, Nevada, and Utah. ColumbiaGrid has developed cost allocation methodologies for different types of projects that are analyzed during its transmission planning and expansion process (see Appendix B.3). Since ColumbiaGrid is not an RTO, the boundaries between each of its vertically-integrated utility members are similar to the boundaries between SPP and its neighbors. The utility members include Avista Corporation, Bonneville Power Administration, Chelan County Public Utility District (“PUD”), Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. They collectively own over 22,000 miles of high-voltage transmission.

ColumbiaGrid’s biennial transmission planning process starts with a regional needs assessment conducted over a 10-year planning horizon. “Study Teams” comprised of project sponsors, impacted system representatives, interested participants, and ColumbiaGrid staff then develop projects to address needs and impacts. While Study Teams are responsible for developing a cost allocation methodology for each project, ColumbiaGrid has already outlined guidelines and principles for the cost allocation of reliability, economic, and transmission-service-request driven projects, as well as so called “expanded scope” projects that are a combination of the previous types. Table 3 below shows the drivers, project categories, and cost allocation guidelines ColumbiaGrid has developed.

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Table 3
Summary of ColumbiaGrid Cost Allocation Guidelines

<table>
<thead>
<tr>
<th>Driver of transmission need</th>
<th>Project category name</th>
<th>If no cost allocation agreement is reached, Staff may recommend:</th>
<th>Board action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local reliability</td>
<td>Single System Project</td>
<td>N/A – costs allocated to the individual affected system</td>
<td>N/A</td>
</tr>
<tr>
<td>Regional reliability</td>
<td>Existing Obligation Project (“EOP”)</td>
<td>Costs allocated to cost causer and/or those that may benefit from the EOP by delaying or eliminating the need for their own upgrade</td>
<td>Review and approve Study Team or ColumbiaGrid Staff recommendation with option to modify</td>
</tr>
<tr>
<td>Economics</td>
<td>Capacity Increase</td>
<td>New cost allocation or default allocation based on proportion of additional capacity received</td>
<td>Informational only, may not disapprove or modify</td>
</tr>
<tr>
<td>Transmission service and interconnection requests</td>
<td>Requested Service Project</td>
<td>Cost allocated to requesting customer and potentially to transmission owner if project can delay or eliminate needed upgrades</td>
<td>Review and approve Study Team or ColumbiaGrid Staff recommendation with option to modify</td>
</tr>
<tr>
<td>Combination of above</td>
<td>Expanded Scope Project</td>
<td>Cost allocation based on the category of the expansion(s)</td>
<td>Informational only, may not disapprove or modify</td>
</tr>
</tbody>
</table>


In the event that the Study Team cannot agree on a cost allocation methodology, the ColumbiaGrid Staff and Board may be called upon to provide a cost allocation recommendation. Ultimately, the final biennial transmission plan will need the approval of the ColumbiaGrid Board, comprised of three independent directors. The most recent 2012 update to the 2011 Biennial Transmission Expansion Plan included $2.4 billion of projects.44

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Observations: Similar to NTTG, cost allocation in ColumbiaGrid is considered in conjunction with the transmission planning process. ColumbiaGrid, however, is more formally structured and provides specific guidance on cost allocation methodologies to be applied to projects meeting individual or a combination of needs but still allows seams projects to benefit sponsors differently. Unlike NTTG, there is more emphasis on general stakeholder rather than state representative involvement since a large portion of the ColumbiaGrid footprint consists of public power companies, such as the Bonneville Power Administration.

D. ISO-NE, NYISO, and PJM’s Northeastern ISO/RTO Planning Coordination Protocol

ISO New England (“ISO-NE”), the New York Independent System Operator (“NYISO”), and PJM are parties to the Northeastern ISO/RTO Planning Coordination Protocol (“Protocol”), approved by the FERC in 2004, which supports and enhances each ISO/RTO’s separate planning processes by providing an overarching forum and process for coordinating system planning in the Northeast region (see Appendix B.4). The Protocol develops a coordinated effort to ensure “on-going reliability and the enhanced operational and economic performance of the systems of the parties.”

The Protocol outlines two main responsibilities of the parties. The first responsibility is to coordinate the generator interconnection and long-term transmission service requests that may have cross border impacts. The second is to produce a Northeastern Coordinated System Plan (“NCSP”) that integrates: “(1) the system plans of the parties, (2) on-going load growth and retirements or deactivations of infrastructure, (3) market-based additions to system infrastructure, such as generation or merchant transmission projects, (4) distributed resources, such as demand side and load response programs, and (5) transmission upgrades identified, jointly, by the parties to resolve seams issues or to enhance the coordinated performance of the systems.” The NCSPs are developed on a periodic basis for a 10-year outlook and are supported by two main groups: (1) the Joint ISO/RTO Planning Committee (“JIPC”), comprised of staff from the ISO/RTOs to conduct the analyses; and (2) the Inter-Area Planning Stakeholder Advisory Committee (“IPSAC”), which provides input from stakeholder groups such as market

47 Ibid.
participants from each party, governmental agencies, regional state committees, and regional reliability councils. 48

To develop the NCSP, the Protocol outlines the data requirements and format, timing of data exchange and verification, and processes for jointly developing the plan and incorporating stakeholder reviews. Although neighboring Canadian entities (Hydro-Québec TransÉnergie, the Independent Electric System Operator of Ontario, and the New Brunswick System Operator) are not signatories to the Protocol, they have agreed to participate on a limited basis to exchange data and other relevant information on a periodic basis. 49 Cost allocation is addressed through each party’s own tariff. 50

The most recently completed NCSP from 2009 reviewed a wide variety of topics of regional concern and impact such as proposed environmental regulations that may trigger significant retirements, transmission interconnection and operational integration of wind resources to meet state enacted RPS requirements, and demand side resource development. 51 It has also identified specific areas of improvement such as increasing the economic transfer capability between ISO-NE and NYISO, for further analysis in a separate economic study. 52

Observations: The Northeastern ISO/RTO Planning Coordination Protocol is a helpful example of seams planning because the processes and committees have already produced several coordinated system plans, which have in turn identified seams-related upgrades. However, it is not clear how many of the identified seams projects are the direct result of the coordinated planning effort. The participating system operators believe that the protocol meets many of the interregional planning requirements of FERC Order 1000, but would need further modifications to develop a cost allocation methodology. 53

E. UMTDI Cost Allocation Principles

The Upper Midwest Transmission Development Initiative (“UMTDI”) was created by the governors of Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin to “identify and

48 Ibid., Section 2.1: Inter-area Planning Stakeholder Advisory Committee and Section 2.2: Joint ISO/RTO Planning Committee.
49 Ibid., Section 1: Introduction.
50 Ibid., Section 4.4: Cost Allocation.
resolve regional transmission planning and cost allocation issues associated with the delivery of renewable energy from wind rich areas within the five-state footprint to the region’s customers.”  

UMTDI has an Executive Committee—comprised of a utility commissioner and a governor’s representative from each state—that worked with MISO staff to discuss legal issues, cost allocation, and regional planning. Through this effort, UMTDI developed eight cost allocation principles for transmission investments needed to interconnect renewable generation (see Appendix B.5).

The UMTDI cost allocation principles are based on the concept that cost causers and beneficiaries should bear the cost of transmission investments. The principles note that the methodologies used should be flexible and consider more than a single benefit metric and that, over time, the distinction between reliability and economic driven projects will tend to blur. The principles also recognize the importance of regional planning to leverage resources throughout the region for effective transmission builds, which tend to be more efficient at higher voltages. Some of these concepts have been included in the MISO’s Multi Value Project (“MVP”) evaluation criteria during the planning phases of the Regional Generation Outlet Study.

Observations: Somewhat similar to the RSC role in SPP cost allocation, UMTDI provided input to MISO’s transmission planning and cost allocation process. MISO’s adoption of the MVP evaluation criteria recognizes that regional transmission projects, especially those at higher voltages, can address a number of different drivers and provide benefits, which may vary by market participant over time. The example provides some insight into how a public policy-oriented scope was expanded to consider benefits more broadly within the transmission planning process.

F. NESCOE DRAFT FRAMEWORK FOR PUBLIC POLICY PROJECTS AND ASSOCIATED COST ALLOCATION

In response to FERC Order 1000, the New England States Committee on Electricity (“NESCOE”) developed a draft framework for considering transmission projects to meet public policy requirements and the associated cost allocation within the ISO-NE market (see Appendix

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55 Ibid., p. 3.
57 Ibid.
58 Ibid.
B.6). NESCOE is a not-for-profit organization comprised of representatives from all six New England Governors to provide input and advance policies to promote reliable and economic electricity while maintaining environmental quality.  

ISO-NE’s tariff currently addresses only reliability and economic (i.e., market efficiency) transmission projects. According to the draft framework, NESCOE envisions a separate public policy-focused assessment. To start, NESCOE will review the laws and regulations of the six New England states and consider feedback from stakeholders (such as public officials) and other market participants. NESCOE will then provide to ISO-NE documentation of these public policy requirements and make them available to the public. Based on the identified public policy requirements, ISO-NE will conduct a two-step “Public Policy Study” which will follow the parameters of an Economic Study under ISO-NE’s tariff. This study, which will be publicly available, will identify transmission and associated costs needed to meet the requirements. ISO-NE will perform more detailed analyses at NESCOE’s request and according to parameters and assumptions identified by NESCOE.

If the ISO’s studies find that public policy requirement needs align with reliability or market efficiency needs, ISO-NE will determine to what extent the proposed transmission solution addresses reliability needs. States which are determining if the proposed transmission project would meet their public policy objectives will need to agree with the ISO’s identified allocation to reliability needs. The remaining portion will then be considered a public policy project for cost allocation. The framework does not provide a specific cost allocation approach but notes that (1) projects will only move forward if benefits outweigh the costs and (2) an evaluation of a project’s benefits should include mechanisms for cost control, assurance of delivery of benefits (e.g., RECs), whether or not PPAs have been signed, and other contractual arrangements or methods to satisfy the public policy requirement.

To qualify as a public policy project under the ISO-NE tariff, the draft framework requires that each state accepting an allocation of costs needs its state regulatory commission to approve both allocated costs and the PPAs that require the transmission investment. In a significant departure from ISO-NE’s current tariff, cost allocation for public policy projects would thus be determined through agreement by the states on how to share costs for each particular project. This approach

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may lead to costs shared broadly across all states, several states, or only a single state, depending on the agreed-upon scope of the identified benefits.

**Observations:** This is a potentially helpful example because NESCOE envisions greater state participation in defining the policy requirements that transmission planners need to meet. Furthermore, states are explicitly responsible for developing acceptable cost allocations for identified public policy projects. This approach reiterates the value of state input and participation in RTO planning, identification of benefits and metrics, and cost allocation processes—particularly for public policy projects. Nonetheless, the proposed framework is also limiting because (1) it will be difficult and contentious to determine which portions of a project specifically address public policy, reliability, and market efficiency needs; (2) the framework currently provides little guidance on how benefits should be measured and acceptable cost allocation shares could be derived; (3) the iterative study process and requirement that states individually pre-approve cost allocation will likely be very time consuming; and (4) the requirement that states approve PPAs for renewable resources utilizing the planned transmission facilities may create significant project development challenges because developers may not be able to find counterparties willing to sign PPAs until after transmission access has been secured.

**G. SEAMS COST ALLOCATION FOR MICHIGAN PARs TO ADDRESS LAKE ERIE LOOP FLOWS**

Persistent loop flows around Lake Erie have been negatively impacting the systems of MISO, NYISO, PJM, and the Ontario Independent Electricity System Operator ("Ontario IESO") for several years, causing excessive congestion.61 One of the proposed solutions to better align actual flows with scheduled contract paths was the installation of several phase angle regulators ("PARs") in both the U.S. and Canada. The U.S.-based facilities are located in the MISO-portion of Michigan in ITC’s territory, but will impact the flows on all the other RTOs’ systems. While all parties have highlighted the benefits of the PARs, cost allocation remains unsettled.

In a joint filing at the FERC, MISO and ITC proposed using a distribution factor ("DFAX") analysis to determine the percentage that each entity contributes to Lake Erie loop flows as a measure of cost causation (see Appendix B.7).62 PAR costs would then be allocated in proportion to these power flows. The DFAX methodology is identical to that approved by FERC for the cost allocation of PJM-MISO cross border reliability projects (see Appendix B.1). Based on MISO’s most recent analysis, the costs are proposed to be allocated 47.0% to MISO; 29.2%

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62 Ibid., p. 15.
to NYISO; and 23.8% to PJM. After the total costs of the PARs are allocated to each market, each of the U.S. RTOs would then decide how to recover its share of the costs from its own loads. (There is no allocation to Canadian entities, as they are non-FERC jurisdictional and are already assuming the entire costs of the PARs on the Canadian side of the border.)

However, the RTOs have not come to agreement over the proposed cost allocation. In fact, after an unsuccessful year-long settlement process at the FERC, the case has now been set for a hearing, starting on July 30, 2012, with initial decisions due by November 13, 2012.

Observations: Though cost allocation for the U.S.-based PARs is still unresolved, this is an instructive case as the facilities are wholly located within one market but clearly provide significant congestion relief benefits to neighboring markets. Despite its interregional impacts, this project would not fit the definition of an “interregional” project under FERC Order 1000, which defines interregional projects as those that physically cross the seams between regions (see Section V below). Moreover, despite the fact that the MISO’s proposed cost allocation methodology has already been approved in the seams agreement with PJM for cross border reliability projects, PJM argues that it cannot accept the proposed cost allocation methodology because the PAR project does not meet the definition of a cross border reliability project under the seams agreement. This highlights the challenges that can be associated with narrow definitions of project types.

H. European “Transit Flow” Compensation Mechanism

The integrated European electricity system offers some parallels to the current U.S. market structure within the Eastern interconnection. For example, the European electricity system is highly interconnected but jurisdiction is split between members and non-members of the European Union (somewhat similar to FERC jurisdictional and non-jurisdictional entities). Furthermore, each European country has a national regulator (similar to separate state public utility commissions), which oversees a single or small number of government-owned or independent transmission system operators (“TSOs”). The TSOs ensure reliable operation of the high-voltage grid and facilitate non-discriminatory generation interconnection. In addition to

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63 Ibid., p. 15.
64 Ibid., p. 16.
system operations, some TSOs in Europe may also own the transmission infrastructure and be responsible for its expansion.\(^{67}\) However, as in US RTO markets, the TSOs of the 27 member countries of the European Union are required to be independent of other market participants.\(^ {68}\)

In an effort to foster more cross border electricity trading, European Union regulation eliminated use-of-system charges for individual import/export transactions at national boundaries and for wheeling electricity through countries (collectively referred to as “transit flows”), thereby essentially de-pancaking the interconnected European system.\(^ {69}\) However, as cross border electricity flows have increased, so have congestion costs and the need for investment in additional national and cross border transmission capacity.\(^ {70}\)

Prior to 2002, cross-border capacity expansion and its cost allocation and recovery had been negotiated on a bilateral basis. Beginning in 2002, a voluntary European Inter-Transmission System Operators Compensation mechanism (“ITC mechanism”) was introduced to compensate TSOs within the agreement for the infrastructure costs of hosting transit flows, which are based on actual power flows rather than assumed contract path flows, including loop flows.\(^ {71}\) Various compensation mechanisms had been debated and tried until a legally binding agreement became effective in March 2011, signed by the European Network of Transmission System Operators for Electricity (“ENTSO-E”) and 41 TSOs from 34 countries, which includes both European Union members and non-members (see Appendix B.8).\(^ {72}\) ENTSO-E, an umbrella organization for


\(^ {68}\) Ibid.


\(^ {71}\) European Network of Transmission System Operators for Electricity, “ENTSO-E puts in place an enduring inter-TSO compensation mechanism,” March 24, 2011.

\(^ {72}\) Ibid.
European TSOs, is responsible for establishing arrangements for the collection and disbursement of all payments from the ITC mechanism.\textsuperscript{73}

The ITC mechanism establishes a fund which will compensate TSOs both for transmission losses and system costs caused by hosting cross-border flows. The fund was established by regulation\textsuperscript{74} based on the forward-looking Long-Run Average Incremental Costs (“LRAIC”) of transmission infrastructure needed to accommodate such cross-border flows of electricity.\textsuperscript{75} The most recent fund for 2011 was set at €100 million and may be reassessed or refined based on experience.\textsuperscript{76} Contributions into the fund are collected from each TSO based on its share of historical net flows onto and from its national transmission system compared to the other nations.\textsuperscript{77} For “perimeter” countries which are not part of the ITC agreement, imports and exports are charged at €0.8/MWh and charges are added to the fund.\textsuperscript{78}

Disbursements from the fund for such “cross border infrastructure compensation” are determined annually, starting with a calculation of transmission losses. The ENTSO-E is responsible for modeling each country in the interconnected European system with and without transit flows to calculate the net losses attributed to hosting transit flows on an hourly basis.\textsuperscript{79} The cost of these calculated volumes of losses are then compensated based on rates or costs in each TSO’s own national tariff.\textsuperscript{80} The second type of disbursement is based on the incremental infrastructure costs each TSO is estimated to incur to accommodate the identified transit flows. Disbursements to each country are based on a formula, which includes consideration of each nation’s transit flows compared to the total system-wide flows and a load factor.\textsuperscript{81}


\textsuperscript{74} Ibid.

\textsuperscript{75} Ibid.

\textsuperscript{76} Ibid.

\textsuperscript{77} Ibid.

\textsuperscript{78} European Network of Transmission System Operators for Electricity, “ENTSO-E puts in place an enduring inter-TSO compensation mechanism,” March 24, 2011.

\textsuperscript{79} Referred to as the With and Without Transit (“WWT”) methodology.

\textsuperscript{80} European Network of Transmission System Operators for Electricity, “ENTSO-E puts in place an enduring inter-TSO compensation mechanism,” March 24, 2011.

**Observations:** The ITC mechanism was developed over several years of experimentation, largely driven by the depancaking of cross border transmission charges and liberalization of the European electric system. However, while the mechanism seeks to compensate countries for hosting cross-border and loop flows based on transmission losses and generic estimates of incremental system expansion costs, it does not specifically address transmission expansion nor does it seek to optimize flows between and across countries.

**I. EUROPE-WIDE TRANSMISSION SYSTEM PLANNING**

In 2009, the European Commission also enacted regulation to identify gaps in resource adequacy and transmission investments within and between the national markets.\(^{82}\) The European Commission delegated to ENTSO-E the responsibility of developing a non-binding biennial Ten-Year Network Development Plan (“TYNDP”) for the entire EU footprint.\(^{83}\) A major driver of this effort is the European commitment to reduce carbon emissions (which has greatly increased the penetration of renewable generation), the need to coordinate resources for doing so, and the objective of fostering competition within the European electricity market.

The first TYNDP was published by ENTSO-E in 2010 as a pilot program with a full plan expected in 2012 (see Appendix B.9 for the Executive Summary of the TYNDP).\(^{84}\) For this pilot effort, the final plan was an aggregate of the most recently available national and regional planned and projected transmission needs that were the result of regional, multilateral, or bilateral negotiations between TSOs (rather than the result of European Commission mandates or incentives).\(^{85}\) Projects approved by each TSO and its national regulator typically will need to pass certain socio-economic cost-benefit analyses, which vary from country to country.

The 2010 TYNDP highlighted several criteria used by European TSOs to evaluate transmission projects against projected costs, such as the ability of the project to: (1) maintain system adequacy and operational security to meet demand growth and reduce outages; (2) integrate renewable energy; (3) foster competition and reduce prices; (4) produce environmental benefits such as CO\(_2\) emission reduction; (5) garner social acceptance especially with regard to siting issues; (6) be technically feasible; (7) reduce production, operational, maintenance, or overall investment costs; and (8) reduce network losses and congestion.\(^{86}\) This non-exhaustive list

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84 Ibid.

85 Ibid., p. 163.

86 Ibid., pp. 136-140.
considers both quantitative and qualitative criteria and is implemented differently by each TSO and nation.

While the 2010 pilot TYNDP did not rank projects or conduct economic analyses, it evaluated and included high-voltage transmission investments (new builds or upgrades) of “European significance” that addressed at least one of the three pillars of European Union energy policy: (1) security of supply; (2) tackling climate change by integrating renewable energy sources; and (3) market integration (lowering aggregate generation costs by increasing cross-border trading of power). The 2010 TYNDP identified a potential investment need of 42,100 km of new and upgraded high-voltage AC and DC transmission lines (both within and between countries) over the next 10 years. Over the next five years, the estimated cost of investments of “European significance” is between €23 billion and €28 billion.

Lastly, the pilot program also focused on establishing and refining the processes and procedures that will be used in future TYNDPs, development of future scenarios, tracking resource adequacy, and identifying challenges to transmission development.

**Observations:** While ad hoc transmission upgrades have already occurred between countries, planning for European cross border investments, much like interregional transmission planning in the U.S., has only recently become more formalized and encouraged by the regulatory process. The 2010 pilot TYNDP provides some insights into the various benefits metrics considered in the European planning processes, which include a variety of quantitative and qualitative criteria. Given the similar policy goals throughout Europe, such as climate-change-related mandates, policy makers and national regulators have become important stakeholders in the TYNDP process. At this stage, however, cost allocation for cross border projects has not been formalized as part of the TYNDP process.

87 Ibid., p. 9.
88 Ibid., p. 163. The members of ENTSO-E collectively operate 300,000 km of high-voltage transmission lines.
89 Ibid., p. 16.
V. FERC ORDER 1000 REQUIREMENTS

As noted earlier, FERC issued its rulemaking on “Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,” as Order No. 1000 on July 21, 2011. As the title of Order 1000 suggests, the rule is as equally focused on transmission planning as it is on cost allocation. FERC Order 1000 requirements for interregional planning and cost allocation will need to be considered in the development of the proposed seams cost allocation framework for SPP.

With respect to interregional planning and cost allocation, Order 1000 recognizes that joint coordinated planning, as already discussed in FERC Order 890, “may identify solutions to… needs that are more efficient than those that would have been identified if needs and potential solutions were evaluated only independently by each individual transmission provider.”90 While previous FERC orders have been largely focused on regional planning—planning within an RTO region or within a pre-defined region as reported to FERC in Order 890 compliance—Order 1000 recognizes that “the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential.”91 Furthermore, the FERC noted that challenges associated with cost allocation are a major barrier to getting needed transmission built.92

Order 1000 establishes minimum requirements on interregional planning with the goal of identifying interregional projects93 “that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities.”94 To do that, entities can leverage their existing regional planning processes by adding processes to accommodate interregional transmission planning. Order 1000 requires that the interregional transmission coordination procedures for each pair of seams neighbors be memorialized in each transmission provider’s OATT and optionally in a separate coordination agreement filed with the Commission.95 The FERC requires that interregional planning processes facilitate: (1) the articulation of

91 Ibid., P 350.
92 Ibid., P 485.
93 Order 1000 refers to “interregional projects,” while this report uses the slightly broader term “seams projects,” which may be wholly located within one seams entity’s footprint as discussed in Section VII.
94 Order 1000, P 393.
95 Ibid., P 475.
transmission needs and potential solutions for each region; and (2) identification and joint evaluation of cost-effective interregional solutions to those regional needs.\(^9\)

An important component of the interregional planning process is the exchange of data, with a description of the type of transmission studies to be conducted,\(^7\) and transparency (including establishing websites or email lists to disseminate information).\(^8\) Order 1000 requires that data be exchanged at least annually,\(^9\) supported by a joint effort to harmonize differences in assumptions, models, and criteria used to evaluate proposed interregional projects.\(^10\) Interregional project are defined as projects that are physically located in both regions.\(^11\)

The order also requires that interregional projects must first be proposed as an interregional project in each region in which the project would be located, thereby triggering a process for the seams neighbors to jointly evaluate the proposed project.\(^12\) While the FERC did not specify a timeline for interregional transmission coordination or a deadline for project proposals, Order 1000 notes that the time frame for an interregional process should be within the same general time frames as each region’s consideration of intra-regional projects and to allow for coordination and joint evaluation.\(^13\)

In terms of cost allocation, Order 1000 requires that regions develop a common method or methods for allocating the entire prudently-incurred costs of a new interregional facility among the beneficiaries of the transmission facility in which the facility is located.\(^14\) However, rather than prescribe uniform methodologies, Order 1000 articulated broad principles to allow for flexibility and encourage direct negotiation between entities.\(^15\) The six cost allocation principles that apply to interregional transmission projects are summarized in Table 4.

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\(^9\) Order 1000, P 396.
\(^7\) Ibid., P 398.
\(^8\) Ibid., P 458.
\(^9\) Ibid., P 454.
\(^10\) Ibid., P 437.
\(^11\) Ibid., P 416.
\(^12\) Ibid., P 436, P 442.
\(^13\) Ibid., P 438, P 439, P 440.
\(^14\) Ibid., P 578, P 640.
\(^15\) Ibid., P 561, P 604, P 606.
**Table 4**
FERC Order 1000 Interregional Cost Allocation Principles

<table>
<thead>
<tr>
<th>Principle</th>
<th>Costs allocated to each seams entity must be roughly commensurate with estimated benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principle 2</td>
<td>A region that receives no benefit from an interregional facility must not be involuntarily allocated any costs of that facility</td>
</tr>
<tr>
<td>Principle 3</td>
<td>Benefit-cost thresholds, if used, cannot exceed 1.25 for purpose of interregional cost allocation</td>
</tr>
<tr>
<td>Principle 4</td>
<td>Costs cannot be assigned involuntarily to transmission planning regions in which the transmission facility is not located</td>
</tr>
<tr>
<td>Principle 5</td>
<td>The cost allocation method and data requirements for determining benefits and identifying beneficiaries must be transparent with adequate documentation to allow a stakeholder to determine how they were applied</td>
</tr>
<tr>
<td>Principle 6</td>
<td>Different entities may use different cost allocation methods for different types (i.e., reliability, congestion relief, public policy) of projects as long as the methods are set out and explained in detail</td>
</tr>
</tbody>
</table>

*Sources and notes:*

Principle 1 requires that allocated costs are at least approximately linked to the beneficiaries of an upgrade. Specifically, for interregional projects the benefits to each entity should be roughly commensurate with the costs allocated to each. Though Order 1000 declined to specifically define “benefits” or “beneficiaries,” it is clear that benefits may be related broadly to reliability, congestion relief, or meeting public policy goals. Principle 2 requires that sufficient benefits exist, either at present or in a likely future scenario, before project costs are allocated to a region. Principle 3 does not require the use of benefit-cost ratios but, to the extent that one is used, seeks to ensure that the threshold is not so high as to preclude projects that would provide “worthwhile” benefits. In special scenarios, a benefit-cost threshold higher than 1.25 may be used, but seams entities will be required to justify the higher threshold and the

106 Order 1000, P 622.
107 Ibid., P 624.
108 Ibid., P 637.
109 Ibid., P 646, P 647.
FERC will need to approve its use. Principle 4 is consistent with Order 1000’s definition of an interregional project, which is limited to projects that are physically located in both regions, but does not preclude cost allocations to other regions as long as these regions voluntarily agree to such allocations. Principle 5 reiterates cost allocation and data transparency requirements for determining benefits and identifying beneficiaries for an interregional facility to ensure that stakeholders are able to determine how cost allocation methods were applied to a proposed transmission facility. And, finally, Principle 6 recognizes that different cost allocation methodologies may be used by each seams entity and these methodologies may be different for each type of project.

Order 1000 also requires that developers of interregional projects first propose them through the regional planning processes of each region where the facility is located to trigger the interregional coordination process. The interregional project would only be eligible for cost allocation under the interregional cost allocation methodologies developed pursuant to Order 1000, if each portion of the interregional project ultimately is also approved by the corresponding seams entity’s regional planning process. This provision is intended to forge a closer alignment between transmission planning and cost allocation. Lastly, Order 1000 does not require, but strongly encourages state agency participation in an open stakeholder process as well as multilateral seams coordination.

Compliance filings for the interregional aspects of Order 1000 are due on April 11, 2013—18 months after the effective date of the final rule.

VI. FRAMEWORK FOR INTERREGIONAL PLANNING AND COST ALLOCATION

This section presents our proposed framework for interregional planning and cost allocation. To make the individual building blocks of the proposed framework more tangible, we begin with a case study summarizing recent experience with the multi-party Acadiana Load Pocket project that resulted in a successful cost allocation. As we discuss the recommended interregional planning and cost allocation framework and the related principles and guidelines for benefit

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100 Order 1000, P 657.
111 Ibid., P 436.
112 Ibid., P 582.
113 Ibid., P 402.
114 Ibid., P 417.
measurement and cost allocation, we will refer to this project and the “lessons learned” from this case study to make our recommendations more tangible. Section VI.B discusses key considerations for our framework, including the importance of integrating seams cost allocation with the interregional planning process. Section VI.C then presents an overview of the “building blocks” of our proposed framework and how each of them supports seams cost allocation.

A. CASE STUDY: ACADIANA LOAD POCKET PROJECT

To help develop a robust cost allocation framework, we closely reviewed experience with a recent “seams project”—the Acadiana Load Pocket (“ALP”) Project. The approximately $200 million ALP Project is a series of new transmission lines and substations jointly developed by three transmission system operators—Cleco Power (“Cleco”), Lafayette Utilities System (“LUS”), and Entergy Gulf States Louisiana (“EGSL”)—to address a variety of reliability and economic considerations related to serving a load pocket in south-central Louisiana.

While the ALP Project does not involve RTO seams, it specifically addresses transmission needs along the seam between three individual transmission service providers. The challenges encountered in developing the project and the associated cost allocation proved to be helpful in our effort to develop the proposed interregional planning and cost allocation framework. Specifically, the ALP Project is a helpful case study because: (1) it is a seams project involving multiple transmission providers; (2) it provides both reliability and economic benefits to the sponsors; (3) the reliability and economic benefits differ significantly for each of the sponsors; (4) cost allocation was implemented by aligning it with physical ownership of newly constructed facilities; (5) there was strong public utility commission involvement; and (6) the project has already been approved by the Louisiana Public Service Commission.

The ALP is defined as the electrical loads south of U.S. Highway 190 to the Gulf of Mexico, west of the Atchafalaya Basin, and east of the City of Jennings as shown in Figure 2 below.\(^{115}\) The loads within the ALP area include Cleco, LUS, EGSL, South Louisiana Electric Cooperative Association, South Louisiana Electric Membership Corporation, and Louisiana Energy and Power Authority.\(^{116}\) In 2008, load was approximately 1,700 MW while total generation capacity was only 965 MW.\(^{117}\)

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\(^{116}\) Ibid., p. 4.

\(^{117}\) Ibid., Exhibit TJW-2, p 1 and p. 5.
The ALP region had been experiencing several problems, including an increase in transmission loading relief ("TLR") procedures to curtail non-firm service, an over-reliance on inefficient generating units needed for voltage support, disconnects between modeling assumptions and actual operational limits, a lack of operational flexibility in the load pocket, and limitations to accommodate additional transmission service.

**Figure 2**
*Acadiana Load Pocket Project*


The ALP area had been experiencing reliability problems since the early 2000’s and a new substation was completed in 2005 to alleviate some of the TLR procedures that forced the
curtailment of non-firm transmission service and relied on more expensive generation within the load pocket.\footnote{Whitmore Testimony, 7/14/08, p. 7 and p. 11.} Despite the new substation, conditions within ALP continued to worsen and a joint study effort, including SPP as the Independent Coordinator of Transmission (“ICT”) for Entergy, identified the following major issues within the ALP:

- **Increase in TLR procedures and their severity** — Between November 2006 and November 2007, SPP reliability coordinators initiated 125 TLR procedures, primarily on EGSL’s lines for the loss of Cleco’s or LUS’s lines. The TLR procedures included both firm and non-firm curtailments for importing energy from external generators and required re-dispatch of Cleco’s Teche and LUS’s Bonin Power plants (discussed below).\footnote{Ibid., p. 12.}

- **Over-reliance on inefficient units** — Because of import constraints, two plants within ALP, Cleco’s Teche Power plant and LUS’s Bonin Power plant, were required to be online during moderate to high load conditions.\footnote{Ibid., p. 10.} The Teche plants are described as “old, less efficient steam turbines” with units 1, 2, and 3 placed in service in 1953, 1956, and 1971, respectively.\footnote{Ibid., p. 5.} Cleco’s Teche Unit 3 is the single largest generation contingency in ALP\footnote{Ibid., p. 10.} and provides both load-serving capability and voltage support, which may complicate any scheduled maintenance and cause reliability concerns if the unit was to be offline for an extended period of time.\footnote{Ibid., p. 13.} If a solution such as the ALP Project was implemented, estimated fuel savings to Cleco would be $144.2 million between 2010 and 2016 and $905.6 million between 2010 and 2039.\footnote{Ibid., p. 25.} LUS may also realize economic benefits such as fuel cost savings and increased generation flexibility.\footnote{Ibid., p. 19.}

- **Disconnects between planning model assumptions and operation** —
  - Long-term modeling of flows versus operational realities — In the long-term model, only firm network resources were dispatched and confirmed long-term firm transmission transactions are modeled to meet each control area’s load. However, the increase in (more efficient) merchant generation with short-term economic power sales causes a deviation in modeled power flows and actual use
of the transmission system. The result was that the long-term model did not accurately capture how heavily the transmission system was being used to import into ALP.

- **Natural gas prices** — Unforeseen increases in natural gas prices caused economic dispatch to favor imported energy, putting stress on the existing transmission system which was not designed for such significant reliance on imports.127
- **Power flow model correction** — A smaller conductor used to “expeditiously” replace lines damaged by Hurricane Lili in 2002 was incorrectly recorded in the power flow model and caused a fault, forcing lines out of service.128

- **Lack of operational flexibility** — Increased reliance on imports means that it was more difficult to obtain scheduled outages on the transmission system to perform routine maintenance.129

In 2008, a joint study facilitated by SPP identified several upgrade options, one of which was the ALP Project, comprised of a reliability component to address TLRs and related concerns and an additional economic component as shown in Table 5 below.

While the reliability component addressed historical and current reliability concerns, the economic component was deemed valuable to the parties to create “optionality” by allowing the removal of must-run status for older units and increased operational flexibility.

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126 Whitmore Testimony, 7/14/08, p. 7.
Table 5
ALP Project Components, Benefits, and Estimated Costs

<table>
<thead>
<tr>
<th>Component</th>
<th>Benefits</th>
<th>Total Est. Cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reliability Component (Responsible Entity):</strong></td>
<td></td>
<td>$71.9</td>
</tr>
<tr>
<td>- New 230 kV line from Labbe - Bonin (LUS)</td>
<td>• Relieves Entergy TLR procedures (allows for increased economic import)</td>
<td></td>
</tr>
<tr>
<td>- 500/230 kV auto transformer at Wells (Cleco)</td>
<td>• Accommodates load growth and improves load serving capability</td>
<td></td>
</tr>
<tr>
<td>- New 230 kV line from Wells - Labbe (Cleco/LUS)</td>
<td></td>
<td>Allocated roughly based on load ratio share and then matched with component ownership</td>
</tr>
<tr>
<td>- New 230 kV line from Labbe - Meaux (EGSL)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- 230/138 kV auto transformer at Meaux (Cleco)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Economic Component (Responsible Entity):</strong></td>
<td></td>
<td>$128.1</td>
</tr>
<tr>
<td>- 500/230 kV auto transformer at Richard (Cleco/EGSL)</td>
<td>• Allows removal of must-run designation for Cleco’s Teche and LUS’s Bonin</td>
<td></td>
</tr>
<tr>
<td>- New 230 kV line from Richard - Sellers Road (Cleco)</td>
<td>• Economic benefits largely to Cleco (est. fuel cost savings of $906 million 2010-2039)</td>
<td></td>
</tr>
<tr>
<td>- New 230 kV substation at Sellers Road to connect Labbe-Meaux and Richard - Sellers Road (Cleco)</td>
<td>• Additional generation dispatch flexibility and potential fuel cost savings for LUS</td>
<td></td>
</tr>
<tr>
<td>- New 230 kV substation at Segura near Moril (Cleco)</td>
<td></td>
<td>Approx. 70% allocated to Cleco (with smaller shares to EGSL and LUS) and then matched with component ownership</td>
</tr>
<tr>
<td>- New 230 kV line from Sellers Road - Segura (Cleco)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- 230/138 kV auto transformer at Segura (Cleco)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- New 138 kV line from Segura - Moril (Cleco)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Estimated Cost (as of 2008)</strong></td>
<td></td>
<td>$200.0</td>
</tr>
</tbody>
</table>


Cost allocation was developed by first determining which portion of the entire project addressed reliability concerns and which portion economic needs. For the reliability component, cost allocation was based on an adjusted load ratio share of Cleco, LUS, and EGSL as a proxy of received reliability benefits. (The adjustment was made to account for additional loads that each

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130 Ibid., p. 19.
utility served under contract, using projected 2012 load.) The adjusted load ratio shares as applied to the estimated reliability component costs are shown in column [2] in Table 6.

Table 6
ALP Project Reliability Component by Adjusted Load Ratio Share

<table>
<thead>
<tr>
<th>Sponsor</th>
<th>Adj. Projected 2012 Load (MW)</th>
<th>Adj. Load Ratio Share (%)</th>
<th>Based on Adj. Load Ratio Share ($ Million)</th>
<th>Based on Ownership</th>
<th>Based on Revised Estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td>EGSL</td>
<td>877</td>
<td>47%</td>
<td>$33.6</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Cleco</td>
<td>732</td>
<td>39%</td>
<td>$28.0</td>
<td>$26.6</td>
<td>$30.1</td>
</tr>
<tr>
<td>LUS</td>
<td>270</td>
<td>14%</td>
<td>$10.3</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,879</strong></td>
<td><strong>100%</strong></td>
<td><strong>$71.9</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Sources and notes:**
[2]: Percentage of each utility's projected load as a share of total.

According to filings made on behalf of Cleco, the $28.0 million share of the reliability component (as shown in column [3] of Table 6 above) was approximately aligned with the $26.6 million direct cost of constructing and owning the new transmission components interconnected to the Cleco system (as shown in column [4]). Therefore, in the first iteration of the Memorandum of Understanding (“MOU”), Cleco assumed $26.6 million in reliability-related ALP Project costs. In an updated MOU, Cleco and LUS each slightly expanded their projected buildouts with Cleco’s total estimated reliability costs increasing by $3.5 million to $30.1 million (as shown in column [5]). Despite this revision, the underlying allocation does not change. In fact, the MOU is structured so that each utility is individually responsible for components of the ALP Project in a way that is roughly commensurate with benefits received. For the economic component, Cleco is the main beneficiary and therefore will own and construct the majority of those facilities at a total estimated cost of $87.1 million.\textsuperscript{131}

\textsuperscript{131} Whitmore Testimony, 7/14/08, p. 23.
There are at least five important “lessons learned” from the ALP Project case study, as summarized by SPP Staff.\textsuperscript{132} First, there was general agreement that the various problems identified in the ALP had to be addressed and that \textbf{a seams solution could provide both individual and joint benefits}. Second, it was recognized that \textbf{needs and drivers were different for the parties involved}. The ALP Project provided both reliability and economic benefits, which accrued to parties differently. Third, \textbf{transmission planning and cost allocation was jointly considered} so that a solution and its associated costs produced equitable results. Fourth, \textbf{cost allocation via transmission ownership, not financial transfers, was easier to accomplish}. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each “seams entity” shared costs by building, owning, and maintaining a segment of the buildout. Similarly, each entity is responsible for recovering approved ALP Project-related costs through its own transmission tariff. Parties were also able to agree to the \textbf{approximate magnitudes of contribution rather than a strict matching of costs to benefits}. Cost allocation was determined by considering the approximate magnitude of the reliability and economic benefits to each party involved while also considering the geographic location of the future facilities and operational flexibility. And finally, \textbf{strong state-level participation} via Commissioner Jimmy Field of the Louisiana Public Service Commission and the ICT staff helped facilitate the process.

\textbf{B. Considerations for the Proposed Cost Allocation Framework}

We developed our cost allocation framework based on our review of barriers to seams cost allocation, the Draft Seams Cost Allocation Whitepaper, experiences elsewhere with interregional planning and cost allocation, FERC Order 1000, the ALP Project lessons, and discussions with SPP staff, SPP RSC staff, and stakeholders. Our framework also includes a set of cost allocation principles and methodologies to be used by SPP and its seams neighbors. Several objectives were identified by the Joint Project Team during the development effort, including that this framework:

\begin{enumerate}
\item Be compliant with FERC Order 1000;
\item Define a clear cost allocation methodology that provides enough guidance to be actionable;
\item Be flexible enough to be applied to all of SPP’s neighbors, which consist of both FERC jurisdictional and non-jurisdictional entities;
\item Accommodate both bilateral and multilateral agreements to address multi-party seams;
\end{enumerate}

\textsuperscript{132} Kelley, David, SPP Seams Steering Committee, “Acadiana Load Pocket,” memo to Seams Cost Allocation Task Force (“SCATF”), September 12, 2011.
5. Be able to be applied to individual seams projects or groups of seams projects (identified either unilaterally or jointly);

6. Be robust enough to accommodate different types of seams projects and projects that offer different types of benefits to different seams entities; and

7. Allow for learning based on experience.

These objectives also ensure consistency among seams agreements with different entities, while allowing for variation amongst agreements to account for a range of different types of projects and seams entities.

While the focus of our report is on seams cost allocation, our review of relevant experiences strongly suggests that seams cost allocation issues cannot be successfully addressed without consideration of several related components of the overall interregional transmission planning process. In fact, cost allocation is an integral part of interregional planning. For example, if costs are to be allocated based on benefits, there are fundamental requirements to calculating those benefits for each seams entity. These include availability of validated system data and planning models and a clear understanding of how transmission additions are planned and evaluated by each seams entity. Another consideration is state-level involvement in the planning process. As mentioned in the lessons learned from the ALP Project and interregional planning and cost allocation efforts elsewhere, state-level involvement during the planning and analysis stage more likely leads to an agreeable alignment of allocated costs and benefits to each of the seams entities.

Ideally, the cost allocation framework would be an integral part of a bilateral or possibly multilateral interregional planning agreement between the individual seams neighbors. It would include a process and timeline for proposing or identifying potential seams projects as well as commitments to meet regularly, develop jointly the models needed to accurately evaluate seams projects, and assess the benefits of the project to each entity consistent with (at minimum) each entity’s internal planning process and cost allocation methodologies. The framework would also be flexible enough to consider additional benefit metrics and cost allocation methodologies that are not currently used in the entity’s internal processes.

Through our discussions with SPP and SPP RSC Staff, we found that SPP’s joint operating agreements (“JOAs”) with Associated Electric Cooperative, Inc. (“AECI”) and MISO were the most logical starting points in our efforts to develop a more robust interregional planning and cost allocation framework. Each JOA is structured as a bilateral agreement and describes the

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133 In addition to the JOAs, SPP has a seams agreement with less detailed language with Entergy and three operating agreements with Southwestern Power Administration (“SWPA”), Tennessee Valley Authority (“TVA”), and Western Area Power Administration (“Western”), which are largely focused on the reliable
process for the development of a Joint Coordinated System Plan ("JCSP") to be led by a Joint Planning Committee ("JPC", comprised of planning staff from both entities), with input from an Interregional Planning Stakeholder Advisory Committee ("IPSAC").134

As set out in the JOAs, the purpose of the JCSP is to identify transmission expansions or enhancements to maintain reliability, improve operational performance, provide an economic benefit, or enhance the competitiveness of electricity markets in the combined footprint.135 The JOAs describe in some detail the types of models, studies, and updates (e.g., planning models, load flow, short circuit, and stability studies) that would be required to develop the JCSP and the timing of such information exchange and planning meetings. The JOAs also note that “single party planning” (e.g., for each entity’s internal or regional system) and generator interconnection and long-term firm transmission service requests in one system which may impact the other system should be coordinated with the JCSP process. With respect to cost allocation for seams projects, however, the JOAs only state that it would be decided on a case-by-case basis.

Our proposal is to leverage the existing JOAs by expanding on the already-specified processes and committees, provide guidance on missing but critical components, and adding proposed cost allocation principles and benefits measurements. We discuss each of these points in the following sections and present illustrative “straw man” tariff language in Appendix C that could serve as the starting point to expand the existing JOA into a comprehensive cost allocation framework between SPP and its seams neighbors.

C. BUILDING BLOCKS OF THE PROPOSED INTERREGIONAL PLANNING AND COST ALLOCATION FRAMEWORK

We have identified seven “building blocks” needed to support the proposed interregional planning and cost allocation. These building blocks are shown in Figure 3 and discussed in this and the following sections of our report. We also provided in Appendix C a redlined version of and inserts to SPP’s existing JOA to provide a “straw man” illustration of how these building

blocks and our recommendations for the proposed cost allocation framework could be integrated into SPP’s existing JOAs.

**Figure 3**

**Building Blocks of Proposed Interregional Planning and Cost Allocation Framework**

1. Regular interregional planning meetings
   - Leverage existing JOAs and expand

2. Regular exchange of planning data

3. Process to propose and analyze seams projects
   - Building blocks most closely related to seams cost allocation—largely missing from or underspecified in current JOAs

4. Evaluation criteria and benefit metrics

5. Seams cost allocation principles and guidelines
   - Discussed further in Sections VII-X with “straw man” JOA additions provided in Appendix C

6. Payment mechanisms and transmission rights

7. Integration with internal planning and cost allocation
   - Leverage existing JOAs and expand

Optional: Pre-specified formulaic evaluation and cost allocation methodology
   - Optional building block – may be added as experience is gained over time
   - Discussed further in Section XI

1. **Building Blocks Nos. 1, 2, and 7**

Building blocks Nos. 1, 2, and 7 already exist in some form in the JOAs but would need to be expanded. For example, **building block No. 1** requires a commitment to **regular interregional planning meetings** of the seams entities, as well as coordination with state, federal, and multi-state entities. While the current JOAs already provide for these commitments, we recommend more direct participation of regulatory commission staff from states affected by the particular seam in the planning and cost allocation discussions under the JOAs. Involvement by state regulatory staff in the evaluation of proposed seams projects, through a more prominent role of the IPSAC, for example, would likely facilitate the development of seams projects and cost
allocations that will ultimately be acceptable to each of the involved state commissions in their determination of needs, permitting, and, where applicable, retail rate recovery of the selected projects. As mentioned in our review of seams cost allocation elsewhere, Northern Tier Transmission Group’s cost allocation framework emphasizes the importance of early involvement by state commissions.\textsuperscript{136}

In addition, while the JOAs may specify bilateral meetings between entities, they should be flexible enough to \textit{evolve into agreements between multiple entities}, if doing so can more effectively address challenges along seams, such as on the eastern side of SPP that involve multiple entities.\textsuperscript{137} In the WECC for example, there are several standing seams-related planning groups where all the transmission owners involved with certain seams (\textit{e.g.}, the seam between Arizona, California, and Southern Nevada) meet periodically to coordinate transmission planning.

For \textbf{building block No. 2}, we recommend that seams entities should commit to the timely exchange of planning data as already envisioned in the current JOAs, which provide detailed lists of data to be exchanged for the purpose of developing the JCSP. However, to further facilitate identification and analyses of seams projects, we additionally recommend that seams neighbors \textit{jointly develop and validate load-flow cases and other planning models} for the combined footprint and their combined planning horizon. This would allow each seams entity to accurately analyze the system of its neighbor to develop potential seams projects and prepare credible initial system analyses and cost-benefit evaluations of the projects.

\textit{Building block No. 7} addresses the \textit{integration of the interregional planning and seams cost allocation with each entity’s internal planning and cost allocation processes}. This includes adding to the JOAs specific provisions that address who can propose a seams project, who can build and operate it, how planning analyses for seams projects are initiated, and how seams projects are integrated with internal planning processes and cost recovery, including planning in response to generation interconnection and transmission service requests, which can impact the overall benefits of seams projects.

Illustrative redlines to the existing JOA that provide a “straw man” starting point for addressing our recommendations related to building blocks Nos. 1, 2, and 7 are found in Appendix C.1.

\textsuperscript{136} Northern Tier Transmission Group, “NTTG Cost Allocation Principles,” discussion of Principle 3a, p. 10.

\textsuperscript{137} This is mentioned in the JOA with MISO in Section 9.1.1 (j): “The JPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective inter-regional planning coordination.”
2. Building Blocks Nos. 3, 4, 5, and 6

Building blocks Nos. 3 through 6 are most directly related to seams cost allocation. They are also underspecified and largely missing from the existing JOAs. We briefly describe these four building blocks below. Illustrative redlines to the existing JOA that could serve as the starting point to implement our recommendations for building block No. 3 are provided in Appendix C.1. In addition, Appendix C.2 provides straw man inserts to illustrate how building blocks Nos. 4, 5, and 6 could be added to the existing JOA.

**Building block No. 3** serves to define the parameters of a seams project and requires the specification of a *process to propose and analyze seams projects*. The JOAs largely rely on the JCSP process to identify seams projects. We propose to establish additional options under which seams entities (e.g., through their participating transmission owners) could *unilaterally or jointly* propose seams projects outside the JCSP process. SPP will also need to specify how their transmission owners and other market participants can propose seams projects to SPP. Our recommendations as to building block No. 3 are discussed in more detail in Section VII immediately below.

To implement **building block No. 4**, we recommend that each seams entity comprehensively specify the *evaluation criteria and benefit metrics* they will use for seams project evaluation. These criteria and metrics would not need to be identical across seams entities but would, at a minimum, need to include a comprehensive list of all benefits and metrics that each entity uses in its internal transmission planning process. In addition, we recommend the addition of benefits and metrics that are unique to seams projects, such as the value of wheeling through and out revenues. Our recommendations as to building block No. 4 are discussed in more detail in Section VIII of this report.

**Building block No. 5** consists of pre-specified *seams cost allocation principles and guidelines*. Rather than resolve seams cost allocation on a case-by-case approach, as is provided for under the current JOAs, we recommend the addition of principles and guidelines that would serve as the overarching framework for developing transmission cost allocation for seams projects. Section IX of this report specifies a number of recommended principles and guidelines and discusses our recommendations for building block No. 5 in more detail. We also provide case studies of how cost allocation shares might be derived for specific types of projects, based on the evaluation criteria and benefit metrics derived in building block No. 4.

**Building block No. 6** specifies *payment mechanisms* that allow for the actual sharing of project investment costs or project revenue requirements across the seam. Given the different characteristics of seams projects and limitations that certain entities may have in paying for transmission upgrades they do not own, we recommend that the seams agreements specify
several options for payment mechanisms, such as shared ownership or financial transfers that can be used to implement the agreed-upon cost allocations. We additionally recommend that physical or financial transmission rights are provided to each seams entity in exchange for these ownership shares or payments. Our recommendations for building block No. 6 are discussed in more detail in Section X of this report.

3. Optional Building Block

Finally, we recommend an optional building block that could allow for the inclusion of pre-specified formulaic evaluation and cost allocation methodologies for specific project types. Several seams cost allocation methodologies in other markets include such pre-specified formulaic approaches (i.e., those for interregional reliability and economic projects between the MISO and PJM). While such formulaic approaches have the potential to streamline the evaluation and cost allocation of seams projects, many seams projects will not “fit” the pre-specified qualifications criteria. We thus recommend that seams projects that do not fit such pre-specified options be evaluated under the general cost allocation framework as summarized above. Our recommendations for such an optional cost allocation building block are discussed in more detail in Section XI of this report.

VII. PROCESS TO PROPOSE AND ANALYZE SEAMS PROJECTS
(BUILDING BLOCK NO. 3)

The current JOAs do not contemplate pre-defined thresholds for a project to qualify as a “seams” project. We recommend that seams agreements remain free of specific thresholds (other than the filing requirements discussed below). Specifically, we recommend that there be:

1. No pre-defined threshold limits — we advise against thresholds based on criteria such as voltage class, total cost, and total benefits, because even “small” seams projects may offer substantial benefits.

2. No strict configuration requirement — we recommend that “seams projects” can either be defined as single project (or even components of a larger regional project) or be comprised of a portfolio of seams-related projects grouped together.

3. No physical location requirement — we recommend that the definition of seams projects be more broad than the definition of “interregional projects” under FERC Order 1000, to include projects that either cross the seam (as interregional projects are defined in Order
1000) or be located wholly within one entity’s footprint as long as the projects provide clear benefits to both seams entities.¹³⁸

4. No limitation to specific project types — we recommend acknowledging that seams projects serve one or several purposes. Projects may be driven by reliability needs, operational and economic benefits, policy requirements, or a combination of these factors, and these factors may differ for each seams entity. Seams projects should also be able to include transmission upgrades that facilitate, expand, or provide an alternative to seams entities’ internal transmission upgrades identified in their internal planning processes, including their evaluation of generation interconnection and transmission service requests.

We propose to start with a broad definition of seams projects because our discussions with SPP and other stakeholders indicated that seams-related challenges tend to cover a wide range of circumstances that makes it impractical to focus on specific thresholds. Any such thresholds or restrictive definitions can lead to sub-optimal solutions by prematurely disqualifying beneficial seams-related projects. For example, while the Acadiana Load Pocket had been identified as an area with a number of seams-related problems, the solution was a combination of upgrades to existing facilities as well as new substations, transmission lines, and capacitor banks.¹³⁹ Therefore, we recommend that the underlying qualification criteria should only be that a proposed seams project be able to address both seams entities’ transmission needs and offer commensurate benefits to both.

We also recommend that seams projects must be proposed—jointly or unilaterally—through a predefined process that clearly establishes the responsibilities of both seams entities. In addition to specifying a seams proposal process through the JOA, SPP (and neighboring RTOs) will need to specify internal processes (e.g., through the regional transmission planning process) under which individual transmission owners and other market participants can propose candidate seams projects to SPP. SPP can then further consider these candidate seams projects and then formally propose them under the interregional planning and seams cost allocation agreements with neighboring seams entities.

¹³⁸ Note that only the latter is defined as an “interregional” project in FERC’s Order 1000.

A. **Process for Unilaterally Proposed Seams Projects**

The current JOAs are focused on coordinating data exchange and planning studies so that entities can jointly produce the JCSP, which may in turn identify beneficial seams projects. We recommend that the framework be expanded to include a process under which seams entities can propose potential seams projects unilaterally as long as the unilateral proposal meets certain criteria. The submission of such a qualifying unilateral proposal would obligate the other seams entity to participate in a joint study of the proposed project within a pre-specified, agreed-upon timeframe.

To facilitate the timely assessment of unilaterally-proposed seams projects, the seams entities will need to specify (e.g., in their expanded JOA) how the evaluation of seams projects will be integrated into their existing transmission planning schedules and timeframes. This will allow the entities to define deadlines by which seams projects will need to be proposed for consideration in the next planning cycle. SPP’s internal processes may also need to specify by when SPP staff, transmission owners, or other market participants will need to propose projects for further evaluation as a potential seams project.

To trigger the joint obligations under the recommended framework, the seams entity proposing a project unilaterally would be required to submit a formal proposal to its neighbor that meets all agreed-upon pre-specified requirements. Our proposed requirements are shown in Table 7. Clearly defining the requirements that need to be met for unilaterally-proposed seams projects helps prioritize resources and focus attention on those projects that are deemed sufficiently valuable.

As the table shows, a formal unilateral proposal would, first, need to include a detailed description of the proposed seams project and, second, a *qualitative* discussion of the project’s needs, purpose, and benefits to both seams entities, which could differ on either side of the seam. Third, we recommend that such unilateral proposals include a preliminary *quantitative* analysis (e.g., power flow and/or economic studies) of the project’s benefits to both entities. This requires that the proposing seams entity has enough information about the neighboring system to undertake a preliminary quantitative analysis of seams-related impacts in the combined footprint and estimate benefits to both seams entities that, as discussed further below, are consistent with the metrics used by the neighboring seams entities in their transmission planning process. Finally, we recommend that seams project proposals also include a proposed preliminary cost allocation that is consistent with specified cost allocation principles and benefits identified in the preliminary analysis of the project.
Table 7
Recommended Requirements for Unilaterally-Proposed Seams Projects

<table>
<thead>
<tr>
<th>Requirements for Unilaterally-Proposed Seams Projects</th>
<th>Notes and Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Detailed description of the project</td>
<td>Needs to provide necessary project information such as:</td>
</tr>
<tr>
<td></td>
<td>• Geographic area</td>
</tr>
<tr>
<td></td>
<td>• Seams entities impacted</td>
</tr>
<tr>
<td></td>
<td>• Full technical description of the proposed project, including project costs</td>
</tr>
<tr>
<td>2. Qualitative discussion of the project’s purpose and potential benefits to both neighbors based on agreed upon benefits and metrics</td>
<td>• Articulates drivers of the proposed seams project</td>
</tr>
<tr>
<td></td>
<td>• Description of project benefits to both seams entities</td>
</tr>
<tr>
<td>3. Preliminary quantitative analyses of the project’s potential benefits to both entities relying on the specified transmission benefits and metrics relevant to each seams entity or both. The proposing entity needs to include: (1) appropriate documentation, such as assumptions and data used in the analysis, and (2) analyses and results that are consistent (though not necessarily comprehensive in scope) with the planning methods and metrics of each entity</td>
<td>• Requires updated and jointly-validated planning models for combined footprint</td>
</tr>
<tr>
<td></td>
<td>• Requires solid understanding of neighbor’s benefit metrics used in transmission planning</td>
</tr>
<tr>
<td>4. Proposal for preliminary cost allocation consistent with specified principles and guidelines as a starting point for discussions</td>
<td>• Requires specification of cost allocation principles and guidelines</td>
</tr>
<tr>
<td></td>
<td>• Requires seams entities to develop a shared understanding of how the specified cost allocation principals and guidelines would be applied (e.g., through the joint development of case studies and “test projects”)</td>
</tr>
</tbody>
</table>

The submission of a seams project proposal that meets these specified requirements would trigger the obligations under the proposed framework. For example, the neighboring seams entity would be obligated to conduct a joint study with the proposing entity within an agreed-upon timeframe (e.g., 6-12 months or to include the project in the JCSP study process). This joint study would comprehensively assess the benefits that the proposed project provides to both seams entities, thereby confirming, refining, or expanding the preliminary analyses by the seams project proponent.
As noted, regional planning entities that cover the systems of several transmission owners, may need to modify internal processes to specify: (1) how seams projects can be proposed by internal planning staff, individual transmission owners, and other market participants; (2) how the nominated seams project would be evaluated internally to decide whether to proceed with a formal seams project proposal; and (3) the schedule and timeline under which internally-nominated projects would be evaluated and, if desirable, formally proposed as a seams project under the interregional planning and seams cost allocation framework.

**B. PROCESS FOR JOINTLY-PROPOSED SEAMS PROJECTS**

Under the proposed framework, seams projects could also be proposed jointly based upon mutual agreement of the seams entities. Such joint seams project proposals could be made either (1) as the result of joint planning studies under the JCSP or (2) based on *ad hoc* agreements between the seams entities.

In this case, the seams entities would jointly prepare the project documentation and preliminary analysis and cost allocations specified in Table 7 above. After obtaining stakeholder input, the parties could then prepare the final seams project study either as a standalone analysis or, if timely enough, within the JCSP study effort.

**VIII. EVALUATION CRITERIA AND BENEFIT METRICS**

*(BUILDING BLOCK NO. 4)*

A key building block and the foundation of any successful cost allocation framework is the detailed and comprehensive articulation of seams project evaluation criteria and benefit metrics. We refer to “benefits” as the obligations, goals, economic benefits, cost reductions, avoided costs, and other improvements and savings that the transmission investment may meet or achieve in the context of the transmission needs and drivers in each seams entity’s internal (local and regional) transmission planning process. We refer to “metrics” as the means used to quantify, monetize, or more qualitatively describe each benefit. In Section VIII.A we first lay out the recommended benefit principles applicable to seams projects, followed by the benefit metrics that can be derived from SPP’s and other seams entities’ transmission planning process in Section VIII.B. In Section VIII.C, we describe additional benefits that seams projects may provide or can be added over time, which are not currently considered explicitly in internal planning processes.
A. Benefit Principles Applicable to Seams Projects

As the ALP Project experience clearly demonstrated, a single seams project can provide a range of different benefits to various seams entities. Had the ALP Project only been evaluated on reliability grounds, there may not have been “enough” individual benefits to justify even the cost of the reliability component. Furthermore, SPP is faced with a particular challenge in that certain commonly-used metrics within organized markets—such as adjusted production cost or “APC” savings—may not be used in the transmission planning effort of non-market or non-jurisdictional seams entities. Therefore, it is important that seams entities who are parties to the interregional cost allocation framework agree on a well-specified set of benefit principles and metrics. We therefore provide a recommended set of “benefit principles” that could be adopted by the neighboring seams entities within their JOAs as listed in Table 8. Illustrative JOA language is provided in Appendix C.2.

While these principles set the stage for defining benefits and metrics for all seams entities who are party to the cost allocation framework, we recommend that seams entities not be required to use the same exact benefits and metrics—though we expect there to be a significant degree of overlap, especially with regard to reliability-related benefits and metrics.

The JOAs only broadly mention benefits such as maintaining reliability, improving operational performance, providing an economic benefit, or enhancing the competitiveness of electricity markets. However, there are no details within the JOAs that would define “reliability” or “economic” benefits or specify metrics that should be used to measure them. We recommend that the specified seams-related benefits and metrics for each seams entity include, at minimum, all benefits and metrics that the seams entity uses in its internal transmission planning efforts. We also recommend that each seams entity has the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity, even if these benefits and metrics are not currently used in its internal transmission planning process.

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### Table 8
**Recommended Benefit Principles**

<table>
<thead>
<tr>
<th>Principle</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Seams projects (either as single projects or a group of projects) may offer combinations of different types of benefits;</td>
</tr>
<tr>
<td>2.</td>
<td>It is possible that entirely different sets of benefits may accrue to each seams entity from a particular seams project;</td>
</tr>
<tr>
<td>3.</td>
<td>The benefits and metrics used for the evaluation of seams projects by each entity will include all benefits and metrics considered in each seams entity’s local and regional transmission planning process;</td>
</tr>
<tr>
<td>4.</td>
<td>Each seams entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity’s internal transmission planning process;</td>
</tr>
<tr>
<td>5.</td>
<td>The seams entities recognize that seams projects may offer unique benefits beyond those currently considered in either entity’s internal transmission planning process. If deemed significant, the entities agree to develop metrics to capture any such additional seams-related benefits;</td>
</tr>
<tr>
<td>6.</td>
<td>The seams entities recognize that additional benefits may be documented as more experience is gained with the planning and evaluation of seams projects. If deemed significant, the seams entities agree to develop metrics to capture any such additional seam-related benefits; and</td>
</tr>
<tr>
<td>7.</td>
<td>The seams entities recognize that seams projects may serve to avoid or delay the cost of (1) transmission projects in their existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy generation interconnection and transmission service requests.</td>
</tr>
</tbody>
</table>

Additionally, as shown in the above table, we recommend that seams entities agree that seams projects can offer unique benefits beyond those currently considered in either seams entity’s internal transmission planning process and that additional benefits may be documented as more experience is gained with the planning and evaluation of seams projects. If deemed significant, the seams entities would agree to develop metrics to capture any such additional seams-related benefits.

As addressed in our discussion of cost allocation principles and guidelines (Section IX), benefit principles Nos. 4-7 also help mitigate “fairness concerns” related to the potentially different scope of benefits that the proposed framework defines for different seams entities under benefit principle No. 3. In addition, one of the proposed cost allocation principles presented in Section IX.A requires that the allocated benefits of a seams project, when compared to its allocated costs, must be sufficient to support the project’s approval based on the criteria that are used in each entity’s internal transmission planning process. This means even if one seams entity (such as SPP) utilizes a more comprehensive definition of project benefits, the project will still be beneficial to the seams entity when considering both its share of benefits as well as its share of costs. This will ensure that the seams project and its cost allocation: (1) offers
acceptable net benefits to each seams entity; (2) is more attractive than pursuing the project without cost sharing; and (3) is more attractive than not pursuing the project (and thus not realizing any of its benefits).

B. Benefits and Metrics Used in Entities’ Internal Planning Processes that Would also be Applied to Seams Projects

As noted earlier, we recommend that the specified seams-related benefits and metrics for each seams entity include, at minimum, all benefits and metrics that the seams entity uses in its internal transmission planning efforts. To provide an illustrative example, we have summarized the benefits and metrics SPP currently uses to evaluate regional projects. By specifying the full set of these metrics in the JOA, including through references to relevant SPP-internal documents such as the Integrated Transmission Planning (“ITP”) manual, SPP’s seams neighbors would be able to evaluate whether or not a potential seams project would meet SPP’s planning criteria.

Table 9 summarizes the benefits currently considered by SPP in its internal evaluation of local and regional transmission projects and how those benefits are measured quantitatively, are monetized, or are only qualitatively considered.

To illustrate how the above list of benefits applied in SPP’s internal transmission planning processes may differ from those of other seams neighbors, we provide as a purely illustrative example the benefits and metrics that a non-jurisdictional entity may be considering in its transmission planning efforts. This list, shown in Table 10, is based on our review of Western Area Power Administration (“Western”) 2011 Strategic Plan. It has not been confirmed by Western and we use it solely as an illustration for the broad range of benefits that might be considered by non-RTO entities, even though their evaluation criteria and benefit metrics may be less formulaic or clearly stated than those in RTO markets.

The fact that seams neighbors may consider different benefits or analyze similar benefits differently has also been illustrated by the ALP Project case study discussed earlier in this report. Each of the sponsors of the ALP Project received either reliability or economic benefits (or both) but even similar benefits were categorized differently by the different sponsors and different metrics were used for similar categories of benefits. For example, Cleco found that the ALP Project would help reduce the cost of running one of its oldest and most expensive generators, thus providing an economic benefit. LUS also found that the ALP Project could help it avoid running more costly generators during summer peak, but considered that to be largely a

141 The most recent ITP manual can be found at: http://spp.org/section.asp?pageID=128.
reliability benefit with only some economic impacts. On the other hand, Entergy quantified reliability benefits as a reduction in TLRs and firm curtailments. Therefore, while broad categories of benefits are a useful starting point for the analysis of seams projects, specific benefit descriptions and metrics are needed to produce actionable results.

Table 9
Summary of SPP Internally-Used Benefits and Metrics That Would Also be Applied to Seams Projects

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Specific Benefits</th>
<th>Qualitative and/or Quantitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability benefits</td>
<td>Ability of project to avoid reliability violations</td>
<td>Quantified as number/duration of violations; monetized as avoided cost of regional/local upgrades</td>
</tr>
<tr>
<td>Reduced costs</td>
<td>Ability of project to produce adjusted production cost savings</td>
<td>Monetized through PROMOD or similar simulations</td>
</tr>
<tr>
<td></td>
<td>Ability to replace or delay future or previously approved projects</td>
<td>Monetized as the avoided cost of replaced or delayed projects</td>
</tr>
<tr>
<td></td>
<td>Energy value of reduced transmission losses</td>
<td>Monetized based on quantification through power flow simulations</td>
</tr>
<tr>
<td></td>
<td>Capacity value of reduced transmission losses</td>
<td>Monetized as avoided capacity</td>
</tr>
<tr>
<td></td>
<td>Reduced emissions costs</td>
<td>Monetized as allowances not purchased</td>
</tr>
<tr>
<td>Improved / increased ATC</td>
<td>Value of improved Available Transfer Capabilities</td>
<td>Quantified as incremental capacity (MW)</td>
</tr>
<tr>
<td></td>
<td>Export/import improvements</td>
<td>Quantified as incremental capacity (MW)</td>
</tr>
<tr>
<td></td>
<td>Ability to serve new load</td>
<td>Monetized as an offset to proposed seams project cost based on how much new load can pay for part of the project</td>
</tr>
<tr>
<td></td>
<td>Access to beneficial services from other markets such as ancillary services or diversity exchange</td>
<td>Monetized value can be cost of additional generation in SPP footprint to supply those services</td>
</tr>
<tr>
<td>Improved / increased competition</td>
<td>Levelization of LMPs</td>
<td>Qualitative consideration</td>
</tr>
<tr>
<td></td>
<td>Improved competition in SPP markets</td>
<td>Qualitative consideration</td>
</tr>
</tbody>
</table>
Table 10
Illustrative List of Benefits and Metrics Considered in a Non-RTO Seams Entities’ Transmission Planning Process

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Specific Benefits</th>
<th>Qualitative and/or Quantitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>Avoid reliability violations</td>
<td>Quantified as number/duration of violations and monetized as avoided cost of regional/local upgrade</td>
</tr>
<tr>
<td></td>
<td>Reduce frequency and cost of supply interruptions during low-hydro years</td>
<td>Quantified as number/duration of likely events and monetized as cost of interruptions or replacement power</td>
</tr>
<tr>
<td>Load serving benefits</td>
<td>Reduce the dispatch of high-cost generation resources needed to serve load in presence of internal transmission congestion or import constraints</td>
<td>Monetized as reduced generation and emission costs</td>
</tr>
<tr>
<td></td>
<td>Avoid cost of local transmission upgrades needed to support load growth</td>
<td>Monetized as avoided cost of regional/local upgrade</td>
</tr>
<tr>
<td>Increased off-system sales (to maximize value to electric service customers)</td>
<td>Increase in ATC and thus off-system sales</td>
<td>Monetized as incremental off-system sales profits and/or transmission rights</td>
</tr>
<tr>
<td></td>
<td>Increase in sales of ancillary services to other systems (e.g., for wind balancing)</td>
<td>Monetized as incremental off-system sales profits and/or transmission rights</td>
</tr>
<tr>
<td>Reduced transmission losses</td>
<td>Reduce transmission losses</td>
<td>Monetized as energy and on-peak capacity savings</td>
</tr>
<tr>
<td>Renewables integration benefits</td>
<td>Ability to avoid or delay local/regional transmission upgrades needed to integrate renewable resources for Western’s strategic goals or RPS, if any</td>
<td>Monetized as revenue (or offset to costs) from accommodating multiple transmission service requests and/or generator interconnection requests</td>
</tr>
<tr>
<td></td>
<td>Renewable integration benefit of CO₂ and other emission reductions</td>
<td>Quantified as tons of CO₂ avoided and measured as part of meeting Western’s strategic goals and monetized for other emissions with allowance prices</td>
</tr>
<tr>
<td></td>
<td>Proactively respond to a group of renewables interconnection requests rather than serially</td>
<td>Qualitative benefit for queue efficiency and may help to address chicken-and-egg issue for intermittent generation</td>
</tr>
<tr>
<td>Economic and renewable development</td>
<td>Ability of project to promote renewables and economic development consistent with policy objectives</td>
<td>Quantified as jobs created, economic impact on communities, potential fiscal benefits such as taxes or land-lease payments</td>
</tr>
<tr>
<td>Operational benefits</td>
<td>Ability of project to improve operating and maintaining flexibility and efficiency</td>
<td>Qualitatively described and monetized as must-run payments or cost of outage if maintenance is needed</td>
</tr>
</tbody>
</table>
In the context of how benefits can be defined for the purpose of cost allocation, it is also important to recognize that benefits can be considered both directly and indirectly. The definition of a direct benefit is the cost savings, efficiency gains, avoided costs, or revenue offsets provided by a seams project. Examples of this type of benefit are APC savings, additional wheeling revenues associated with ATC increases, or the avoided cost of other transmission projects. For the purpose of cost allocation, however, benefits can also be considered indirectly—such as through an entity’s contribution to the need for a seams project or on a “cost causation” basis. For example, an entity’s contribution to flows on a constrained facility that caused a reliability concern can be considered a proxy for the share of reliability benefits that the entity receives from a seams project which alleviates or eliminates the reliability concern.

C. BENEFITS APPLICABLE TO SEAMS PROJECTS

Internally-considered benefits and metrics are good starting points but may not comprehensively reflect the benefits of seams projects. For example, SPP quantifies APC savings calculated from PROMOD simulations, where imports are priced at the average internal load LMP and exports are priced at the average internal generation LMP. This leaves out wheeling revenues and other gains from trade due to differences in the load and generation LMPs between regions. Therefore, internally-considered benefits and metrics will need to be reviewed to see if they leave “gaps” that may be relevant for seams projects. This effort may identify additional benefits provided by seams projects that may not be applicable to region-internal transmission investments. Table 11 provides examples of such additional seams-project-related benefits and metrics that are not typically applicable to region-internal projects.

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Specific Benefits</th>
<th>Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental wheeling through and out revenues</td>
<td>The ability of a seams project to increase export ATC, support transmission service requests and, as a result, generate incremental wheeling through and out revenues that offset a portion of the project’s costs</td>
<td>Estimates of additional wheeling volumes derived from transmission service requests and/or PROMOD modeling</td>
</tr>
<tr>
<td>Benefits from increased reserve sharing capability</td>
<td>The extent to which increased intrietie ATC with the neighboring system allows for a reduction of a seams entity’s planning reserve requirement or the cost of planning reserves.</td>
<td>Quantified as a reduction in MW of reserve capacity</td>
</tr>
</tbody>
</table>
We recommend that the seams entities consider including these additional benefits and metrics in the evaluation process and cost allocation framework for seam projects. We also recommend that the seams entities agree that additional benefits and metrics can be considered on a project-specific basis upon mutual agreement of the seams entities. As noted earlier, illustrative “straw man” JOA language implementing these benefits and metrics recommendations for the proposed seams cost allocation framework is provided in Appendix C.

IX. SEAMS COST ALLOCATION PRINCIPLES AND GUIDELINES (BUILDING BLOCK NO. 5)

The fifth building block, and a main focus of this report, is the specification of general cost allocation principles and guidelines that build on the identified seams project-related benefits and metrics. The “cost allocation principles,” as discussed in Section IX.A, serve as the overarching framework for the development of cost allocations for specific seams projects based on their identified benefits. We also additionally provide specific “cost allocation guidelines” in Section IX.B, which explain via examples how certain benefits and metrics can be used to derive cost allocations for seams projects that are consistent with the specified cost allocation principles. These principles and guidelines are then applied to illustrative case studies in Section XII.

A. COST ALLOCATION PRINCIPLES

The cost allocation principles of a comprehensive framework will, at minimum, need to be consistent with the six interregional cost allocation principles specified in FERC Order 1000 as discussed in Section V above. However, based on our review of seams cost allocation principles and methodologies elsewhere we propose a broader set of cost allocation principles as shown in Table 12.

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142 As noted earlier, our recommended definition of a “seams project” is broader than in Order 1000, which defines as “interregional” only projects that physically cross the seam between regions. In our proposed framework, “seams projects” may be wholly located within one seams entity’s footprint as long as both seams entities agree that the project justifies cost allocation because it provides meaningful benefits to both entities.
Table 12
Recommended Cost Allocation Principles

<table>
<thead>
<tr>
<th>Principle</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>The cost of seams projects should be allocated to seams entities such that they are at least roughly commensurate with total benefits identified for each of the seams entities based on the benefits and metrics specified. Neither entity should be allocated a share of the cost of a seams project in which it receives no benefit.</td>
</tr>
<tr>
<td>2.</td>
<td>The application of cost allocation methodologies and identification of benefits and beneficiaries must be transparent.</td>
</tr>
<tr>
<td>3.</td>
<td>Different cost allocation methods can be applied to different types (e.g., transmission needs driven by reliability, economic, or public policy requirements) or different portions of transmission facilities.</td>
</tr>
<tr>
<td>4.</td>
<td>The seams entities will quantify and, if possible, monetize the identified benefits based on the metrics provided. The seams entities will also recognize non-monetized and non-quantified benefits in their assessment of the overall reasonableness of proposed seams project cost allocations.</td>
</tr>
<tr>
<td>5.</td>
<td>The seams entities agree that the monetized reliability, load serving, public policy, or other benefit of a seams project will be at least equal to the avoided cost of achieving the same benefit solely through cost-effective local or regional transmission upgrades.</td>
</tr>
<tr>
<td>6.</td>
<td>If benefit-to-cost ratios are used to assess the desirability of seams project to a seams entity or the seams entities as a group, the benefit-to-cost threshold must not exclude projects with significant net benefits. The threshold should not exceed 1.25.</td>
</tr>
<tr>
<td>7.</td>
<td>Benefits to each seams entity need to be sufficient to support each seams project’s approval through each entity’s internal planning process considering the costs allocated to each seams entity; and</td>
</tr>
<tr>
<td>8.</td>
<td>Seams project costs allocated to each seams entity will be recovered via the existing internal (local and regional) cost allocation process of each entity.</td>
</tr>
</tbody>
</table>

As shown in Table 12, many of the proposed cost allocation principles simply implement Order 1000 requirements. However, principles Nos. 4, 5, and 7 go beyond Order 1000 requirements. For example, the proposed principle No. 4 reflects the expectation that cost allocations be mostly based on quantifiable benefits and thus requires that the seams entities will attempt to quantify and monetize the identified benefits based on the metrics provided. It also states, however, that non-monetized and non-quantified benefits should still be considered at least qualitatively in the seams entities’ assessment of the overall reasonableness of any proposed cost allocations. Principle No. 5 provides a framework for the monetization of reliability, load serving, public policy, and similar other benefits of seams projects by requiring that the monetized value of such benefits be at least equal to the avoided cost of achieving the same benefit(s) through cost-effective local or regional transmission solutions.

Finally, the proposed cost allocation principle No. 7 goes beyond Order 1000 requirements by specifically addressing “fairness concerns” related to the potentially different scope of benefits that the proposed framework defines for different seams entities. The principle requires that both
the allocated benefits of a seams project, when compared to its allocated costs, are sufficient to support the project’s approval based on the criteria that are used in each entity’s internal transmission planning process. This means even if one seams entity (e.g., SPP) utilizes a more comprehensive definition of project benefits, the project will still be beneficial to the seams entity considering both its share of benefits as well as its share of costs.

While it is still possible that the broader scope of benefits will result in a larger share of allocated costs, the entity is not asked to approve a seams project at terms that are any less attractive than the terms that would be considered for local and regional projects in the entity’s internal planning process. In other words, while it is still correct that the seams entity with the broader scope of considered benefits will tend to share more of a projects’ costs, the cost allocation outcome will (1) result in a project with acceptable net benefits; (2) be more attractive than pursuing the project without cost sharing; and (3) also be more attractive than not pursuing the project (and thus not realizing any of its benefits).

In addition, as noted in our discussion of benefits principles, the potential for greatly differing scopes of seams project-related benefits considered by each of the seams entities is mitigated by benefit principles Nos. 4 through 7 (see Table 8), which note that (1) each seams entity has the option to consider some or all of the benefits and metrics used by the other entity; (2) the seams entities will recognize benefits that are unique to seams projects even if they go beyond those considered in their internal planning processes; (3) additional benefits may be documented and considered as more experience is gained in the evaluation of seams projects; and (4) benefits will be at least as large as the cost of avoided cost-effective regional or local project alternatives.

**B. Cost Allocation Guidelines**

We recommend that seams agreements and associated business practice manuals include “cost allocation guidelines” that provide additional guidance on and illustrations of how benefit metrics would be applied in accordance with the cost allocation principles. This provides an opportunity for seams entities to memorialize how they weigh and prioritize the list of benefits detailed in the seams agreement. It also provides an opportunity for entities to explain the seams cost allocation framework through concrete (even if illustrative) examples. While an infinite number of guidelines and examples could be created, we suggest that entities focus on developing a core set of guidelines based on the benefit metrics most important to the entities involved, showing how the identified benefits would be considered in developing cost allocations.
We recommend an approach to developing guidelines under which the costs of a seams project allocated to each party can be based on one or a combination of several mechanisms. The first cost allocation mechanism would simply allocate seams project costs based on the share of monetized benefits. In other words, costs would be allocated in proportion to the present value of project benefits received by each entity compared to the sum of the entities’ present value of total benefits received.

In addition, cost allocation for some seams projects may also lend itself to consideration of more qualitative, non-monetized benefits and cost causation ratios. For example, the seams entities could stipulate in their agreement that the cost of a seams project could also be shared based on:

- Each entity’s relative contribution to the need for a project if the seams entities can agree that such contributions to need are either a reasonable proxy for the project’s benefits (or roughly proportionate to the benefits) received by each entity. Examples of such allocations could be applying load-ratio shares or shares of power flows that contribute to the costs of a reliability-driven upgrade, or allocating the costs of a renewables-integration driven upgrade in proportion to PPAs signed by load-serving entities in their footprint or the entities’ RPS requirements.

- Each entity’s projected or allocated usage share of the project’s added transmission capability (e.g., allocated shares of increased flow-gate capacity) if the seams entities agree that such usage shares are either a reasonable proxy for the benefits (or roughly proportionate to benefits) received by each entity.

- Finally, the costs of seams projects could be allocated based on the project’s physical location in each entity’s footprint (e.g., shares of circuit miles or direct assignment of project segments) if the seams entities agree that such footprint-based shares will be roughly proportionate to the benefits received by each party.

We provide in Section XII a recap of the ALP Project and two case studies which serve as an illustration for applying these cost allocation guidelines to seams projects.
X. PAYMENT MECHANISMS TO IMPLEMENT SEAMS COST ALLOCATION
(BUILDING BLOCK NO. 6)

The final building block of our proposed seams cost allocation framework specifies the payment mechanisms that can be used to implement the agreed-upon cost allocations. We propose as a starting point the consideration of two types of payment mechanisms: (1) physical ownership shares; and (2) financial transfers. To facilitate such implementation of cost allocation, we also recommend that, to the extent feasible and practical, an entity sharing the cost of seams projects should also receive physical or financial rights for a commensurate share of the project’s added transmission capability (e.g., a share of increased flow gate capability).

Cost allocation based on physical ownership shares can be implemented through either (1) physical ownership of individual project segments or (2) co-ownership of the seams project or individual project segments. In either case, ownership of individual project segments would be assigned so that the investment and operating cost of each owned portion of the project is consistent with the determined cost allocations. Co-ownership of seams projects or individual project segments may be necessary where the project cannot be divided into fully-owned segments or if a proposed project (or project segment) is entirely within the service territory of only one of the seams entities. In other words, different shares of the seams project would be allocated to existing or new transmission owners within each of the two seams entities. The transmission owners would then simply recover the cost of their portion of the seams project as they would recover the cost of any other internal (regional or local) transmission project.

If the seams project is developed by a single corporate entity, the company could form a transmission-owning subsidiary in each of the neighboring seams entities, each of which would recover the costs associated with its ownership share of the seams project through the respective seams entity’s existing regional or local cost recovery options. As discussed in Section VI.A, such an ownership-based approach was used to allocate costs of the ALP Project. It also is and has been used routinely for transmission cost allocation throughout the WECC, such as within NTTG.

Where ownership-based allocation of project costs is neither feasible nor practical, cost allocation can be implemented through financial transfers from one seams entity to the other. These payments would correspond to the determined share of the seams project’s revenue requirements. We also recommend such payments be implemented in conjunction with the assignment of physical or financial rights for a commensurate share of the project’s added transmission capability. The revenue requirements associated with payments to the neighboring seams entity would be recovered consistent with the cost recovery of the revenue requirements of local and regional projects in the transmission owner’s regional footprint.
Examples of transmission rights provided under either the ownership or financial transfer options may be rights to a share of added flowgate capacity or rights to ATC increases provided by a seams project. In Day-2 markets, such rights may involve auction revenue rights or capacity transfer rights, similar to the rights that RTOs may already provide to the sponsors of “elected” or “participant funded” transmission upgrades.

Without obtaining any such transmission rights, many non-RTO and non-jurisdictional entities simply may not be able to assume the required ownership obligations or make financial payments to the neighboring seams entity. Most likely, only neighboring RTOs would be able to implement a financial transfer mechanism without obtaining rights to the transmission capability added by the seams projects for which they are paying. However, even for neighboring RTOs, the receipt of transmission rights in return for owning or paying for a portion of a seams project will increase the certainty of capturing project benefits and thus reduce inherent barriers to the joint pursuit of seams projects.

XI. OPTIONAL BUILDING BLOCK: PRE-SPECIFIED FORMULAIC EVALUATION AND COST ALLOCATION METHODOLOGY

As more experience with cost allocation of seams projects is gained, neighboring seams entities may find it helpful to specify more formulaic project evaluation and cost allocation options that would apply to specific types of seams projects. Examples of such pre-specified formulaic options are the frameworks that MISO and PJM have specified for cross border reliability and market efficiency projects (as summarized in Section IV.A). Ideally, such options would be created once it becomes clear that certain project evaluations and cost allocation formulas work well for specific types of seams projects that will likely be encountered periodically.

This option would allow seams entities to fully or partly pre-specify: (1) project qualification criteria; (2) the specific benefits and metrics used in the evaluation of seams transmission projects; and (3) a formula for cost allocation that relies on these benefits and metrics. Such pre-specified formulas could be developed for some or several types of projects, such as reliability, congestion relief, or public policy projects. Projects that do not “fit” any such pre-specified options will still be considered under the more general cost allocation framework described above.

A variation to this approach may be a less formulaic approach which would provide more specific guidelines for specific types of projects. For example, an agreement between SPP and
AECI might note that for reliability-only projects, acceptable cost allocations would be based on each entity’s avoided costs of implementing their own solutions.

XII. CASE STUDIES: QUALITATIVE APPLICATION OF FRAMEWORK TO CANDIDATE SEAMS PROJECTS

As part of our effort to develop a robust seams cost allocation framework, we wanted to test it on actual or proposed projects. In Section XII.A we provide an overview of the feedback we received from stakeholders on candidate seams projects to evaluate. Based on this feedback and in discussions with the Joint Project Team, we apply our proposed framework to an actual seams project in Section XII.B and, on an illustrative basis, to two proposed seams projects in Sections XII.C and XII.D.

A. CANDIDATE SEAMS PROJECTS

We asked members of SPP Staff, RSC staff, the SPP Seams Steering Committee, and representatives of seams neighbors to provide candidate seams projects, including the following information:

- Why is the project needed from your company’s perspective?
- What are the project’s possible benefits?
- Have there already been any studies of the project?
- What are the barriers to the project (why has it not been pursued)?
- Are there lower cost projects that would be interesting to evaluate?

The following candidate seams projects were received (see Appendix D for more detailed descriptions of each):

- Acadiana Load Pocket (“ALP”) Project involving seams entities Entergy/Cleco/LUS
- Branson Area Project involving seams entities SPP/AECI
- Quarry Project (Western Entergy Area) involving seams entities SPP (AEPW)/Entergy
- Danville Area EHV Station involving seams entities SPP (OGE)/Entergy
- Murfreesboro Project involving seams entities SPP (AEPW)/Entergy

As also discussed in Section VI.A, the ALP Project provides a case study of an actual “seams” project that has been under development for several years and provides particularly helpful lessons for the development of a robust framework. Except for the ALP Project, the remainder of the candidate seams projects are currently only in the early proposal stages. For some of the
projects, preliminary initial analyses have been conducted but are not conclusive and (to the best of our knowledge) seams cost allocation has not even been approached.

In addition to the ALP Project case study, we selected two of these proposed projects to illustrate the application of the proposed framework and its ability to consider different types of projects, benefits, cost allocation methodologies, and payment mechanisms.

The first of these two additional case studies, the Branson Area Project, highlights the need for closer integration of top-down and bottom-up transmission planning studies with seams coordination. It also illustrates the intrinsic value of seams projects, which often is not captured in internal planning processes. The Branson Area case study documents the ability of the proposed framework to consider projects between multiple market and non-market areas with potentially very different benefits considerations and physical ownership options of different project segments as a means to implementing cost allocation.

The second case study, the Quarry Project, is an illustrative example of a seams project that is wholly within one seams entity’s footprint but may benefit both market and non-market seams neighbors by addressing reliability concerns in a load pocket as well as unfulfilled transmission service requests. These case studies also provide additional guidance on how to apply the cost allocation principles and guidelines discussed in Section IX.B.

B. ALP Project

As described in Section VI.A, the ALP Project is a successful example of a multi-party cost allocation for a seams project. To test the robustness of our proposed framework, we compare the ALP Project experience against our benefit principles (Section VIII.A), cost allocation principles (Section IX.A), and payment mechanisms (Section X). Table 13 below reproduces the recommended benefit principles and highlights the principles (with a blue arrow) that apply to the ALP Project. (Those principles that that do not directly apply appear in grey font.)
Table 13
Recommended Benefit Principles as Applied to the ALP Project

1. Seams projects (either as single projects or a group of projects) may offer combinations of different types of benefits;
2. It is possible that entirely different sets of benefits may accrue to each seams entity from a particular seams project;
3. The benefits and metrics used for the evaluation of seams projects by each entity will include all benefits and metrics considered in each seams entity’s local and regional transmission planning process;
4. Each seams entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity’s internal transmission planning process;
5. The seams entities recognize that seams projects may offer unique benefits beyond those currently considered in either entity’s internal transmission planning process. If deemed significant, the entities agree to develop metrics to capture any such additional seams-related benefits;
6. The seams entities recognize that additional benefits may be documented as more experience is gained with the planning and evaluation of seams projects. If deemed significant, the seams entities agree to develop metrics to capture any such additional seam-related benefits; and
7. The seams entities recognize that seams projects may serve to avoid or delay the cost of (1) transmission projects in their existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy generation interconnection and transmission service requests.

As Table 13 shows, the ALP Project utilizes the majority of the benefits principles, which creates the foundation for considering cost allocation. The two principles not directly applicable to the ALP Project relate to the evolution of benefits based on project experience. Table 14 below follows the same format, but applied to the recommended cost allocation principles.
Table 14
Recommended Cost Allocation Principles as Applied to the ALP Project

1. The cost of seams projects should be allocated to seams entities such that they are at least roughly commensurate with total benefits identified for each of the seams entities based on the benefits and metrics specified. Neither entity should be allocated a share of the cost of a seams project in which it receives no benefit.

2. The application of cost allocation methodologies and identification of benefits and beneficiaries must be transparent.

3. Different cost allocation methods can be applied to different types (e.g., transmission needs driven by reliability, economic, or public policy requirements) or different portions of transmission facilities.

4. The seams entities will quantify and, if possible, monetize the identified benefits based on the metrics provided. The seams entities will also recognize non-monetized and non-quantified benefits in their assessment of the overall reasonableness of proposed seams project cost allocations.

5. The seams entities agree that the monetized reliability, load serving, public policy, or other benefit of a seams project will be at least equal to the avoided cost of achieving the same benefit solely through cost-effective local or regional transmission upgrades.

6. If benefit-to-cost ratios are used to assess the desirability of seams project to a seams entity or the seams entities as a group, the benefit-to-cost threshold must not exclude projects with significant net benefits. The threshold should not exceed 1.25.

7. Benefits to each seams entity need to be sufficient to support each seams projects’ approval through each entity’s internal planning process considering the costs allocated to each seams entity; and

8. Seams project costs allocated to each seams entity will be recovered via the existing internal (local and regional) cost allocation process of each entity.

As Table 14 shows, the ALP Project utilizes all of the cost allocation principles except for (as far as we were able to determine) a specific benefit-to-cost ratio. This demonstrates that the benefit and cost allocation principles are flexible enough to consider such a complicated project and lead to successful cost allocation between the entities. Table 15 below follows the same format as applied to payment mechanism.
Table 15

Recommended Payment Mechanisms as Applied to the ALP Project

1. Cost allocation may be implemented through physical ownership shares of either (1) individual project segments, or (2) co-ownership of the seams project or individual project segments; or

2. Cost allocation may be implemented through financial transfers.

3. Each entity will recover allocated costs consistent with cost recovery of local and regional projects within its footprint.

4. To the extent feasible and practical, an entity sharing the cost of seams projects should also receive a physical or financial transmission right for a commensurate share of the project’s added transmission capability.

The ALP Project cost allocation and payment mechanism was based on ownership of individual segments of the project and utilizes most of the payment mechanism guidelines listed in Table 15 above. Consistency with benefits and cost allocation principles and payment mechanisms shows that a seams project similar to the ALP Project could have been approved based on our proposed framework.

C. Branson Area Project

The Branson Area Project was suggested by both AECI and SPP as a candidate seams project that would address reliability concerns and load serving needs in the Branson area with additional potential economic benefits to the broader region. The 345 kV, $240 million project spans the Missouri-Arkansas border and has three main components as shown in Figure 4 below: a line from Brookline to Compton Ridge, one from Osage Creek to Compton Ridge, and a third from Compton Ridge to Cox Creek. Based on comments by AECI and SPP, the project would address the load serving needs of AECI (e.g., to serve a potential 100 MW data server farm in the Branson area) and provide both reliability and economic benefits to SPP (e.g., to prevent overloading of the 161 kV system and APC savings, respectively). The Project is also a component of various upgrades that have been identified in SPP’s recent transmission service request study.

The Branson Area Project has been studied for several years, most recently in the 2011 Joint Project Study, which tracked benefits to SPP, AECI, the Southwestern Power Administration (“SPA”), MISO, and Entergy through a preliminary high-level analysis of seams-related challenges. However, the power flow and production cost analyses found only modest

reliability benefits (e.g., in terms of number of facilities overloaded or resolved, potential cost of outages in low hydro years, reducing the number of overloaded facilities under low hydro conditions) and economic benefits (APC savings and ATC increases) to SPP and AECI.\textsuperscript{144}

\textbf{Figure 4}

\textit{Proposed Branson Area Project Components}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure4.png}
\caption{Proposed Branson Area Project Components}
\end{figure}

\textit{Sources and notes:} SPP, “Joint Project Study Results,” February 22, 2011, p. 4

However, while the high-level Branson Area Project study did not yet find compelling benefits, a 2011 “bottom-up” analysis of transmission service requests (“TSRs”) appears to point to a different conclusion. In analyzing the TSRs and necessary related transmission upgrades in SPP’s 2011 AG2 study, we found that the majority of the service requests (55% of total MWs requested) involved transfers from SPP to Entergy that required the Branson Area Project as well as many SPP-internal and other third party upgrades. In fact, the various components of the Branson Area Project were needed for 42 out of 57 TSRs.

\textsuperscript{144} \textit{Ibid.}
This suggests that the Branson Area Project may be a desirable project, but its benefits cannot be realized unless related SPP and third-party upgrades are implemented as well.

In the absence of a complete analysis of the Branson Area Project in combination with the SPP-internal and third-party upgrades identified in SPP’s TSR study, we developed a hypothetical example of the total costs and benefits of the necessary upgrades. This example is summarized in Table 16 below.

<table>
<thead>
<tr>
<th>Illustrative Costs</th>
<th>All regions</th>
<th>$1,200 Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Illustrative Costs</td>
<td></td>
<td>$900 SPP-internal upgrades</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$240 Branson Area Project</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$60 Third-party upgrades</td>
</tr>
<tr>
<td>SPP</td>
<td>$210 Network service requests</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$550 Point-to-Point transmission service requests</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$200 Avoided ITP and reliability project costs</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$100 APC savings</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$1,060 subtotal (65%)</td>
<td></td>
</tr>
<tr>
<td>AECI</td>
<td>$80 Avoided cost of internal load serving projects</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$80 subtotal (5%)</td>
<td></td>
</tr>
<tr>
<td>Entergy</td>
<td>$150 Transmission service requests (w/ SPP)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$150 Avoided reliability project costs (w/ MISO)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$300 subtotal (18%)</td>
<td></td>
</tr>
<tr>
<td>MISO</td>
<td>$100 Transmission service requests (w/ Entergy)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$100 70% APC/30% LLMP savings</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$200 subtotal (12%)</td>
<td></td>
</tr>
</tbody>
</table>

The accommodation of all TSRs in the 2011 AG2 study (and assuming none of the requests evaluated in earlier studies drop out) would require SPP-internal transmission upgrades costing $900 million, as noted in the first row of the center column of Table 16. The cost of the

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Note, however, that any of the SPP-internal upgrades identified in the TSR study are transmission projects needed beyond existing projects and those that are already authorized to proceed with construction. The upgrades identified in this TSR study will thus overlap with any proposed transmission upgrades already (footnote continued on next page)
Branson Area Project (estimated at $240 million) and other third-party upgrades (e.g., in MISO and Entergy, assumed at $60 million) are assumed to bring seams-related project costs to a total of $1,200 million.

For illustrative purposes, the bottom portion of the table lists different types of hypothetical monetized benefits for SPP, AECI, Entergy, and the MISO. Starting with SPP, we hypothetically assumed that transmission revenues from additional SPP network service and point-to-point transmission service requests (i.e., for wheeling out service) would pay for a significant portion of these upgrades. Based on estimates in the 2011 AG2 study, we assumed that $210 million of project costs would be recovered through the present value of incremental network service revenues (at existing rates). Wheeling out revenues from point-to-point transmission service requests (at existing rates) would provide approximately $110 million of incremental annual revenue requirements. Considering that the majority of these service requests are for five-year terms and assuming that many of them would get renewed or that other requests would take their place, these annual wheeling revenues may pay for at least $550 million worth of the identified upgrades (conservatively using a 20% charge rate).146

This suggests that SPP’s incremental revenues associated with transmission service requests (and assumed renewals) would (at least hypothetically) pay for $760 million of the $1,200 million in identified upgrades. Furthermore, some of the $900 million in identified SPP-internal upgrades may overlap with projects identified in SPP’s integrated transmission planning process (“ITP”) and local reliability needs. As shown in Table 16 we hypothetically assumed $200 million in avoided costs of these other projects. Lastly, we have also assumed that, through the combination of these projects, SPP would realize APC savings of $100 million in present value terms. This means that under our hypothetical assumptions SPP would realize a total of $1,060 million in benefits from increased transmission revenue, avoided project costs, and production cost savings. (Additional benefits not included in our hypothetical example may relate to other SPP metrics such as reduced losses and increased competition.)

For AECI, the combined upgrades would allow for additional load-serving capability. We hypothetically assumed that the monetized benefit would be equal to $80 million in avoided cost

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146 As discussed below, it is possible to estimate incremental wheeling service revenues through PROMOD modeling, but that type of analysis has not been conducted. Some TSR customers will also be willing to pay more than the current transmission rate to obtain the requested service.
of an AECI-internal stand-alone project. For other entities such as Entergy and MISO, the $1,200 million of transmission projects is assumed to offer benefits from increased transfer capability amongst themselves and between SPP, AECI, and each of these entities. As shown in Table 16, the hypothetical increase in ATC is assumed to facilitate a present value of $150 million in additional transmission service revenue for Entergy (for service to SPP). In addition, similar to the monetized benefits for SPP, the upgrades are also assumed to avoid $150 million in hypothetical Entergy reliability projects (for service with MISO). The upgrades are also assumed to generate for MISO $100 million in transmission service revenue (for service with Entergy) and produce $100 million in adjusted production cost and load-LMP savings for MISO (consistent with MISO’s own internal metric).

This illustrative example shows that capturing additional transmission service revenues (e.g., estimated based on long-term wheeling out or through service requests) can be a significant “benefit” that should be considered in the evaluation of seams projects. The value of the incremental revenues can offset a substantial portion of project costs, but are not captured in any of SPP’s monetized internal transmission planning metrics. Furthermore, it is also important to note that there may be customers who requested third-party service (e.g., Entergy-to-MISO service) who may have to pay for some of the $900 million in SPP-internal upgrades.

The analysis of SPP’s TSR study also showed that, while the Branson Area Project alone may not benefit SPP and AECI, closer coordination between TSR studies and ITP studies and interregional coordination of TSR studies can identify expanded project configurations that offer significantly higher benefits than the initially-identified seams project. Leveraging TSR studies may be an efficient way to identify promising seams projects as opposed to relying solely on top-down transmission studies such as the ITP or future studies to develop Joint Coordinated System Plans with neighbors.

Based on the hypothetical assumptions in this illustrative example, the total monetized benefits of $1,640 million outweigh total project costs of $1,200 million. The expanded seams project scope provides benefits to several seams entities—SPP, AECI, Entergy, and MISO. If SPP had seams agreements with each of them, then a four-way cost allocation may in fact be possible. As shown in Table 16, if the shares of the present values of monetized benefits would be used to determine cost allocations, SPP’s share would be 65% of the $1,200 million in total project costs ($760 million of which would be offset directly by increased transmission service revenues even at existing rates), AECI would share 5% of total project costs, Entergy 18%, and MISO 12%. This cost allocation could be implemented based on physical ownership of individual project segments. With respect to the three lines of the Branson Area Project itself, for example, SPP could own the Brookline-Compton Ridge and Osage Creek-Compton Ridge (the two western lines) and AECI could own Compton Ridge-Cox Creek (the eastern line).
The fact that revenues associated with transmission service requests can offset a significant portion of total project costs even at current transmission rates also suggests that estimates of the long-term present value of such wheeling revenues would need to be calculated. Such estimates can be derived through a combination of approaches. For example:

- Starting with existing transmission service requests, experience-based “realization rates” could be derived to estimate how many of the submitted service requests will go forward at the standard (current of estimated future) wheeling rate. One would also estimate how many of these services requests would be extended or replaced with others after their initial term.

- The approximate magnitude and direction of TSRs can also be validated with historical market data. For example, if export ATC between SPP and Entergy is limited as suggested in SPP’s TSR study and historical market prices show there would likely be significant trading opportunities (e.g., average annual/seasonal on-peak/off-peak price spreads that exceed wheeling charges), then it would be reasonable to assume that incremental ATC would attract additional wheeling activity. This analysis based on historical price differences could also be used to validate that the TSRs are consistent with economic opportunities.

- Finally, the market simulations used to obtain estimates of adjusted production cost savings could be used to estimate changes in power transfers and associated wheeling revenues between and across individual regions. As noted earlier, adjusted production costs will not capture such wheeling revenues because SPP exports are priced at the SPP-internal average generation LMP, which does not include any wheeling out charges.

**D. QUARRY PROJECT**

The Quarry Project was suggested by America Electric Power West (“AEPW”) as a candidate seams project with benefits to both SPP and Entergy. The “Western Region” of Entergy (in which the proposed project would be located) is a load pocket with limited import capability (i.e., limited export capability from AEPW to Entergy) and a Local Area Procedure (“LAP”) on the Mt. Zion-Grimes 138kV transmission line for the loss of the Grimes-Bentwater 138 kV transmission line. In SPP’s *2010 ICT Strategic Transmission Expansion Plan* ("ISTEP") as the Independent Coordinator of Transmission ("ICT") for Entergy, SPP documented that the Western Region had 1,117 non-firm and 1,455 firm available flowgate capability (“AFC”).

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limiting events from January through September 2009, as shown in Figure 5 below. Similarly, the Western Region experienced 5,952 MWh of non-firm transmission loading relief (“TLR”) curtailments during the same time. All events and curtailments listed in Figure 5 for Western are associated with the Mt. Zion-Grimes limitation.

**Figure 5**

2010 ISTEP-Studied AFC Events and TLR Curtailments

The proposed Quarry Project consists of a new 8.5 mile 345 kV line from Quarry to Rivtin with a substation and transformer for a total estimated cost of $53 million.\(^{148}\) It would be wholly located within the Entergy’s Western Region footprint in eastern Texas. Based on the 2010 ISTEP analysis, the proposed project could provide annual APC savings throughout Entergy of $4 million, reduce congestion costs, and “levelize” LMPs in modeled year 2016.\(^{149}\) Other

\(^{148}\) Ibid., p. 23.

\(^{149}\) Ibid., p. 24.
benefits mentioned in the ISTEP, but not monetized, include increased transfer capability within
the load pocket of approximately 300 MW (with a greater increase if constructed in coordination
with other projects), and potential reductions in the number of AFC events and TLR curtailments.150 Based solely on the APC savings, the project was estimated to yield a benefit-cost ratio of 0.41.151 The left column of Figure 6 summarizes the major ISTEP findings.

The center and right columns in Figure 6 illustrate hypothetically-assumed total benefits to
Entergy and SPP. For example, Entergy might consider APC savings as noted in the first light
green box in the Entergy column. Another possible benefit of the proposed Quarry Project might
include avoiding the cost of a smaller project to remove the Grimes-Mt. Zion line from LAP, as
shown in the second light green box in the Entergy column. Indirectly, this may relate back to
the 2010 ISTEP benefits (referred by the letters b, c, f, and g in grey boxes next to the light green
illustrative Entergy benefits) by reducing congestion costs and congested hours across the
Entergy footprint and specifically over Grimes-Mt. Zion. Since Entergy’s Western Region is a
load pocket, perhaps similar to the ALP, increasing Entergy’s ability to serve load at lower cost
could also be viewed as a reliability benefit. This may be related back to the 2010 STEP benefits
noted in a, b, c, d, f, and g. Lastly, the increase in capacity (grey box e under the 2010 ISTEP
benefits) may help increase off-system sales from the load pocket or conversely help
accommodate additional transmission service requests (“TSRs”). These (hypothetical) Entergy
benefits may be monetized and could be the first steps in considering cost allocation. It is also
worthwhile to note that the non-monetized benefit of increasing transfer capabilities as analyzed
by ISTEP (grey benefit box e) can influence both monetized and non-monetized benefits for
Entergy. As in the ALP Project example, increasing access to load pockets also provides non-
monetized (or more difficult to monetize) operational and maintenance benefits, reliability
benefits via reduced TLR curtailments, increased transmission revenues from decreased AFC
events, and synergies with other projects.

150 Ibid., p. 22 and p. 31.
151 2010 ISTEP provides production cost savings in year 2016 of $4 million versus a total capital cost of
$53 million for a benefit-cost ratio of 0.41. Based on these numbers, we infer that the carrying charge is
$9.8 million.
# Figure 6

2010 ISTEP and Hypothetical Benefits of the Proposed Quarry Project

<table>
<thead>
<tr>
<th>Benefits from ISTEP 2010 Analysis</th>
<th>Hypothetical Entergy Benefits</th>
<th>Hypothetical SPP Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monetary</td>
<td></td>
<td></td>
</tr>
<tr>
<td>a) $4 million in APC savings in 2016</td>
<td>APC savings</td>
<td>APC savings</td>
</tr>
<tr>
<td>b) $11 million in congestion cost savings in Entergy in 2016</td>
<td>Reliability upgrades to remove Grimes-Mt. Zion from LAP</td>
<td>Increase in TSR revenue due to increased transfer capability</td>
</tr>
<tr>
<td>c) $2.8 million in congestion cost savings over Grimes-Mt. Zion in 2016</td>
<td>Increased load serving capability by reducing cost to serve load (pocket)</td>
<td></td>
</tr>
<tr>
<td>d) -$2.01/MWh in LMP levelization</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-Monetary</td>
<td></td>
<td></td>
</tr>
<tr>
<td>e) Over 300 MW of additional transfer capability into load pocket</td>
<td>Increased operational and maintenance flexibility in load pocket</td>
<td>Synergies with other planned or proposed projects</td>
</tr>
<tr>
<td>f) 1,215 fewer congested hours in Entergy in 2016</td>
<td>Decrease in AFC and TLR events</td>
<td></td>
</tr>
<tr>
<td>g) 786 fewer congested hours over Grimes-Mt-Zion in 2016</td>
<td>Synergies with other Construction Plan projects</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Benefit: $4.0 million</th>
<th>$8.5 million + $4.5 million</th>
<th>Cost: $9.8 million</th>
<th>B-C Ratio: 0.41</th>
</tr>
</thead>
</table>

**Sources and Notes:** SPP, 2010 ICT Strategic Transmission Expansion Plan ("ISTEP"), May 6, 2011 for ISTEP benefits; all other data are illustrative.
Potential benefits to SPP were not analyzed in the ISTEP but Figure 6 above provides some hypothetical monetary and non-monetary benefits as illustrated in the last column. SPP also considers APC savings in its internal planning process and some may be attributable to the proposed Quarry Project. However, the likely greatest benefit to SPP may be the ability to fulfill TSRs to Entergy and consequently increase wheeling revenues, which provide an offset. Lastly, the non-monetary benefits to SPP may include synergies with other planned or proposed projects.

At the bottom of Figure 6 we show the 2010 ISTEP benefit, cost, and the 0.41 benefit-cost ratio under the ISTEP benefits in the left column. However, based on our hypothetical assumptions about other Entergy and SPP benefits, the combination of avoiding a smaller reliability upgrade, load serving savings, increased off-system sales, and additional TSR revenues (from both Entergy and SPP entities) produces a combined benefit of $13 million—65% of which accrues to Entergy and 35% of which accrues to SPP—and outweighs the estimated cost of $9.8 million. Based on these assumptions, the project would thus be cost effective for the combined Entergy-SPP footprint. While the benefits that Entergy may gain from its system (assumed to be $8.5 million) are not sufficient to offset Entergy’s total cost of $9.8 million, after allocating 35% of total project cost to SPP, both Entergy and SPP will realize a benefit-cost ratio of 1.33.

XIII. CONCLUSIONS

We identified a number of significant barriers to seams cost allocation, which stem from challenges in planning for seams projects, how entities consider projects and calculate benefits, and the lack of workable cost allocation principles, guidelines, and mechanisms. We reviewed several approaches and developments that address these barriers, including the SPP’s Draft Cost Allocation Principles for Seams Transmission Expansion Projects whitepaper, FERC’s Order 1000, experience with a recent seams project, and examples from RTO and non-RTO regions in the U.S. and Europe—which included cost allocation principles, seams planning, and benefit measurements as applied to a variety of project types including reliability, economic, and public policy upgrades.

We found that a successful cost allocation framework requires well-specified benefit metrics and cost allocation principles, while allowing for flexibility to consider a wide range of different types of seams projects and seams entities. Our review experience from other markets also strongly suggests that a seams cost allocation framework needs to designed as an integral part of the interregional planning process.
Our proposed framework leverages SPP’s existing JOAs with neighboring transmission entities as the starting point. The framework includes seven required (and one optional) building block, which address seams planning, data requirements and exchanges, project proposal processes and qualification, evaluation criteria and benefit metrics, seams cost allocation principles and guidelines, payment mechanisms and transmission rights, integration with internal processes, and optional formulaic cost allocation methodologies that could be developed as more experience is gained with specific project types. We applied the framework to proposed seams projects suggested by stakeholders to test its robustness in accommodating different types of projects with different benefits to both market and non-market entities. The framework is also consistent with the experience gained in the planning and successful cost allocation for the Acadiana Load Pocket project, a case study of a multi-utility seams project which is currently under construction.

In terms of next steps, we understand that SPP staff is actively working towards the Order 1000 compliance deadline, which is April 11, 2013 for interregional planning and cost allocation. We believe it is imperative that there be significant coordination between SPP and the RSC and hope that SPP and the RSC will be able to build on our proposed framework, including the straw man JOA language provided in Appendix C, to fully develop a robust interregional planning and cost allocation methodology that can be implemented through SPP’s ongoing coordination efforts with its neighbors. We hope that this report can be used as the basis for this coordinated work to meet the Order 1000 mandate.
Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning (Summary of Final Report)

Presented at: SPP RSC Quarterly Meeting

Presented by: Johannes Pfeifenberger Delphine Hou

April 23, 2012

Presentation Content

Overview of Final Report

Implementation of Proposed Cost Allocation Framework

Required and Optional Provisions of Proposed Framework

Conclusions and Next Steps

Appendix: Summary of Key Seams Cost Allocation Building Blocks
Overview of Final Report

Our report is organized as follows:

Executive Summary
I. Background
II. Barriers to Interregional Planning and Cost Allocation
III. Review of SPP’s Draft Seams Cost Allocation Whitepaper
IV. Efforts at Interregional Planning and Cost Allocation Elsewhere
   • Summarizes 9 examples of successful or promising practices from RTO and non-RTO regions in the U.S. and Europe
   • Examples address cost allocation principles, seams planning processes, and benefit measurements as applied to a variety of project types such as reliability, economic, and public policy upgrades
V. FERC Order 1000 Requirements
VI. Framework for Interregional Planning and Cost Allocation
   • Summarizes Acadiana Load Pocket “case study” and lessons learned as an example of successful multi-party seams cost allocation.
   • Presents our framework comprised of seven “building blocks”

Section VI: Framework for Interregional Planning & Cost Allocation

1. Regular interregional planning meetings
2. Regular exchange of planning data
3. Process to propose and analyze seams projects
4. Evaluation criteria and benefit metrics
5. Seams cost allocation principles and guidelines
6. Payment mechanisms and transmission rights
7. Integration with internal planning and cost allocation

Optional building block – may be added as experience is gained over time

Leverage existing JOAs and expand

Building blocks most closely related to seams cost allocation: largely missing from or underspecified in current JOAs

Discussed in Sections VII through X of our report (see also Appendix to this presentation)
Overview of Final Report (cont’d)

Sections VII through X present key cost allocation aspects of our proposed framework:

VII. Process to Propose and Analyze Seams Projects (B. Block No. 3)
• Discusses process to unilaterally or jointly propose seams projects

VIII. Evaluation Criteria and Benefit Metrics (Building Block No. 4)
• Presents benefit principles applicable to seams projects
• Specifies (required and optional) benefits and metrics to be used by each seams entity

IX. Seams Cost Allocation Principles and Guidelines (B. Block No. 5)
• Presents cost allocation principles, including FERC Order 1000 principles
• Specifies cost allocation guidelines, including illustrative examples for how cost allocations may be implemented

X. Payment Mechanisms (Building Block No. 6)
• Discusses payment mechanisms to implement cost allocations, including physical ownership and financial transfers
• Recommends awarding transmission rights consistent with cost allocation

The remainder of the report is organized as follows:

XI. Optional Building Block: Pre-Specified Formulaic Evaluation and Cost Allocation
• Provides for optional formulaic approaches once experience with specific types of seams projects is gained (e.g., similar to PJM-MISO cross border reliability and market efficiency cost allocation).

XII. Case Studies: Qualitative Application of Framework to Candidate Seams Projects
• Illustrative application of the proposed framework to three seams projects: ALP, Branson Area Project (with AECI), and Quarry Project (with ETR).

XIII. Conclusions (including next steps)

Appendices
Overview of Final Report (cont’d)

The appendices to our report include:

**Appendix A** – Copy of the SPP RSC Draft Cost Allocation Principles for Seams Transmission Expansion Projects (“Draft Seams Cost Allocation Whitepaper”)

**Appendix B** – Copies of key documents on interregional cost allocation and seams issues in other markets

**Appendix C** – Provides illustrative tariff language for interregional planning and cost allocation provisions in SPP’s existing JOAs

- **C1.** Illustrative redline of Article VII of JOA (Coordinated Interregional Transmission Planning and Cost Allocation)
- **C2.** Illustrative JOA inserts for evaluation criteria and benefit metrics (BB No. 4), seams cost allocation principles and guidelines (BB No. 5) and payment mechanisms and transmission rights (BB No. 6)

**Appendix D** – Summary of five candidate seams projects suggested by stakeholders (three of which were chosen as illustrative case studies)

Implementation of Proposed Framework

With some modifications, clarifications, and expansion, the existing JOAs can serve as a foundation to implement Building Blocks Nos. 1, 2, and 7 of the proposed interregional planning and cost allocation framework. (See Appendix C1 for illustrative tariff language)

<table>
<thead>
<tr>
<th></th>
<th>Existing</th>
<th>To add</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Regular interregional planning meetings</td>
<td>Regular meetings to develop Joint and Coordinated System Plan</td>
<td>More explicit state regulatory involvement, perhaps via IPSAC</td>
</tr>
<tr>
<td>2. Regular exchange of planning data</td>
<td>Detailed data list exists</td>
<td>Jointly develop and validate load flow and other planning models for combined footprint</td>
</tr>
<tr>
<td>7. Integration with internal planning and cost allocation</td>
<td>Each party is required to conduct regional planning and notify the seams neighbor of any approved local and regional upgrade and TSRs and GI requests</td>
<td>Include public policy requirements; validate consistency in modeling assumptions; specify how seams projects can be proposed; consider synergies with transmission service and generation interconnection requests</td>
</tr>
</tbody>
</table>
Implementation of Proposed Framework

Need to add Building Blocks Nos. 3, 4, 5, and 6 as they are most closely related to seams allocation but either missing or largely unspecified in the current JOAs. (See Appendix C for illustrative tariff language)

<table>
<thead>
<tr>
<th></th>
<th>Existing</th>
<th>To add</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. Process to propose and analyze seams projects</td>
<td>Focused on projects that are identified in Joint &amp; Coordinated System Plan</td>
<td>Add project qualification criteria and more flexible process with commitment to jointly analyze</td>
</tr>
<tr>
<td>4. Evaluation criteria and benefit metrics</td>
<td>Broad reliability and economic considerations</td>
<td>Add new section on internally-used plus seams-specific benefits and metrics</td>
</tr>
<tr>
<td>5. Seams cost allocation principles and guidelines</td>
<td>Case-by-case review</td>
<td>Add new section</td>
</tr>
<tr>
<td>6. Payment mechanisms and transmission rights</td>
<td>Does not exist</td>
<td>Add new section</td>
</tr>
<tr>
<td>OPTIONAL: Pre-specified formulaic evaluation and cost allocation methodology</td>
<td>Does not exist</td>
<td>Possibly add new section if parties can agree to formulaic methodology</td>
</tr>
</tbody>
</table>

Required and Optional Provisions of Framework

The proposed framework attempts to balance (1) the need for flexibility in the evaluation and cost allocation of seams projects with (2) the need for actionable methodology based on clearly-identified, transparent principles and metrics:

♦ Specifies requirements for key elements, such as:
  • Regular planning meetings with state regulatory involvement
  • Jointly developed and validated planning models for combined footprint
  • Pre-specified seams project proposal and evaluation process
  • Pre-specified benefit and cost allocation principles
  • Each entity is required to consider all benefits and metrics used internally
    • Recognition that seams projects offer unique benefits (such as wheeling out revenue and the avoided costs of internal projects)
    • Share of benefits and allocated cost must meet internal B/C criteria
  • Pre-specified options to derive and implement cost allocations
  • Integration with each seams entity’s internal planning and cost allocation processes
  • Must meet or exceed interregional requirements of Order 1000
Balancing flexibility with specificity needed to be actionable (cont’d)

♦ The framework also provides for flexibility as to:
  • The type of seams neighbors (RTOs, non-RTO, non-jurisdictional)
  • Different types and combinations of seams projects
  • The type and combination of benefits that may accrue differently to the seam neighbors
  • Joint or unilateral proposal of seams projects
  • Seams entities’ ability to use different sets of benefits and metrics, consistent with their internal project evaluation processes
  • Optional consideration of additional benefits (e.g., based on experience gained in the evaluation of seams projects)
  • Alternative mechanisms to derive cost allocation shares
  • Alternative payment mechanisms to implement cost allocation
  • The option to add formulaic evaluation and cost allocation provisions for specific types of seams projects over time

Conclusions and Next Steps

Conclusions

♦ The proposed framework is based on reviews of: barriers to seams planning and cost allocation, SPP’s ongoing efforts, FERC Order 1000 requirements, project case studies, and experiences from other U.S. and European markets
  • The framework was validated by qualitatively “testing” it on the Acadiana Load Pocket Project, the Branson Area Project, and the Quarry Project
  • We believe it strikes the proper balance between (1) a methodology that is sufficiently well-specified to be actionable and (2) the flexibility needed for successful application to a wide range of seams projects and seams entities

Next Steps

♦ SPP and the SPP RSC will convene a task force to work on implementing interregional planning and cost allocation provisions of Order 1000
  • We believe it is imperative that there be significant coordination between SPP and the RSC
  • We hope that SPP and the RSC will be able to build on our proposed framework (including illustrative JOA language) as the basis for coordinated work to implement Order 1000 requirements
Appendix:

Summary of Key Seams Cost Allocation Building Blocks

Building Block No. 3

Process to Propose and Analyze Seams Projects

- As long as the proposed seams project addresses both seams entities’ transmission needs and offers benefits to both, the project could be:
  - A single line or several lines that are logically grouped together
  - Crossing seam or (unlike Order 1000) be wholly within one entity’s footprint
- No threshold such as voltage class, total cost, or total benefits
  - Some “small” projects may offer substantial benefits
- Projects can be proposed unilaterally and must include:
  - A detailed description of the project
  - A qualitative discussion of the project’s purpose and benefits to both neighbors (which could differ on either side of the seam)
  - Preliminary analyses (e.g., power flow studies) of the project’s benefits to both entities … documenting results, assumptions, and data consistent with the planning methods and metrics of each entity as specified in the agreement
  - A proposed preliminary cost allocation consistent with specified cost allocation principles and benefits identified in screening analyses
- Seams entities can agree to jointly propose any seams project(s)
- Seams entities committed to jointly analyze any proposed project(s)
Building Block No. 4
Evaluation Criteria and Benefit Metrics

Interregional cost allocation (e.g., as would be specified in the JOA) should be based on a set of guiding principles such as:

♦ Recognition that seams projects may offer combinations of different types of benefits and entirely different sets of benefits may accrue to each entity;
♦ Benefits and metrics used for the evaluation of seams projects by each entity will include all benefits 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;
♦ Seams 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;
♦ Seams projects may serve to avoid or delay the cost of (1) transmission projects in existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy GI and TSRs.

Building Block No. 4
Benefit Metrics: SPP

Evaluation criteria and benefit metrics applied to seams projects should include, at minimum, internally-considered criteria and metrics. Some of SPP's defined benefits and metrics include:

<table>
<thead>
<tr>
<th>SPP Internally Used Benefits</th>
<th>Quantitative / Qualitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted production cost savings</td>
<td>Monetized through PROMOD simulations</td>
</tr>
<tr>
<td>Ability to replace or delay previously approved projects</td>
<td>Monetized as the avoided cost of previously approved projects</td>
</tr>
<tr>
<td>Energy value of reduced transmission losses</td>
<td>Monetized based on quantification through power flow simulations</td>
</tr>
<tr>
<td>Capacity value of reduced transmission losses</td>
<td>Monetized as avoided capacity</td>
</tr>
<tr>
<td>Value of improved ATC</td>
<td>Quantified as incremental capacity (MW)</td>
</tr>
<tr>
<td>Additional robustness metrics</td>
<td>As specified</td>
</tr>
</tbody>
</table>
For non-RTO regions, evaluation criteria and benefits metrics may be less formulaic or clearly stated. We provide as an illustrative example below, benefits and metrics based on our interpretation of Western Area Power Administration's 2011 Strategic Plan.

**Illustrative Internally-Used Benefits**

<table>
<thead>
<tr>
<th>Illustrative Internally-Used Benefits</th>
<th>Quantitative / Qualitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoid reliability violations</td>
<td>Quantified as number/duration of violations and monetized as avoided cost of regional/local upgrade</td>
</tr>
<tr>
<td>Reduce frequency and cost of supply interruptions during low-hydro years</td>
<td>Quantified as number/duration of likely events and monetized as cost of interruptions or replacement power</td>
</tr>
<tr>
<td>Reduce dispatch of high-cost generation needed to serve load in presence of internal transmission congestion or import constraints</td>
<td>Monetized as reduced generation and emission costs</td>
</tr>
<tr>
<td>Avoid cost of local transmission upgrades needed to support load growth</td>
<td>Monetized as avoided cost of regional/local upgrade</td>
</tr>
<tr>
<td>Reduced transmission losses</td>
<td>Monetized as energy and on-peak capacity savings</td>
</tr>
<tr>
<td>Increase ATC (and off-system sales)</td>
<td>Monetized as incremental off-system sales profits and/or transmission rights</td>
</tr>
</tbody>
</table>

In addition to internally-considered benefits and metrics, there are benefits and metrics that are unique to seams projects.

- We propose that the seams entities consider including at minimum the seams-specific metrics listed below in the evaluation process.

<table>
<thead>
<tr>
<th>Seams-Specific Benefits</th>
<th>Quantitative / Qualitative Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental wheeling through and out revenues</td>
<td>Estimates of additional wheeling volumes may be derived from transmission service requests and PROMOD modeling</td>
</tr>
<tr>
<td>Benefits from increased reserve sharing capability</td>
<td>Quantified as a reduction in MW of reserve capacity</td>
</tr>
</tbody>
</table>

- Additional benefits and metrics can be considered on a project-specific basis upon mutual agreement of the seams entities.
Building Block No. 5
Seams Cost Allocation Principles and Guidelines

The agreement would specify the “general cost allocation principles” that will be applied to seams projects, such as:

- Cost allocated should be at least roughly commensurate with total benefits to each entity; neither seams entity shall be allocated cost without receiving benefits.
- Cost allocation methodologies and identification of benefits and beneficiaries must be transparent.
- Different cost allocation methods may be applied to different types or different portions of transmission facilities (e.g., transmission needs driven by reliability, economic, or public policy requirements).
- The seams entities will quantify and, if possible, monetize benefits; but they will also recognize non-monetized and non-quantified benefits in assessing overall reasonableness of proposed 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.
- If minimum benefit-to-cost thresholds are utilized, they should not exceed 1.25.
- The share of benefits to each seams entity should be sufficient to support the seams projects’ approval through each entity’s internal planning process.

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Building Block No. 5
Seams Cost Allocation Principles and Guidelines

The agreement would also pre-specify flexible cost allocation mechanisms. For example, it may specify that cost allocation to each entity should be based on one or a combination of:

- The share of seams projects’ total benefits received by each entity as a proportion of the sum of the entities’ total benefits received (consistent with specified principles and metrics).
- If shares are reasonably proxies for received benefits or roughly proportionate to benefits received, cost allocation can also be based on:
  - The share of seams projects’ physical location in each Party’s footprint (e.g., shares of circuit miles or investment dollars).
  - The share of each entity’s relative contribution to the need for a project (e.g., power flows that contribute to a reliability-driven upgrade).
  - The share of each entity’s projected or allocated usage of the seams projects’ transmission capability (e.g., shares of increased flow-gate capacity).

The Brattle Group
Building Block No. 6
Payment Mechanisms

Once a reasonable cost allocation has been determined, the cost allocation shall be implemented consistent with following principles:

♦ To the extent feasible, cost allocation shall be implemented through either
  • Physical ownership of individual segments of a project by the seams entities or their transmission owners such that the cost of each owned portion is consistent with the determined cost allocation; or
  • Co-ownership of the project (or individual segments) where the project (or segment) cannot be divided into fully-owned segments or if a proposed project (or segment) is entirely within the service territory of one of the seams entities

♦ Where ownership allocation is not feasible, cost allocation should be implemented through payments (from one entity to the other) that correspond to the obtained physical or financial rights to the projects’ transmission capability

♦ Each entity will recover allocated costs consistent with cost recovery of local and regional projects within its footprint

Provision of transmission rights:

♦ To the extent feasible and practical, an entity sharing the cost of seams projects should receive a physical or financial right for a commensurate share of the projects’ capability (e.g., a share of increased ATC or flow-gate capacity)

Optional Building Block
Pre-specified Formulaic Options

As more experience with the cost allocation of seams projects is gained, the seams entities may pre-specify cost allocation options.

♦ These pre-specified formulaic cost allocations would be based on (i) specific metrics for the evaluation of the seams project and (ii) a pre-specified cost allocation methodology that formulaically relies on these benefits and metrics
  • Entities that already use similar pre-specified metrics (e.g., use of APC in SPP and MISO) would be more likely to adopt this approach
  • Examples: PJM-MISO interregional evaluation and cost allocation process for reliability and economic projects
  • A less formulaic option (e.g., in an agreement between SPP and AECI) might include a cost allocation in proportion to each entity’s avoided costs of implementing their own alternative solutions to the identified reliability problems

♦ Different formulas can be applied to specific project types (e.g., reliability, economic, public policy, multi-value)

Projects that do not fit the pre-specified options would be considered under the general cost allocation principles
Integrated Marketplace Update

April 23-24, 2012

Bruce Rew, P.E.
Integrated Marketplace Recent Successes

- Pre-populated MP registration packets sent out
- TCR mock auctions #2 started
- Initial Balancing Authority Emergency Ops procedures developed
- Training on schedule with high engagement
- Vendor API specs – late with minimal impact
- Completed initial Market Participant Engagement Approach
- Vendor software development progressing (sample screen shots attached)
Status of Integrated Marketplace Tariff Revisions

- Tariff Revisions were filed on time February 29, 2012 (ER12-1179)
- Interventions and protests filed
- SPP Staff currently working on responses to protests to be filed in the next few weeks
Integrated Marketplace Update

• Program completed majority of design and identified projected needs in January
• Completed gap analysis of initial program projections with current program projections based on final designs
  – made appropriate adjustments
• Updated estimates of project health through go live with areas of concern noted
Program Status Change in February

Our Program management approach is to be conservative and get any concerns out early

• End of January, analyzed scenarios to complete required testing and market trials and trending of work stream slippage

• Decision made to change status to yellow
  – Yellow is defined as concerned about meeting a key milestone on the date assigned

• Provides transparency and stakeholder involvement in solutions
Program Status Change in February

• Precautionary as we work through concern areas
• Provide focus on evaluation of actions necessary to maintain program targets
• Areas of concern
  – Potentially significant overlap between end of testing and scheduled beginning of market trials
  – Post Operations-Pre Settlements
  – System interface complexities
Assessment of Actions to Mitigate Impacts

- Focusing resources on the more critical work and optimizing time
- Scheduling highly focused “sprints” to accomplish tasks sooner
- Reexamining program scope and eliminating work that isn’t absolutely necessary
- Completing assessment of implementation impacts based on available mitigation steps
Market Participant Engagement Reporting

- Monitor and report on Market Participant activities leading up to major program milestones such as the start of Market Trials Connectivity Testing and Market Trials Structured/Unstructured Testing
- Bridge gap between the Participant Mobilization Metrics and reporting on full set Integrated Marketplace Readiness Metrics
## Participant Engagement 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>May 31, 2012</td>
<td>• Technical Specifications Reviewed (Markets, Settlements, TCR)</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 Design Complete</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>Aug 31, 2012</td>
<td>• Participant System Build Underway</td>
<td>MP</td>
</tr>
<tr>
<td>Sept 30, 2012</td>
<td>• MP Approach Completed for TCR Market Trials</td>
<td>MP</td>
</tr>
<tr>
<td>Sept 30, 2012</td>
<td>• Participant Interface (MP to SPP) Build Complete</td>
<td>MP</td>
</tr>
<tr>
<td>Oct 1, 2012</td>
<td>• MP/TO Training on MCST Tool Complete</td>
<td>SPP</td>
</tr>
<tr>
<td>Oct 31, 2012</td>
<td>• MP/TO Testing with the MCST tool</td>
<td>SPP</td>
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<tr>
<td>Oct 31, 2012</td>
<td>• MP Approach Completed for Market Trials Connectivity Testing</td>
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</tr>
<tr>
<td>Nov 30, 2012</td>
<td>• TCR Market Trials Resources Trained</td>
<td>MP</td>
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*Continued on next slide*
## Participant Engagement Activities

<table>
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<tr>
<th>Date</th>
<th>Participant Activity</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dec 2012 (tbd)</td>
<td>• Begin using MCST for Model Change Submissions</td>
<td>SPP</td>
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<tr>
<td>Dec 28, 2012</td>
<td>• Participant System Build Complete</td>
<td>MP</td>
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<tr>
<td>Dec 28, 2012</td>
<td>• Participant Interface (MP-SPP) Testing Complete</td>
<td>MP</td>
</tr>
<tr>
<td>Jan 31, 2013</td>
<td>• Participant System Testing Underway</td>
<td>MP</td>
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<tr>
<td>Jan 2013 (tbd)</td>
<td>• Market Trials Connectivity Test Scheduled <em>(date pending completion of Market Trials Connectivity Approach)</em></td>
<td>SPP</td>
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<tr>
<td>Feb 28, 2013</td>
<td>• MP Approach Completed for Market Trials Structured/Unstructured Test</td>
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<td>Mar 30, 2013</td>
<td>• Participant System Testing Complete</td>
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<tr>
<td>Apr 30, 2013</td>
<td>• Market Trials Structured/Unstructured Resources Trained</td>
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<td>May 14, 2013</td>
<td>• Participant System Internal Integration Testing Complete</td>
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<tr>
<td>May 17, 2013</td>
<td>• Market Trials Connectivity Testing Complete</td>
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</table>
Executive Sponsors (or MOPC Reps) will be contacts for MP escalation points

Dates are tentative and to indicate the intended timeframes
Market Participant Milestones

- **May 2, 2011**: SPP begins Marketplace software builds
- **April 2, 2012**: Participants develop market software/ensure staffing adequate and trained
- **May 16, 2012**: Participants ready to begin TCR mock auctions
- **June 1, 2012**: Participants make appropriate regulatory filings
- **January 1, 2013**: Participants finalize registration data necessary to participate in Marketplace
- **MAY 15, 2013**: Participants’ market systems ready for interface testing with SPP

**MAY 15, 2013**

**PARTICIPANTS READY FOR SYSTEM INTEGRATION**
Sample: Input – Constraints
Sample: Day-Ahead Market Screens – Resource
Sample: RTBM – Dashboard
Marketing Program Financial/Health (DOEs)

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<tr>
<th>Activity</th>
<th>Status</th>
<th>Variance Analysis &amp; Comments</th>
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<td>Marketing Program Drivers</td>
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<tr>
<td>Marketing Program Results</td>
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<tr>
<td>Marketing Program Reachability</td>
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<td></td>
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</table>

Marketing Program Critical Path Milestones

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<tr>
<th>Workstream</th>
<th>Title</th>
<th>% Complete</th>
<th>Baseline End</th>
<th>Tracking End</th>
<th>Actual End</th>
<th>Notes</th>
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<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
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<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
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<tr>
<td>Market Approval of Implementation Budget</td>
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<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
<tr>
<td>Market Approval of Implementation Budget</td>
<td>100%</td>
<td>26 May-11</td>
<td></td>
<td>26 May-11</td>
<td>26 May-11</td>
<td>€</td>
</tr>
</tbody>
</table>
Helping our members work together to keep the lights on... today and in the future
Integrated Marketplace Update

April 23-24, 2012

Bruce Rew, P.E.
Integrated Marketplace Recent Successes

- Pre-populated MP registration packets sent out
- TCR mock auctions #2 started
- Initial Balancing Authority Emergency Ops procedures developed
- Training on schedule with high engagement
- Vendor API specs – late with minimal impact
- Completed initial Market Participant Engagement Approach
- Vendor software development progressing (sample screen shots attached)
Status of Integrated Marketplace Tariff Revisions

- Tariff Revisions were filed on time February 29, 2012 (ER12-1179)
- Interventions and protests filed
- SPP Staff currently working on responses to protests to be filed in the next few weeks
Integrated Marketplace Update

- Program completed majority of design and identified projected needs in January
- Completed gap analysis of initial program projections with current program projections based on final designs
  - made appropriate adjustments
- Updated estimates of project health through go live with areas of concern noted
Program Status Change in February

Our Program management approach is to be conservative and get any concerns out early

• End of January, analyzed scenarios to complete required testing and market trials and trending of work stream slippage

• Decision made to change status to **yellow**
  – Yellow is defined as concerned about meeting a key milestone on the date assigned

• Provides transparency and stakeholder involvement in solutions
Program Status Change in February

• Precautionary as we work through concern areas
• Provide focus on evaluation of actions necessary to maintain program targets
• Areas of concern
  – Potentially significant overlap between end of testing and scheduled beginning of market trials
  – Post Operations-Pre Settlements
  – System interface complexities
Assessment of Actions to Mitigate Impacts

- Focusing resources on the more critical work and optimizing time
- Scheduling highly focused “sprints” to accomplish tasks sooner
- Reexamining program scope and eliminating work that isn’t absolutely necessary
- Completing assessment of implementation impacts based on available mitigation steps
Market Participant Engagement Reporting

- Monitor and report on Market Participant activities leading up to major program milestones such as the start of Market Trials Connectivity Testing and Market Trials Structured/Unstructured Testing
- Bridge gap between the Participant Mobilization Metrics and reporting on full set Integrated Marketplace Readiness Metrics
# Participant Engagement 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>May 31, 2012</td>
<td>• Technical Specifications Reviewed (Markets, Settlements, TCR)</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 Design Complete</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>Aug 31, 2012</td>
<td>• Participant System Build Underway</td>
<td>MP</td>
</tr>
<tr>
<td>Sept 30, 2012</td>
<td>• MP Approach Completed for TCR Market Trials</td>
<td>MP</td>
</tr>
<tr>
<td>Sept 30, 2012</td>
<td>• Participant Interface (MP to SPP) Build Complete</td>
<td>MP</td>
</tr>
<tr>
<td>Oct 1, 2012</td>
<td>• MP/TO Training on MCST Tool Complete</td>
<td>SPP</td>
</tr>
<tr>
<td>Oct 31, 2012</td>
<td>• MP/TO Testing with the MCST tool</td>
<td>SPP</td>
</tr>
<tr>
<td>Oct 31, 2012</td>
<td>• MP Approach Completed for Market Trials Connectivity Testing</td>
<td>MP</td>
</tr>
<tr>
<td>Nov 30, 2012</td>
<td>• TCR Market Trials Resources Trained</td>
<td>MP</td>
</tr>
</tbody>
</table>

*Continued on next slide*
## Participant Engagement Activities

<table>
<thead>
<tr>
<th>Date</th>
<th>Participant Activity</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dec 2012 (tbd)</td>
<td>• Begin using MCST for Model Change Submissions</td>
<td>SPP</td>
</tr>
<tr>
<td>Dec 28, 2012</td>
<td>• Participant System Build Complete</td>
<td>MP</td>
</tr>
<tr>
<td>Dec 28, 2012</td>
<td>• Participant Interface (MP-SPP) Testing Complete</td>
<td>MP</td>
</tr>
<tr>
<td>Jan 31, 2013</td>
<td>• Participant System Testing Underway</td>
<td>MP</td>
</tr>
<tr>
<td>Jan 2013 (tbd)</td>
<td>• <em>Market Trials Connectivity Test Scheduled (date pending completion of Market Trials Connectivity Approach)</em></td>
<td>SPP</td>
</tr>
<tr>
<td>Feb 28, 2013</td>
<td>• MP Approach Completed for Market Trials Structured/Unstructured Test</td>
<td>MP</td>
</tr>
<tr>
<td>Mar 30, 2013</td>
<td>• Participant System Testing Complete</td>
<td>MP</td>
</tr>
<tr>
<td>Apr 30, 2013</td>
<td>• Market Trials Structured/Unstructured Resources Trained</td>
<td>MP</td>
</tr>
<tr>
<td>May 14, 2013</td>
<td>• Participant System Internal Integration Testing Complete</td>
<td>MP</td>
</tr>
<tr>
<td>May 17, 2013</td>
<td>• Market Trials Connectivity Testing Complete</td>
<td>MP</td>
</tr>
</tbody>
</table>
Participant Engagement Reporting Timeline

Executive Sponsors (or MOPC Reps) will be contacts for MP escalation points

*Dates are tentative and to indicate the intended timeframes*
Market Participant Milestones

- May 2: SPP begins Marketplace software builds
- April 2: Participants develop market software/ensure staffing adequate and trained
- May 16: Participants ready to begin TCR mock auctions
- June 1: Participants make appropriate regulatory filings
- January 1: Participants finalize registration data necessary to participate in Marketplace
- Participants’ market systems ready for interface testing with SPP

**MAY 15, 2013**
**PARTICIPANTS READY FOR SYSTEM INTEGRATION**
Sample: Input – Constraints
Sample: Day-Ahead Market Screens – Resource
Sample: RTBM – Dashboard
SPP EPA Impact Assessment

Regional State Committee
April, 2012

Michael Desselle
mdesselle@spp.org

Outline

• Contextual Overview
• Assessment Process
• Key Data: MW, Generation, and Margin
Contextual Review

• SPC directed SPP to perform an impact assessment regarding member plans for compliance
  – This assessment is for the reliability impacts of the Cross State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS)
  – Assessing EPA Rules against meeting the reliability criteria
  – SPP completed a survey of plans, generation changes, retrofits, and retirements and modeled those plans

Contextual Review

• Key Considerations
  – Information has not been vetted through standard model development processes for its utilized purpose
  – Dispatch was developed by stakeholders, and not a Security Constrained Economic Dispatch
  – This assessment should not be utilized to determine need for additional transmission or generation or relied upon as conclusive regarding all impacts to the SPP region
  – Off peak models were developed based on winter peak models
  – System dynamics were not evaluated
Assessment Process

• Initial teleconference was held on January 20th 2012
  – Members and SPP agreed to study the following years
    ▪ 2013 to determine immediate CSAPR impacts
    ▪ 2014 to determine impacts from the MATS outages
    ▪ 2015 to determine CSAPR and MATS impacts and determine what resources would be lost or might need extensions through 2016
  – 2011 Model Build 2 Scenario 0 would act as the baseline for comparison
• Scenarios for each year were developed

Assessment Process - Scenarios

<table>
<thead>
<tr>
<th>Year</th>
<th>Reliability Scenario A</th>
<th>Reliability Scenario B</th>
<th>Adequacy Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>CSAPR rules are implemented in April 2012 with allowances available, no penalties exceeding CSAPR state caps</td>
<td>CSAPR rules are implemented April 2012 with state caps on the allowance and variability limit in place</td>
<td>Yes</td>
</tr>
<tr>
<td>2014</td>
<td>None</td>
<td>None</td>
<td>Yes</td>
</tr>
<tr>
<td>2015</td>
<td>MATS rule is in place, and these are expected plans</td>
<td>MATS rule is in place and estimated impact regarding uncertainty of unit availability</td>
<td>Yes</td>
</tr>
</tbody>
</table>
Assessment Process (cont.)

- Members reviewed an initial survey draft and provided feedback
- Confidential Impact Assessment Survey was updated
  - Included projected load
  - Fields were provided for outages, imports, and exports

Assessment Process (cont.)

- SPP adjusted generation in the models to reflect the survey responses
- Where members had an inadequate amount of generation follow ups were conducted to determine if other generation was available.
- Individual BAs imported when there was insufficient generation to meet those loads
- Powerflow analysis was conducted to determine the system intact and N-1 impacts
## Results Generation Changes in MWs

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retire/Mothball</td>
<td>330</td>
<td>914</td>
</tr>
<tr>
<td>Derate</td>
<td>0</td>
<td>60</td>
</tr>
<tr>
<td>Revise Dispatch</td>
<td>3,480</td>
<td>4,075</td>
</tr>
<tr>
<td>Retrofit</td>
<td>6,859</td>
<td>10,080</td>
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</table>

## Planning Criteria Potential Issues

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<tr>
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<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Scenario A</td>
<td>Scenario A</td>
</tr>
<tr>
<td></td>
<td>Peak</td>
<td>Off-Peak</td>
</tr>
<tr>
<td>Thermal Overloads</td>
<td>14</td>
<td>3</td>
</tr>
<tr>
<td>Local Planning Criteria</td>
<td>18</td>
<td>12</td>
</tr>
<tr>
<td>Voltage Issues</td>
<td>52</td>
<td>2</td>
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<tr>
<td>SPP Planning Criteria</td>
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<td></td>
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<tr>
<td>Voltage Issues</td>
<td>70</td>
<td>14</td>
</tr>
<tr>
<td>Total Voltage Issues</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Annual Generation Unavailable

![Chart showing annual generation unavailable capacity (GW-hrs) for years 2013 to 2015. The chart displays the availability of capacity, with different colors representing retired and outaged capacity.](image)

**Unavailable Capacity (GW-hrs)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Retired Capacity</th>
<th>Outaged Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>35000</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>40000</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>35000</td>
<td></td>
</tr>
</tbody>
</table>

### Resource Adequacy – Capacity Margin

![Chart showing weekly capacity margin over time for years 2013 to 2015. The chart includes data on capacity margin surveyed as a percent of non-retired capacity.](image)

**Weekly Capacity Margin**

(surveyed, as percent of non-retired capacity)

- 2013: [Data points]
- 2014: [Data points]
- 2015: [Data points]

**SPP Capacity Margin (12%)**

- 2013: [Data points]
- 2014: [Data points]
- 2015: [Data points]
Resource Adequacy 2013 Reserve Margin

2013 Weekly Resource Adequacy (Surveyed)

Resource Adequacy 2014 Reserve Margin

2014 Weekly Resource Adequacy (Surveyed)
Resource Adequacy 2015 Reserve Margin
2015 Weekly Resource Adequacy (Surveyed)

Michael Desselle
mdesselle@spp.org

QUESTIONS?
Southwest Power Pool, Inc.
SECOND QUARTERLY
PROJECT TRACKING REPORT
APRIL 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).

During the next reporting periods, SPP will be engaging the Project Cost Working Group (PCWG) to determine if there are improvements that can be made in the Project Tracking process currently in use by SPP and the project owners. These improvements include determining the most efficient Project Tracking Report period for providing further analysis to the Market and Operating Policy Committee (MOPC) on the status of active projects in the portfolio, as well as synchronizing the current process used for cost analysis of existing projects with the recently approved PCWG cost process for new projects.

In this Second Quarterly Report of 2012, the reporting period is December 1, 2011 through February 29, 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. Each year prior to the 2nd Quarterly Project Tracking Report SPP brings the project tracking window forward to the current year. A project is considered part of the active portfolio if its actual in-service or projected in-service date is after December 1, 2011 but before December 31, 2022. In the 1st Quarter, there was one new Notification to Construct (NTC) issued by SPP for a Generation Interconnect upgrade. The Board-approved ITP projects are normally issued during the 1st Quarter. However, the pending approval of the Business Practices for Notifications to Construct with Conditions delayed the issuance of these projects until the next reporting period.

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.
### 1st 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>211</td>
<td>$1,278,619,957</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>13</td>
<td>$41,612,000</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>7</td>
<td>$26,437,247</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>56</td>
<td>$481,431,685</td>
</tr>
<tr>
<td>Generation Interconnect</td>
<td>16</td>
<td>$120,092,528</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>17</td>
<td>$896,694,117</td>
</tr>
<tr>
<td>High Priority</td>
<td>22</td>
<td>$1,448,740,590</td>
</tr>
<tr>
<td>Other Sponsored Upgrades</td>
<td>48</td>
<td>$279,824,967</td>
</tr>
<tr>
<td><strong>TOTALS</strong></td>
<td><strong>390</strong></td>
<td><strong>$4,573,453,091</strong></td>
</tr>
</tbody>
</table>

**Figure 1:** 2012 1st Quarter Project Summary

### 1st 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>69</td>
<td>17.8</td>
<td>223.1</td>
<td>240.9</td>
</tr>
<tr>
<td>115</td>
<td>79</td>
<td>177.6</td>
<td>209.4</td>
<td>387.0</td>
</tr>
<tr>
<td>138</td>
<td>77</td>
<td>113.3</td>
<td>136.3</td>
<td>249.6</td>
</tr>
<tr>
<td>161</td>
<td>30</td>
<td>46.9</td>
<td>56.2</td>
<td>103.2</td>
</tr>
<tr>
<td>230</td>
<td>17</td>
<td>179.1</td>
<td>27.0</td>
<td>206.1</td>
</tr>
<tr>
<td>345</td>
<td>47</td>
<td>2,200.5</td>
<td>0.0</td>
<td>2,200.5</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>319</strong></td>
<td><strong>2,735.3</strong></td>
<td><strong>651.9</strong></td>
<td><strong>3,387.2</strong></td>
</tr>
</tbody>
</table>

**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 two upgrades, with latest Engineering and Construction (E&C) cost estimates at $6,482,565, completed in the timeframe of the 1st Quarter of 2012. Westar Energy (WR) reported the projects associated with Halstead-Mud Creek Junction-Mid-American Junction were completed with 8.3 miles of reconduced 69 kV. There were also three other completed projects reported for the first time during the period, with all of their in service dates within the previous 4th Quarter of 2011. Omaha Public Power District (OPPD) reported completing the S1341 tap projects for $17 million in September, 2011.

There are 62 upgrades, with latest E&C cost estimates of $374.3 million, on schedule to be completed within the next four years. There are 23 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.

There were two Transmission Service upgrades, with latest E&C cost estimates at $3.1 million completed in the 1st Quarter of 2012. There are four upgrades in a delay with no mitigation status. There were several Generation Interconnect upgrades reported complete this quarter. On December 1, 2011 American Electric Power (AEP) completed most of the Turk plant Generation Interconnect upgrades, seven 138 kV upgrades totaling over $51.5 million E&C. Also, Westar Energy (WR) reported two upgrades for the Caney River Wind Project as completed in the previous quarter on September 13, 2011, for a total E&C cost estimate of $7.5 million. That brings the total to $59 million in total Generation Interconnect upgrades completed this reporting period by SPP members.

There are 18 Transmission Service upgrades, with estimated E&C costs of $233.2 million, on schedule to be completed within the next four years. There are eight Generation Interconnect upgrades, at an estimated E&C cost of $43 million, scheduled to be completed in the next four years, with one of those scheduled to complete in March 2012.
Figure 5 shows the number and costs for the projects completed over the last 12 month period. The 1st Quarter of 2012 was similar in the number of projects completed to the 4th quarter of 2011, with the exception of the Generation Interconnect projects for the Turk power plant. However, SPP is already aware of several projects being completed just outside of the reporting period, as is noted in the correction column of Figure 5. Also, as was reported earlier in Sections III and IV, several upgrades were reported as complete in this quarter with in-service dates in the 4th Quarter, raising the 4th Quarter’s total completed projects by $24.5 million.

There were three zonal upgrades completed this quarter. The final three upgrades in the Oklahoma Gas and Electric (OGE) 161 kV project were completed, with a total project estimated cost of $31 million.

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 4th Quarter reporting period had ended.

### Projects Completed By Quarter

<table>
<thead>
<tr>
<th>Reliability</th>
<th>2nd Q 2011</th>
<th>3rd Q 2011</th>
<th>4th Q 2011</th>
<th>1st Q 2012</th>
<th>Net Corrections</th>
<th>Totals YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Voltage</strong></td>
<td>9</td>
<td>14</td>
<td>4</td>
<td>2</td>
<td>2</td>
<td>31</td>
</tr>
<tr>
<td><strong>Estimated Cost</strong></td>
<td>$52,448,369</td>
<td>$51,348,548</td>
<td>$17,137,625</td>
<td>$6,482,565</td>
<td>$19,607,000</td>
<td>$147,024,107</td>
</tr>
<tr>
<td><strong>Transmission Service</strong></td>
<td>5</td>
<td>13</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>24</td>
</tr>
<tr>
<td><strong>Estimated Cost</strong></td>
<td>$30,471,058</td>
<td>$31,790,738</td>
<td>$165,000</td>
<td>$3,076,364</td>
<td>$213,200</td>
<td>$65,716,360</td>
</tr>
<tr>
<td><strong>Generation Interconnect</strong></td>
<td>0</td>
<td>0</td>
<td>3</td>
<td>7</td>
<td>1</td>
<td>11</td>
</tr>
<tr>
<td><strong>Estimated Cost</strong></td>
<td>$0</td>
<td>$0</td>
<td>$8,363,996</td>
<td>$51,506,000</td>
<td>$25,590,000</td>
<td>$85,459,986</td>
</tr>
<tr>
<td><strong>Balanced Portfolio</strong></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td><strong>Estimated Cost</strong></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td></td>
<td>$0</td>
</tr>
<tr>
<td><strong>High Priority</strong></td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td><strong>Estimated Cost</strong></td>
<td>$0</td>
<td>$960,895</td>
<td>$0</td>
<td>$0</td>
<td></td>
<td>$960,895</td>
</tr>
</tbody>
</table>

**Figure 5:** Completed Project Summary through 1st Quarter 2012

### 1st 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>
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**Figure 6:** Completed Transmission for 1st Quarter 2012
VI. Future Projections:

2nd Quarter 2012:

The 2nd Quarter of 2012, ending May 31, 2012 is scheduled to have 20 projects completed across all project types at an estimated cost of $262 million. The largest of these is ITC Great Plains and OGE’s Valiant-Hugo-Sunnyside 345 kV transmission service projects, which are scheduled to complete April 1st with a current estimated cost of $188.8 million. Figure 7 shows the 2nd Quarter estimated completed projects broken out by Project Type.

March 2012 through February 2013:

The next 12 months are scheduled to have a total of 139 upgrades completed at an estimated cost of $1.07 billion. This is slightly higher than last quarter’s projections, with an increase in reliability and zonal sponsored projects. More than half of the projects are scheduled to complete in June of 2012. Figure 7 shows the next 12 months estimated completed projects broken out by Project Type.

There are scheduled to be 817 miles of new transmission added to the system during the next 12 month period. 404 miles of 345 kV transmission lines are still scheduled to be completed. The large transmission service upgrades Hugo-Valliant-Sunnyside scheduled for April of 2012 will add 139 miles of 345 kV and Rose Hill-Sooner 345 kV will add 106 miles in June 2012. The Balanced Portfolio upgrade Spearville-Post Rock 345 kV is scheduled to add 90 miles in June of 2012. There will also be 202 miles of reconductored transmission placed into the system, with 105 miles being 115 kV. Figure 9 shows the details of the estimated transmission miles to be completed over the next 12 months.
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<th>Scheduled Complete Next Quarter</th>
<th>Scheduled Complete Next 12 Months</th>
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Figure 7: Upgrades Scheduled to Complete Next Quarter/Next 12 Months
### 2nd Quarter Projected Transmission Miles Complete

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<th>Voltage</th>
<th>Number of Upgrades</th>
<th>New Miles</th>
<th>Reconductor Miles</th>
<th>Total Miles</th>
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**Figure 8: Transmission Miles Scheduled to Complete 2nd Quarter**

### Projected Transmission Miles Complete Next 12 Months

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<th>Reconductor Miles</th>
<th>Total Miles</th>
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**Figure 9: Transmission Miles Scheduled to Complete Next 12 Months**
### SPP 2nd Quarter 2012 Project Tracking List - Branch

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<th>Project Name</th>
<th>Project Type</th>
<th>Original Cost Estimate</th>
<th>Current Cost Estimate</th>
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<th>Comments</th>
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*Note: Some projects may have additional costs not listed here.*
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Note: The table contains various financial and project-related details, including dates, amounts, and descriptions. For a comprehensive understanding, each entry should be reviewed in context with the surrounding text.
<table>
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<tr>
<th>Project ID</th>
<th>Description</th>
<th>Transmission</th>
<th>In-Service Date</th>
<th>Outage Date</th>
<th>Original Cost</th>
<th>Current Cost</th>
<th>Status</th>
<th>Notes</th>
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<td>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.</td>
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<td>WR Line - Clay Center Junction - Clay Center Switching Station 115 kV</td>
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<td>$6,790,959</td>
<td>$7,476,817</td>
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Project types "zonal - sponsored" and "regional reliability - non OATT" do not receive NTCs and are not filed at FERC but are being tracked because they are expected to be built in the near term.