Southwest Power Pool
REGIONAL STATE COMMITTEE

Doubletree Hotel at Warren Place
January 28, 2008

• MINUTES •

Administrative Items:
Members in attendance or represented by proxy were:
  Julie Parsley, Public Utility Commission of Texas (PUCT)
  David King, New Mexico Public Regulation Commission (NMPRC)
  Jeff Cloud, Oklahoma Corporation Commission (OCC)
  Jeff Davis, Missouri Public Service Commission (MPSC)
  Mike Moffet, Kansas Corporation Commission (KCC)
  Sam Loudenslager; for Colette Honorable, Arkansas Public Service Commission (APSC)

President Parsley called the meeting to order at 1:05 p.m. Cheryl Robertson (SPP) called roll and a quorum was declared. There were 69 in attendance (Attendance & Proxies – Attachment 1). Others in attendance via phone were: David Kays (OG+E).

President Parsley asked for adoption of the August 24 and October 29, 2007 meeting minutes (RSC Minutes 8/24/07 and 10/29/07 - Attachment 2). David King moved to approve the August and October minutes as presented. Jeff Davis seconded the motion. The minutes were approved unanimously.

President Parsley stated that FERC Commissioner Phillip Moeller and his aide Robert Ivanauskas would join the meeting following a tour of ERCOT. The agenda will be changed in order to accommodate their late arrival.

Business Meeting
Cost Allocation Working Group Report

- Concepts Paper on Economic Upgrades
  Dr. Mike Proctor provided the Cost Allocation Working Group report (CAWG Report & Presentation – Attachment 3). Dr. Proctor reviewed the Concepts Paper on Economic Upgrades in SPP written for the purpose to outline the design for cost allocation of economic upgrades so that tariff language can be developed over the next few months. At the same time, SPP staff in support of the CAWG is to develop a draft balanced portfolio of economic projects in order to show how the process will work before filing with FERC. The cost allocation for economic upgrades will use the postage stamp rate design for extra high voltage (EHV) transmission upgrades of 345 kV or higher. A balanced portfolio will be screened by SPP to determine economic upgrades with benefits greater than costs over a ten-year period. Dr. Proctor offered the following recommendation: The CAWG recommends that the SPP RSC adopt the Concepts Paper for Economic Upgrades for purposes of implementation by the SPP RTO. David King moved to adopt the concepts paper as presented. Jeff Davis seconded the motion, which passed unanimously.
Regional State Committee  
January 28, 2008

- Wind Generation Base Plan Funding Policy Discussion  
  Larry Holloway provided a report regarding wind and Base Plan funding (Wind Report – Attachment 4). Mr. Holloway reviewed the treatment of wind generation under the current Tariff, why wind may be treated differently than other resources in terms accredited capacity and presented alternatives for consideration. It was concluded that an alternate Cost Allocation Plan (CAP) for wind generation supplying SPP load needs to be developed.  
  **Mike Moffet moved to include the CAP for wind generation in the work plan. David King seconded the motion, which passed unanimously.** President Parsley requested that Mr. Holloway or another person present a plan on cost methodology for wind at the April RSC meeting.

- 2008 Work Plan  
The CAWG Work Plan was reviewed (Work Plan – Attachment 5).

- Empire District Electric Waiver Request  
  Dr. Mike Proctor provided background for the Empire District waiver request (Empire Waiver – Attachment 6). Dr. Proctor pointed out that the waiver request had been delayed until better figures were available. Costs have come down as the EDE projects continue to be restudied as a part of the ongoing Aggregate Study process coupled with the fact that the RSC appears to be about to make policy changes for wind as illustrated by Mr. Holloway’s presentation and the CAWG as well as the Markets and Operations Policy Committee (MOPC) recommends that the RSC and the SPP Board of Directors approve the Empire District waiver for full base plan funding. **Mike Moffet moved to approve the Empire waiver. Jeff Davis seconded the motion, which passed unanimously.**

FERC Update  
Commissioner Philip Moeller joined the meeting and was asked to share comments with the group. Commissioner Moeller expressed his thanks to Dr. Proctor for all his good work, appreciation for the RTO effort and noted that he operated with an open door policy welcoming emails and phone calls. He applauded the group for passing the Concept Paper for Economic Upgrades and stressed that we need to build transmission sooner than later. Commissioner Moeller stated that with the reappointments of Commissioners Kelliher and Wellinghoff, the Commission is able to offer stability for a measurable length of time. A major issue throughout the country today is FERC exercising its penalty authority as the reliability standards kick in and the battle of benefits and competition.

John Rogers provided an update on FERC activities:
- The Commission issued a Notice of Proposed Rulemaking proposing changes to the principal financial forms for electric utilities and licensees. The proposed effective date for these changes will be the calendar year 2009. Comments are due 45 days after publication in the Federal Register.
- The Commission approved eight new critical infrastructure protection reliability standards to protect the nation’s bulk power system against potential disruptions from cyber security breaches. The mandatory reliability standards require certain users, owners and operators of the bulk power system to establish policies, plans and procedures to safeguard physical and electronic access to control systems, to train personnel on security matters, to report security incidents, and to be prepared to recover from a cyber incident.
- The Commission conditionally accepted Duquesne’s exit from the PJM RTO. Duquesne plans to withdraw from PJM effective May 31, 2008, if he is able to join the Midwest Independent System Operator. The Commission approved the withdrawal subject to a compliance filing and Duquesne meeting certain obligations.

In December, the Commission issued a rehearing order on Order No. 890, largely reaffirming the findings in Order No. 890.

The Commission recently issued two orders involving SPP. The Commission accepted in part and rejected in part a recent SPP filing regarding its Large Generator Interconnection Procedures and Interconnection Agreement and directed a compliance filing. The Commission also issued an order on SPS, OG&E and
AEP’s application to terminate their purchase obligations from Qualifying Facilities under PURPA. The Commission granted OG&E and AEP’s requests and denied SPS’s request without prejudice.

John introduced Commissioner Moeller’s aide, Robert Ivanauskas, and Patrick Clarey (FERC) noting that Patrick is acting in an outreach capacity to the Midwest ISO and SPP.

**AEP Waiver**

Dr. Proctor then provided background for the American Electric Power waiver (AEP Waiver Request – Attachment 7). The AEP waiver was for costs in excess of the Safe Harbor Cost Limit for Base Plan funding. **It is the recommendation of the MOPC that the SPP Board of Directors approve 100% the AEP waiver for such amount to fully Base Plan fund the project. Jeff Davis moved to approve the AEP waiver as requested. David King seconded the motion, which passed with Sam Loudenslager abstaining.**

**Overview of Board of Directors and Stakeholders Survey**

Michael Desselle provided a review of the SPP Stakeholders and SPP Board of Directors Surveys. This is the second year of the SPP Stakeholder Survey. Many categories were above the mid point including meeting logistics and the Energy Imbalance Market showed significant improvement. Two areas in need of improvement were: transmission planning and Tariff administration. There is an action plan under development to improve stakeholder satisfaction.

The SPP Board of Directors Survey was conducted for the third time. Five of twelve items showed significant improvement and other results were not significantly different. The Strategic Planning Committee has developed an action plan/straw proposal to get feedback for going forward.

**STEP 2007, OEPTTF and EHV Report**

Jay Caspary provided a presentation regarding the SPP Transmission Expansion Plan (STEP), the Oklahoma Electric Power Transmission Task Force (OEPTTF) study, and the Extra High Voltage (EHV) report (STEP, OEPTTF, EHV Presentation – Attachment 8). The STEP 2008-2017 includes $2.2 billion of transmission projects. The MOPC will present this plan to the SPP Board of Directors for approval on January 29. The OEPTTF approved a Scope in December and hopes to finalize a study in the first quarter of 2008. Mr. Caspary reviewed the EHV Overlay Study completed in 2007 and a restudy where results are expected in the first quarter of 2008. He also provided information on the Joint Coordinated System Plan (JCSP) with MISO, PJM, TVA and others. Joint Operating Agreements require development of joint plans every few years.

**EPRI Report – The Power to Reduce CO₂ Emissions Highlight**

Les Dillahunty provided a report on reducing CO₂ emissions (Power to Reduce CO₂ Emissions – Attachment 9). The full report is published on the EPRI website.

**Project Tracking (written report)**

The SPP First Quarter 2008 Project Tracking Report and the 2007 STEP Project Tracking Summary were provided for review (Project Tracking – Attachment 10).

**RSC Financial Update**

Les Dillahunty (SPP) presented the RSC Financial Report (RSC Financial Report – Attachment 11). Mr. Dillahunty reported that the RSC remained well under budget for 2007. An RFP was sent to vendors on Friday regarding bids for a cost benefit study associated with the possible expansion of SPP markets.

Sam Loudenslager reported that the Customer Response Task Force (CRTF) working under the Market Working Group in regard to the current Energy Imbalance Market has arranged for Berkeley Labs to perform a Demand Response Survey for SPP as they have done for the Midwest ISO. Results will be ready for a Demand Response Forum tentatively scheduled before the July meeting. Members will be surveyed in March as to what they are doing in regards to the Demand Response and Energy Efficiency issues. The results will be provided to the RSC and SPP. Mr. Loudenslager encouraged a good response to this effort in order to get good information. The RSC was asked to consider a Demand Response workshop at the July meeting at which time survey results could be reported. The RSC will make this decision in April.
Regional State Committee  
January 28, 2008

**SPP Update**
Nick Brown congratulated the RSC for its great work in adopting the Concept Paper for Economic Upgrades and stated that it was cause for celebration.

In looking forward:
- The Strategic Planning Committee has started a process of strategic initiatives. Organizational groups will provide input and the RSC is invited to suggest projects to be in the front and center of these initiatives. The current plan recognizes the importance of communication with policy makers to realize transmission expansion. Working closely with state regulators to reach and educate groups is critical to the actual expansion.
- SPP is also reviewing the committee structure working with members to ease the burden of the number of meetings.
- The EPRI PRISM as presented by Mr. Dillahunty offers a strong portfolio approach and it will take all initiatives to achieve the desired outcome.
- Mr. Brown announced that Quentin Jackson, SPP Director, will be leaving the Board of Directors following tomorrow’s meeting. He provided excellent service to the Board and will be missed.

**SPP Regional Entity Trustees**
President Parsley asked John Meyer, Chair of Regional Entity Trustees (RET), to provide an update of the group’s activities. Mr. Meyers deferred to Michael Desselle. Mr. Desselle provided a report regarding violation updates stating that there had been 164 self reported violations to date. After June 18 the process will be slower as violations are confidential until filed at FERC. Three member audits have been performed since June reporting no violations. A Compliance Workshop was held last week in Tulsa and was a great success. Currently the group is working on the new Regional Standard under development, Under Frequency Load Shedding.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**
President Parsley noted that the next regularly scheduled RSC meeting is in Oklahoma City on April 21, 2008. In the event of a called teleconference regarding Tariff language, the group will be given a one week notice.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
AGENDA

Monday, January 28, 2008
1:00 pm- 5:00 pm
Hyatt Regency – Town Lake
Austin, TX

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a quorum
   b. Adoption of August 24 and October 29, 2007 Minutes

3. BUSINESS MEETING
   a. Cost Allocation Working Group..........................................................Dr. Mike Proctor
      • Concepts Paper on Economic Upgrades (Action Item)
      • Wind Generation Base Plan funding Policy Discussion.........................Larry Holloway
      • Empire District Electric and American Electric Power Waiver Request (Action Item)
      • 2008 Work Plan
   b. Overview of Board of Directors and Stakeholders Survey........................Michael Desselle
   c. STEP 2007, OEPTTF & EHV Report............................................................ Jay Caspary
   d. EPRI Report – The Power to Reduce CO₂ Emissions Highlights ................Les Dillahunty
   e. Project Tracking (written report)

4. UPDATES
   a. RSC Financial Report
   b. Other RSC officer reports
   c. FERC
   d. SPP
   e. RE

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

6. ADJOURNMENT
**Southwest Power Pool, Inc.**
**REGIONAL STATE COMMITTEE**
Hyatt Regency, Austin, Texas
January 28, 2008

**ATTENDANCE LIST**

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<tr>
<td>Venita McEllon-Allen</td>
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<td>Walt Shumate</td>
<td>On Behalf of ECI</td>
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<td>Phyliss Bernard</td>
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<td>Stacy Buckley</td>
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<td>John Rogers</td>
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<td>Patrick Clarey</td>
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January 22, 2008

Mr. Les Dillahunty  
Secretary  
SPP Regional State Committee  
415 N. McKinley  
#140 Plaza West  
Little Rock, AR 72205-3020

Dear Mr. Dillahunty:

I will not be able to attend the January 2008 RSC meeting. By this letter, I hereby give my proxy to Sam Loudenslager.

Sincerely,

Colette D. Honorable  
Chairman

cc: The Honorable Julie Parsley
Southwest Power Pool
REGIONAL STATE COMMITTEE
August 24, 2007
Teleconference

• M I N U T E S •

Administrative Items:
Members in attendance or represented by proxy were:
  Mike Moffet, Kansas Corporation Commission
  Steve Gaw, Missouri Public Service Commission
  Sam Loudenslager, for Paul Suskie, Arkansas Public Service Commission

Others in attendance:
  Tom DeBaun, Kansas Corporation Commission
  Jason Gray, Kansas Corporation Commission
  Larry Holloway, Kansas Corporation Commission
  Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
  Adrianne Brandt, Public Utility Commission of Texas
  Mike Proctor, Missouri Public Service Commission
  Greg Meyer, Missouri Public Service Commission
  Joyce Davidson, Oklahoma Corporation Commission
  Harry Skilton, SPP Director
  Bary Warren, Empire
  Rob Janssen, Redbud
  Walt Shumate, EEI
  Tim Woolley, Xcel Energy
  David Kays, Oklahoma Gas and Electric
  Jake Langthorn, Oklahoma Gas and Electric
  Carl Monroe, Southwest Power Pool
  Les Dillahunt, Southwest Power Pool
  Jay Caspary, Southwest Power Pool
  Keith Tynes, Southwest Power Pool
  Cheryl Robertson, Southwest Power Pool

Steve Gaw called the meeting to order at 9:10 a.m. Carl Monroe called roll and a quorum was declared.

Business Meeting:
Dr. Mike Proctor provided a report from the Cost Allocation Working Group (CAWG) meeting on July 25, 2007 (CAWG Report – Attachment 1). Topics included were:

  • STEP Screen to Portfolio Transition
    Charles Cates (SPP Staff) led a discussion regarding the 2006 STEP Screening process, stakeholder and SPP staff recommendations and the WFLR Process from the EHV Overlay Study. SPP has agree to include in the screening process TLRs on flowgates and off-peak benefits.

  • Integration vs. Off Ramp Facilities
Regional State Committee  
August 24, 2007

Raj Rana (AEP) led a discussion regarding off ramp facilities versus integration facilities. The group decided that further discussion was needed regarding off ramp facilities where situations in which lower voltage upgrades are needed to bring benefit/cost ratio up to have the EHV project implemented.

- **Aggregate Study Improvement Task Force Update**
  Jason Atwood provided an update on the Aggregate Study Improvement Task Force (ASITF). The Market and Operations Policy Committee (MOPC) directed that the ASITF present a report of potential Aggregate Study revisions prior to the October 16 MOPC meeting. The task force is made up of 7 members and 2 observers: 3 Transmission Owners; 3 Transmission Dependent Utilities; 1 Independent Power Producer; 1 FERC Staff; and 1 State Commission Staff. The group has agreed to remove the System Impact Study from the Aggregate Study process and has added the 15 day tariff required for execution of the study agreement in the 4 month open window or the transmission customer will be placed in the next Aggregate Study.

- **Early Buy-In for Economic Upgrades**
  Dr. Mike Proctor led a discussion regarding buy-in for Economic Upgrades considering: the pre-approval process; the specification of the lower bound on the benefit to cost ratio under which a project is allowed to qualify for the portfolio; project cancellation; ongoing evaluation of approved projects; and risks associated with project cancellation. Dr. Proctor listed two action items for the August CAWG meeting:
  - Project completion costs compared to benefits, criteria for cancellation should be equivalent to benefit/cost criteria for inclusion of a project
  - Proposed modifications to postage stamp rate design for an unbalanced portfolio

- **Topics for Next CAWG Meeting**
  Dr. Mike Proctor asked the RSC if modeling assumptions used for evaluation of an economic portfolio should match the modeling assumptions that go into the EHV project and asked for direction moving forward. Following discussion, the group decided that the CAWG should develop a list of key assumptions for the economic model, which hopefully will be consistent with the EHV project.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
Southwest Power Pool
REGIONAL STATE COMMITTEE
Doubletree Hotel at Warren Place
October 29, 2007

• M I N U T E S •

Administrative Items:
Members in attendance or represented by proxy were:
Julie Parsley, Public Utility Commission of Texas (PUCT)
Jeff Cloud, Oklahoma Corporation Commission (OCC)
Jeff Davis, Missouri Public Service Commission (MPSC)
Mike Moffet, Kansas Corporation Commission (KCC)
Paul Suskie, Arkansas Public Service Commission (APSC)

There were 53 in attendance (Attendance – Attachment 1). Others in attendance via phone:
David Douglass, Aquila
Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
Jay Caspary, Southwest Power Pool, Inc.

President Parsley called the meeting to order at 1:08 p.m. Cheryl Robertson (SPP) called roll and a quorum
was declared. President Parsley asked for adoption of the July 23 and October 11, 2007 meeting minutes
(RSC Minutes 7/23/07 and 10/11/07 - Attachment 2). **Jeff Cloud moved to approve the July and October
minutes as presented. Mike Moffet seconded the motion. The minutes were approved by
acclamation.**

Election of Officers:
President Parsley stated that the Annual Meeting is time to elect RSC officers for 2008. **Mike Moffett moved
that Julie Parsley continue to serve as President. Jeff Cloud seconded the motion, which passed
unanimously. President Parsley moved that David King serve as Vice President. Jeff Davis seconded
the motion, which passed unanimously. President Parsley moved that Mike Moffet serve as
Secretary/Treasurer. Jeff Davis seconded the motion, which passes unanimously.**

Updates:

RSC Financial Report
Dillahunty reported that the RSC remained under budget for 2007 mainly due to the fact that no cost/ benefit
study had been initiated and travel expenses remained below budget.

FERC Update
John Rogers provided an update on FERC activities:
• In October, the Commission approved an ISO New England proposal to improve market transparency
  by reducing the time to release of offer and bid market data from six to three months. This proposal
  is consistent with the Commission’s proposal in an Advanced Notice of Proposed Rulemaking on
  Competition that the Commission issued in June.
• FERC conditionally accepted the 2008 NERC Business Plan and Budget for Regional Entities which
  also includes SPP’s Regional Entity funding.
The Commission issued decisions on two SPP proposals. On October 15, the Commission rejected SPP’s proposal for permitting external generator participation in the energy imbalance market and directed SPP to file a new proposal in 60 days. On October 29, the Commission issued a data request in response to SPP’s proposed amendments to its generator interconnection procedures.

The Commission made two organizational changes. First, the Chairman elevated the Division of Reliability to the Office of Reliability in recognition of the growing importance of the Commission’s work on reliability. As part of this change, Michael McLaughlin, Division Director of Market Development-Central, was named Deputy Office Director. Second, a new unit within the Office of Energy Market Regulation was formed. The Energy Innovations Unit will provide expertise to promote and manage the Commission’s activities with regard to demand response, energy efficiency, distributed generation, renewable energy issues, and advanced technologies relevant to the transmission grid and wholesale markets.

SPP Update
Nick Brown provided an update on SPP activities. The SPP Strategic Planning Committee has reviewed progress on nine action items in the SPP Strategic Plan and has rated four items as A priorities. Two items discussed in depth were the EHV Overlay and the Transmission Expansion Plan. He noted that there is cause for concern about the EHV Overlay project, the STEP and transmission planning in general with the recent rejection of coal plants in Kansas and Oklahoma. Mr. Brown encouraged the RSC to help make the EHV Overlay a reality and to maintain its commitment to expand transmission. He stated that SPP appreciates the RSC’s earlier work and approval of a cost allocation mechanism for reliability upgrades and encouraged the RSC to move post haste on the critical path toward a cost allocation plan for economic upgrades.

Business Meeting
2008 Budget Approval
Les Dillahunty presented the 2008 & 2009 RSC Budget for approval (2008 Budget – Attachment 4). The cost/benefit study is listed as a place holder as the Cost Benefit Task Force needs to define the scope and bid for any external resources deemed to be required. Following discussion, Jeff Cloud moved to approve the 2008 RSC Budget of $703,017 as presented. Paul Suskie seconded the motion, which passed unanimously.

Cost Allocation Working Group Report
Dr. Mike Proctor provided the Cost Allocation Working Group report (CAWG Report – Attachment 5). Dr. Proctor provided background on the process of Base Plan Funded Projects, the cost allocation issue previously initiated by the RSC. This review was presented as background information due to the addition of four new commissioners on the RSC Board and due to Empire District’s waiver request which might result in possible changes in the current cost allocation methodology for certain Base Plan Funded Projects.

Dr. Proctor noted that Empire requested a waiver on August 23, 2007 for the recovery of all cost exceeding the Safe Harbor Cost Limit for the Cloud County wind farm, pursuant to Attachment J of the SPP OATT. This request may require a general policy change and as a result a change in the SPP tariff for similar requests in the future. The CAWG is looking for alternatives to address the tariff issue. Empire supports an extension beyond the 120 day decision period to afford a better opportunity for discussion at the SPP’s January cycle of meetings.

Jeff Davis expressed that with the recent rejection of coal plants, there is a need to work out wind projects. Jim Eckelberger, SPP Board Chairman, added that there is a need to build a robust transmission system and the SPP Board is very interested in moving forward.

Transmission Ownership/Construction Task Force (TOCTF) Report Overview
Mel Perkins provided an overview of the Transmission Ownership/Construction Task Force activities (TOCTF Report – Attachment 6). The TOCTF was formed in April of 2007 to address the policy for allocation of rights and responsibilities associated with the ownership, construction, and operation of transmission upgrades. The TOCTF suggested that the group’s term be
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extended through January 2008 in order to provide greater specificity to the results of their recommendations.

**Future Market Efforts**
Carl Monroe provided a report on SPP’s future market efforts. Mr. Monroe addressed two efforts (Future Market Efforts – Attachment 7):

- **Balancing Authority Consolidation** - The Balancing Authority (BA) consolidation was required by FERC in 2005 in conjunction with approving the 2004 RTO filing. SPP is required to study the feasibility of consolidating BA’s and file a report within 15 months of the February 1, 2007 start of the EIS Market.
- **Future Markets** – The Market Working Group (MWG) offered the Cost Benefit Task Force three scenarios to include in the cost/benefit study to be undertaken:
  1. Day Ahead Market
  2. Ancillary Service Market
  3. Both

The CBTF working with the MWG will continue to move forward with the development of the project scope, a cost/benefit study and analysis that will be reported to the SPP and RSC.

**2007 SPP Transmission Expansion Plan (STEP) and EHV Progress Reports**
Les Dillahunty provided a presentation of 2007 STEP and EHV Overlay Study as well as the multi-colored Project Tracking Chart (Progress Reports & Project Tracking – Attachment 8). Mr. Dillahunty reported that 2007 STEP projects through 2017 amount to $2.18B without recent commitments. The STEP addresses a 10 year plan focusing on reliability needs based on firm commitments; the EHV Overlay is a 20 year visionary blueprint for near term planning to incorporate into collaborative, inter-regional assessments; and the CAWG Economic Portfolio effort investigates economically beneficial projects within the SPP footprint.

**Inter-Regional Cost Sharing and Siting Discussion**
Dr. Proctor stated that he would continue to follow this issue with Midwest ISO but has nothing to report at this meeting.

**Update on Organizational Metrics**
Michael Desselle discussed the Organizational Metrics Task Force document previously distributed to members of several committees. Organizational Metrics have been developed with the help of Mark Rossi (Gestalt) to create a dashboard measuring 4 areas:

- Reliability and Market Performance Metrics
- Financial Metrics
- Learning and Growth Metrics
- Overall Performances

Mr. Desselle requested feedback from the Board of Directors, RSC, and the Market and Operations Policy Committee in the next three weeks. It is the OMTF’s goal is to implement and track organizational metrics starting early in 2008.

**SPP Regional Entity Trustees**
President Parsley asked John Meyer, Chair of Regional Entity Trustees (RET), to provide an update of the group’s activities. Mr. Meyer stated that the RET met on August 20 discussing: violation status, hearing procedures, the compliance monitoring and enforcement program, and the Delegation Agreement. On August 21, the group met with FERC staff regarding compliance and reliability. Topics discussed included: independence for RTO, staff size, situation awareness/reliability assessment and Standards Process oversight. FERC conditionally accepted the Regional Entity budgets for 2008 in an order on October 18.

NERC is performing an audit of the SPP Reliability Coordinator with participation of FERC on October 29-31. The
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audit is supported by SERC with observation by the SPP Regional Entity. The results will not be available for several months. Notice was received on October 4 of an upcoming FERC compliance audit of both the RE and the RTO. This audit will review compliance of Bylaws, Delegation Agreement, Membership Agreement, RTO Tariff, and FERC orders. Every RE will be audited but SPP and New York ISO are the first to undergo this type of audit.

President Parsley thanked Mr. Meyer for his report and stated that in the future RET reports would be included on the agenda.

**Resolutions**  
President Parsley presented a resolution for Ms. Sandy Hochstetter (APSC) and a resolution for Mr. Steve Gaw (MPSC) in appreciation of their past contributions to the Regional State Committee.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**  
President Parsley noted that the next regularly scheduled RSC meeting is in Austin, Texas on January 28, 2008.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
# Concepts Paper on Economic Upgrades

## Executive Summary

**IA. Purpose: Cost Allocation for a Balanced Portfolio of Economic Upgrades**

This paper proposes a region wide cost allocation with a postage stamp rate design for economic upgrades that are included in a balanced portfolio.

**IB. Specifications for Economic Upgrades**

Economic upgrades are extra high voltage ("EHV") transmission upgrades of 345 kV or higher and additions to the SPP Transmission System that have been shown to provide customers with potential savings that exceed the cost of the proposed transmission upgrade(s). An economic upgrade will reduce congestion on the SPP Transmission System that result in savings in Production Costs for the SPP footprint. Economic upgrades may also provide other benefits to the power grid that result in both increased reliability and lower costs in other areas such as capital costs and end-use consumer costs. It should be noted that upgrades of voltages less than 345 kV can be included if needed to deliver the benefits of the EHV upgrade, where the cost of the lower voltage facilities does not exceed the cost of the EHV facilities.

- A portfolio of economic upgrades is a set of economic upgrades for which the benefits exceed the costs, both of which are measured in revenue requirements over a ten-year period.

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In order to qualify for economic cost allocation, the portfolio of economic upgrades must be approximately balanced across the entire SPP footprint. In a balanced portfolio of economic upgrades, over the ten-year period analyzed, the benefits to each SPP zone must exceed the costs allocated to each SPP zone.

**IC. Requirement for Benefit to Cost Ratio to Qualify for Cost Allocation**

SPP, with input from the Transmission Owners, will estimate the revenue requirement for the potential economic upgrades using a fixed charge rate. These costs for economic upgrades in a balanced portfolio of economic upgrades will be allocated region-wide based on load ratio share. This will simulate a postage stamp rate design similar to the Base Plan Region-wide Charge under the SPP Tariff.

To estimate costs at the zonal level, the revenue requirement for the portfolio of economic upgrades will be allocated to each SPP zone based on load ratio share. The cost for each SPP zone will be used to calculate the benefit to cost ratio for that SPP zone and to determine whether the portfolio of economic upgrades is balanced.

For each SPP pricing zone, SPP will estimate benefits from proposed portfolios of economic upgrades using the adjusted production cost metric which includes generation costs for generators within each zone, purchase power costs for energy imported into each zone, and subtracts out revenues from sales for energy exported from each zone. In addition there are other economic benefits to transmission investment that can currently be measured or with further development that includes stakeholder input are likely to be measurable in the not too distant future. All benefits from a portfolio will be calculated on a zonal level within SPP over a ten-year period for the purpose of comparing transmission expansion alternatives and determining whether a portfolio of economic upgrades is balanced.

SPP will estimate the revenue requirement (cost) and the annual benefits for each proposed portfolio of economic upgrades over a ten-year planning time frame. In order for a portfolio of economic upgrades to qualify for economic cost allocation, the portfolio of economic upgrades must be a balanced portfolio of economic upgrades and the benefits of the portfolio of economic upgrades must exceed the costs over the ten-year period analyzed. In a balanced portfolio of economic upgrades the benefits to each SPP zone must exceed the costs allocated to each SPP zone per the postage stamp rate design.

**ID. Process of Balancing Benefits with Costs and Approving Portfolios of Economic Upgrades**

When a balanced portfolio of economic upgrades cannot be achieved by considering only EHV transmission upgrades, benefits to deficient zones may be increased through other means, such as including lower voltage facilities that increase economic benefit to the deficient zones or including existing zonal costs in the postage stamp rate to increase economic benefit to the deficient zones.

As part of the transmission planning process, SPP develops alternative portfolios of economic upgrades; and performs an evaluation of costs, benefits and balance of each portfolio. In the winter of each year, SPP will make a recommendation of a balanced portfolio of economic upgrades to the Markets and Operations Policy Committee and Regional State Committee. Both the
Markets and Operations Policy Committee and Regional State Committee will make recommendations to the SPP Board of Directors. The SPP Board of Directors will approve the economic upgrades included in the balanced portfolio of economic upgrades as part of the SPP Transmission Expansion Plan.

II. Introduction

Last year the SPP Regional State Committee ("RSC") requested its Cost Allocation Working Group ("CAWG") consider alternative cost allocations for economic upgrades. While the initial plan was to have a policy level recommendation available to the SPP RSC in October of 2007, because of turnover in the membership of the SPP RSC, it was determined to delay that recommendation until the January 2008 meeting of the SPP RSC. This concepts paper represents the recommendation of the CAWG with respect to a cost allocation for economic upgrades.

As set out in the Executive Summary section of this paper there are several key components to this proposal. Almost all of these components (rate design, EHV upgrades, cost benefit criteria, and balanced portfolio) were presented to the SPP RSC at its July 2007 meeting in various strawmen proposals from SPP staff, Transmission Owners and Transmission Customers. Since that time, several unresolved details of these proposals have been discussed and resolved at CAWG meetings. However, the most critical issue for the CAWG was what to do if a balanced portfolio of economic upgrades could not be found. This critical issue was ultimately resolved with a proposal to move costs assigned to zones that are deficient in benefits from transmission upgrades in the portfolio from being included only in the calculation of the zonal rate to be included in the calculation of a region-wide postage stamp rate. While there are still details to be worked out regarding the implementation of this proposal, from a conceptual perspective, this proposal will reasonably assign the upgrade costs of the portfolio of economic upgrades among the various transmission customers within the SPP footprint.

In the remainder of this concepts paper the details associated with each key component to the cost allocation for economic upgrades is presented. It is the intent of this paper to set out enough of the design for cost allocation of economic upgrades that tariff language can be developed over the next several months. At the same time, the expectation is that SPP staff will develop portfolios of economic upgrades for SPP RSC and stakeholder review. In this way, the SPP RSC, stakeholders and the SPP Board of Directors should have a fairly clear understanding of how this cost allocation proposal will work before it is filed with the Federal Energy Regulatory Commission.

III. Economic Upgrades

IIIA. Description of Economic Upgrades

Economic upgrades are those transmission upgrades and additions to the SPP Transmission System that have been shown to provide customers with potential savings that exceed the cost of the proposed transmission upgrade(s). An economic upgrade will reduce congestion on the SPP Transmission System that result in savings to Adjusted Production Costs as described in Section IV.B.1, and may provide other benefits as described in Section IV.B.2.

An economic upgrade is not needed in order to satisfy reliability criteria at the time the economic upgrade is expected to be completed. However, an economic upgrade may displace or defer the need for a reliability upgrade. Also, an economic upgrade is not needed to accommodate either requests for transmission service or interconnection service pursuant to Attachments Z1 and V, respectively, of the SPP Tariff.
As part of the transmission planning process pursuant to Attachment O of the SPP Tariff, stakeholders, including regulatory authorities, may propose potential economic upgrades. Also, SPP staff may identify potential economic upgrades as a result of investigating Transmission Loading Relief ("TLR") events and observing congestion on the SPP Transmission System. SPP performs a screening analysis of these potential economic upgrades in order to:

- Establish a relative ranking of the potential economic upgrades based on the ratio of the estimated benefit to the estimated cost; and
- Aid in developing alternative portfolios of economic upgrades to achieve a general balance of benefits throughout the SPP Region.

The potential economic upgrades may be screened individually or in various combinations. As part of the transmission planning process, SPP solicits input from stakeholders and state regulators on how to combine individual upgrades for the purpose of screening. Also, SPP solicits input from stakeholders and from the SPP RSC on the metrics to be used in the screening process. In order to perform the screening analysis, for each potential economic upgrade or combinations of potential economic upgrades, SPP estimates the cost and the benefit due to the upgrade(s). The screening analysis provides a relative ranking of the potential economic upgrades. SPP considers the highest ranking potential economic upgrades in developing alternative portfolios of economic upgrades for more robust analysis as described in Section IV.B.

**III-B. Network Upgrade Groups that Qualify for Economic Cost Allocation**

Network upgrade groups that qualify for economic cost allocation, as described in Section IV:

- Must be 345 kV and above ("EHV");
- May include lower voltage facilities needed to integrate the EHV upgrade(s) and achieve the benefits; however, the cost of the lower voltage facilities cannot exceed the cost of the EHV upgrade(s) included in the network upgrade group;
- Must meet the benefit to cost ratio requirements in Section IV.B.4; and
- Must be part of a balanced portfolio of economic upgrades, as described in Section V.

Negative reliability impacts resulting from the EHV upgrade(s) will be mitigated as part of the development of the overall EHV network upgrade group and included as part of the network upgrade group.

**III-C. Portfolio of Economic Upgrades**

A portfolio of economic upgrades is a set of network upgrade groups that:

- Qualify for economic cost allocation; and
- Can be assumed to be implemented within a set time frame.

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1 SPP performs set year analysis (e.g. 2012 and 2016), then interpolates and extrapolates the data to determine expected values for years not analyzed. The process for performing the screening analysis is open to input from stakeholders for further improvement.

2 EHV to lower voltage transformers are classified as lower voltage facilities for the purposes of economic cost allocation.
While individual upgrades may vary in estimated time for completion, the benefits from the portfolio will be evaluated as if all upgrades are simultaneously available to the power system. Thus, it is important that all of the economic upgrades included in a portfolio can be implemented within a set time frame; i.e., there is no large discrepancy in the time required to complete the upgrades included in a portfolio. SPP will develop proposed portfolios of economic upgrades to be evaluated.

IV. Requirement for Benefit to Cost Ratio to Qualify for Cost Allocation

IVA. Calculation of Costs

SPP, with input from the Transmission Owners, will estimate the costs of a potential economic upgrade. In addition the revenue requirements for the first ten-years of these upgrades will be estimated using a fixed charge rate. These costs for economic upgrades in a balanced portfolio of economic upgrades will be allocated region-wide based on load ratio share. This will simulate a postage stamp rate design similar to the Base Plan Region-wide Charge under the SPP Tariff.

To calculate costs at the zonal level, the revenue requirement for the portfolio of economic upgrades will be allocated to each SPP zone based on its load ratio share. The cost for each SPP zone will be used to calculate the benefit to cost ratio for that SPP zone and to determine whether the portfolio of economic upgrades is balanced.

IVB. Calculation of Benefits

This section discusses a potential methodology to use to identify and measure the value of economic transmission upgrades proposed by SPP in the annual planning process.

Taken together, these types of benefits are often identified as “societal benefits”. The societal benefit is made up of a set of mutually agreed upon metrics that reflect the economic performance of various aspects of transmission investment. These metrics can then be combined via a mutually agreed formula. The final metric reflects the overall societal benefit of a project. These metrics can be calculated for transmission alternatives and compared to assist in final project selection.

1. Adjusted Production Costs: Application of Economic Model

To calculate the adjusted production cost metric, software is used that estimates the unit commitment and economic dispatch of modeled generators within a context of a modeled transmission system and load delivery points. The commitment and dispatch of the generators is constrained by the software to ensure that no overloads will occur on any monitored transmission element (typically taken as the NERC book of flowgates, but can include additional potential future flowgates). The

3 This requirement is for evaluation purposes and is not intended to restrict the timing of the implementation of individual economic upgrades.
software produces a security constrained economic dispatch and unit commitment.

The program outputs are related to the production costs of the units modeled in the simulation. Production cost for each unit is based upon the fuel used, variable O&M costs, environmental costs and both scheduled and forced outages. Furthermore, the adjusted production cost also takes into account the economics associated with purchases and sales detected by the software between the various areas included in the model.

The adjusted production cost method proposed by SPP takes advantage of these outputs from the simulations to formulate an economic metric that has meaning for the customers served within the SPP footprint. The proposed metric is called the “adjusted production cost”. Adjusted production cost would be calculated as follows:

\[
\text{Adj Prod Cost} = \text{Production Cost} - \text{Revenue from Sales} + \text{Cost of Purchases}
\]

Where:

\[
\text{Revenues from Sales} = \text{Net Export} \times \text{Zonal LMP}_{\text{Gen Weighted}}
\]

and

\[
\text{Cost of Purchases} = \text{Net Import} \times \text{Zonal LMP}_{\text{Load Weighted}}
\]

The adjusted production cost metric is especially useful for comparing transmission expansion alternatives. The adjusted production cost from one alternative can be compared to other alternatives to determine its relative economic performance. This metric can also be used directly in the calculation of present value and net revenue requirement for the purpose of regulatory justification.

An analysis of the sensitivity of the adjusted production cost metric shall be performed with respect to changes in assumptions for key input variables. SPP shall solicit input from the stakeholders and the Regional State Committee regarding the appropriate sensitivity analyses to be performed, including: the specification of key input variables; sensitivity ranges for these variables; and the weights to be given to various sensitivities.

2. Other Measurable Benefits

In addition to the adjusted production cost metric, there are other economic benefits to transmission investment that either are measurable now or could be with further development and refinement based upon SPP stakeholder input. Many of these items, perhaps all, could be measured using economic metrics for use in transmission project selection and regulatory justification. Additional benefits that can be readily measured using an economic metric are described in Appendix 1 and include:

- Reduction in system losses;
- Differing environmental impacts; and

---

4 SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages.
Improvement to capacity margin and operating reserves requirements.

Additional benefits that merit further consideration but which will require further development and refinement based upon stakeholder input are described in Appendix 2 and include:

- Energy, capacity and ancillary service market facilitation;
- Increased competition in wholesale markets;
- Reliability enhancement, including storm hardening and black start capability; and
- Critical infrastructure and homeland security.

3. Benefits Calculated at Zonal Level

Adjusted production cost benefits are calculated on a zonal level within SPP for the purpose of comparing transmission expansion alternatives. The method used for this calculation is a simplification in that it does not attempt to track specific generating units that increase output for increased sales or decrease output for increased purchases. Instead, each zone’s imports or exports are calculated by comparing total generation to total load, with net imports being priced at load weighted LMPs and net exports being priced at generation weighted LMPs.

The zones used in this process that are internal to SPP are the zones specified in Attachment H of the SPP Tariff and listed Appendix 3. The zones used in this process that are external to SPP are the first tier zones listed Appendix 4. The option is available to increase or decrease the granularity of the internal and/or first tier zones.

The adjusted production cost metric will determine the total adjusted production cost for each zone based on the transmission in place for a specific case. To determine the benefit derived from a transmission expansion project the metric must be calculated with and without the transmission expansion. The adjusted production cost of the scenario with the expansion is then subtracted from the scenario without. The resultant difference will be the adjusted production cost change – savings if negative, increase if positive.

4. Benefits Must Exceed Costs

SPP will calculate the costs and the benefits for each proposed portfolio of economic upgrades. SPP will estimate the annual benefits over a ten-year planning time frame by calculating the annual benefits for three specific years within the ten-year planning time frame (early year, intermediate year and late year) and interpolating the annual benefits for the in between years. For example, SPP may calculate the annual benefits for years 1, 5 and 10 in the planning time frame and interpolate the annual benefits for years 2, 3, 4, 6, 7, 8 and 9. SPP, with input from the Transmission Owners, will estimate the revenue requirement for each proposed portfolio of economic upgrades over the same ten-year planning time frame.

In order for a portfolio of economic upgrades to qualify for economic cost allocation, the portfolio of economic upgrades must be a balanced portfolio of economic upgrades, as described in Section V; and the benefits of the portfolio of economic upgrades must exceed the costs over the ten-year period analyzed.
The benefit to cost criterion is:

\[ NPVB > NPVC \]

Where:

- \( NPVB = \) net present value of the benefits of the portfolio of economic upgrades over the ten-year period analyzed; and
- \( NPVC = \) net present value of the revenue requirements for the portfolio of economic upgrades over the ten-year period analyzed.

A discount rate will need to be specified for use in the calculation of the net present value of benefits. For the screening analysis performed as part of the development of the 2007 SPP Transmission Expansion Plan, a discount rate of 8% per year was used to calculate the net present value of benefits over the ten-year period analyzed. Also, a sensitivity analysis to the discount rate could be performed as part of the process to develop alternative portfolios of economic upgrades.

The net present value of the benefits will be calculated only for SPP, unless a first tier entity as listed in Appendix 4 agrees to participate in the allocation of costs pursuant to a seams agreement with such entity.

V. Process for Balancing Benefits with Costs and Approving Portfolios of Economic Upgrades

VA. Requirement for a Balanced Portfolio of Economic Upgrades

In order for a portfolio to qualify for economic cost allocation, the portfolio of economic upgrades must be a balanced portfolio of economic upgrades. In a balanced portfolio of economic upgrades, over the ten-year period analyzed, the benefits to each SPP zone as described in Section VI.B.3 must exceed the costs allocated to each SPP zone as described in Section VI.A.

VB. When A Balanced Portfolio of Economic Upgrades Cannot be Achieved

SPP may not be able to achieve a balanced portfolio of economic upgrades based on the description of network upgrade groups that qualify for economic cost allocation in Section III.B. In this case, in order to achieve a balanced portfolio of economic upgrades, SPP may include lower voltage facilities that increase economic benefit to deficient zones.

If a balanced portfolio of economic upgrades still cannot be achieved, in order to increase economic benefits to deficient zones (where allocated costs from the postage stamp rate exceed benefits from the portfolio of economic upgrades), SPP will include in the cost-benefit analysis the transfer of a portion of zonal revenue requirements from the existing zonal rates of these deficient zones to the postage stamp rate. Over the ten-year analysis period such transfers
decrease the costs to deficient zones and increase the costs to zones in which benefits exceed the costs allocated from the postage stamp rate. Such transfers are limited to what are needed to balance the portfolio over the ten-year period, and because they represent a reallocation of cost, do not change the overall benefit to cost ratio of the portfolio of economic upgrades. To the extent that transfers of a portion of existing zonal revenue requirements are used to achieve a balanced portfolio of economic upgrades that is ultimately implemented, SPP will permanently move such existing zonal revenue requirements to the postage stamp rate.

VC. Process for Approval of a Portfolio of Economic Upgrades

As part of the transmission planning process pursuant to Attachment O of the SPP Tariff, SPP develops alternative portfolios of economic upgrades; and performs an evaluation of costs, benefits and balance of each portfolio. In the winter of each year, SPP will make a recommendation of a balanced portfolio of economic upgrades to the Markets and Operations Policy Committee and Regional State Committee. Both the Markets and Operations Policy Committee and Regional State Committee will make recommendations to the SPP Board of Directors. The SPP Board of Directors will approve the economic upgrades included in the balanced portfolio as part of the SPP Transmission Expansion Plan.
Appendix 1
Quantifiable Benefit Metrics Using Currently Available Methods and Tools

1. Reduction in System Losses

It is relatively easy to quantify the changes to system losses. There are two components, energy and capacity.

The energy component of losses is a standard value provided by the simulation. It is a straightforward calculation to determine the change in losses among alternatives and the costs associated with such losses by multiplying the losses by the average marginal cost of energy supplied in the modeling output. The energy component of losses can be captured as part of production cost analysis.

The capacity component of losses can be determined either by looking at the peak hour loss reduction from the economic modeling runs or, alternatively, by comparing peak load AC powerflow simulations of the alternatives. The difference in losses on peak can be assigned a capacity value since a reduction of losses (or conversely an increase in losses) represents a reduction (increase) in the amount of capacity that must be purchased for the system under study. Because the capacity impact occurs as marginal capacity, typically a value applicable to peaking capacity is applied, but the final determination of the capacity value would be subject to stakeholder review.

2. Differing Environmental Impacts

It is also relatively easy to compute the economic value of differing environmental impacts from various transmission alternatives as these items, if modeled appropriately, are an output of the software. SO₂, NOₓ, mercury and carbon are values that can be modeled for the fuel type used in the unit. The value per pound of each emission type is subject to stakeholder determination.

The cost of emissions can be calculated for the base, system as is scenario. A transmission expansion alternative can allow more cost effective, lower emissions based power access to market. The emission cost reduction of this alternative can be calculated by taking the difference. This represents the environmental savings for the given transmission expansion alternative.

3. Improvement to Capacity Margin and Operating Reserves Requirements

Planning reserve requirements have been set by the regions based upon a loss of (firm) load expectation (“LOLE”) of one day for every ten years. This approach uses expected values of incremental transfer capability on peak as part of the supply available to the system under study. Various transmission alternatives, especially large packages of transmission upgrades such as those considered in the EHV overlay study, have an impact on these transfer capabilities. As a result, planning reserve requirements could be adjusted and, therefore, a capacity value of changes to planning reserve requirements can be calculated.

Operating reserves are needed to regulate load changes and to support transmission contingencies without shedding firm load. Operating reserve requirements may also be adjusted to account for a more robust transmission grid and these benefits can be captured.
To calculate these economic benefits, the value of capacity used in calculating benefits from improved capacity margin is subject to stakeholder determination.
Appendix 2
Potential Economic Benefit Metrics that Can be Developed Over Time

1. Energy, Capacity and Ancillary Service Market Facilitation

Market structure matters in identifying the economic benefits related to the various markets impacts resulting from transmission investment. As price information becomes transparent, planners and interested stakeholders have access to additional information regarding the economic performance of the existing transmission system. This additional information can be used to glean insights into the value of transmission investment alternatives.

Investments and upgrades to the transmission grid provide support for enhanced market functionality. For example, a transmission upgrade into a load or generation pocket can free up trapped markets and enable more economic transactions for that area. Additionally, upgrades providing reactive power reinforcements can better facilitate transactions across the grid and lead to better market interactions.

Cost benefit calculations related to market facilitation (e.g., enhanced competition and increased liquidity), will likely need to wait until formal markets develop for energy, capacity, and ancillary services within the SPP footprint. Once a history develops for market based prices for a given product, then techniques can be created to estimate or bound market effects for economic benefit determination.

2. Increased Competition in the Wholesale Markets

Until SPP establishes a future market design and a cost history is developed, the adjusted production cost methodology will capture the underlying production cost savings due to reduction in congestion on the system resulting from the various transmission alternatives under consideration. Since rational market behavior would imply that suppliers would take full advantage of the supply and demand curve in constrained markets, the adjusted production costs are a conservative indicator of the savings due to congestion reduction.

In Locational Marginal Pricing ("LMP") based markets, congestion can be readily measured by comparing LMP prices across nodes in the market and determining the value of increasing the capability of that interface. Security Constrained Production Cost programs can estimate these LMP differentials. As a result, impacts on congestion can be estimated. Stakeholder acceptance of this measure may require a history of market behavior to establish credibility.

3. Reliability Enhancement: Storm Hardening/Black Start Capability

Storm hardening is a legitimate benefit of transmission investment. While various alternatives may satisfy planning criteria, the various alternatives will reinforce the grid in different ways. It is possible to use security constrained production cost programs and insurance valuation techniques to estimate the economic value of storm hardening for each alternative.

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5 The descriptions of how these benefits might be measured represent the present thinking of SPP, and are included to help provide depth of understanding for each benefit area. Such descriptions are not meant to limit future development of benefit metrics, nor should they be assumed as a specific endorsement of the only or best method for benefit measurement by the SPP Regional State Committee.
To perform this work, SPP will develop a list of key combinations of contingencies to use to represent the storm scenarios under study subject to stakeholder review. In addition, probabilities should be assigned to each of these combinations for the final valuation to be determined. If pattern of certain outages has occurred in the past, perhaps due to hurricanes or tornados, those outage patterns may be used as the basis for the definition of the multiple contingencies.

Once these contingencies are identified, then SPP can use its security constrained production cost program to model these contingencies for each alternative and compare adjusted production costs during the storms and can also estimate and compare the unserved energy portion for each alternative for the given contingency sets. Unserved energy represents economic loss for end-use customers; and an estimate of the economic loss for unserved energy is subject to stakeholder determination. The probabilities can be applied to calculate a weighted cost for each transmission alternative.

4. Critical Infrastructure/Homeland Security

This item is also an indication of a reliability benefit, but can be calculated as an economic benefit. Generally, as transmission elements are added to a network, redundancy is added and the network becomes more robust. This has a direct relationship to the proposed CIP-002 standard in the use of contingency sets to identify critical infrastructure\(^6\) on the US electric system. Transmission alternatives may add different levels of “robustness” to the network with the varying level of ability to prevent the spread of events to a regional level. The more robust alternatives may be able to reduce or possibly eliminate the designation of critical infrastructure.

If combinations of contingencies are defined and used for the CIP-002 analysis, then these combinations can be modeled in the security constrained dispatch program similar to the method proposed for storm hardening. Costs and levels of un-served energy can be compared for the various alternatives.

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\(^6\) Each regional entity is tasked to identify and document a risk-based assessment methodology to use to identify its Critical Assets. The risk based assessment considers control centers and backup control centers, transmission substations, generation resources, systems and facilities, loading shedding control systems, special protection systems and any additional resources that support the reliable operation of the bulk grid.
Appendix 3
List of Zones Included in the SPP Footprint

The following is a present list of zones in the SPP as specified in Attachment H of the SPP Tariff.

Zone 1: American Electric Power – West
    American Electric Power (Public Service Company of Oklahoma, Southwestern Electric Power Company)
    East Texas Electric Cooperative, Inc.
    Tex-La Electric Cooperative of Texas, Inc.
    Deep East Texas Electric Cooperative, Inc.
Zone 2: Cleco Corporation (will be treated as a first tier zone)
Zone 3: City Utilities of Springfield, Missouri
Zone 4: Empire District Electric Company
Zone 5: Grand River Dam Authority
Zone 6: Kansas City Power & Light Company
Zone 7: Oklahoma Gas & Electric Zone
    Oklahoma Gas & Electric Company
    Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy)
Zone 8: Midwest Energy, Inc.
Zone 9: Aquila Networks-MPS/L&P
    Aquila Networks-MPS
    Aquila Networks-L&P
Zone 10: Southwestern Power Administration (will be treated as a first tier zone)
Zone 11: Southwestern Public Service
Zone 12: Sunflower Electric Cooperative
Zone 13: Western Farmers Electric Cooperative
Zone 14: Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy)
Zone 15: Aquila Networks-WPK (may be treated as a first tier zone)
Appendix 4
Description of First Tier Zones/Entities
to Which SPP is Interconnected

The following is the present list of first tier zones which are directly interconnected to the SPP.

- Nebraska Public Power District
- Omaha Public Power District
- Associated Electric Coop, Inc.
- Entergy Corp. (Entergy Electric System)
- Cleco Corporation
- Lafayette Utilities System
- Louisiana Energy & Power Authority
- AmerenUE/MISO
- Southwestern Power Administration
- Electric Reliability Council of Texas (“ERCOT”)
- Western Electricity Coordinating Council (“WECC”)

Public Service of Company of Colorado, Public Service Company of New Mexico and El Paso Electric Company are interconnected to SPP via the WECC ties.
Background

SPP has four processes for regional transmission planning:

1. **Reliability Upgrades** – each year, using forward looking power flow models, SPP reviews its existing system to identify violations on its existing system and works with TOs to specify needed transmission upgrades.

2. **Deliverability Upgrades** – through its aggregate study process, using forward looking power flow models, SPP evaluates transmission service requests, including new or changed Designated Resources, to determine transmission upgrades needed (if any) to grant such requests.

3. **Economic Upgrades** – through a economic cost-benefit study process using forward looking economic models to determine benefits, SPP evaluates transmission upgrades that will potentially provide economic benefits to market participants.

4. **Extra High Voltage (EHV) Overlay** – through both power flow and economic models, SPP studies the long-term benefits of alternative EHV backbone transmission upgrades.

According to SPP Bylaws, the SPP “RSC has primary responsibility for determining regional proposals and the transition process in the following areas:

(a) whether and to what extent participant funding will be used for transmission enhancements;
(b) whether license plate or postage stamp rates will be used for the regional access charge;”

[Section 7.2 of SPP Bylaws]

– As used in the by-laws, participant funding represents an entity voluntarily taking on the obligation to pay the transmission owner the revenue requirements for transmission enhancements as opposed to those revenue requirements being rolled into rates; i.e., a direct assignment of costs rather than the inclusion of those costs in a SPP license plate or postage stamp rate.

– License plate rates apply to specific pricing zones within the SPP, while a postage stamp rate applies to transmission customers throughout the SPP footprint.

– Thus, SPP bylaws give the RSC responsibility for cost allocation and rate design.

The Concepts Paper on Economic Upgrades is the policy level document that meets this responsibility with respect to Economic Upgrades. It is not intended to meet any responsibility of the SPP RSC with respect to the EHV Overlay. Previously, the SPP RSC has adopted similar policy level documents for Reliability and Deliverability Upgrades; i.e. Base Plan Funding. The CAWG is in the process of reviewing and proposing changes to what is currently implemented for these two processes.
SPP Planning Chart

SPP Regional Planning

Reliability Upgrades
- Studied Each Year for $\Delta$ in Load, Trans and Generation

Deliverability Upgrades
- Aggregate Studies for Transmission Service DR & PTP

Economic Upgrades
- Studied Each Year for $\Delta$ in Power Grid Economics

EHV Overlay
- One Time Study to Establish Long-Term Grid Development

SPP RSC Proposed Cost Allocation “Base Plan Funding” Implemented by SPP Under Review by CAWG

SPP RSC Proposed Cost Allocation “Balance Portfolio” of Economic Upgrades Concepts Paper

Will Require A New Cost Allocation Proposal
Introduction

- CAWG was tasked by the SPP RSC to develop alternatives for cost allocation of economic upgrades.
- At the July 2008 SPP RSC meeting, the CAWG presented the RSC with strawmen proposals from SPP, TOs and TCs.
- Since that time, the CAWG has worked through details of these proposals and its conclusions are presented in the attached concepts paper.
- The CAWG and its stakeholder group have thoroughly reviewed the concepts paper and the CAWG unanimously endorses this paper.
Cost Allocation

• As indicated in the SPP Bylaws, rate design is a major element of cost allocation, but it is not the only element.

• Cost Allocation also includes:
  – A specification of facilities that are included – covered by the rate design; and
  – A specification of processes to be followed in order to determine the facilities to be included.
Rate Design

• As indicated in its July 2008 report, all three entities (SPP Staff, TOs and TCs) proposed the use of a postage stamp rate design.
• The concepts paper proposes to use a postage stamp rate design that assigns the costs to all SPP transmission customers on the same dollars per MW of 12 month coincident peak demand.
• A major concern of this rate design approach is to ensure that certain SPP transmission customers are not benefiting at a cost to remaining customers. This issue is addressed in the concepts paper by using a balanced portfolio approach to economic upgrades (details later).
Economic Upgrades Specified

• Economic upgrades are:
  – Extra high voltage ("EHV") transmission upgrades of 345 kV or higher; and
  – Additions to the SPP Transmission System that have been shown to provide customers with potential savings that exceed the cost of the proposed transmission upgrade(s).

• An economic upgrade will reduce congestion on the SPP Transmission System that result in savings in Production Costs for the SPP footprint.

• Economic upgrades may also provide other benefits to the power grid that result in both increased reliability and lower costs in other areas such as capital costs and end-use consumer costs.
Why 345 kV and Above?

• The primary reason for looking at 345 kV and Above (EHV) upgrades to the transmission system is that higher voltage projects are likely to provide more broadly distributed benefits across the SPP footprint. Alternatively, lower voltage transmission facilities are likely to primarily benefit local zones.

• However, lower voltage (below 345 kV) upgrades can be included for the following reasons:

  1) They are needed to integrate the EHV upgrade(s) and achieve the benefits; however, the cost of the lower voltage facilities cannot exceed the cost of the EHV upgrade(s) included in the network upgrade group; and

  2) In order to achieve a balanced economic portfolio, SPP may include lower voltage facilities that increase economic benefit to deficient zones (zones that are allocated more costs through the postage stamp rate than they receive in benefits).
What Benefits Are Measured?

• **Adjusted Production Cost Savings** – this metric is the same that is used in rate cases and fuel adjustment clauses to determine the variable operating cost of the utility (i.e., fuel, variable O&M, purchased power net of revenues from sales of power).

• **Reduction in system losses** – this metric includes dollar impacts for both energy and capacity;

• **Differing environmental impacts** – this metric is measured through including the costs of emissions; and

• **Improvement to capacity margin and operating reserves requirements** – this metric is measured through reduced capacity to meet the SPP planning capacity margin and SPP operating reserve margin.
Are There Other Benefits?

• Energy, Capacity and Ancillary Service **Market Facilitation** - upgrades to the transmission grid provide support for enhanced market functionality (adjusted production costs only covers one aspect of energy markets).

• **Increased Competition** in the Wholesale Markets – upgrades to the transmission grid provide a more open and transparent system resulting in increased choices for designated resources.

• **Storm Hardening** and **Black Start Capability** – upgrades to the transmission system can provide insurance against line outages from storms.

• **Critical Infrastructure** and **Homeland Security** – upgrades to the transmission system reduce the number of facilities that are critical, in the sense that if taken out of service, they have a major impact on the power grid.
Are These Other Benefits Measurable?

• Yes they are.

• SPP must develop measures for each. Appendix 2 to the Concepts Paper describes SPP’s current thinking about developing these measures.

• The SPP RSC is not adopting these descriptions as the only way to develop these measures.
How Are Candidates for Economic Upgrades Developed by SPP?

• Stakeholders can propose economic upgrades that SPP will screen to determine whether or not these upgrades are likely to have economic benefits that exceed costs.

• SPP also develops its own proposals from its knowledge of transmission planning, congestion and TLRs on the system. In regard to highly congested areas, SPP has the input from its market monitors.
What Is the Screening Process?

• The screening process is meant to be a modeling exercise in which SPP determines the likely benefits of an economic upgrade or group of economic upgrades. In this regard SPP receives input from stakeholders and states regarding:
  – the grouping of economic upgrades; and
  – the specific metrics used in the screening process.
What is a Portfolio of Economic Upgrades?

• A portfolio of economic upgrades is a set of upgrades that are evaluated in terms of benefits on a simultaneous basis over a set ten-year period.

• This evaluation will include detailed modeling of adjusted production costs for the first, middle and last year of the ten-year period. Adjusted production costs for between years will be interpolated.

• Other benefit measures will also be estimated over the same ten-year period.
What Cost-Benefit Criteria Must An Acceptable Portfolio of Economic Upgrades Meet?

• **Benefits > Costs:** The present value of 10 years of benefits must exceed the present value of 10 years of levelized revenue requirements from the cost of implementing the economic upgrades in the portfolio.
  – This condition must be met within the SPP footprint, unless SPP has in place an agreement by which a neighbor is willing to fund a portion of the costs of the upgrade.

• **Balanced:** For an acceptable portfolio, when benefits are evaluated at a zonal level, no zone should receive less benefit than it is allocated in costs through the region-wide postage stamp rate.
What Happens When SPP Cannot Develop A Balanced Portfolio?

• First, SPP can include **lower voltage upgrades** that provide net benefits to deficit zones.

• Second, if a portfolio of economic upgrades cannot balance the portfolio, a **transfer of costs from the zonal rate** of deficit zones to the region-wide postage stamp rate will be used to balance costs and benefits.
  
  – Such a transfer reduces the cost to the deficit zone from 100% to that zones load ratio share (less than 100%), and increases costs to other zones by their load ratio share.
  
  – A redistribution of costs does not change the overall benefit to cost ratio of the portfolio.
What Is the Rational Behind the Transfer from Zonal Costs to Region-Wide Costs?

• For example, think of the SPP region divided into two sub-regions
  A: currently has a highly developed transmission system, with few opportunities for economic upgrades; and
  B: currently has a less developed transmission system, with several opportunities for economic upgrades.

• Those zones in A are not likely to benefit from upgrades to the extent of those zones in B, leaving them in a deficit position.
  – Dollars that are currently supporting the highly developed transmission system in A are then transferred from their zonal charges and placed in a region-wide postage stamp rate, reducing costs to zones in A and increasing the allocation of costs to zones in B.
  – At the same time, A is taking on costs from the postage stamp rate that are primarily providing benefits to B.

• This transfer helps to equalize the economic capability across the SPP footprint without charging more highly developed portions of the system with the cost of upgrades to the less developed portions of the system.
  – By moving zonal costs to a postage stamp rate, more costs can be collected through a region-wide rate, and less costs are assigned to zones (license plate) rates.

• If all zones are currently at the same level of development, SPP is likely to develop a balanced portfolio based solely on transmission upgrades, and transfers are not likely to be needed to provide balance.
Further Questions?

- It is the intent of this paper to set out enough of the design for cost allocation of economic upgrades that tariff language can be developed over the next several months. At the same time, the expectation is that SPP staff will develop economic portfolios for SPP RSC and stakeholder review. In this way, the SPP RSC, stakeholders and the SPP Board of Directors should have a fairly clear understanding of how this cost allocation proposal will work before it is filed with the Federal Energy Regulatory Commission.

- The CAWG recommends that the SPP RSC adopt the Concepts Paper for Economic Upgrades for purposes of implementation by the SPP RTO.
Wind and Base Plan Funding

Larry Holloway
Kansas Corporation Commission

Issues

• Treatment of wind generation under the current tariff
• Why wind may be different
• Alternatives for consideration

III.B, Attachment J of the Tariff

Network Upgrades, with a cost that exceed $100,000, associated with new or changed Designated Resources shall be classified as Base Plan Upgrades if the Designated Resource or the associated upgrades (as applicable) meets each of the following conditions:

• 1. The Transmission Customer’s commitment to the Designated Resource has a duration of at least five years;
• 2. In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer’s existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer’s projected system peak responsibility determined pursuant to SPP Criteria 2; and
• 3. The cost of Network Upgrades associated with the new or changed Designated Resource is less than or equal to $180,000/MW times the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity (the “Safe Harbor Cost Limit”).

III.B.2 of Attachment J is the Issue

(emphasis added)

• "In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer’s existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer’s projected system peak responsibility determined pursuant to SPP Criteria 2;"

Where did this Provision come from?

(as I recall it)

• During the development and negotiations for the initial Cost Allocation Plan (CAP) the following items were considered for Base Plan Funding (BPF):
  – Cost allocation of reliability upgrades to the constructing zone
  – Regional cost allocation of high voltage upgrades
  – Using some type of economic model to allocate the costs of all reliability upgrades
  – Regional cost allocation of all upgrades
  – Etc.

Why the Compromise CAP?

• Concerns with various proposals
  – Either a total zonal or a total regional allocation was perceived to have free riders
  – Also did not provide any incentive to locate generation with any consideration to costs of transmission upgrades
  – Did not recognize the need for Load Serving Entities (LSEs) to jointly own or purchase generation
  – Some cost allocation schemes could cause members to leave SPP
  – Far less consensus and commitment on the part of members at that time
  – A more socialized cost allocation scheme was perceived as creating problems for state commission approval.
Is Access to new or changed DNRs an Economic or a Reliability Concern?

- Many argued, at the time that access to new or changed DNRs was actually an economic concern, since generation decisions relied on the purchaser’s economic evaluation.
  - However, it was decided that making sure all firm generation capacity could be used on a firm basis by network customers in SPP was a reliability concern.
  - The rational is that it does nothing to satisfy reliability criteria for the overload, etc., if LSE’s cannot access their required capacity margin.
  - The 125% of peak load requirement represents a 20% capacity margin.

- G = 125% L and CM = (G – L) / G, then
  - CM = (1.25L – L) / 1.25L = 0.25L / 1.25L = 20%
  - This is not that large of a margin, when the minimum is 12%

Why wind may be different

- The productivity of wind generation is based upon the location of the resource.
- Wind generation requires intensive land usage – A 1,000 MW wind farm would cover around 70 square miles – a magnitude of 10 times more than needed for a large coal or nuclear site.
- High productivity wind farms need unobstructed wind.
  - The result is these are going to be commonly located at distances very remote to the load.
- These areas in SPP are in regions that currently have little transmission access.
- And, of course, the accredited capacity for wind is generally around 10% of nameplate.
  - But to use and justify wind generation the load must have access to the production whenever it is available.
- Over time Production zones will likely require proportionally more transmission upgrades than the rest of the region.
  - The zonal net positive MW-mile allocator has the potential to over-allocate the costs to the zones where transmission customers see little benefit.
  - These zones also have the fewest transmission customers to shoulder the costs.

Why wind is different (cont)

- We could encourage wind by changing the qualification criteria of Appendix J III.B.2 to requested transmission capacity, which is typically nameplate capacity.
- The current language only allows accredited capacity.
- This would treat wind differently.
  - This also does nothing to address the concerns with the zonal allocation to production zones, which must be addressed before wind can be treated differently.

III.A.2 Appendix J, the CAP for BPF Upgrades

- If the cost of a Base Plan Upgrade is greater than $100,000, then:
  - i. X% of the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge. The initial value of X shall be 33%.
  - ii. (100-X)% of the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge. This portion of the annual transmission revenue requirement for each Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones’ share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment II to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10 MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000. Qualified BPF costs are allocated under
  - Basically 1/3 regionally and 2/3 zonally based upon zonal benefits perceived as incremental MW-miles of transmission capacity.
Concerns – why wind is different

- Example 1 – Most of the zonal allocation goes to zone 1
- Example 2 – Most of the zonal allocation goes to zone 2
- Example 3 – Zonal allocation to all zones
- Example 4 – Zonal allocation to zone 1
- Result
  - Zone 1 and 2 rates go up substantially to benefit wind purchase by LSEs and Loads in Zone 3 and 4
- Big picture
  - This may be an unsustainable outcome
  - This does not support some sort of regional resource planning (that is supposed to be one of the focuses of the RSC)
  - Right now it looks like wind in the western part of SPP and baseload in the eastern part (2 new large coal units in Arkansas)
  - Few believe wind can reliably provide more than 25% of a utilities energy needs

SPP – potential internal wind requirements

- SPP 2006 results from SPP 2007 EIA-411
  - 42,882 MW peak load
  - 201521 GWH energy
  - Results in about a 54% load factor
- How does this translate into amount of wind needed at different RPS levels?
  - Just for SPP alone – without exports.
Conclusions

– Wind will be developed primarily in only a portion of SPP
  • Many utilities will want access to the wind
  • Fits into fuel diversity and other concerns RSC added to tariff language
– Adopting a policy of treating wind nameplate capacity as accredited capacity may unfairly allocate costs to supply zones.
  • This is why allowing Base Plan Funding for accredited capacity does not work
– An alternate Cost Allocation Plan for wind generation supplying SPP load needs to be developed
1. Policy for Cost Allocation for Economic Upgrades and Portfolio Development

2. Waiver Reviews


4. Initiate the tariff required regional allocation factor and zonal allocation review.

5. Interpretation and clarification of Base Plan Funding, the use of Operating Directives, etc.

6. Review of STEP/EHV/OEPTTF and other special studies.

7. Review of Aggregate Study and Generation Interconnection Queue Improvements.

8. Seams/inter-regional cost allocation.


11. EIS market performance.

12. EHV Cost Allocation.
Organizational Roster
The following members represent the SPP Staff: Les Dillahunty, Vice President, Regulatory Policy; Pat Bourne, Director, Transmission Policy; Jay Caspary, Director, Engineering; John Mills, Manager, Tariff Studies.

Background
Attachment J of the SPP Tariff Addresses recovery of costs associated with new transmission facilities. Subsection III of this section addresses Base Plan funding for network upgrades, including Safe Harbor Cost Limit of $180,000/MW, and provides for waivers, whereby application may be made for additional Base Plan funding for a network upgrade in excess of the Safe Harbor Limit based on three independent factors.

On August 23, 2007, SPP received a request for waiver under Attachment J of the SPP Tariff for costs in excess of the Safe Harbor Cost Limit for Base Plan funding from Empire District Electric Company (EMDE) for new Designated Resources for 100MW Cloud County Wind farm, based on the upgrade costs associated with transmission from these resources. SPP’s 120 day deadline under Attachment J was December 21, 2007. A November, 2007 EMDE letter asked SPP to reconsider and issue a revised recommendation for discussion by the CAWG, RSC, MOPC and BOD.

Analysis:
EMDE requested a waiver based upon Section III.C 2. iv of Attachment J for other circumstances due to fuel type requesting the lesser of language in Section III B 3 a or b be reconsidered. This waiver request has been discussed in the August, September, October and the January meetings of the Cost Allocation Working Group (CAWG). Based on the discussion and action of the CAWG during their January 4, 2008 meeting, the CAWG is recommending that the SPP Regional State Committee (RSC) request further CAWG discussion and evaluation leading to changes to the tariff language to address the manner in which wind resources are treated for Base Plan funding. The CAWG will also recommend that the EMDE waiver be approved as submitted due to three factors: 1. stronger incentives for long term contracts should be provided, 2. the Base Plan funding credit policy is currently under review and likely to be changed, 3. the substantial investment made by EMDE to accomplish the interconnection of this DR.

Recommendation
The Markets and Operations Policy Committee recommends to the Board of Directors to approve the Empire District Electric Company (EMDE) waiver for full base plan funding in conjunction with the CAWG recommendation.

Approved: The recommendation of SPP Staff is to provide an additional Base Plan funding of only $50,625 based on the 20 year reservation and existing tariff provisions. SPP staff acknowledges that a policy revision as is under consideration by the CAWG/RSC; that is ultimately approved through the SPP/FERC process would alter the resulting recommendation.
Markets and Operations Policy Committee

January 15-16, 2008

Approved: Two opposed – Calpine (suggested an extension till CAWG and RSC policy decision), Sunflower (should also cover interconnection costs); Three abstentions – Trans Elect (Not a party), Western Farmers (did not consider the size of the wind farm versus the cost of upgrades), AECC (capacity rating of wind farm reflects the value to the system and should be used for Base Plan Funding determination)

Action Requested: Approve Recommendation.
November 19, 2007

Mr. John Mills  
Manager, Tariff Studies  
Southwest Power Pool, Inc.  
415 North McKinley Street  
#140 Plaza West  
Little Rock, Arkansas  72205

Re:  Response to SPP Waiver Recommendation to CAWG of October 24, 2007  
And Clarification of EDE Waiver Request For OASIS Reservation #1222640  
Cloud County/Meridian Way Wind Farm Designated Resource

Dear Mr. Mills,

In reference to SPP staff’s recommendation to the Cost Allocation Working Group presented on October 24, 2007, The Empire District Electric Company (Empire) is providing the following response and clarifications.

In our October 12, 2007 response and our initial request for waiver of August 23, 2007 (attached), Empire believes it sufficiently explained the numerous provisions, justifications, and circumstances that SPP staff, CAWG, RSC, MOPC, and BOD should consider in granting the requested waiver. Empire completely disagrees with the methodology SPP staff used in making its recommendation to the CAWG on October 24 and believes such recommendation does not support the general direction of federal, state, and SPP policy in support of renewable resources. We believe that the SPP has clear and sufficient authority to grant Empire’s waiver request just as the SPP has done with previous waivers for additional base plan funding.

However, we realize that our request has generated discussions and raised key issues regarding policy and strategy regarding the future treatment of renewable resources. Such issues and strategy are being currently discussed by the CAWG. The approach that Empire took in making and justifying the “up to amount of $18 million” in our August 23 request for waiver has created an issue surrounding the legal authority that the SPP Board of Directors has regarding the waiver process.

In order to avoid further debate on whether or not the SPP BOD has the authority to grant Empire’s waiver as requested, Empire would like to clarify its waiver request to specifically focus on the basis and circumstances for the granting of this specific waiver. All parties now have the benefit of the latest Aggregate Facilities Study SPP-2007-AG1-AFS-5 posted on November 2, 2007 that indicates a projected allocation of transmission upgrade engineering and construction (E&C) costs to Empire of approximately $6 million.

Empire requested 100MW of long term firm network transmission service to begin upon commercial operation in November 2008 for Phase I of the 201MW Meridian Way/Cloud County wind farm. The Meridian Way/Cloud County wind farm is located within the service area of Mid-Kansas Electric Company (Sunflower) near Concordia, Kansas. According to the aforementioned Aggregate Facility Study, SPP will not be able to provide the requested service until June 2010.
Empire is not only concerned about SPP staff’s denial for Empire to obtain additional Base Plan funding, but is also concerned that long term firm service may not be granted by the SPP based on its i) modeling assumptions and in-service dates of the required upgrades and ii) SPP’s requirement that all 3rd party “indeterminate” upgrades and associated costs must be adequately addressed prior to service confirmation. It is probable that Empire may also incur substantial 3rd party costs in order to confirm SPP firm transmission service for this designated resource.

Based on AFS-5, Attachment J, III. B of the SPP OATT, and SPP staff’s default value of 10% of nameplate capacity, Empire’s Base Plan funded amount of the estimated E&C upgrade costs would be $1.8 million, (safe harbor limit of $180,000/MW x 10MW), which would leave approximately $4 million of upgrades to be addressed in the waiver Empire has requested from SPP.

Therefore, to clarify, Empire formally requests a waiver to obtain base plan funding of all allocated SPP upgrades in excess (projected to be approx. $4 million) of the $1.8 million to secure long term firm service for the 100MW designated resource. Hence, the total projected amount of Base Plan funding for this Empire designated resource would be approximately $6 million. If this resource were a fossil fuel unit, it would be eligible for $18 million in Base Plan funding.

Empire respectfully requests this waiver to be evaluated on, but not be limited to, the following facts and circumstances, as allowed pursuant to Attachment J, III. C of the SPP OATT.

1) Empire’s twenty (20) year commitment to this designated resource significantly exceeds the five (5) year minimum commitment for base plan funding eligibility,

2) the Meridian Way/Cloud County Wind Farm is expected to have an annualized capacity utilization factor of approximately 40%, which is greater than and/or comparable to peaking/combined cycle natural gas fired units that currently receive Safe Harbor funding and waivers based on “transmission service requested” - not on accredited capacity,

3) the cumulative requested Base Plan Funding to Empire for this designated resource (projected to be approx. $6 million) and the most recent Iatan II (100MW) and Plum Point (100MW) resources (projected to be approx. $12 million) would be $18 million, which is significantly (50%) less than the $36 million (200MW x $180,000/MW) eligible funding for Iatan II and Plum Point designated resources alone,

4) renewable resources provide a hedge for Empire and other load serving entities against escalating fuel costs or fuel cost volatility,

5) renewable resources should be treated comparably to traditional fossil fuel resources with respect to base plan funding, especially in light of the fact that SPP models all resources in the same manner in the Aggregate Study transmission service process,

6) there is support developing for the increased use of renewable resources and the needed transmission infrastructure investment necessary to integrate and deliver renewable energy to load,

7) renewable resources reduce the emission of air pollutants,

8) the growing interest in national and state renewable portfolio standards, emission caps, or carbon taxes, give the SPP the opportunity to expressly support the continued development and delivery of renewable energy in the SPP footprint,

9) And lastly, the value of fuel diversity for load serving entities and within the region. It was clear in paragraph 57 of FERC Order ER05-652, dated April 22, 2005, that FERC was in full support of fuel diversity as one of an exhaustive list of factors that the SPP BOD could consider in its evaluation of waiver requests. However, upon “Rehearing” in paragraph 19 of FERC Order ER05-652 dated September 8, 2005, FERC reversed its Order “requiring SPP to remove the fuel diversity provision from the non-exhaustive list of waiver criteria. Upon further consideration, we (FERC) find that SPP did not sufficiently explain how parties paying the costs associated with the proposal benefit from increased fuel diversity. SPP may seek to re-file the fuel diversity waiver provision with this supportive information.” Such an SPP filing has not occurred to date. Empire believes there is now evidence to support such an SPP filing at FERC. Such supporting information can be provided to SPP upon request.
Each of the waiver requests that have been submitted to date, including this waiver, should not be considered as setting any precedent and compared with previous waiver requests, as each involves unique factors and circumstances that should be evaluated on a case-by-case basis.

We respectfully request SPP staff to re-consider and re-issue a revised recommendation for discussions by the CAWG, RSC, and MOPC leading to the BOD’s decision in January.

In addition, as conveyed in our waiver request of August 23, 2007, that in the event this waiver is denied in whole or part, and future tariff modifications/policy changes are made that would have affected the decision on this waiver, Empire requests that the SPP Board of Directors re-consider Empire’s waiver at the appropriate time.

If additional information and/or explanation is needed, please do not hesitate to contact me or Bary Warren.

Again, thank you for your consideration and services.

Respectfully submitted,

Rick McCord
Director, Supply Management
October 12, 2007

Mr. John Mills  
Manager, Tariff Studies  
Southwest Power Pool, Inc.  
415 North McKinley Street  
#140 Plaza West  
Little Rock, Arkansas 72205

Re: Response to SPP October 4, 2007 Request For Information  
Empire Waiver Request For OASIS Reservation #1222640  
Cloud County/Meridian Way Wind Farm Designated Resource

Dear Mr. Mills,

In reference to your correspondence of October 4, 2007 requesting additional information, The Empire District Electric Company (Empire) is providing the following response.

In our August 23, 2007 request (attached), Empire sets forth the SPP Open Access Transmission Tariff (OATT) provisions, justifications, and circumstances that we believe warrant the granting of the requested waiver. Empire believes that the SPP has sufficient authority to grant Empire’s waiver request just as the SPP has done with previous waivers for additional base plan funding.

We want to re-emphasize that Empire’s twenty (20) year commitment to the designated resource, the Cloud County/Meridian Way wind farm, significantly exceeds the five (5) year minimum commitment for base plan funding eligibility and will bring added fuel diversity to Empire and the region.

With respect to SPP’s authority to grant this waiver as requested, Attachment J of the tariff and the related FERC Order are sufficiently clear and give SPP the authority to grant additional base plan funding in whole or in part for network upgrades.

Empire would also like to clarify that our request for waiver is for “up to” an additional $16,200,000 (capped) of base plan funding eligibility, allowing for a total of $18,000,000 ($1,800,000/MW of accredited capacity or $180,000/MW of transmission service requested) for the required transmission system upgrades which would be comparable to any fossil fuel designated resource serving load within the footprint. Based upon the SPP’s August 30, 2007 posting of SPP-2007-AG1-AFS-4, the allocated Engineering and Construction (E&C) costs associated with Empire’s portion of the Meridian Way wind farm are estimated to be approximately $6.3 Million, but could be changed depending upon the customer service requests that are finalized as part of the SPP 2007-AG1 process.
Each of the waiver requests that have been submitted to date, including this waiver, should not be considered as setting any precedent, as each involves unique factors and circumstances that have to be evaluated on a case by case basis.

Policy Discussion

Empire’s waiver has generated much discussion related to SPP’s base plan funding policy for designated resources and modeling procedures, zonal MW-Mile allocation impacts, the 125% capacity reserve margin condition, and the overall impact of the Attachment J provisions for wind as a designated resource. If the RSC and SPP believe a general policy change is appropriate, then it may be fitting to proceed with the granting of our waiver and codify such change within the SPP tariff for similar requests in the future.

Empire encourages the SPP staff, CAWG, RSC, MOPC and Board of Directors to 1) finalize its evaluation and discussion, and grant Empire’s waiver prior to SPP’s deadline (yet to be determined) for confirming the requested transmission service, and 2) pro-actively address policy changes that would be appropriate for future transmission service requests related to wind as designated resources serving load within the SPP region.

Empire had requested that the SPP render its decision on the waiver, with input from the RSC, at its October 30, 2007 Board of Directors meeting – even though the provisions of the SPP tariff allow for up to 120 days (December 23, 2007) for such a decision to be made.

SPP has been delayed in the posting of SPP-2007-AG1-AFS-5 due to the recent events regarding a proposed designated resource in Oklahoma. This event has affected the transmission requests in aggregate study SPP-2006-AG3, and could have an affect on the estimated E&C costs allocated to customers in AG1-AFS-5 and all succeeding service requests. In addition to the event in Oklahoma, there are other key decisions pending regarding another proposed designated resource that impact other SPP members also participating in the SPP-2007-AG1 aggregate study.

These key events are unusual and could be significant that may delay the Aggregate Study results beyond the December 23, 2007 (120 day) waiver decision deadline. Empire could support giving SPP staff, the CAWG, RSC, MOPC, and the SPP Board of Directors additional time beyond December 23, 2007, unless Empire is faced with rendering its decision on whether to commit to transmission service to SPP prior to the Waiver request being finalized. It appears that additional time beyond the 120 day decision period may afford better opportunity for discussions on our Waiver request during the January cycle of meetings, as well as changes in future SPP policy and strategy related to base plan funding for designated resources serving load within the SPP footprint.

We emphasize that our support for an extension is based on our belief that Empire would not be put into a position of having to legally confirm SPP firm transmission service for this designated resource without knowing the outcome of our waiver request - which could substantially affect the applicable base plan funding and direct assignment of transmission upgrade costs identified in SPP-2007-AG1.
The entirety of the facts, justifications, and issues regarding our request has not been set forth in this correspondence, but rather are more fully described in the accompanying letter of August 23, 2007.

We understand the policy issues that our waiver request has raised as well as events that have occurred which are affecting SPP's transmission service request process. However, we respectfully request that our waiver be decided upon as expeditiously as possible and within a time frame that may exceed the December 23, 2007 deadline, but prior to Empire being faced with its commitment decision on the transmission service requested.

If additional information and/or explanation is needed, please do not hesitate to contact me or Bary Warren.

Again, thank you for your consideration and services.

Respectfully submitted,

Rick McCord
Director, Supply Management
August 23, 2007

Mr. John Mills
Manager, Tariff Studies
Southwest Power Pool, Inc.
415 North McKinley Street
#140 Plaza West
Little Rock, Arkansas 72205

Re: Empire Request For Waiver (#2) Per Attachment J of the SPP OATT
For OASIS Request: #1222640 — Cloud County Wind Farm Designated Resource

Dear John,

Pursuant to Section III C.1 (Waiver Process) of Attachment J of the Southwest Power Pool (SPP) Open Access Transmission Tariff, The Empire District Electric Company (Empire) respectfully requests a waiver for up to an additional $16,200,000 in Base Plan funding related to Engineering and Construction costs of SPP determined direct assignment Network Upgrade facilities associated with Empire’s 100 MW of firm transmission service OASIS request:

#1222640(Cloud County -100 MW): SPP-2007-AG1-AFS-3

The transmission service requested is to deliver power from a designated resource, a 100 MW wind farm nearing construction in the proximity of Concordia, Kansas and within the Balancing Authority area of Mid Kansas Electric Company (subsidiary of Sunflower Electric Power Corporation and formally Aquila-West Plains) associated with the requested 100 MW of network integrated transmission service to Empire.

On June 19, 2007, Empire and Cloud County Wind Farm, LLC, a subsidiary of Horizon Wind Energy, entered into a twenty (20) year power purchase agreement. Empire anticipates that the wind farm will be fully operational in late 2008 or early 2009 and begin receiving energy under the terms of the power purchase agreement at that time.

The current results of SPP-2007-AG1-AFS-3 for Empire’s Cloud County designated resource indicate the following:

i) the estimated Engineering and Construction transmission costs, directly assignable to Empire, are projected to be from $8,000,000 to $80,000,000, depending on who and what facilities remain in the SPP-2007-AG1-AFS process;

ii) additional/undetermined 3rd party (1st tier non-SPP transmission owning members) required upgrades and;

iii) potential for additional SPP re-dispatch service costs required of Empire to begin service as requested.

1 SPP-2007-AG1-AFS-4 is currently being completed and expected to be posted by SPP in late August/early September
Based on Attachment J, III. B. 3. (a) and (b), Empire’s designated resource would be eligible for only $1,800,000 (10 MW (100 MW × 10% - SPP’s default value for dependable capacity of a wind farm - x $180,000/MW)) of the maximum Safe Harbor Limit amount of $18,000,000.

Empire is requesting a waiver of the application of the “lesser of” provision of the $180,000/MW Safe Harbor Limit in Attachment J, III. B. 3. (a) – the planned maximum net dependable capacity applicable to the Transmission Customer. Empire requests that the Safe Harbor Cost Limit be determined using only Attachment J, III.B.3. (b) – the requested capacity (meaning the transmission reservation capacity amount (100MW)).

Approval to waive the “net dependable capacity provision” would place Empire’s Cloud County designated resource on equal footing with other fossil fuel designated resources and transmission only reliability upgrades in terms of regional funding.

Pursuant to Attachment J III. C. iv. – “If a request for a waiver is received by SPP based on other circumstances, such waiver request shall also be considered...” Empire believes that the Cloud County Wind Farm resource, as a designated resource, should be eligible for the full Safe Harbor Limit of $180,000/MW based on its requested transmission service capacity of 100 MW. It is important to note that SPP models all designated resources – regardless of fuel type (wind, natural gas, hydro, coal, nuclear) - in a similar manner/nameplate – and not solely based on “expected” net dependable capacity.

Empire believes that the SPP footprint includes a prominent wind resource sub-region that could be important to the United States power industry. It is important to proactively encourage the development of these wind resources now. The continued reduction/disadvantage in Base Plan Funding for the use of such intermittent resources will only discourage such development.

Empire has re-evaluated its position on the eligibility requirements for the Safe Harbor Limit and believes that the Base Plan Funding eligibility should apply to any designated resources.

The addition of the 100 MW power purchase agreement with Cloud County Wind Farm, LLC will increase Empire’s wind energy capability from wind farm power purchase agreements from 150 MW to 250 MW, thus generating approximately 15% of our annual energy requirements in the year 2009. This resource, like the Empire energy output purchase from the Elk River Wind Farm, is expected to produce a capacity or utilization factor of approximately 40% on an annualized basis. This annualized capacity or utilization factor exceeds most peaking resources within the SPP region and rivals most intermediate natural gas fired combined cycle resources in expected annual capacity utilization factor. The delivery of energy to load is one of the primary purposes of the transmission system, and therefore designated resources with this level of annual capacity or utilization factor should be an additional consideration for Base Plan Funding eligibility.

Empire continues to support the condition of 125% capacity resource margin for Base Plan Funding; however through the waiver process, consideration of the significant energy contribution of this type of resource should also be taken into account as a viable circumstance for waiver approval. All load serving entities are required to carry a 12% planning capacity margin and Empire has and will continue to meet and exceed that minimum requirement.
Fundamentally, we believe this Waiver raises the issue of strategy and funding.

- Strategy - in terms of the encouragement of the development and use of wind resources as designated resources for existing and prospective SPP members, and

- Funding - in terms of the regionalization of a portion of the transmission costs for wind resources in a manner similar to the way SPP funds transmission upgrades required for reliability (no resources involved), and transmission upgrades required for traditional fossil fuel generation resources.

If SPP models and grants transmission service for designated resources in the same manner - regardless of the fuel type - then it seems appropriate for the Safe Harbor Limit to be based on (b) the amount of transmission service requested/granted.

Therefore, The Empire District Electric Company respectfully requests the following:

a) SPP staff distribute the Waiver Request to the MOPC and CAWG as soon as possible;
b) Waiver of Attachment J, III. B.3 (a) and eligibility for the Safe Harbor Limit of up to $18,000,000 (an additional $16,200,000) pursuant to (b) – transmission reservation capacity - based on the following circumstances:

   i) the current and future “favorable” circumstances within the SPP region and national outlook for renewable resources,

   ii) the fact that wind resources in north central Kansas will bring additional fuel diversity to the SPP region and Empire,

   iii) the cumulative projected Base Plan Funding to Empire for this designated resource (up to $18,000,000) and the most recent Iatan II and Plum Point resources (projected to be approximately $12,000,000) would be $30,000,000 which is less than the $36,000,000 (200 MW x $180,000/MW) eligible funding for just the Iatan II, and Plum Point designated resources alone,

   iv) designated resources are modeled in the same manner by SPP regardless of the fuel source, and

   v) the Cloud County Wind Farm is expected to have an annualized capacity utilization factor of approximately 40%, which is greater than and/or comparable to peaking/combined cycle natural gas fired units that are typically eligible for the full Safe Harbor Limit funding amount.

c) This Waiver request be reviewed by the CAWG, MOPC, and RSC and decided upon by the SPP Board of Directors no later than the October 30, 2007 SPP Board of Directors meeting in Tulsa, Oklahoma, and

d) That in the event this Waiver is denied and that similar waivers are approved in the future or tariff modifications/policy changes are made that would have affected this Waiver request, Empire requests that the SPP Board of Directors reconsider Empire’s Waiver request.
Empire appreciates the efforts of SPP staff, the CAWG, RSC, MOPC, and Board of Directors in carefully evaluating and discussing each waiver and the related policies. Empire representatives will be available to discuss this Waiver request at future CAWG, RSC, RTWG, MOPC and BOD meetings.

Thank you in advance for your assistance and timely consideration of this request.

Empire looks forward to SPP staff’s recommendation and the Board of Directors’ decision, and finalization of the service agreements related to this new and important designated resource for the customers of The Empire District Electric Company and the Southwest Power Pool region.

Sincerely,

Rick McCord
Director, Supply Management

cc. Harold Colgin II, Empire Vice President of Energy Supply
    Mike Palmer, Empire Vice President of Commercial Operations
    Barry Warren, Empire Director of Transmission Policy and Compliance
Organizational Roster
The following members represent the Southwest Power Pool:

Les Dillahunty, Vice President, Regulatory Policy
Pat Bourne, Director, Transmission Policy
Jay Caspary, Director, Engineering
John Mills, Manager, Tariff Studies

Background
Attachment J of the SPP Tariff Addresses recovery of costs associated with new transmission facilities. Subsection III of this section addresses Base Plan funding for network upgrades, including Safe Harbor Cost Limit of $180,000/MW, and provides for waivers, whereby application may be made for additional Base Plan funding for a network upgrade in excess of the Safe Harbor Limit based on three independent factors.

On November 2, 2007, SPP received a request for waiver under Attachment J of the SPP Tariff for costs in excess of the Safe Harbor Cost Limit for Base Plan funding from American Electric Power (AEP) for new Designated Resources for 455MW for the Turk Power plant, based on the upgrade costs associated with transmission from these resources. SPP’s 120 day deadline under Attachment J is January 29, 2008.

Analysis:
AEP requested a waiver based upon Section III.C.2. ii of Attachment J for other circumstances due to fuel type requesting the lesser of language in Section III B 3 a or b be considered. This waiver request has been discussed in the November and the January meetings of the Cost Allocation Working Group (CAWG). Based on the discussion held in this meeting, the CAWG is recommending that the SPP Regional State Committee (RSC) approve the AEP waiver for such amount to fully Base Plan fund the project.

Recommendation
The recommendation of the MOPC to the Board of Directors is to approve 100% the AEP waiver for such amount to fully Base Plan fund the project.


Approved Recommendation: Unanimously; One abstention – Calpine (concern for 100% funding without conclusion of the cost from aggregate study)

Action Requested: Approve Recommendation.
November 2, 2007

John Mills
Southwest Power Pool
Tariff Studies
415 N. McKinley
#140 Plaza West
Little Rock, AR 72205

Subject: Request for Waiver for OASIS Request # 1162214

Dear John:

As provided in Attachment J Section III.C of the SPP OATT, American Electric Power Service Corporation ("AEPSC") submits this waiver request concerning treatment of the transmission upgrade costs allocated to SPP OASIS Request #1162214. Specifically, AEPSC seeks Base Plan Funding treatment for all of the allocated upgrade expenses to the extent they exceed the Safe Harbor Cost Limit.

AEPSC’s 455 MW 20 year request was submitted on behalf of Southwestern Electric Power Company to provide network transmission service from it’s ownership share of the Turk power plant to be located in Hempstead County Arkansas. Based on SPP Aggregate Study 2006-AG3-AFS-8, the Engineering and Construction cost allocated to AEPSC are estimated to $94,008,494. This cost allocation is $12,108,494 above the Safe Harbor Cost Limit of $81,900,000. AEPSC is seeking a waiver for this cost above the Base Plan Funding limit so that all of the allocated expenses associated with AEPSC’s request are eligible for Base Plan Funding.

Section III.C.2.ii of Attachment J provides for a waiver based on the extent to which the term of the request exceeds the minimum 5 year requirement set forth in Section II.B.1. AEPSC’s request is for a 20 year term of service. The Turk facility is expected to have a useful life of at least 35 years and therefore the use of the service can be expected to continue for several years beyond even this already lengthy initial term. The length of this request and AEPSC’s commitment to the life of the Turk power plant justify full Base Plan Funding treatment.

In April of this year, the SPP Staff, MOPC and Board recommended and approved similar, if not identical, waiver request for Arkansas Electric Cooperative Corporation and Oklahoma Municipal Power Authority for transmission requests associated with their respective ownership shares of the same Turk power plant. While conducting its review of
their requests the SPP staff expressed an interest in information regarding the fuel mix of the company surrounding this plant. On this subject I would note that, in addition to this 455 MW coal fired resource, SPP-2006-AG3 also includes long term requests for 775 MW of gas fired generation. This combination of coal and gas fired generation allows AEPSC to maintain the diverse fuel mixture of its fleet.

If you have any questions on this waiver request or if you feel there is any further information I might provide in order to facilitate the approval of this request, please do not hesitate to contact me.

Sincerely,

C. Richard Ross
Director Market Development

CC Robert W. Bradish
Venita McCellon-Allen (SWEPCO)
Overview

- SPP Transmission Expansion Plan (STEP)
  - Highlights of STEP
  - Notices to Construct (Appendix B)
- Oklahoma Electric Power Transmission Task Force (OEPTTF) Study
- EHV Overlay Restudy
- Joint Coordinated System Plan

2007 SPP Transmission Expansion Plan Stakeholder Involvement

- November 8, 2006 - Scope Reviewed and Approved by TWG
- May 15, 2007 - Spring Planning Summit
  - Reviewed violation identified with analysis
  - Stakeholders requested to provide potential solutions
- August 15, 2007 - Fall Planning Summit 100 kV and above - public review of recommended plans
- August 16 through August 23, 2007 - Stakeholder feedback on recommended plans
- October 9, 2007 - Fall Local Planning Web Conference 69kV and below - public review of recommended plans
- October 9 through October 17, 2007 - Stakeholder Feedback on recommended plans
- November 7, 2007 - SPP Staff provided overview of SPP Transmission Expansion Plan 2008-2017 Report to TWG
- December 4, 2007 - TWG reviewed the SPP Transmission Expansion Plan 2008-2017 Report and recommended changes
- January 3, 2008 - TWG accepted the SPP Transmission Expansion Plan 2008-2017 Report, as modified

SPP Transmission Expansion Plan (STEP) Executive Summary

- $2.2B of transmission projects
- A comprehensive summary of all transmission projects planned or needed in the 2008 – 2017 planning horizon:
  - 96 Models vs. 15 Models – it parallels Tariff Studies processes, increased granularity
  - Recognition of ZONAL upgrades - Additional $32M in total upgrades
- SPP is asking for mitigation of reliability issues resulting from projects that are unable to be completed within the given SPP Expansion Plan need date
- Quarterly Requests for Review
  - Staff will not wait 12 months before making recommendations as reliability projects are identified
  - Issue “Notification to Construct”
  - Project owners can expedite necessary commitments
MOPC Concerns

"Some upgrades cannot be implemented in time. Will the T.O. be at risk of "non-compliance" with the RE?"

• "NO" - STEP tariff requirements (FERC OATT) & "RE Compliance" (NERC stds) are not the same.
• Where necessary, mitigations will always be identified first.
• STEP is only used to supplement some RE data requirements
  1. Prevents duplication of effort
  2. Supplements NERC stds "long term, category B"
  3. Supplements NERC stds "Category C & D"

MOPC Concerns cont.

"Many projects had the need date advanced. How did this happen?"

• 11 reasons were identified as listed in the report on page 14.
• These include:
  1. 96 models
  2. New "scenario 5" model
  3. Forecast load changes
  4. Generation dispatch changes
  5. Etc.

Executive Summary ‘Appendix A’ All Upgrades, 2008-2017

2008 - 2017 Cost by Network Upgrade Type Appendix A $2.2 Billion

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>2007 STEP</th>
<th>2006 STEP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zonal Upgrades</td>
<td>$20 M</td>
<td>$3</td>
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<tr>
<td>Base Plan Fundable, Reliability Upgrades</td>
<td>$716 M</td>
<td>$147 M</td>
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<tr>
<td>“Existing Facilities”, pre January 1, 2006</td>
<td>$14 M</td>
<td>$55 M</td>
</tr>
<tr>
<td>Proposed Economic Upgrades</td>
<td>$495 M</td>
<td>$1.4 M</td>
</tr>
<tr>
<td>Outside Appendix B financial commitment window</td>
<td>$226 M</td>
<td>$730 M</td>
</tr>
<tr>
<td>Regional Reliability upgrades</td>
<td>$4 M</td>
<td>$0</td>
</tr>
<tr>
<td>Zone Criterial reliability upgrades</td>
<td>$65 M</td>
<td>$55 M</td>
</tr>
<tr>
<td>Facility owner &quot;planned projects&quot;</td>
<td>$120 M</td>
<td>$378 M</td>
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<tr>
<td>Upgrades from Transmission Service Agreements</td>
<td>$221 M</td>
<td>$52 M</td>
</tr>
<tr>
<td>Upgrades from Generation Interconnection Agreements</td>
<td>$65 M</td>
<td>$0</td>
</tr>
<tr>
<td>Total</td>
<td>$2.2 B</td>
<td>$1.4 B</td>
</tr>
</tbody>
</table>

Recommendation

• The SPP RTO staff recommends that the SPP BOD approve this report, “SPP Transmission Expansion Plan 2008-2017”
• The MOPC recommends that the SPP BOD approve the “SPP Transmission Expansion Plan 2008-2017”

Appendix B

Financial Commitment Window

• 2 year window for 2006 STEP
• MOPC said, "too short"
• TWG recommended 4 year window
• Appendix B
• SPP reliability upgrades in financial commitment window years 1 - 4, (2008-2011) recommended to receive a “Notification to Construct” (2006 “Letters of Authorization”)
Appendix A – Projects Summary

Oklahoma Electric Power Transmission Task Force (OEPTTF)

- Scope approved in December
- January 24th, 2008, Oklahoma City – Transmission Expansion in Oklahoma and Beyond Summit
- Optimal grid expansion in OK, TX, and beyond based on latest STEP and up to 6,000 MW new OK wind development, primarily in panhandle
- Finalize study in 1st quarter 2008

EHV Overlay Restudy

EHV Overlay Study completed in early 2007
Wind Assumptions are Key

- CREZ 1500/600 transmission expansion and 13,000 MW of new wind in base for EHV Overlay Study
  - Majority of new wind in Texas Panhandle
  - Sensitivity evaluated 20,000 MW of new wind
- DRAFT NREL/AWEA/DOE report for Wind Vision shows significant shift in expected wind development compared to wind potential maps
  - 2030 developments projected to exceed 35,000+ MW in SPP, without counting any development in Texas

EHV Overlay Restudy

- Working with Quanta/Infrasource on restudy
  - Approved scope
  - Completed stakeholder survey
  - Finalizing modeling
  - Developing scenarios
  - Evaluating 345 kV build-out options
  - Comparing economic alternatives
  - Results expected first quarter 2008
Joint Coordinated System Plan

- Working on Joint Coordinated System Plan (JCSP) with MISO, PJM, TVA and others:
  - Joint Operating Agreements require development of joint plans every few years
  - Interregional collaborative planning is needed today
  - 2018 reliability and 2024 economic analysis will compliment DOE/NREL Eastern Interconnection wind integration study
  - Focus on expansion planning and operational impacts of significant wind development
  - November 1, 2007 kickoff meeting in Pittsburgh
  - Economic planning workshops:
    1. Nashville - Dec 11-12, 2007
    3. Preliminary resource forecasts shared at Feb 5 meeting - webinar available
Conclusion

The PRISM targets are technically very aggressive, but potentially achievable. The MERGE analysis illustrates that sustained electric sector CO2 emission reductions are possible only through the deployment of a full portfolio of advanced technologies, most of which are currently not commercially available. To achieve the PRISM targets, we must start now to demonstrate, deploy and commercialize advanced technologies.
The Power to Reduce CO2 Emissions
PRISM

*Achieving all targets is very aggressive, but potentially feasible.

EIA Base Case 2007

<table>
<thead>
<tr>
<th>Technology</th>
<th>EIA 2007 Reference</th>
<th>Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>Efficiency</td>
<td>Load Growth = 1.9%/yr</td>
<td>Load Growth = 1.1%/yr</td>
</tr>
<tr>
<td>Renewables</td>
<td>30 GW by 2030</td>
<td>70 GW by 2030</td>
</tr>
<tr>
<td>Nuclear Generation</td>
<td>12.5 GW by 2030</td>
<td>94 GW by 2030</td>
</tr>
<tr>
<td>Advanced Coal Generation</td>
<td>No Existing Plant Upgrades</td>
<td>160 GW Plant Upgrades</td>
</tr>
<tr>
<td></td>
<td>40% New Plant Efficiency by 2020-2030</td>
<td>40% New Plant Efficiency by 2020-2030</td>
</tr>
<tr>
<td>CCS</td>
<td>None</td>
<td>Widely Deployed After 2020</td>
</tr>
<tr>
<td>PHEV</td>
<td>None</td>
<td>14% of New Vehicle Sales by 2017; 42%/yr Thereafter</td>
</tr>
<tr>
<td>DEE</td>
<td>&lt; 0.1% of Base Load in 2030</td>
<td>5% of Base Load in 2030</td>
</tr>
</tbody>
</table>

PRISM - 2030

EIA Base Case*

- 5408 TWh
- Conventional Hydropower: 25.6%
- Non-Hydro Renewables: 3.0%
- Nuclear Power: 16.6%
- Natural Gas: 13.6%
- Other Fossil: 1.7%
- Coal w/o CCS: 59.6%

Advanced Technology Targets

- 5401 TWh
- Conventional Hydropower: 4.9%
- Non-Hydro Renewables: 6.7%
- Nuclear Power: 26.5%
- Natural Gas: 9.7%
- Other Fossil: 0.6%
- Coal with CCS: 14.6%

*Base case from EIA “Annual Energy Outlook 2007”
PRISM Conclusion

1. The emissions "profile" for the U.S. electricity sector as it aggressively implements advanced technologies would represent a slowing, stopping, and eventually declining level of annual CO2 emissions.

2. Achieving the indicated emissions reductions requires deployment of a diverse set of new and existing technologies, none of which will provide the majority of potential reductions. In other words, there is no "silver bullet" that represents the bulk of emissions-reducing potential.

3. Consequently, if one or more of these technology options are not available, even more aggressive levels of technology performance and deployment would be necessary in the remaining technology areas to achieve the estimated emissions-reduction potential.

4. Key enabling grid-related technologies are needed to fully realize the emissions-reduction potential associated with end-use efficiency, renewables, plug-in hybrid electric vehicles, and distributed energy resources.

Technology Development Pathways

Four key strategic technology deployment challenges that must be met for the U.S. electricity sector to significantly reduce CO2 emissions over the coming decades:

1. Deployment of smart distribution grids and communications infrastructures
2. Deployment of transmission grids and associated energy storage infrastructures with the capacity and reliability to operate with 20-30% intermittent renewables
3. Deployment of advanced light water reactors
4. Deployment of commercial-scale coal-based generation units operating with 90% CO2 capture and with the associated infrastructures to transport and sequester the captured CO2.
Estimated Funding Needs for Technology Pathways

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<tbody>
<tr>
<td>$100M / yr</td>
<td>$130M/yr</td>
<td>$120M/yr</td>
<td>$70M/yr</td>
<td>$60M/yr</td>
<td>$100M/yr</td>
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Economic Assessment (MERGE)

<table>
<thead>
<tr>
<th></th>
<th>Limited Portfolio</th>
<th>Full Portfolio</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Nuclear</td>
<td>Existing Production Levels</td>
<td>Production Can Expand</td>
</tr>
<tr>
<td>Renewables</td>
<td>Cost Decline</td>
<td>Costs Decline Faster</td>
</tr>
</tbody>
</table>

Policy A
Reduce carbon emissions by 2% per year through 2050 (starting in 2010)

Policy B
Stabilize carbon emissions at 2010 levels through 2020
Reduce carbon emissions by 3% per year through 2050

Policy C
Stabilize carbon emissions at 2010 levels through 2020
Reduce carbon emissions by 2% per year through 2050
MERGE Results

- Policy Constraint A: 2010 – 2% yr.
- Policy Constraint B: 2020 – 3% yr.
- Policy Constraint C: 2020 – 2% yr.

Change in GDP Discounted through 2050

- Limited
- Full

- Requirement to immediately reduce emissions increases policy cost
- Value of technology remains high because long-term requirements do not change
- Less stringent target decreases policy cost
- Value of technology is lower because problem is smaller

Generation Mix and Wholesale Electricity Prices

- Limited Portfolio
- Full Portfolio

$160/MWh
$65/MWh

(In Year 2000 $)
Natural Gas Prices

In the Limited Portfolio scenario, achieving emissions reductions would require a significant amount of fuel switching to natural gas for electricity generation and large accompanying reductions in electricity demand. These effects place severe constraints on economic growth and drive natural gas prices up. By 2050, natural gas consumption in the electric sector is more than five times higher in the Limited Portfolio scenario than in the Full Portfolio scenario, at prices more than $3.00/Mcf higher.
Conclusion

The PRISM targets are technically very aggressive, but potentially achievable. The MERGE analysis illustrates that sustained electric sector CO2 emission reductions are possible only through the deployment of a full portfolio of advanced technologies, most of which are currently not commercially available. To achieve the PRISM targets, we must start now to demonstrate, deploy and commercialize advanced technologies.
Project Tracking 2008, 1st Quarter

10 Year Horizon Projects:
- 23% Complete
- 56% On Schedule
- 8% Delayed
- 4% Mitigation Provided
- 6% On Schedule beyond 2 Yr

2 Year Horizon Project:
- 85% Complete
- 11% On Schedule
- 4% Delayed
- 0% Mitigation Provided
10 Year Horizon Projects

- This Chart Tracks $874M Total
  - $837,000,000 Transmission
  - $37,000,000 Devices

- Projects On Schedule in Green, $701M
  - $674,000,000 Transmission
  - $27,000,000 Devices

- Projects Completed in Blue, $56M
  - $50,000,000 Transmission
  - $6,000,000 Devices

- Projects with Mitigation in Yellow, $70M
  - Issue: Project Ownership Contested on 5 projects
  - Staff established contact and in negotiation with potential Project Owners.
10 Year Horizon Projects
Yellow = Mitigation Provided

- 41 projects, $70M Total
  - 8 Devices, $3,000,000
  - 33 Transmission, $67,000,000
- No Mitigation Plan required for certain projects due to be completed before 08SP. Mitigation Plan required only if Project not completed before 08SP. Example: Chambers Spring – Tontitown 345 kV line.
10 Year Horizon Projects
Red = Delayed

- 19 projects, $47M Total
- 2 Devices, $900,000
- 17 Transmission, $46,000,000
2 Year Horizon Projects
Design and Construction needs to begin by 2009.

- This Chart Tracks $432M Total
  - $416,000,000 Transmission
  - $16,000,000 Devices

- Projects On Schedule, $351M
  - $338,000,000 Transmission
  - $13,000,000 Devices

- Projects Mitigation Provided, $49M
  - $47,000,000 Transmission
  - $2,000,000 Devices

- Projects Delayed, $32M
  - $31,000,000 Transmission
  - $900,000 Devices
2007 STEP Project Tracking Summary

<table>
<thead>
<tr>
<th>2007 Quarter</th>
<th>1st Qtr</th>
<th>2nd Qtr</th>
<th>3rd Qtr</th>
<th>4th Qtr</th>
</tr>
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<tbody>
<tr>
<td>On Schedule 2 Yr</td>
<td>80</td>
<td>87</td>
<td>91</td>
<td>266</td>
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<tr>
<td>On Schedule Beyond 2 Yr</td>
<td>0</td>
<td>0</td>
<td>1005</td>
<td>821</td>
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<tr>
<td>Mitigation Provided</td>
<td>57</td>
<td>17</td>
<td>147</td>
<td>204</td>
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<tr>
<td>Complete</td>
<td>0</td>
<td>29</td>
<td>115</td>
<td>202</td>
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<tr>
<td>Delayed</td>
<td>20</td>
<td>38</td>
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</tr>
</tbody>
</table>

* All $ values are in millions

WWW.SPP.ORG
**SPP 1st Quarter 2008 Project Tracking Report - Branch Xfr**

**Executive Summary**

$1.4 million upgrades have been completed this quarter. $5.6 million in transmission lines and facilities were added.

**#2. SPP is tracking the development of 51 upgrades currently requiring mitigation plans (YELLOW)**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTO Reliability</th>
<th>Need Date</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line - Finney Tap - Port Robson 69kV</td>
<td>06/30/06</td>
<td>Blue</td>
<td>06/01/06</td>
<td>$207,621,794</td>
<td>06/01/10</td>
<td>Blue</td>
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<tr>
<td>Line - Siloam Springs - Chambers Spring 161 kV</td>
<td>06/01/07</td>
<td>Blue</td>
<td>05/01/06</td>
<td>$1,700,000</td>
<td>06/01/09</td>
<td>Blue</td>
</tr>
<tr>
<td>Line - Chisholm - Grant 69 kV Rebuild</td>
<td>06/01/07</td>
<td>Blue</td>
<td>12/31/06</td>
<td>$528,600</td>
<td>06/01/04</td>
<td>Blue</td>
</tr>
<tr>
<td>Line - SPA Hilltop - EES Hilltop 161 kV</td>
<td>06/01/07</td>
<td>Blue</td>
<td>07/04/07</td>
<td>$2,378,100</td>
<td>06/01/10</td>
<td>Blue</td>
</tr>
<tr>
<td>Line - Tomahawk - Bendix 161 kV</td>
<td>06/01/07</td>
<td>Blue</td>
<td>12/31/06</td>
<td>$1,500,000</td>
<td>06/01/04</td>
<td>Blue</td>
</tr>
<tr>
<td>Line - Okmulgee - Weleetka 138 kV Ckt 1</td>
<td>06/01/06</td>
<td>Green</td>
<td>06/01/06</td>
<td>$4,278,100</td>
<td>06/01/10</td>
<td>Green</td>
</tr>
</tbody>
</table>

**Southwest Power Pool**

Project Tracking Report

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**Branch/Adding**

1/8/2008 3:23 PM
<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Use Date</th>
<th>RTO Reliability Date</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
<th>Project Status Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line - Maud - 138 kV Ckt</td>
<td>06/30/08</td>
<td>12/31/07</td>
<td>$1,195,964</td>
<td>18 months</td>
<td></td>
<td>Mitigation Plan verified by SPP staff.</td>
</tr>
<tr>
<td>Line - Chisholm - Battlefield 115 kV Ckt</td>
<td>06/01/06</td>
<td>06/01/07</td>
<td>$359,964</td>
<td>18 months</td>
<td></td>
<td>Project delayed to 10/31/07 due to scheduling &amp; line clearance availability, Curtail generation at Sooner Power Plant as a mitigation plan.</td>
</tr>
<tr>
<td>Line - Vilonia - 69 kV Ckt</td>
<td>06/30/08</td>
<td>06/01/10</td>
<td>$4,500,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Stillwater - Morrison 138 kV</td>
<td>12/31/10</td>
<td>06/01/07</td>
<td>$2,987,338</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Osage - 138 kV Ckt</td>
<td>11/30/07</td>
<td>12/31/07</td>
<td>$500,000</td>
<td>6 months</td>
<td></td>
<td>Project delayed due to ice storm.</td>
</tr>
<tr>
<td>Line - Maud - 138 kV Ckt</td>
<td>06/30/06</td>
<td>06/01/07</td>
<td>$1,375,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Sleepy Hollow - Fort Supply</td>
<td>06/01/08</td>
<td>06/01/07</td>
<td>$1,000,000</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - XFR - Artesia 115/69 kV</td>
<td>06/01/06</td>
<td>06/01/07</td>
<td>$2,750,000</td>
<td></td>
<td></td>
<td>Project Under Construction, will be completed early 2008</td>
</tr>
<tr>
<td>Line - Artesia - 138 kV Ckt</td>
<td>06/01/06</td>
<td>06/01/07</td>
<td>$2,250,000</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Bailey Co 115/69 kV</td>
<td>04/01/07</td>
<td>06/01/07</td>
<td>$1,192,636</td>
<td>6 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Terry Co 115/69 kV</td>
<td>11/20/07</td>
<td>06/01/07</td>
<td>$3,365,000</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Greensburg - Judson Large 115 kV Ckt 1</td>
<td>11/20/07</td>
<td>06/01/07</td>
<td>$167,500</td>
<td>4~6 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Sun City - Medicine Lodge 115 kV</td>
<td>11/20/07</td>
<td>06/01/07</td>
<td>$148,000</td>
<td>4~6 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - XFR - Holly - Vici 115/69 kV</td>
<td>10/15/07</td>
<td>06/01/07</td>
<td>$2,032,500</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - XFR - Hesston - Golden Plain - Gatz 69 kV Rebuild</td>
<td>06/01/07</td>
<td>06/01/07</td>
<td>$1,000,000</td>
<td>18 months</td>
<td></td>
<td>Will convert North Clovis 69 kV distribution substation to 115 kV to prevent installing 2nd 115/69 kV autotransformer. Project has been budgeted. This project as proposed will not be pursued.</td>
</tr>
<tr>
<td>Line - XFR - Gaines County Interchange 69 kV - Gaines County Interchange 115 kV</td>
<td>06/01/07</td>
<td>06/01/07</td>
<td>$2,250,000</td>
<td>18 months</td>
<td></td>
<td>Mitigation Plan verified by SPP staff.</td>
</tr>
<tr>
<td>Line - XFR - Howard Interchange 115 kV</td>
<td>06/01/07</td>
<td>06/01/07</td>
<td>$2,750,000</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - South Hays 230/115</td>
<td>10/01/07</td>
<td>06/01/07</td>
<td>$2,030,000</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Mullen Gr - Hays 115/230 Substation</td>
<td>10/01/07</td>
<td>06/01/07</td>
<td>$1,100,000</td>
<td>6 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - XFR - Swissvale 345/230 kV 92 Addition</td>
<td>12/31/07</td>
<td>06/01/07</td>
<td>$5,600,000</td>
<td>18 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Greensburg - Judson Large 115 kV Ckt 1</td>
<td>11/20/07</td>
<td>06/01/07</td>
<td>$167,500</td>
<td>4~6 months</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Sun City - Medicine Lodge 115 kV</td>
<td>11/20/07</td>
<td>06/01/07</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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**Notes:**
- Facilities owned by Oklahoma Rural Elec. Coop. GRDA will provide TOD procedure for SPP review.
- Facilities owned by Oklahoma Rural Elec. Coop. GRDA will provide TOD procedure for SPP review.
### Project Tracking Report

**Branch/Xfmr**

<table>
<thead>
<tr>
<th>SS# Area</th>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTO Reliability</th>
<th>Need Date</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
<th>Project Status Confirmation</th>
</tr>
</thead>
<tbody>
<tr>
<td>540</td>
<td>Line - St. Joseph-Cooper 115 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$125,000</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>540</td>
<td>Line - St. Joseph-Fairport 115 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$125,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>540</td>
<td>Line - Martin City - Toms Road 161 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$47,663</td>
<td></td>
<td></td>
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<tr>
<td>540</td>
<td>Line - Lake Road to Industrial Park 161 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$10,000</td>
<td></td>
<td>8 months</td>
<td></td>
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<tr>
<td>540</td>
<td>Line - Nevada 161 - Nevada Plant 69 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$350,000</td>
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<tr>
<td>540</td>
<td>Line - Craig Interconnection</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$75,000</td>
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<td></td>
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<tr>
<td>540</td>
<td>Line - Loma Vista 161 - Monore 161 kV (North Raymore 161kV Substation)</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$4,582,582</td>
<td></td>
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<tr>
<td>541</td>
<td>Line - Stiefel - Antioch 161 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$2,116,400</td>
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<td></td>
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<tr>
<td>541</td>
<td>Line - Pleasant Valley Sub</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td>$2,390,000</td>
<td></td>
<td>6 months</td>
<td></td>
<td>Informational UPDATE - Not for SPP reliability - need for substation delayed to 2008, mitigation not needed</td>
</tr>
<tr>
<td>541</td>
<td>XFR - Sub 167 - Riverton 161/69 kV Ckt</td>
<td>06/07/08</td>
<td>06/01/08</td>
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<td>544</td>
<td>XFR - Sub 107 - Revertion 161/69 kV Ckt</td>
<td>06/07/08</td>
<td>06/01/08</td>
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<tr>
<td>544</td>
<td>Line - Neosho - Sub 292 - Tipton Ford 161 kV Ckt</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>544</td>
<td>Line - ReinMiler - Tipton Ford 161 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
<td></td>
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<tr>
<td>541</td>
<td>Line - Springfield - Brookline 161 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
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<tr>
<td>541</td>
<td>Line - Neosho - Springfield 161 kV</td>
<td>06/07/08</td>
<td>06/01/08</td>
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<tr>
<td>SPP Area</td>
<td>Project Name</td>
<td>In-Service Date</td>
<td>RTO Reliability</td>
<td>Cost Estimate</td>
<td>Project Lead Time</td>
<td>Project Status</td>
<td>Project Status Comments</td>
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<tr>
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<td>------------------------</td>
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</tr>
<tr>
<td>534</td>
<td>Line - Phillipsburg, Rhoades 115 kV Ckt 1</td>
<td>12/01/08</td>
<td>12/01/08</td>
<td>$6,250,000</td>
<td>12 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>534</td>
<td>Line - Gill Energy Center - Puck 69 kV Rebuild</td>
<td>06/01/08</td>
<td>06/01/08</td>
<td>$4,815,000</td>
<td>12 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Murray Gill Energy Center - Maud Huitt 69 kV Uprate</td>
<td>06/01/08</td>
<td>06/01/08</td>
<td>$150,000</td>
<td>8 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Dealing - Coffeyville 69 kV Rebuild</td>
<td>06/01/08</td>
<td>06/01/08</td>
<td>$1,190,000</td>
<td>7 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Stranger Creek - Thornton Street 115 kV Addition</td>
<td>12/01/08</td>
<td>06/01/07</td>
<td>$2,960,000</td>
<td>12 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
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</tr>
<tr>
<td>536</td>
<td>XFR - County Line 115/69 kV Replacement</td>
<td>07/01/08</td>
<td>06/01/07</td>
<td>$2,880,000</td>
<td>14 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
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</tr>
<tr>
<td>536</td>
<td>Line - Emporia Energy Center 345 kV Switchyard Connections</td>
<td>07/01/08</td>
<td>05/01/08</td>
<td>$300,000</td>
<td>8 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Chisholm - White Junction 69 kV Rebuild</td>
<td>07/01/08</td>
<td>07/01/08</td>
<td>$2,400,000</td>
<td>8 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Wichita - Reno County 345 kV Addition</td>
<td>12/01/08</td>
<td>07/01/08</td>
<td>$42,800,000</td>
<td>12 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>XFR - Reno County 345/115 kV #2 Addition</td>
<td>12/01/08</td>
<td>01/01/09</td>
<td>$2,860,000</td>
<td>14 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Tap Emporia Energy Center in/out of Lang - Swissvale 345 kV</td>
<td>12/01/08</td>
<td>01/01/09</td>
<td>$500,000</td>
<td>18 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - Gill Energy Center East - Gill Energy Center Jct 69 kV Rebuild</td>
<td>06/01/08</td>
<td>06/01/09</td>
<td>$1,250,000</td>
<td>18 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - SW Lawrence - Wakarusa 115 kV Rebuild</td>
<td>06/01/08</td>
<td>06/01/09</td>
<td>$1,400,000</td>
<td>18 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
<tr>
<td>536</td>
<td>Line - R prio County - Summit 345 kV Addition</td>
<td>12/01/08</td>
<td>01/01/11</td>
<td>$42,800,000</td>
<td>24 months</td>
<td>Green</td>
<td>Mitigation is interruption of demand in Leavenworth area. Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009.</td>
<td></td>
</tr>
</tbody>
</table>

**Year 2009**

$177,116,469
<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
<th>TO Reliability Need Date</th>
<th>Cost Estimate</th>
<th>Project Lease Time</th>
<th>Project Status</th>
<th>Project Status Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line - Rose Hill - Sooner 345 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,900,000</td>
<td>12 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>XFR - Stranger Creek 345/115 kV Addition</td>
<td>06/01/09</td>
<td>06/01/10</td>
<td>$8,500,000</td>
<td>24 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>XFR - Spangville 230/115 kV</td>
<td>06/01/09</td>
<td>06/01/10</td>
<td>$4,800,000</td>
<td>6 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Multi - 161 kV Tap of Nashua to Liberty West</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$2,900,000</td>
<td>12-18 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Freeman - Anacostia 69 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$20,000</td>
<td>3-5 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Multi - 161 kV Tap of Pitts City to Stranger Creek</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$7,127,000</td>
<td>12-18 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Italian - Pflate City, 161 kV Tap 1</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,350,000</td>
<td>6-12 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Longview - Sampson 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,250,000</td>
<td>12-18 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Samson - Graceland East 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,250,000</td>
<td>12-18 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Spray - Larena 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$155,000</td>
<td>6 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - SUB 124 - AURORA H.T. - SUB 341 - Joplin NorthWest</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$750,000</td>
<td>12 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Sub 429 - Joplin Northwest 7th - Sub 341 - Joplin NorthWest</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,250,000</td>
<td>12 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
</tr>
<tr>
<td>Line - Sub 436 - Joplin Southwest - Sub 422 - Joplin 24th &amp; Connecticut</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$5,000</td>
<td>6 months</td>
<td>Completed</td>
<td>Done for Zone Access. Not for SPP Reliability.</td>
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</table>

**Year 2010**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
<th>TO Reliability Need Date</th>
<th>Cost Estimate</th>
<th>Project Status</th>
<th>Project Status Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line - Winslow - 115 kV Additon</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$3,000,000</td>
<td>12 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - 115 kV Tap of Nashua to Liberty West</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$5,000</td>
<td>3-5 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - Freeman - Anacostia 69 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$20,000</td>
<td>3-5 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Multi - 161 kV Tap of Pitts City to Stranger Creek</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$7,127,000</td>
<td>12-18 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - Italian - Pflate City, 161 kV Tap 1</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,350,000</td>
<td>6-12 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - Longview - Sampson 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,250,000</td>
<td>12-18 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - Samson - Graceland East 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,250,000</td>
<td>12-18 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - Spray - Larena 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$155,000</td>
<td>6 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - SUB 124 - AURORA H.T. - SUB 341 - Joplin NorthWest</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$750,000</td>
<td>12 months</td>
<td>Completed</td>
</tr>
<tr>
<td>Line - Sub 429 - Joplin Northwest 7th - Sub 341 - Joplin NorthWest</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,250,000</td>
<td>12 months</td>
<td>Completed</td>
</tr>
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</table>

**Total Cost** $159,000,200
<table>
<thead>
<tr>
<th>GPP Area</th>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTD Reliability</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Line - Lone Jack - Greenwood 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,600,000</td>
<td>24 months</td>
<td>Cancelled</td>
</tr>
<tr>
<td></td>
<td>Line - Hallack - New Republic 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$711,000</td>
<td>-</td>
<td>Cancelled</td>
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<tr>
<td></td>
<td>Line - Warrensburg Plant - Warrensburg East 69kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$2,422,300</td>
<td>12-18 months</td>
<td>Cancelled</td>
</tr>
<tr>
<td></td>
<td>Line - Atchison - Kansas City 115 kV</td>
<td>06/01/12</td>
<td>06/01/10</td>
<td>$12,179,000</td>
<td>24 months</td>
<td>TO Zonal/local upgrade. Not for SPP reliability.</td>
</tr>
<tr>
<td></td>
<td>Line - Sub 184 - MerSTP Subdiv 115 kV - Nevada (SWPA) 181 kV</td>
<td>06/01/11</td>
<td>06/01/10</td>
<td>$2,300,000</td>
<td>24 months</td>
<td>Cancelled</td>
</tr>
</tbody>
</table>

**Year 2011**

<table>
<thead>
<tr>
<th>GPP Area</th>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTD Reliability</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>XFR - SWPS 804 - SWPS Sub 181 kV</td>
<td>10/01/10</td>
<td>10/01/10</td>
<td>$9,053,875</td>
<td>24 months</td>
<td>Exploratory project - still under study.</td>
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<tr>
<td></td>
<td>XFR - Anyaierko 138/69 kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$2,000,000</td>
<td>12 months</td>
<td>TO Zonal/local upgrade. Not for SPP reliability.</td>
</tr>
<tr>
<td></td>
<td>XFR - Franklin 345/230 kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$1,500,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - XFR - Spearville 345/230 kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$4,500,000</td>
<td>12 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Liberty - LHC 115 kV</td>
<td>01/01/13</td>
<td>06/01/11</td>
<td>$75,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
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<tr>
<td></td>
<td>XFR - Lawrenceville 220/115 kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$200,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
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<tr>
<td></td>
<td>XFR - Substation - Indian River 115 kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$200,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
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<tr>
<td></td>
<td>XFR - Pacia 345/161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$16,925,000</td>
<td>24 months</td>
<td>Cancelled</td>
</tr>
<tr>
<td></td>
<td>XFR - College - Craig 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$1,787,800</td>
<td>24 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Pelkie - Middle Creek 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$2,922,850</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Quayson - Green</td>
<td>01/01/13</td>
<td>06/01/11</td>
<td>$1,632,300</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Hodgson - LCP 161 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$3,833,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Cedar Niles - Owasso 69 kV</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>$3,796,200</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Neosho Valley 69 kV</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>$4,525,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Olinson - Springfield 69kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$46,500</td>
<td>24 months</td>
<td>Exploratory project - still under study.</td>
</tr>
</tbody>
</table>

**Year 2012**

<table>
<thead>
<tr>
<th>GPP Area</th>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTD Reliability</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>XFR - College - Craig 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$16,925,000</td>
<td>24 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Pelkie - Middle Creek 161 kV</td>
<td>06/01/10</td>
<td>06/01/10</td>
<td>$2,922,850</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Quayson - Green</td>
<td>01/01/13</td>
<td>06/01/11</td>
<td>$1,632,300</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Hodgson - LCP 161 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$3,833,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Cedar Niles - Owasso 69 kV</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>$3,796,200</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Neosho Valley 69 kV</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>$4,525,000</td>
<td>18 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td></td>
<td>XFR - Olinson - Springfield 69kV</td>
<td>06/01/11</td>
<td>06/01/11</td>
<td>$46,500</td>
<td>24 months</td>
<td>Exploratory project - still under study.</td>
</tr>
<tr>
<td>SPP Area</td>
<td>Project Name</td>
<td>In-Service Date</td>
<td>RTO Reliability</td>
<td>Cost Estimate</td>
<td>Project Lead Time</td>
<td>Project Status</td>
</tr>
<tr>
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<td>--------------</td>
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<td>-----------------</td>
<td>---------------</td>
<td>------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>546</td>
<td>Line - Southwest Disposal - Battlefield 161 kV</td>
<td>06/01/12</td>
<td>06/01/12</td>
<td>$8,637,000</td>
<td>24 months</td>
<td></td>
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<tr>
<td>546</td>
<td>Line - James Road - Harri Lake 69 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$15,185,600</td>
<td>24 months</td>
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</tr>
</tbody>
</table>

**Year 2013**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTO Reliability</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line - Barn - Lonestar Ordinance Tap 69kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$25,000</td>
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<tr>
<td>Line - Deacres - Lake Lamoer 69 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$1,496,600</td>
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<tr>
<td>Line - Mayek - Eth Springs REC 161 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$300,000</td>
<td>12 months</td>
<td></td>
</tr>
<tr>
<td>Line - Winnsboro - Magnolia Tap 69 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$290,000</td>
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<tr>
<td>Multi - France - Barton's Chapel 345kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$6,000,000</td>
<td>Deferred</td>
<td>Project deferred beyond the planning horizon as per 2007 Expansion Plan.</td>
</tr>
<tr>
<td>Line - Egg - Hill West 69 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$290,000</td>
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<td></td>
</tr>
<tr>
<td>Multi - N. Amarillo - Haxo - Yan Buren 69kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$391,100</td>
<td>30 months</td>
<td>Not recommended project - need to convert north Amarillo 69 kV loop to 115 kV instead.</td>
</tr>
<tr>
<td>Multi - Potter County - Roosevelt 345 kV 230/345 kV transformer</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$38,504,390</td>
<td>36 months</td>
<td></td>
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<tr>
<td>Multi - Potter County - Roosevelt 345 kV 230/345 kV transformer</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$38,504,390</td>
<td>36 months</td>
<td></td>
</tr>
<tr>
<td>XFR - Roosevelt County Interchange 115 kV - Roosevelt County Interchange 230 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$2,750,000</td>
<td>24 months</td>
<td></td>
</tr>
<tr>
<td>Line - S-Air - Minnaha 69 kV Rebuild</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$450,000</td>
<td>12 months</td>
<td></td>
</tr>
<tr>
<td>Line - Earlsboro - Fixico 69 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$150,000</td>
<td>8 months</td>
<td></td>
</tr>
<tr>
<td>Line - HSL East - HSL West 69 kV</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$250,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line - Maud - Fixico Tap</td>
<td>06/01/13</td>
<td>06/01/13</td>
<td>$75,000</td>
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<td></td>
</tr>
<tr>
<td>Line - Westwood 69 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$2,700,000</td>
<td>18 months</td>
<td></td>
</tr>
<tr>
<td>Line - Quitman - Westwood 69kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$1,600,000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Year 2014**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTO Reliability</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>XFR - Weatherford Southeast - Weatherford Southeast 138kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$1,800,000</td>
<td>18 months</td>
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</tr>
<tr>
<td>Line - W-W - Rogers 69kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$2,900,000</td>
<td>18 months</td>
<td></td>
</tr>
<tr>
<td>Multi - Bismark Sub 115 kV - Mustang Station E 115 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$1,742,892</td>
<td>30 months</td>
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<tr>
<td>Line - CIF - Interstate 138 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$500,000</td>
<td>30 months</td>
<td></td>
</tr>
<tr>
<td>Line - Ray - Sub 138 - Welden 69 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$4,500,000</td>
<td>24 months</td>
<td></td>
</tr>
<tr>
<td>Line - Sheeter CTs on Moundridge - Newton 69 kV</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$20,000</td>
<td>18 months</td>
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<tr>
<td>Multi - Hale Co -- LH Cox Interchange -- Cox Interchange 115 kv</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$10,564,000</td>
<td>18 months</td>
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<tr>
<td>Multi - Hale Co -- LH Cox Interchange -- Cox Interchange 115 kv</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$890,921</td>
<td>30 months</td>
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<tr>
<td>Multi - Sooner - Rose Hill 240/115 kV Sub</td>
<td>12/01/10</td>
<td>06/01/14</td>
<td>$27,200,000</td>
<td>18 months</td>
<td></td>
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<tr>
<td>Line - Sub 371 - FAIRPLAY EAST - SUB 502 - ROLLN PLANT</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$4,236,000</td>
<td>18 months</td>
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<tr>
<td>Multi - Sub 371 - FAIRPLAY EAST</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$1,960,986</td>
<td>18 months</td>
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<tr>
<td>Multi - Sub 370 - Nichols St. - SUB 395 - REPUBLIC EAST</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$4,550,000</td>
<td>18 months</td>
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<tr>
<td>Line - Sub EXPLORER SPRING CITY TAP - SUB 399 - JOPLIN SOUTHWEST</td>
<td>06/01/14</td>
<td>06/01/14</td>
<td>$1,150,000</td>
<td>12 months</td>
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</tbody>
</table>

**Year 2015**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
<th>RTO Reliability</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line - Snyder - Snyder 138 kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$1,600,000</td>
<td></td>
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<tr>
<td>Line - Quitman - Westwood 69kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$1,600,000</td>
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<tr>
<td>Line - East Variation - Bartlesville 69 kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$1,900,000</td>
<td>54 months</td>
<td></td>
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<tr>
<td>Multi - Woodawn - Backen - Kill Creek Tap</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$6,000,000</td>
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<td></td>
</tr>
<tr>
<td>Multi - Woodawn - Backen - Kill Creek Tap</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$6,000,000</td>
<td></td>
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<tr>
<td>Line - Maud - Fixico Tap</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$30,000,000</td>
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<tr>
<td>Line - Russell to Glasses 138 kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$150,000</td>
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<tr>
<td>Line - notifying - Richey Park ad</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$750,000</td>
<td>16 months</td>
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<tr>
<td>Line - Roosevelt County Interchange 115 kV - Corry County Interchange 115 kV</td>
<td>12/01/12</td>
<td>06/01/15</td>
<td>$200,000</td>
<td>30 months</td>
<td></td>
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<tr>
<td>Line - Chisholm 345/115 kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$3,900,000</td>
<td>24 months</td>
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<tr>
<td>Multi - Hale Co -- LH Co Interchange -- Cox Interchange 115 kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$6,950,000</td>
<td>30 months</td>
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<tr>
<td>Multi - Hale Co -- LH Co Interchange -- Cox Interchange 115 kV</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$890,921</td>
<td>30 months</td>
<td></td>
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<tr>
<td>Multi - Chisholm Energy Center - Chisholm - St. John 115kV Rebuild</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$8,637,000</td>
<td>9 months</td>
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<tr>
<td>Line - Tipton - City Center 115 kV Uprate</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$10,000</td>
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<tr>
<td>Line - Lawrence Hill - Win 115 kV Rebuild</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$1,400,000</td>
<td>18 months</td>
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<tr>
<td>Multi - Missouri City - Missouri City Station 69 kV Uprate</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$30,000</td>
<td>12 months</td>
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</tr>
<tr>
<td>SPP Area</td>
<td>Project Name</td>
<td>In-Service Date</td>
<td>RTO Reliability</td>
<td>Need Date</td>
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<td>Line - 536</td>
<td>06/01/15</td>
<td>06/01/15</td>
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<tr>
<td>539</td>
<td>Line - 539</td>
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<td>06/01/15</td>
<td>$3,000,000</td>
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<tr>
<td>541</td>
<td>Line - 541</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$13,000</td>
<td>6 months</td>
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<tr>
<td>546</td>
<td>Line - 546</td>
<td>06/01/15</td>
<td>06/01/15</td>
<td>$5,000,000</td>
<td>24 months</td>
</tr>
</tbody>
</table>

**Year 2016**

- **Project Name**: Multi-Fort Scott-AECI tie
  - **In-Service Date**: 06/01/15
  - **RTO Reliability**: 06/01/15
  - **Need Date**: 06/01/15
  - **Cost Estimate**: $3,000,000
  - **Project Lead Time**: 18 months
  - **Project Status**: GREEN

- **Project Name**: Line - Greenleaf - Clay Center 115 kV
  - **In-Service Date**: 06/01/15
  - **RTO Reliability**: 06/01/15
  - **Need Date**: 06/01/15
  - **Cost Estimate**: $7,520,000
  - **Project Lead Time**: 12 months
  - **Project Status**: GREEN

- **Project Name**: Line - Avondale - Gladstone 161 kV
  - **In-Service Date**: 06/01/15
  - **RTO Reliability**: 06/01/15
  - **Need Date**: 06/01/15
  - **Cost Estimate**: $130,530
  - **Project Lead Time**: 12 months
  - **Project Status**: GREEN

- **Project Name**: Line - Norton - NEERGRD 69 kV
  - **In-Service Date**: 06/01/15
  - **RTO Reliability**: 06/01/15
  - **Need Date**: 06/01/15
  - **Cost Estimate**: $1,881,000
  - **Project Lead Time**: 24 months
  - **Project Status**: GREEN

- **Project Name**: Line - Mead - Plaza 69 kV Uprate
  - **In-Service Date**: 06/01/15
  - **RTO Reliability**: 06/01/15
  - **Need Date**: 06/01/15
  - **Cost Estimate**: $60,000
  - **Project Lead Time**: 12 months
  - **Project Status**: GREEN

- **Project Name**: Line - Northeast - Crosstown 161 kV
  - **In-Service Date**: 06/01/15
  - **RTO Reliability**: 06/01/15
  - **Need Date**: 06/01/15
  - **Cost Estimate**: $650,000
  - **Project Lead Time**: Cancelled
  - **Project Status**: project no longer needed; no longer problem in Aggregate Study

**Year 2017**

- **Project Name**: Line - Clinton 161 - Clinton Green St 69 kV
  - **In-Service Date**: 06/01/16
  - **RTO Reliability**: 06/01/16
  - **Need Date**: 06/01/16
  - **Cost Estimate**: $441,000
  - **Project Lead Time**: 12 months
  - **Project Status**: YELLOW
  - **Project Status Comments**: TO Zonal/local upgrade. Not for SPP reliability.

**Year 2020**

- **Project Name**: Line - Cline Creek - Cline Creek 26th 69 kV
  - **In-Service Date**: 06/01/16
  - **RTO Reliability**: 06/01/16
  - **Need Date**: 06/01/16
  - **Cost Estimate**: $2,679,913
  - **Project Lead Time**: 24 months
  - **Project Status**: Deferred
  - **Project Status Comments**: Project name should be Mooreland - TUCO. Required only by June 2020 as per 2007 Expansion Plan. Status Deferred.
## SPP 1st Quarter 2008 Project Tracking Report - Device

### Project Tracking

<table>
<thead>
<tr>
<th>SPP Area</th>
<th>Project Name</th>
<th>In-Service Date</th>
<th>Final In-Service Date</th>
<th>Cost Estimate</th>
<th>Project Lead Time</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year 2006</strong></td>
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<td></td>
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<tr>
<td>500</td>
<td>Device - Arsenal Hill</td>
<td>06/01/06</td>
<td>06/01/06</td>
<td>$437,000</td>
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<tr>
<td>500</td>
<td>Device - Calhoun</td>
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<td>06/01/06</td>
<td>$334,000</td>
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<tr>
<td>520</td>
<td>Device - Comanche</td>
<td>07/01/05</td>
<td>07/01/05</td>
<td>$457,963</td>
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<tr>
<td>533</td>
<td>Device - Mulberry</td>
<td>03/01/06</td>
<td>03/02/06</td>
<td>$324,000</td>
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<tr>
<td>535</td>
<td>Device - Chisholm</td>
<td>12/31/06</td>
<td>12/31/06</td>
<td>$490,700</td>
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<tr>
<td>539</td>
<td>Device - East Liberal</td>
<td>06/01/06</td>
<td>06/01/06</td>
<td>$600,000</td>
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<td></td>
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<tr>
<td>539</td>
<td>Device - Plainview</td>
<td>06/01/06</td>
<td>06/01/06</td>
<td>$7,000,000</td>
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<td></td>
</tr>
<tr>
<td>540</td>
<td>Device - Warrensburg East</td>
<td>08/01/06</td>
<td>06/01/06</td>
<td>$900,000</td>
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<td></td>
</tr>
<tr>
<td><strong>Year 2007</strong></td>
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<tr>
<td>502</td>
<td>Device - Many</td>
<td>06/01/06</td>
<td>06/01/10</td>
<td>$500,000</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
<td>520</td>
<td>Device - Natchitoches</td>
<td>06/01/09</td>
<td>06/01/10</td>
<td>$0</td>
<td>2 months</td>
<td>On Schedule.</td>
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<tr>
<td>522</td>
<td>Multi - Tulsa Project</td>
<td>07/01/07</td>
<td>06/01/07</td>
<td>-</td>
<td>-</td>
<td>Complete.</td>
</tr>
<tr>
<td>524</td>
<td>Device - Vermillion</td>
<td>12/31/06</td>
<td>12/31/06</td>
<td>$5,711,300</td>
<td>12 months</td>
<td>Delayed beyond the RTO determined need date and no mitigation plan provided.</td>
</tr>
<tr>
<td>525</td>
<td>Device - Rush Springs 69 kV</td>
<td>06/01/08</td>
<td>06/01/06</td>
<td>$90,000</td>
<td>8 months</td>
<td>Deferred beyond the RTO determined need date and no mitigation plan provided.</td>
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<tr>
<td>525</td>
<td>Device - Snyder</td>
<td>12/01/07</td>
<td>04/01/07</td>
<td>$100,000</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
<td>525</td>
<td>Device - Pink Southwest 138 kV</td>
<td>12/01/07</td>
<td>04/01/07</td>
<td>$216,000</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
<td>526</td>
<td>Device - Carlisle Interchange</td>
<td>01/01/07</td>
<td>06/01/07</td>
<td>$771,383</td>
<td>12 months</td>
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<tr>
<td>526</td>
<td>Device - Warrensburg East Interchange</td>
<td>01/01/07</td>
<td>12/31/06</td>
<td>$500,000</td>
<td>12 months</td>
<td>Complete.</td>
</tr>
<tr>
<td>526</td>
<td>Device - Blueview</td>
<td>11/01/07</td>
<td>06/01/08</td>
<td>$300,000</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
<td>526</td>
<td>Device - Locokeen - IGA Interchange</td>
<td>06/01/06</td>
<td>06/01/10</td>
<td>$311,040</td>
<td>12 months</td>
<td>Complete.</td>
</tr>
<tr>
<td>536</td>
<td>Device - UDALL 2</td>
<td>01/01/07</td>
<td>12/31/06</td>
<td>$376,847</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
<td>535</td>
<td>Device - NE Parsons</td>
<td>12/31/07</td>
<td>06/01/07</td>
<td>$1,200,000</td>
<td>14 months</td>
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<tr>
<td>536</td>
<td>Device - Parsons</td>
<td>12/30/07</td>
<td>06/01/07</td>
<td>$525,000</td>
<td>14 months</td>
<td>Complete.</td>
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<tr>
<td>540</td>
<td>Device - St Joe 161 kV 50 MVAR cap</td>
<td>10/01/07</td>
<td>10/01/07</td>
<td>$500,000</td>
<td>14 months</td>
<td>Complete.</td>
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<tr>
<td>540</td>
<td>Device - Nashua 161 kV 50 MVAR cap</td>
<td>10/01/07</td>
<td>10/01/07</td>
<td>$500,000</td>
<td>14 months</td>
<td>Complete.</td>
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<tr>
<td>541</td>
<td>Device - South Whaley</td>
<td>01/01/07</td>
<td>06/01/07</td>
<td>$473,000</td>
<td>14 months</td>
<td>Complete.</td>
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<tr>
<td>544</td>
<td>Device - Comanche</td>
<td>06/01/07</td>
<td>06/01/07</td>
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<td>14 months</td>
<td>Complete.</td>
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<td><strong>Year 2008</strong></td>
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<tr>
<td>520</td>
<td>Device - Comanche</td>
<td>06/01/08</td>
<td>06/01/08</td>
<td>$350,000</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
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<td>06/01/08</td>
<td>$198,000</td>
<td>12 months</td>
<td>Complete.</td>
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<tr>
<td>526</td>
<td>Device - Cold Interchange</td>
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<td>06/01/13</td>
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<td>24 months</td>
<td>Complete.</td>
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<tr>
<td>526</td>
<td>Device - Bailey Co Earth</td>
<td>06/01/06</td>
<td>06/01/13</td>
<td>$1,311,463</td>
<td>24 months</td>
<td>Complete.</td>
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<td>526</td>
<td>Device - BC Earth</td>
<td>06/01/08</td>
<td>06/01/08</td>
<td>$10,240,300</td>
<td>24 months</td>
<td>Complete.</td>
</tr>
</tbody>
</table>

Note: Costs and lead times are estimates provided by SPP staff.
<table>
<thead>
<tr>
<th>SPP Area</th>
<th>Project Name</th>
<th>In-Service Date</th>
<th>SPD Reliability</th>
<th>Need Date</th>
<th>Actual Estimate</th>
<th>Project Status</th>
<th>Project Status</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>536</td>
<td>Device - Nortonville 69 kV Cap</td>
<td>06/01/08</td>
<td>06/01/08</td>
<td>$715,000</td>
<td>18 months</td>
<td>Deferred</td>
<td>Deferred</td>
<td>Mitigation not required if Project completed before 08 Summer Peak. LOA received by Westar 2 February 2007 with required date 1 June 2007. Project deferred beyond the planning horizon as per 2007 Expansion Plan.</td>
</tr>
<tr>
<td>536</td>
<td>Device - Sunset 69 kV</td>
<td>12/31/08</td>
<td>Deferred</td>
<td>$1,200,000</td>
<td>18 months</td>
<td>Deferred</td>
<td></td>
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</tr>
</tbody>
</table>

**Year 2009**

| Device - Newport 69 kV | 06/01/09 | 06/01/11 | $311,040 | 18 months | Cancelled | |
| Device - Tulsa 69 kV | 06/01/09 | 06/01/11 | $165,500 | 12 months | |
| Device - Tulsa 69 kV | 06/01/09 | 06/01/11 | $87,195 | 12 months | |
| Device - Clinton | 06/01/08 | 06/01/09 | $750,000 | 12 months | Cancelled | |
| Device - Warsaw 269.0 | 06/01/09 | 06/01/09 | $409,900 | 12 months | VAR compensations were done in the distribution system in the area. Project required by June 2013 as per 2007 Expansion plan. |

**Year 2010**

| Device - Crosby | - | 06/01/09 | $500,000 | 24 months | Needs further 69 kV analysis to see if complete Plainview-Floyd-Crosby trans. project mitigates its SPP Reliability project. Required by June 2010 as per 2007 Expansion Plan. |

**Year 2011**

| Device - Bushland Interchange 230 kV Cap | - | Deferred | $800,000 | 24 months | Deferred | Needs further analysis - this is a wind farm outlet bus - no capacitors were identified in TS or GI studies. Project deferred beyond the planning horizon as per 2007 Expansion Plan. |

**Year 2012**

| Device - Florence 115 kV Cap | 06/01/12 | 06/01/12 | $1,000,000 | 18 months | |

**Year 2013**

| Device - McFarland | 06/01/13 | 06/01/13 | $500,000 | 12 months | |
| Device - Independence 69 kV | 06/01/13 | 06/01/13 | $108,000 | 12 months | |
| Device - East Kingfisher 69 kV | 06/01/13 | 06/01/13 | $800,000 | 12 months | |
| Device - Edwardsville 115 kV Cap | 06/01/13 | 06/01/13 | $1,000,000 | 18 months | |
| Device - Kennesaw | 06/01/13 | 06/01/13 | $1,000,000 | 18 months | |

**Year 2014**

| Device - Card Bayou | 06/01/14 | 06/01/14 | $450,000 | 12 months | |
| Device - Maldenville | 06/01/14 | 06/01/14 | $900,000 | 12 months | |
| Device - Glenpool | 06/01/14 | 06/01/14 | $500,000 | 12 months | |
| Device - Bixby | 06/01/14 | 06/01/14 | $550,000 | 12 months | |
| Device - Panama 69 kV | 06/01/14 | 06/01/14 | $108,000 | 12 months | |
| Device - Waverly 115 kV Cap | 06/01/14 | 06/01/14 | $1,000,000 | 18 months | |
| Device - Plano/Ville | 06/01/14 | 06/01/14 | $1,000,000 | 18 months | |
| Device - Riverside Sub | 06/01/14 | 06/01/14 | $900,000 | 24 months | |

**Year 2015**

| Device - Massillonville | - | 06/01/15 | $500,000 | 12 months | |
| Device - Altus 69 kV | 06/01/15 | 06/01/15 | $34,000 | 12 months | |
| Device - south Oklahoma Cty Pump 69kV | 06/01/15 | 06/01/15 | $375,988 | 12 months | |
| Device - Vinita | 06/01/15 | 06/01/15 | $200,000 | 12 months | |
| Device - Oklahoma 138 kV Cap | 06/01/15 | 06/01/15 | $1,000,000 | 18 months | |
| Device - Rock Creek 69 kV Cap | 06/01/15 | 06/01/15 | $427,000 | 18 months | |
| Device - Broken Arrow | 06/01/15 | 06/01/15 | $1,000,000 | 24 months | |
| Device - Tulsa Interchange | 06/01/15 | 06/01/15 | $500,000 | 24 months | |

**Year 2016**

| Device - Bailey County Interchange 115kV | - | Deferred | $311,040 | 24 months | Deferred | Needs further analysis in light of additional 115 kV load to be served from bus. Project deferred beyond the planning horizon as per 2007 Expansion Plan. |
| Device - Booker | 06/01/16 | 06/01/16 | $200,000 | 24 months | |
| Device - East 161 | 06/01/16 | 06/01/16 | $452,000 | 6-12 months | Long range plan for north system wind mitigation. Mitigation plan under review by SPP staff. |

**Year 2017**

<p>| Device - Broken Amaze Water | 06/01/17 | 06/01/17 | $550,000 | 12 months | |</p>
<table>
<thead>
<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>99,126</td>
<td>872,500</td>
<td>(773,374) (A)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>99,126</td>
<td>872,500</td>
<td>(773,374)</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Travel</td>
<td>54,292</td>
<td>98,000</td>
<td>(43,708)</td>
</tr>
<tr>
<td>Meetings</td>
<td>40,316</td>
<td>70,000</td>
<td>(29,684)</td>
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<tr>
<td>Administrative</td>
<td>1,282</td>
<td>1,500</td>
<td>(218)</td>
</tr>
<tr>
<td>Outside Services</td>
<td>3,237</td>
<td>3,000</td>
<td>237</td>
</tr>
<tr>
<td>Cost Benefit Studies</td>
<td>-</td>
<td>700,000</td>
<td>(700,000) (B)</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td>99,126</td>
<td>872,500</td>
<td>(773,374)</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

(A) YTD revenue is less than budget given that ytd expenses are less than budget.
(B) YTD study costs are less than budget as no studies have been conducted in 2007.