Southwest Power Pool
REGIONAL STATE COMMITTEE
Airport Marriott, Kansas City, MO
July 27, 2009

• M I N U T E S •

Administrative Items:
The following members were in attendance, via teleconference, or represented by proxy:
   David King New Mexico Public Regulation Commission (NMPRC)
   Mike Moffet, Kansas Corporation Commission (KCC)
   Jeff Cloud, Oklahoma Corporation Commission (OCC)
   Jeff Davis, Missouri Public Service Commission (MoPSC)
   Mike Siedschlag, Nebraska Power Review Board (NPRB)
   Barry Smitherman, Public Utility Commission of Texas (PUCT)
   Paul Suskie, Arkansas Public Service Commission (APSC)

President David King called the meeting to order at 1:05 p.m. He asked for a round of introductions and a quorum was declared. There were 102 in attendance either in person or via phone (Attendance – Attachment 1). President King welcomed guest Commissioners Mark Graham (NPRB), Chairman Robert Clayton (MoPSC), Brandon Presley (Mississippi PSC) and Bill Booth representing Shelley Midura (New Orleans City Council).

President King asked for adoption of the April 27, 2009 meeting minutes (RSC Minutes 4/27/09 - Attachment 2). Paul Suskie moved to approve the minutes and Mike Moffett seconded the motion. The minutes were unanimously approved.

Updates
RSC Financial Report
Les Dillahunty provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Dillahunty reported that the RSC remains under budget. This is mostly due to the fact that a cost/benefit study has not been conducted as budgeted.

Other RSC Officer Reports
There were no other officer reports.

FERC Update
Mr. John Rogers provided an update on FERC activities. Since the April board meeting, notable Commission actions include:

The Commission accepted SPP’s Attachment O Transmission Planning Process filing in May and at the June Commission meeting, the Commission accepted SPP’s cost allocation proposal for wind resources.

In addition, at the May Commission meeting, the Commission accepted multiple transmission planning process Attachment K filings. In conjunction with the orders, the Commission announced that it would be convening regional conferences on transmission planning later this year. These conferences will examine whether the existing transmission planning processing adequately consider transmission needs and solutions on a regional or interconnection-wide basis. The technical conferences will be held:
   • September 3 in Phoenix for the western region;
   • September 10 in Atlanta for the SEARUC and SPP entities and;
Regional State Committee
July 27, 2009

- September 21 in Philadelphia for MISO, PJM, NYISO, NE-ISO and MAPP participants.

In June, the Commission, along with representatives from the Entergy region state regulators, held a technical conference in Charleston, SC in conjunction with the SEARUC meetings to review the ICT arrangement.

At the July Commission meeting, the Commission issued:

- Rehearing order in the Order No. 719 proceeding;
- Smart Grid Policy Statement (Docket No. PL09-4-000).

Lastly, the president has nominated Mr. John Norris to be a FERC Commissioner. Mr. Norris served as Chairman of the Iowa Utilities Board. He also served as a board member and President of the Organization of Midwest ISO States. He is awaiting Senate confirmation before assuming his role at the Commission.

SPP Update
Nick Brown provided an SPP update. Mr. Brown noted a large attendance mostly due to the upcoming initiatives being discussed in today’s RSC agenda and tomorrow’s Board agenda. He stated that in June SPP had 33 meetings scheduled on 19 out of 20 business days. There is a sense of urgency for future markets, renewable energy and the transmission superhighway. Mr. Brown encouraged best pace going forward and that a robust transmission network is paramount to our success. He called attention to a brochure developed by the SPP Communication Department to explain in simple terms the benefits of the “Transmission Superhighway”. This brochure is available as an information tool to help educate the public. It is a concern that in many states the laws are antiquated. SPP is requesting that the regulatory staff identify laws that may be an impediment to the strategic needs of transmission planning.

Business Meeting

RSC 2008 Audit Report
Les Dillahunty stated that the RSC Bylaws require a yearly audit (2008 RSC Audit – Attachment 4). Patricia Salman & Associates provided this service as in the past. No outstanding issues were cited but the group was encouraged to report accurate mileage and to use the correct mileage reimbursement rates for travel reports. **Jeff Davis moved to accept the 2008 RSC Financial Audit as presented. Barry Smitherman seconded the motion, which passed unanimously.**

Synergistic Project Plan Report

Overview
Carl Monroe reported that the Synergistic Planning Project Team (SPPT) was formed in January 2009 to look for opportunities to improve transmission planning and cost allocation unencumbered by Tariff or other limitations. The Board of Directors approved the SPPT’s report and recommended planning principles at the April meeting. The team will continue to discuss and review these principles in August and September with a final report presented to the Board of Directors in October 2009.

Integrated Transmission Plan (ITP)
Bruce Rew provided the Integrated Transmission Plan (ITP) report (ITP Report – Attachment 5). The major objective of the ITP is to design a transmission backbone to connect load centers to low-cost generation. Other objectives include: improving connections between SPP’s east and west regions, make transmission an enabler rather than constraint and strengthen ties to the Eastern and Western Interconnections.

Priority Projects
Bruce Rew presented a list of potential priority projects as a part of the ITP as directed by the SPP Board of directors in April (Priority Projects – Attachment 6). Priority projects consist of those arising
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from: congestion corridors, transmission service requests, generation interconnection corridors, economic projects and those with west – east transfer capability. Ten projects were selected for further evaluation from the approximately 120 initial project candidate list. A consultant has been engaged to analyze these projects; the group will evaluate the list and recommend projects to be funded at the October Board of Directors meeting.

Following considerable discussion, the consensus of the group was that moving to or possibly recommending projects at 765 kv vs. 345 kv is a policy decision to be made following analysis, discussion and decision.

Cost Allocation

Dr. Mike Proctor provided an outline of: Highway/Byway concepts; Highway/Byway cost allocation; Highway/Byway rate design; integrating cost allocation and rate design and the upcoming Cost Allocation Working Group (CAWG) schedule (Proctor Presentation – Attachment 7). In determining what upgrades should be included in the Highway/Byway rate design, it was determined that further discussion was required regarding wind resources. Finalize concepts are expected to be completed prior to the October RSC meeting.

The SPP Balanced Portfolio Report was provided for informational purposes (BP Report – Attachment 8).

Dr. Proctor presented the following waiver requests:

- Westar Waiver Request 1346837 – Meridian Way
- Westar Waiver Request 1346842 – Flat Ridge Wind
- City of Coffeyville, Kansas Request 1352193

Mike Moffet moved to approve the waivers presented. Paul Suskie seconded the motion, which passed unanimously.

Procedures to Site Interstate Transmission

Heather Starnes (SPP) provided information regarding procedures to site interstate transmission (White Paper – Attachment 8). States have primary authority for approving the siting of transmission facilities; however, currently the U.S. Senate is considering legislation that would extend FERC siting authority when a state fails to act or denies an application for transmission siting.

Communication and Next Steps

A plan is underway to provide an “ITP Road Show” for the state regulators (Communication – Attachment 9.) The intent is to provide education regarding SPP’s current transmission planning processes; the Synergistic Planning Project including the ITP, Priority Projects, cost allocation and cost/benefit analysis; and the role of the regulators.

Congestion Hedging Task Force Comments

Keith Sugg (AECC) provided a presentation from the Congestion Hedging Task Force (CHTF) explaining how the Task Force evaluated options for dealing with hedging transmission congestion costs in future markets (CHTF Presentation – Attachment 10). Mr. Sugg asked for feedback from the RSC as to whether the individual states were interested in scheduling presentations for each of the states in order to help inform a larger group about the recommendations or work of the CHTF and to answer any questions. There was agreement to proceed with these explanatory sessions.

Wind Integration Task Force Update

Bruce Rew provided a Wind Integration Task Force (WITF) update (WITF Report – Attachment 11). It is the goal of the group to make a report to the Markets and Operations Policy Committee at the January 2010 meeting.
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Discussion of 6/24/09 FERC Technical Conference – Entergy ICT
Paul Suskie provided a recap of the June 24 FERC Entergy Technical Conference in Charleston, SC. The issues discussed were:

- ICT base transmission plan vs the Entergy construction plan
- Entergy transmission planning
- Application of NERC TPL-001, footnote B
- ICT going forward
- FERC offer to fund a benefit study of Entergy joining SPP
- Retail regulators of Entergy forming an RSC like group

Commissioner Suskie stated that all FERC commissioners were present as well many state commissioners. Each retail jurisdiction was represented at the Conference. Many of the representatives stated that this meeting was a first to have this kind of representation focusing on a single issue. FERC displayed confidence in SPP, which he felt was a great testament to SPP and its Independent Coordinator of Transmission (ICT) role. He stated that Chairman Jon Wellinghoff said that FERC would be willing to pay for part of a study to determine benefits of Entergy’s membership in the SPP RTO. Appreciation was expressed to Commissioner Suskie and FERC Chairman Wellinghoff for their part in arranging this conference.

Eastern Interconnection Planning Collaborative (EIPC) Comments
NARUC is working on a study of the Eastern Interconnection that will be initiated. Through the American Recovery and Reinvestment Act (ARRA) $80 million is being made available to study the three interconnections. Planning authorities are looking for funds to conduct studies. Proposals for funding opportunities are to be submitted to the DOE by August 14, 2009.

States Comments on Order 719 Tariff Language
Commissioner Barry Smitherman provided a memo answering SPP’s request for feedback regarding implementation of proposed tariff provisions in response to FERC Order 719 (PUCT Memo – Attachment 12). Texas proposes a “certification by means of declaration” approach. Other state responses were:

- **Arkansas**: Has a docket requesting all parties to comment 30 days after FERC acts on the proposed tariff language.
- **Kansas**: Plans to follow the Arkansas model of an open docket.
- **Missouri**: Law is clear that Missouri has jurisdiction over aggregators but open to having a docket.
- **Oklahoma**: Gary Clear spoke on behalf of Commissioner Cloud stating that Oklahoma does not currently have a docket. He also, spoke on behalf of OG&E. OG&E plans to provide comments for the Arkansas docket.
- **Nebraska**: Major utilities and the Nebraska Power Review Board will take up the issue.
- **New Mexico**: Waiting to see other states actions.

RSC Consulting Contract
Commissioner Suskie announced that Dr. Mike Proctor is planning to retire in the near future and that there is a request that consideration be given for Dr. Proctor to be placed under contact as an RSC consultant to work with the CAWG. **Commissioner Suskie moved that the Regional State Committee enter into a contract with Dr. Mike Proctor, effective upon his departure from the Missouri Public Service Commission, not to exceed 60 hours per month and $100,000 per year (≈ $138.00/hour).** David King seconded the motion, which passed with Commissioner Davis abstaining.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President King noted that the next regularly scheduled meeting is on October 26, 2009 in Tulsa, OK.

With no further business, the meeting was adjourned at 5:10 p.m.

Respectfully Submitted,
Regional State Committee
July 27, 2009

Les Dillahunty
REGULAR MEETING
Monday, July 27, 2009
1:00 - 5:00 p.m.
Airport Marriott, Kansas City, MO

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of April 27, 2009 Minutes

3. UPDATES
   a. RSC Financial Report
   b. Other RSC Officer Reports
   c. FERC
   d. SPP

4. BUSINESS MEETING
   a. RSC 2008 Audit Report (action item) ......................................................... Les Dillahunty
   b. Synergistic Project Plan Report
      1. Overview ........................................................................................................ Carl Monroe
      2. Integrated Transmission Plan (ITP) .............................................................. Bruce Rew
      3. Priority Projects .............................................................................................. Bruce Rew
      4. Cost Allocation .............................................................................................. Dr. Mike Proctor
         a. Balanced Portfolio Report
         b. Waivers
   c. Procedures to Site Interstate Transmission ........................................... Heather Starnes
   d. Communication and Next Steps ............................................................. Les Dillahunty
   e. Congestion Hedging Task Force Comments ........................................... Keith Sugg (AECC)
   f. Wind Integration Task Force Update .......................................................... Bruce Rew
   g. Discussion of 6/24/09 FERC Technical Conference – Entergy ICT ..... Chairman Paul Suskie
      Chairman Barry Smitherman
   h. Eastern Interconnection Planning Collaborative (EIPC) Comments .......... Bruce Rew
      Chairman Paul Suskie
   g. States Comments on Order 719 Tariff Language concerning Demand Response and
      Aggregators of Retail Customers Certification of Declaration Requirement .......... RSC
      Commissioners
   h. RSC Consulting Contract ......................................................................... Chairman Paul Suskie

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

*The Project Tracking Report will be included in the background material.
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<td>Jeff Knuttek</td>
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Southwest Power Pool  
REGIONAL STATE COMMITTEE  
Skirvin Hotel, Oklahoma City, OK  
April 27, 2009

• M I N U T E S •

Administrative Items:
The following members were in attendance, via teleconference, or represented by proxy:
Stacy Starr-Garcia, for David King New Mexico Public Regulation Commission (NMPRC)
Mike Moffet, Kansas Corporation Commission (KCC)
Jeff Cloud, Oklahoma Corporation Commission (OCC)
Jeff Davis, Missouri Public Service Commission (MoPSC)
Mike Siedschlag, Nebraska Power Review Board (NPRB)
Barry Smitherman, Public Utility Commission of Texas (PUCT)
Paul Suskie, Arkansas Public Service Commission (APSC)

Vice President Mike Moffet called the meeting to order at 1:05 p.m. He asked for a round of introductions and a quorum was declared. There were 103 in attendance either in person or via phone (Attendance & Proxies – Attachment 1). Tim Texel and Mike Siedschlag were recognized and welcomed from the Nebraska Power Review Board.

Vice President Moffet asked for adoption of the January 26, 2009 meeting minutes (RSC Minutes 1/26/09 - Attachment 2). Paul Suskie moved to approve the minutes and Jeff Davis seconded the motion. The minutes were approved unanimously.

Updates
RSC Financial Report
Les Dillahunty provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Dillahunty reported that the RSC remains under budget. There was no technical conference held although there are expected cost expenditures for cost/benefit studies.

Other RSC Officer Reports
There were no other officer reports.

FERC Update
Mr. Patrick Clarey provided an update on FERC activities. In February, the Commission approved two innovative rate treatments for transmission projects designed to bring wind generated electricity to the Southwest. On March 19, 2009, President Obama appointed Jon Wellinghoff as permanent FERC Chair and announced his intention to reappoint Commissioner Suedeen Kelly to another term. Other March activities included:

- Granted a one-time extension to SPP’s wavier request to allow SPP to study pending generator interconnection requests in two transitional clusters pending filing of queue reform filing.

- Accepted SPP’s tariff revisions adopting Order No. 890’s five-year minimum contract term and one-year notice period related to a firm transmission customer’s ongoing right to renew or rollover its contract. Additionally, the Commission instituted a Section 206 proceeding to determine the justness and reasonableness of certain language in SPP’s existing OATT regarding rollover provisions.
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- Approved rate incentives for two ITC Great Plains high-voltage lines in SPP. The lines are part of the KETA and Kansas V Plan projects.

- Issued a proposed policy statement and action plan to provide guidance to inform the development of a smarter grid for the nation’s electric transmission system.

- Held a technical conference exploring challenges posed by the integration of large amounts of variable renewable generation into wholesale markets and grids as well as innovative solutions.

At the April open meeting, Chairman Wellinghoff announced the following staff changes:

- Shelton Cannon, current Office Director of the Office of Energy Market Regulation (OEMR), will retire after 29 years.
- Mike McLaughlin will be the new Office Director of OEMR.
- Jamie Simler will be the new Office Director of the newly created Office of Energy Policy and Innovation.

The Commission also approved rate incentives from the Green Power Express transmission project. The project is a proposed 3,000 mile regional high voltage project designed to deliver renewable energy from the upper Midwest to central and eastern load centers.

Senior staff continues their participation in ongoing outreach to the state commissions covered under classic SPP RTO as well as the SPP ICT arrangement with Entergy and the SPP ITO arrangement with E.ON. On June 24 in connection with the SEARUC Annual Meeting in Charleston, South Carolina, FERC and the Entergy states will hold a joint conference to explore issues with the ICT arrangement.

SPP Update
Les Dillahunty provided an SPP update in the absence of Nick Brown, who was detained at a Washington, D.C. meeting. Mr. Dillahunty extended SPP’s gratitude for the leadership and efforts of the CAWG over the last two years in the development of the Balanced Portfolio. He recognized Larry Holloway, an original member of the CAWG who has retired from the Kansas Corporation Commission, and called attention to his insightful leadership with this group.

Mr. Dillahunty stated that release of the Joint Coordinated System Plan (JCSP) in February may have caused some confusion. There are two initiatives underway: 1) the Eastern Wind Integration Task Force (EWITS), an earlier work of the JCSP is being expanded and carried forward; and 2) the Eastern Interconnection Planning Collaborative (EIPC) which is an effort to provide an integrated, interconnection-wide view of the regional plans and to provide an analysis identifying gaps relative to state, provincial, regional or federal policy goals. It is hoped that the EIPC will move toward an assessment and coordination of a variety of transmission alternatives. Seventeen Planning Authorities from the U.S. and Canada met April 8 to begin these EIPC discussions.

Mr. Dillahunty reminded the group that the SPP Board of Directors will hold the annual educational meeting in Little Rock on June 8 and 9. There is no corresponding RSC meeting in June although the SPP Board of Directors meeting is an open meeting. Please let one of the SPP staff know if you plan on attending and would like more information.

Business Meeting

RSC Bylaws Revision
Due to the recent integration of the Nebraska entities, the Nebraska Power Review Board (NPRB) now wishes to be included in the RSC. The RSC Bylaws do need to undergo a slight modification to accommodate the NPRB participation (Bylaws Revision – Attachment 4). It was recommended that this minor modification be made to include the NPRB. Mike Siedschlag, NPRB Chairman, was asked to comment. Mr. Siedschlag
Regional State Committee  
April 27, 2009

stated that the NPRB included five people appointed by the governor and three staff including Tim Texel, General Counsel. Jeff Davis moved to approve the RSC Bylaws modifications to Article II, 1a:

Regulate the retail electricity or distribution rates or approve retail service areas of transmission-owning members or transmission-dependent utility members of the SPP

Paul Suskie seconded the motion, which passed unanimously.

Jeff Cloud moved to include NPRB as a member of RSC. Paul Suskie seconded the motion, which passed unanimously. Mike Siedschlag will represent NPRB on the RSC.

Order 719 Tariff Language – Demand Response Participation in Markets

Les Dillahunty stated that Jim Eckelberger, SPP Board Chairman, had requested that the RSC agenda include discussion regarding the Order 719 tariff language (Order 719 Tariff Language – Attachment 5). The Markets and Operations Policy Committee (MOPC) proposed tariff revisions are:

MOPC proposed revision to RTWG approved tariff language to require certification, by means of a declaration by the relevant electric retail regulatory authority that a DRR or ARC, when registering to participate in the EIS Market, is not precluded by the laws and regulations of the relevant electric retail regulatory authority.

It was pointed out that FERC allows participation in the DRR and ARC markets if not precluded by state law. Following discussion, Barry Smitherman recommended that the RSC members take this back to each state commission and present comments and answers as to how the “declaration” could be addressed under each state’s laws. These findings will be reported at the RSC’s July meeting. SPP was instructed to send a letter to the RSC with the proposed wording of the Tariff language.

Future Markets Cost/Benefit Study Report

Ron Moe (Ventyx) presented the Future Markets Cost/Benefit Study report (Study for future Market Design Report and Presentation – Attachment 6). Mr. Moe provided background regarding the current Energy Imbalance Service market and Market Working Group’s proposals for future market design, which includes the Day-Ahead Market (DAM), the Ancillary Service Market (ASM), a combined DAM/ASM or a simplified DAM. Six change cases were presented with the findings for each case. Following the presentation, recommendations were made to:

- Implement combined DAM + ASM 2011 - 2016 (CCIIA) ASAP
- If one market change can be implemented faster than two, stage implementation – preferably DAM first, then ASM
- No benefit to waiting, nor to trying to “time” the start of a new market structure

Roy True (ACES Power Marketing) stated that the MOPC endorsed the “SPP Cost Benefit Study for Future Market” report April 15 and asked that the RSC endorse this study and the recommendation to move forward. Mike Moffet moved to endorse the MOPC’s recommendations regarding SPP’s Future Markets. Jeff Davis seconded the motion, which passed unanimously. Barry Smitherman requested that the RSC receive frequent updates moving forward.

Cost Allocation Working Group (CAWG) Report

Dr. Mike Proctor presented the CAWG report (CAWG Presentation – Attachment 7). Dr. Proctor provided an update on:

- 2008 Unintended Consequences: Dr. Proctor provided a summary of the Base Plan projects and stated that the methodology for Unintended Consequences appears to be doing what was intended. The RSC concurred with the CAWG’s endorsement of the Unintended Consequences review.
- CAWG – 2009 Work Plan: Dr. Proctor reported that the Work Plan is being revised and will be ready
for the July meeting.

- **Balanced Portfolio:** For the Balanced Portfolio Summit, the SPP staff did a full analysis of Portfolio 3. Based on the analysis, it was determined that Portfolio 3-D was superior. Further analysis of the upgrades in Portfolio 3-D resulted in Portfolio 3-E, which found it of more benefit to remove Chesapeake and Reno-Summit from the portfolio. **Dr. Proctor recommended that the RSC approve the Balanced Portfolio 3-E “Adjusted” as unanimously approved by the MOPC on April 15. Paul Suskie moved to approve the recommended portfolio. Barry Smitherman seconded the motion, which passed unanimously.** SPP staff is to complete the final report.

- **EHV Cost Allocation:** The CAWG reached these findings:
  
  - If the future use of the EHV system is proportional to each Transmission Customer’s load ratio share, then the crediting mechanism for a two-part rate is relatively simple to implement.
  - If future use of the EHV system is not proportional to each Transmission Customer’s load ratio share, then the crediting mechanism for a two-part rate becomes more complex.

  The CAWG will be working on a final recommendation regarding a simple or more complex two-part rate.

**Synergistic Project Planning Team Report**

Carl Monroe provided an update on progress of the Synergistic Project Planning Team (SPPT) (SPPT Report – Attachment 8). Mr. Monroe stated that SPP Senior Staff recommended the formation of the Synergistic Planning Project Team (SPPT) to address comprehensive transmission planning and allocation of transmission costs without being encumbered by any limitations. He then introduced the team:

- Paul Suskie, Chairman, Arkansas Public Service Commission
- Barry Smitherman, Chairman, Public Utility Commission of Texas
- Kelly Harrison, Vice President – Transmission Operations and Environmental, Westar Energy
- Ricky Bittle, Vice President - Planning, Rates and Dispatching, Arkansas Electric Cooperative Corp
- Rob Janssen, President and General Manager, Dogwood Energy
- Ric Abel, Managing Director, Prudential Capital Group
- Carl Monroe, Executive Vice President and COO, SPP
- Mark Rossi, Accenture, Facilitation and Administration

The group developed five Planning Principles and made the following recommendation:

**SPP should implement an Integrated Planning Process (IPP) to facilitate the creation of a robust, flexible, and cost-effective transmission network for the SPP footprint.**

- Replace the Reliability Assessment, the Balanced Portfolio, and the EHV studies with an Integrated Planning Process
- More proactive in transmission expansion and commitments to a more forward looking transmission system
- Generation Interconnection and Aggregate Study Process studies would be less burdensome
- Would also reduce the cost allocation methods

The **BOD should develop a plan to monitor the approved IPP facilities to ensure construction.**

- SPP Staff will submit a preferred long range transmission plan and the associated cost benefit results to the BOD for approval after input from stakeholders and the RSC.
- Once approved, the BOD develop the appropriate monitoring plans to ensure the long-term commitment to these approved plans Subject to the cost allocation methodology developed.
Regional State Committee
April 27, 2009

Jeff Davis moved that RSC endorse the principles and concepts as set forth in SPPT report and endorse the recommendations. Barry Smitherman seconded the motion, which passed unanimously.

The IPP scope will include:

- Focus on regional needs not local needs
- Connect known load centers to known or expected large generation sources with a transmission backbone
- 20 year time horizon – 40 year benefits/costs analysis
- Strengthen existing ties to Eastern Interconnection and strong enough to provide the option of connecting to Western grid
- Updated every three years and in service dates/projects reviewed/modified; possible review for reliability every year
- Results from this process - list and need date of transmission expansion projects represents the long range plan for transmission expansion in the SPP region

SPP, in collaboration with the RSC, will engage a consultant to perform a detailed cost/benefit analysis of the proposed long-range transmission plan. This analysis will become part of each IPP three-year cycle.

Vice President Moffet commended the group on its excellent work. Barry Smitherman complimented Carl Monroe, the SPP staff and the stakeholders involved for their work and commitment.

Scheduling of Next Regular Meeting, Special Meetings or Events:
Vice President Moffet noted that the next regularly scheduled meeting is on July 27, 2009 in Kansas City, MO.

With no further business, the meeting was adjourned at 5:50 p.m.

Respectfully Submitted,

Les Dillahunty
# Regional State Committee
## For the Six Months Ending June 30, 2009
### Budget vs. Actual

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<tr>
<td><strong>Net Income (Loss)</strong></td>
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SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE

FINANCIAL STATEMENT

FOR THE YEAR ENDED DECEMBER 31, 2008

with

REPORT OF INDEPENDENT AUDITOR
Report of Independent Auditor

Board of Directors
Southwest Power Pool Regional State Committee

We have audited the accompanying statement of cash receipts and disbursements of Southwest Power Pool Regional State Committee, (a non-profit organization, public-benefit corporation) for the year ended December 31, 2008. This financial statement is the responsibility of the Organization’s management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement of cash receipts and disbursements is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statement of cash receipts and disbursements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the statement of cash receipts and disbursements. We believe that our audit provides a reasonable basis for our opinion.

As described in Note 1, this financial statement has been prepared on the cash receipts and disbursements basis of accounting, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the statement of cash receipts and disbursements referred to above presents fairly, in all material respects, the cash receipts and disbursements of Southwest Power Pool Regional State Committee, for the year ended December 31, 2008, on the basis of accounting described in Note 1.

Patricia Salman & Associates, PLLC
May 11, 2009
SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE

STATEMENT OF CASH RECEIPTS AND DISBURSEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

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<td>CASH – December 31, 2008</td>
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See accompanying notes and accountant’s report
SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE
NOTES TO FINANCIAL STATEMENT

Note 1: Significant Accounting Policies

Nature of Operations

The primary purpose of SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE (the Organization) is to provide collective state regulatory agency input to Southwest Power Pool, Inc. on matters of regional importance related to the development and operation of bulk electric transmission. The Southwest Power Pool Regional State Committee is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, New Mexico, Oklahoma and Texas.

The Organization is incorporated in the State of Arkansas as a public-benefit corporation.

Basis of Presentation

The accompanying financial statement has been prepared on the cash receipts and disbursements basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. As a result, certain revenue and the related assets are recognized when received rather than when earned and certain expenses are recognized when paid rather than when the obligation is incurred.

Income Taxes

The Organization is exempt from income taxes under Section 501(c)(4) of the U.S. Internal Revenue Code, except for taxes pertaining to unrelated business income. No provision for income taxes was required for the period ended December 31, 2008.

Note 2: Related-party transactions

The Organization provides regulatory input to Southwest Power Pool, Inc., which in turn provides administrative financial funding for the Organization. Funding for this reporting period was approximately $819,000.
Motion to Adopt 2008 Financial Statements and Audit Report.

I move that the RSC Board of Directors accept the 2008 Financial Statements of Southwest Power Pool Regional State Committee and the related Report of the Independent Auditor which were both submitted, on May 11, 2009, by Patricia Salman & Associates, PLLC.
Helping our members work together to keep the lights on... today & in the future

Integrated Transmission Plan (ITP)
What is Integrated Transmission Planning?

- **ITP**: New effort to develop proactive regional transmission planning principles
- **Goal**: Build robust grid to meet near- and long-term needs
- **Horizon**: 5, 10, and 20 year
- **Focus**: Regional, integrated with local
- **Update**: Every three years
- **Resulting in**: Comprehensive list of needed projects for SPP region over next 20 years

**What is Integrated Transmission Planning?**

- **Major Objective**: Design transmission backbone to connect load centers to low-cost generation
- **Other Objectives**:
  - Integrate SPP’s east and west regions
  - Make transmission an enabler rather than constraint
  - Strengthen ties to Eastern and Western Interconnections
How ITP is being developed?

- Staff is working with Stakeholders on the ITP process
  - Conducting conference calls to gather Stakeholder input
  - Revising the ITP process based on Stakeholder comments/suggestions

Status of ITP

- A detailed schedule developed to meet aggressive timeline
- Third draft of ITP process submitted to stakeholders for comment
- Study scope document under development by staff
Next Steps

• Meeting every other week
• Next Face to Face meeting August 20, 2009 in Kansas City
• Distribute final ITP process September 24, 2009
Bruce Rew
Vice President, Engineering
501-614-3214
questions@spp.org
What are Priority Projects?

- Congestion Corridors
- Transmission Service Requests
- GI Corridors
- Economic Projects
- West – East Transfer Capability
Priority Project Screening

- Approximately 120 Priority Projects initially
- Screening criteria netted down to 20
- Presented at MOPC and netted down from 20 to 10

Priority Projects Screened List

- Hitchland – Woodward (765kV)
- Spearville – Comanche - Medicine Lodge – Wichita (765kV)
- Comanche/Medicine Lodge – Woodward (765kV)
- Woodward – Elk City – LES - Seminole (765 kV)
- Wichita – Wolf Creek (765 kV)
- Stateline - Potter - Roosevelt – Tuco 345kV
- Valliant – NW Texarkana (345 kV)
- Woodward – Woodring (345 kV)
- Cooper South constraint 345 kV solution
- Riverside Station – Tulsa Power Station (Rebuild) 138kV
765 kV Projects

- 765 kV projects will be modeled
- 765 kV projects will also be evaluated as a 765 kV running at 345 kV
How is the Priority Project list finalized?

- Extensive analysis is performed on these projects
- Projects with a Benefit to Cost analysis that is > 1 will be recommended
Conclusion

- A systematic approach to prioritizing projects
- Includes Stakeholder involvement and review
- Submission to the BOD the finalized list of Priority Projects for approval
- Work with Stakeholders to help facilitate implementation of these projects
Highway/Byway Cost Allocation and Rate Design

RSC Meeting
Mike Proctor
Kansas City, MO
July 27

Outline

A. Highway/Byway Concepts
B. Highway/Byway Cost Allocation
C. Highway/Byway Rate Design
D. Integrating Cost Allocation and Rate Design
E. Upcoming CAWG Schedule
A. Highway/Byway Concept

• Highway/Byway is a conceptual framework by which certain transmission facilities are classified:

**Highway = Regional Transmission Facilities** whose primary function is to transmit power from distant generation to load.

**Byway = Local Facilities** that provide Generators and Loads access to one another and access for both to the Highway.

---

Pictorial Representation of Highway/Byway

Different size boxes for G and L indicate differences in MWs or MWhs within the various zones.

Straight arrow direction denotes flow into the zone when L>G and into the highway when G>L.

Curved arrows indicate loop flows onto the Highway from G serving L in each zone.

Imports and Exports are connected to the highway.
B. Cost Allocation

Cost Allocation requires a contextual framework.

1. The reasons behind the transmission upgrades – The drivers that are being assumed for the need of the upgrades.
2. The benefits resulting from the transmission upgrades – A demonstration that the upgrades are cost-beneficial.

Past Contextual Frameworks

Reliability Upgrades
1. Need – maintain reliable transmission grid
2. Benefits – “keep the lights on”

Transmission Service Upgrades
1. Need – reliable delivery of power from resources to load
2. Benefits – demands for power by load are met

Economic Upgrades
1. Need – reduce congestion on the transmission system
2. Benefits – adjusted production cost savings

Generation Interconnection Upgrades
1. Need – access for generator to the transmission system
2. Benefits – generator is able to sell power in RTO market and load may be able to purchase at lower prices.
Contextual Framework for Highway/Byway Rate Design

**CHANGES:**
- Previously, generation designated as resources for loads were located within or close too the zones of the loads being served.
- With the need for renewable energy sources, the best generation locations are no longer in the zones of the loads being served.

**NEED:** A transmission highway to which the best generation sources can connect and which will deliver the power from those resources throughout the SPP footprint.

**BENEFIT:** From a transmission highway
1. Generation located in the best wind regions of SPP will benefit from having access to loads throughout the SPP.
2. Load within the wind regions will benefit from not having the power from the wind generation being trapped within their zones.
3. Load outside the wind regions will benefit from having ready access to renewable energy sources.

C. Rate Design Objectives

**A. Balance Cost Allocation Among**
- **Beneficiaries and Cost Causers**
  - Some beneficiaries may not be direct cost causers
- **Cost Causers and Free Riders/Late Comers**
  - Cost causers related to accesses and uses that determine why facilities are built, but other access and uses may subsequently benefit from same facilities
- **Transmission Access and Transmission Use**
  - Some benefit from just having access to the highway and others get additional benefits from greater use of highway facilities

**B. Differentiate Regional vs. Local Facilities**
- New EHV (345 kV and above) likely to be primarily regional (highway) facilities
- Lower voltage likely to be primarily local (byway) facilities

**C. Simplify Accounting Processes**
- Challenge is to achieve balance without making the rate design too complex
Proposals Thus Far
(50,000 ft View)

May CAWG Meeting
- Westar/OGE & SPP Staff
  - Division of Facilities between Highway/Byway
  - Load Pays Highway Rate
- Two-Part Highway Rate
  - Load funds the highway construction
  - New Generation pays for access to/use of the highway

• June CAWG Meeting
  - Byway Rate using Existing Cost Allocations
  - Generation Pays Highway Rate

• July CAWG Meeting
  - Injection-Withdrawal / Access-Usage Rate
    - From MISO presentation at July 8 OMS meeting.
  - Possibly other Byway Proposals
    - Example: 100% Byway goes to zonal rates.

D. Integrating Cost Allocation With Rate Design

**Primary Question:** What upgrades should be included in the Highway/Byway rate design?

1. All upgrades required to meet the objectives of delivery of power from wind resources\(^1\) throughout the SPP footprint.
   - Appears to have agreement among the states – can we have a brief discussion to confirm?

2. Other upgrades that don’t contribute to delivery of power from wind resources, but are needed for reasons associated with the contextual framework from the past.
   - Needs further discussion among the states at CAWG?

\(^1\)Note: Delivery of power from wind resources is being used as the primary context, but there may be other drivers for the Highway such as carbon policy, smart grid, price sensitive demand, distributed generation, electric cars, etc.
Proposed ITP Strawman

20-year Planning: “Highways”
345-765 kV

10-year Planning: “Byways”
100 kV+

4-year Planning:
Local Issues
69 kV+

Reliability Upgrades

- Once the Highway (ITP 20 year) is in place, are most of the Reliability upgrades (ITP 10 year) Byway in nature?
  - Will 10 year upgrades include 345 upgrades that are not a part of the Highway (20 year)? Probably not, but we will need to decide what to do if this occurs.

- If most, but perhaps not all, of the ITP 10 year upgrades are lower voltage, is the existing allocation for reliability upgrades (1/3 PS & 2/3 Zonal) still appropriate?
  - Should lower voltage upgrades still receive a 1/3 postage stamp allocation, or should these be 100% zonal (strictly Byway)?
  - Should higher voltage upgrades receive a 100% postage stamp allocation (strictly Highway)?
Aggregate Study Upgrades

• Once the Highway is in place, are most of the Aggregate Study upgrades Byway in nature?
  – Will Aggregate Study upgrades include 345 upgrades that are not a part of the Highway?
• If most, but perhaps not all, of the Aggregate Study upgrades are lower voltage, is the existing allocation of reliability upgrades (1/3 PS & 2/3 Zonal) still appropriate?
  – Should lower voltage upgrades still receive a 1/3 postage stamp allocation, or should these be 100% zonal?
  – Should higher voltage upgrades receive a 100% postage stamp allocation?

Economic Upgrades

• Certain economic upgrades are associated with the improved deliverability of wind to the SPP footprint.
  – Even with basic deliverability upgrades, congestion (higher LMPs at load destinations vs. lower LMPs at wind sources) may exist that can be fixed on a cost-beneficial basis.
    • These kinds of EHV economic upgrades should be included in ITP 20 year plan. This will take significant discussion at ESWG.
• Other economic upgrades may be associated with other forms of congestion.
  – Not clear how these will be evaluated in ITP 20 year plan.
  – Adjusted Production Costs can be applied as one of the benefit metrics, but need the Highway (ITP 20 year plan) as a backdrop to properly determine these benefits.
Generation Interconnections

- The Highway will provide the EHV backbone to which generators can connect.
- There will be additional Byway facilities needed to collect wind generation for connecting to the Highway.
  - Are the costs of these collector systems to be 100% allocated to generators?
  - What if some of these collector systems are 345 kV, but are devoted to generation access?

Cost Allocation and Rate Design for Priority Projects

- Final determination of priority projects is in process.
- However, all EHV projects currently being evaluated appear to fit into the “deliverability” category.
  - 765 kV Overlay Projects that connect to Balanced Portfolio Projects, add Highway Facilities for Wind GI, and add West to East Deliverability to SPP footprint:
    - Spearville – Comanche/Medicine Lodge – Wichita (765kV)
    - Comanche/Medicine Lodge – Woodward (765kV)
    - Woodward – Elk City – LES - Seminole (765 kV)
    - Wichita – Wolf Creek (765 kV) – Primarily Adds W→E Deliverability
    - Hitchland – Woodward (765kV) – Primarily Adds Wind GI
  - 345 kV Projects that relieve trapped generation and add Deliverability to SPP footprint
    - Stateline - Potter - Roosevelt – Tuco 345kV – Relieve Trapped Wind Gen
    - Woodward – Woodring (345 kV) – Added Deliverability
    - Valliant – NW Texarkana (345 kV) – Added Southeast Deliverability
    - Cooper South constraint 345 kV solution – Added Northeast Deliverability
- Biggest task will be ranking these projects to determine which ones to include in projects to be implemented prior to ITP
Cost Allocation and Rate Design for Existing Facilities

• SPP Staff providing rate impacts from moving existing 345 kV facilities to a region-wide postage stamp rate.

• Because of aggressive schedule for new facilities, issue on existing facilities put on back burner.
  – SPP Staff provides brief update on rate impact estimates at meetings.

E. Upcoming CAWG Schedule

• August – Two Meetings with focus on Highway Cost Allocation and Rate Design
• September – Two Meetings with focus on Byway Cost Allocation and Rate Design
• October – One Early Meeting (prior to RSC Meeting) to finalize concepts for Highway/Byway Cost Allocation and Rate Design.
SPP Balanced Portfolio Report
MAINTAINED BY
Engineering/Planning

PUBLISHED: 06/23/2009
CAWG Accepted 06/05/2009
MOPC Accepted 06/12/2009
LATEST REVISION: 06/23/2009
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Executive Summary

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio.

After development and review of the Balanced Portfolio, the CAWG endorsed Portfolio 3E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3E “Adjusted” provides a significant benefit vs. cost to the SPP region, and would require lower transfer requirements necessary to achieve balance. The CAWG along with the Economics Modeling and Methods Task Force (“EMMTF”, now called the Economic Studies Working Group “ESWG”) reviewed and approved the study assumptions used in the analysis of the Balanced Portfolio. These assumptions are listed in the appendix. Portfolio 3E “Adjusted” contains a diverse group of 345kV transmission projects addressing many of the top SPP flowgates. The projects associated with Portfolio 3E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M
- Total E&C Costs: $692M

The CAWG endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15th, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E “Adjusted” pending issuance of the final report, according to SPP Tariff.

Portfolio 3E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58.
The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

<table>
<thead>
<tr>
<th>Year</th>
<th>8.00% Year #</th>
<th>Discount Factor</th>
<th>Annual Benefits</th>
<th>Discounted Benefits</th>
<th>Annual Costs</th>
<th>Discounted Costs</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>1</td>
<td>1.00</td>
<td>$131</td>
<td>$131</td>
<td>$94</td>
<td>$94</td>
<td>1.40</td>
</tr>
<tr>
<td>2013</td>
<td>2</td>
<td>0.93</td>
<td>$144</td>
<td>$133</td>
<td>$94</td>
<td>$87</td>
<td>1.53</td>
</tr>
<tr>
<td>2014</td>
<td>3</td>
<td>0.86</td>
<td>$156</td>
<td>$134</td>
<td>$94</td>
<td>$80</td>
<td>1.66</td>
</tr>
<tr>
<td>2015</td>
<td>4</td>
<td>0.79</td>
<td>$168</td>
<td>$134</td>
<td>$94</td>
<td>$74</td>
<td>1.80</td>
</tr>
<tr>
<td>2016</td>
<td>5</td>
<td>0.74</td>
<td>$181</td>
<td>$133</td>
<td>$94</td>
<td>$69</td>
<td>1.93</td>
</tr>
<tr>
<td>2017</td>
<td>6</td>
<td>0.68</td>
<td>$193</td>
<td>$131</td>
<td>$96</td>
<td>$66</td>
<td>2.01</td>
</tr>
<tr>
<td>2018</td>
<td>7</td>
<td>0.63</td>
<td>$202</td>
<td>$128</td>
<td>$96</td>
<td>$61</td>
<td>2.10</td>
</tr>
<tr>
<td>2019</td>
<td>8</td>
<td>0.58</td>
<td>$212</td>
<td>$123</td>
<td>$96</td>
<td>$56</td>
<td>2.20</td>
</tr>
<tr>
<td>2020</td>
<td>9</td>
<td>0.54</td>
<td>$221</td>
<td>$119</td>
<td>$96</td>
<td>$52</td>
<td>2.29</td>
</tr>
<tr>
<td>2021</td>
<td>10</td>
<td>0.50</td>
<td>$230</td>
<td>$115</td>
<td>$96</td>
<td>$48</td>
<td>2.39</td>
</tr>
<tr>
<td>2022</td>
<td>11</td>
<td>0.46</td>
<td>$239</td>
<td>$111</td>
<td>$96</td>
<td>$45</td>
<td>2.48</td>
</tr>
</tbody>
</table>

Ten Year Totals: Yrs 1-10 7.25 1,837 1,281 950 687 1.87
Per Year Levelized: 7.25 177 95 1.87

The table below outlines the benefits by zones for the 10 year analysis of Portfolio 3E “adjusted”.

<table>
<thead>
<tr>
<th>#</th>
<th>Zone</th>
<th>Portfolio Benefits</th>
<th>Portfolio Costs</th>
<th>Zonal ATRR Transfers Out (Col. 5 Attach H)</th>
<th>Regional Allocation of Zonal ATRR Transfers</th>
<th>Net of Zonal Transfers and Transfer Allocation</th>
<th>Net Benefit</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AEPW</td>
<td>$30.9</td>
<td>$21.3</td>
<td>$0.0</td>
<td>$7.0</td>
<td>$7.0</td>
<td>$2.6</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>EMDE</td>
<td>($0.3)</td>
<td>$2.5</td>
<td>($3.7)</td>
<td>$0.8</td>
<td>($2.8)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>3</td>
<td>GRDA</td>
<td>$0.9</td>
<td>$1.9</td>
<td>($1.6)</td>
<td>$0.6</td>
<td>($1.0)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>4</td>
<td>KCPL</td>
<td>$8.4</td>
<td>$7.3</td>
<td>($1.3)</td>
<td>$2.4</td>
<td>$1.1</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>5</td>
<td>MIDW</td>
<td>$12.8</td>
<td>$0.7</td>
<td>$0.0</td>
<td>$2.4</td>
<td>$0.2</td>
<td>$11.9</td>
<td>14.1</td>
</tr>
<tr>
<td>6</td>
<td>MIPU</td>
<td>($1.3)</td>
<td>$3.8</td>
<td>($6.4)</td>
<td>$1.3</td>
<td>($5.2)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>7</td>
<td>MKCE</td>
<td>$11.8</td>
<td>$1.1</td>
<td>$0.0</td>
<td>$3.3</td>
<td>$0.3</td>
<td>$10.4</td>
<td>8.3</td>
</tr>
<tr>
<td>8</td>
<td>OKGE</td>
<td>$22.6</td>
<td>$13.4</td>
<td>$0.0</td>
<td>$4.4</td>
<td>$4.4</td>
<td>$8.7</td>
<td>1.5</td>
</tr>
<tr>
<td>9</td>
<td>PRM</td>
<td>($0.1)</td>
<td>$1.5</td>
<td>($2.1)</td>
<td>$0.5</td>
<td>($1.6)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>10</td>
<td>SUNC</td>
<td>$3.7</td>
<td>$1.0</td>
<td>$0.0</td>
<td>$0.3</td>
<td>$0.3</td>
<td>$2.3</td>
<td>2.7</td>
</tr>
<tr>
<td>11</td>
<td>SWPS</td>
<td>$56.1</td>
<td>$10.9</td>
<td>$0.0</td>
<td>$3.6</td>
<td>$3.6</td>
<td>$41.5</td>
<td>3.9</td>
</tr>
<tr>
<td>12</td>
<td>WEFA</td>
<td>$8.0</td>
<td>$3.0</td>
<td>$0.0</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$5.0</td>
<td>2.0</td>
</tr>
<tr>
<td>13</td>
<td>WRI</td>
<td>$14.2</td>
<td>$11.0</td>
<td>($0.4)</td>
<td>$3.6</td>
<td>$3.2</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>14</td>
<td>NPPD</td>
<td>$5.5</td>
<td>$7.6</td>
<td>($4.6)</td>
<td>$2.5</td>
<td>($2.1)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>15</td>
<td>OPPD</td>
<td>$2.3</td>
<td>$5.9</td>
<td>($5.6)</td>
<td>$1.9</td>
<td>($3.6)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>16</td>
<td>LES</td>
<td>($3.1)</td>
<td>$1.8</td>
<td>($5.5)</td>
<td>$0.6</td>
<td>($4.9)</td>
<td>$0.0</td>
<td>1.0</td>
</tr>
</tbody>
</table>

Total: $176 $95 -$31 $31 $0 $81 1.86
Portfolio 3-E “Adjusted”
Introduction

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV\* projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e. increasing reliability and lowering reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio†.

Economic Benefits: Adjusted Production Cost

Balanced Portfolio development began with an economic screening of projects identified by stakeholders and SPP staff. After receiving stakeholder feedback, SPP staff compiled a list of economic projects with potential for a positive return.

The first step is to conduct an economic analysis individually on each project considered for the Balanced Portfolio. This process is done by determining the adjusted production cost metric for each project in the screen. Adjusted production cost is defined as:

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

Where:

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

and

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

Production cost for each unit is based on fuel, variable O&M costs, environmental costs and both scheduled and forced outages‡. Adjusted production cost savings account for the economy purchase and sale of power in the modeling footprint. This is important when benefits are being calculated for zones within the SPP as well as in differentiating overall benefits from the portfolio compared to the benefits accruing to SPP members.

To calculate adjustments to production costs due to an economic transmission project, commercial production cost analysis software is used to estimate hourly unit commitment and dispatch of modeled

\* Upgrades of voltages less than 345 kV can be included if needed to deliver the benefits of the extra high voltage (EHV) upgrade, where the cost of the lower voltage facilities does not exceed the cost of the EHV facilities.

† The Tariff allows for deficient zones to be balanced by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual transmission Revenue Requirement from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.

‡ SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages.
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 referred to as the NERC book of flowgates, but can include additional congestion points of interest. The software produces a security constrained economic dispatch and unit commitment.

Adjusted Production Cost was the only benefit metric used in the economic analysis. There are other potential benefits which have not been directly quantified such as lowering reserve margins, reducing losses, and providing environmental benefits. For the purpose of this study, these benefit metrics are not used to determine overall portfolio benefits to the region.
Balanced Portfolio Development

The following table provides a timeline for the development of the various candidate portfolios that were developed by the SPP staff and presented during the regularly scheduled CAWG meetings.

### Table: CAWG Timeline for Balanced Portfolio Development

<table>
<thead>
<tr>
<th>Months/Year</th>
<th>Key Discussions at CAWG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aug-Nov 2007</td>
<td>Screening of Candidate Upgrades for Portfolio</td>
</tr>
<tr>
<td>Feb – Apr 2008</td>
<td>Initial Portfolios 1, 2, 3 and 4</td>
</tr>
<tr>
<td>May 2008</td>
<td>Trapped Generation Issues Discussion Begins</td>
</tr>
<tr>
<td>Jun 2008</td>
<td>Spearville-Knoll-Axtell Added to Portfolios 2 and 3</td>
</tr>
<tr>
<td>Jul 2008</td>
<td>Portfolios 2 and 3 at 2008 Wind Levels and Turk</td>
</tr>
<tr>
<td>Aug 2008</td>
<td>Portfolios 2 and 3: Firm Wind Sensitivities</td>
</tr>
<tr>
<td>Sep 2008</td>
<td>Introduction of Portfolios 3-A and 3-B at 345 and 765 kV costs</td>
</tr>
<tr>
<td>Oct 2008</td>
<td>Portfolio 3 (high wind) and 3-A (current wind) Analysis</td>
</tr>
<tr>
<td>Dec 2008</td>
<td>Portfolio 3-C (modify 3 for high wind)</td>
</tr>
<tr>
<td>Jan 2009</td>
<td>Further Analysis of Portfolios 3-A and 3-C with Nebraska</td>
</tr>
<tr>
<td>Feb 2009</td>
<td>EMMTF Effort initiated to update and refine economic models</td>
</tr>
<tr>
<td>Mar 2009</td>
<td>Final Balanced Portfolio Analysis</td>
</tr>
<tr>
<td>Apr 2009</td>
<td>Balanced Portfolio Summit &amp; Balanced Portfolio Recommendation</td>
</tr>
</tbody>
</table>

**August-November, 2007: Screening of Candidate Upgrades for Portfolios**

Over fifty candidate transmission upgrades for screening were gathered by SPP staff. As agreed by stakeholders, the initial screening analysis was performed based on using only the summer months. A discussion at the CAWG led to additional analyses to include spring-fall months in the calculations of adjusted production cost benefits. The screening analysis was then performed for the summer months and the spring-fall months starting with the spring of March 1, 2012. These estimates of annual benefits were compared to the estimates of engineering and construction (E&C) cost obtained by SPP staff from transmission owners. All projects screened were ranked from highest to lowest according to their benefit-to-cost (B/C) ratios. The SPP staff then used these rankings as a basis for developing a collection of economic upgrades as alternative portfolios.

**February-April, 2008: Initial Four Portfolios**

SPP staff developed four initial portfolios, labeled as Portfolios 1, 2, 3 and 4. Each portfolio had specific criteria for determining which projects to include.

1. Portfolio 1 was a collection of every project from the economic project screening process that had a B/C ratio greater than 1.0.

---

§ Note: Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note in the original analysis was the inclusion of Holcomb 2, Red Rock, Hugo 2 as well as 4,600 MW of generic wind capacity which affected the calculated benefits of certain projects.
2. Portfolio 2 was a subset of Portfolio 1 where projects with similar benefits were narrowed to remove upgrades that would not provide additional benefits.

3. Portfolio 3 was assembled with the intent of ensuring each Zone within the SPP region received a project (projects that crossed multiple zones were considered for each zone), with the most beneficial project chosen in each zone.

4. Portfolio 4 was a collection of projects that would be mutually beneficial, thereby raising the overall benefit of the entire portfolio.

These four portfolios, along with their B/C screening ratios, are shown in the following exhibits.
### Screening of Proposed Economic Upgrades

<table>
<thead>
<tr>
<th>Project</th>
<th>Screening B/C Ratio</th>
<th>P1</th>
<th>P2</th>
<th>P3</th>
<th>P4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tolk - Potter</td>
<td>7.20</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>El Dorado - Longwood</td>
<td>3.36</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>Iatan - Nashua</td>
<td>2.95</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
</tr>
<tr>
<td>SWPS - Battlefield</td>
<td>2.66</td>
<td>+</td>
<td>+</td>
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<td></td>
</tr>
<tr>
<td>Chesapeake XF</td>
<td>2.26</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>Tuco - Tolk - Potter</td>
<td>1.73</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>Fairport - Sibley</td>
<td>1.31</td>
<td>+</td>
<td>+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pittsburg - Ft Smith</td>
<td>1.17</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>Spearville-Mooreland/Woodward-Tuco</td>
<td>1.13</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
</tr>
<tr>
<td>Seminole - Muskogee</td>
<td>1.08</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monett XF</td>
<td>1.04</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Redbud - Horseshoe Lake</td>
<td>1.01</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cleveland - Sooner</td>
<td>0.91</td>
<td>+</td>
<td>+</td>
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<td>+</td>
</tr>
<tr>
<td>Sunnyside XF</td>
<td>0.89</td>
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<td>+</td>
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<td>Northwest XF</td>
<td>0.89</td>
<td>+</td>
<td>+</td>
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<td></td>
</tr>
<tr>
<td>Swissvale - Stilwell</td>
<td>0.67</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Anadarko XF</td>
<td>0.48</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Turk - McNeil</td>
<td>0.46</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mooreland/Woodward - Wichita</td>
<td>0.14</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mooreland/Woodward - Northwest</td>
<td>(0.00)</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(Note: “Tolk – Potter” project is a subset of the “Tuco – Tolk – Potter” project.)

The Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note was the inclusion of Holcomb 2, Red Rock, and Hugo 2 as well as 4,600 MW of generic wind capacity, each of which affected the calculated benefits of certain projects.)
Portfolio 1

Because Portfolio 2 eliminated duplicative upgrades from Portfolio 1, Portfolio 1 was not carried forward as a possible Balanced Portfolio candidate.
Portfolio 2
Portfolio 3
May 2008: Trapped Generation

The CAWG review of the four portfolios, including high wind sensitivities, discovered that the production cost analysis contained significant levels of “trapped generation” (generation that cannot get power out of the host zone due to transmission constraints, significantly impacting the modeling results) related to wind generation. The CAWG initiated the Trapped Generation Task Force (TGTF) to address this issue. The following graph demonstrates effects of trapped generation on portfolio B/C ratios.

Trapped Generation in Economic Models

The TGTF developed guidelines for including generation in the production cost modeling, that were reviewed by the Economic Modeling and Methods Task Force (“EMMTF”, now called the Economic Studies Working Group, “ESWG”). The TGTF decided that the base case models should contain wind levels consistent with current wind in service. These models contained 2,600 MW of nameplate wind, down from 4,600 MW of generic wind included in previous models. Change cases could include additional wind generation, but the TGTF recommended that the additional wind above existing levels must be matched with the transmission upgrades that would be needed to deliver the additional wind to the SPP energy market.

June 2008: Wind and Spearville-Knoll-Axtell (SKA)

SPP staff updated the study models after the TGTF determined that 2,600 MW of wind should be used in the base case. The following table illustrates the resultant B/C ratios for Portfolios 2 through 4, where 2,600 MW of wind is also included in the change case. The adjusted production costs

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This coincides with the amount of wind in the SPP footprint at the end of 2008, as well as the transmission upgrades required to delivery wind with firm service.
shown are changes in adjusted production costs. Therefore, a red parenthetical represents lower adjusted production costs after an upgrade takes place, and it is the estimate of overall benefit.

Preliminary Portfolio Results, post-TGTF (June 26, 2008 CAWG Meeting)

<table>
<thead>
<tr>
<th>Project</th>
<th>Total Adjusted Production Cost</th>
<th>SPP</th>
<th>TIER1</th>
<th>Cost ($M)</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic Portfolio - P2</td>
<td>($90,215,000)</td>
<td>($71,327,000)</td>
<td>($18,889,000)</td>
<td>$ 539</td>
<td>1.13</td>
</tr>
<tr>
<td>Economic Portfolio - P3</td>
<td>($92,307,000)</td>
<td>($72,235,000)</td>
<td>($20,072,000)</td>
<td>$ 515</td>
<td>1.22</td>
</tr>
<tr>
<td>Economic Portfolio - P4</td>
<td>($84,031,000)</td>
<td>($64,709,000)</td>
<td>($19,322,000)</td>
<td>$ 776</td>
<td>0.73</td>
</tr>
</tbody>
</table>

SPP staff conducted a sensitivity analysis of Spearville-Knoll-Axtell on the above portfolios to determine its impact. The Spearville-Knoll-Axtell (SKA) 345kV line is a transmission upgrade for which the Kansas Electric Transmission Authority (KETA) issued a Notice of Intent to Proceed with Construction on July 25, 2007. Additionally, the SPP Board of Directors approved this transmission upgrade for inclusion in the SPP Transmission Expansion Plan (STEP). The SPP Board of Directors requested that all projects of 345 kV and above approved for inclusion in the STEP also be considered candidates in the Balanced Portfolio analyses. It was found in the analyses that the SKA project uniformly raised the B/C ratios of all portfolios, and it appeared that the SKA project should be included for consideration, although a similar analysis was not conducted for other low B/C ratio projects that were not included in the original portfolios. The results are shown in the following table.

Impact of Spearville – Knoll – Axtell

<table>
<thead>
<tr>
<th>Project</th>
<th>Total Adjusted Production Cost</th>
<th>SPP</th>
<th>TIER1</th>
<th>Cost ($M)</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic Portfolio - P2</td>
<td>($90,215,000)</td>
<td>($71,327,000)</td>
<td>($18,889,000)</td>
<td>$ 539</td>
<td>1.13</td>
</tr>
<tr>
<td>Economic Portfolio - P3</td>
<td>($92,307,000)</td>
<td>($72,235,000)</td>
<td>($20,072,000)</td>
<td>$ 515</td>
<td>1.22</td>
</tr>
<tr>
<td>Economic Portfolio - P4</td>
<td>($84,031,000)</td>
<td>($64,709,000)</td>
<td>($19,322,000)</td>
<td>$ 776</td>
<td>0.73</td>
</tr>
</tbody>
</table>

Because Portfolio 4 had a B/C ratio well below one, it was not included in further analyses in the Balanced Portfolio development process.

July 2008: Update Designated Resources

Portfolios 2 and 3 were updated to include the Turk Plant, a Designated Resource planned to be on line by 2012. This change lowered the benefit to cost ratios below one, as shown in the following table. These results were based on the 2008 wind levels in SPP (2,600 MW) but do not include the Spearville-Knoll-Axtell line.

Impact of Updates on Portfolios 2 and 3

<table>
<thead>
<tr>
<th>Project</th>
<th>Total Adjusted Production Cost</th>
<th>SPP</th>
<th>TIER1</th>
<th>Cost ($M)</th>
<th>B/C</th>
<th>SPP B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 2</td>
<td>($39,291,000)</td>
<td>($28,825,000)</td>
<td>($9,466,000)</td>
<td>$ 371</td>
<td>0.70</td>
<td>0.53</td>
</tr>
<tr>
<td>Portfolio 3</td>
<td>($42,033,000)</td>
<td>($32,281,000)</td>
<td>($9,751,000)</td>
<td>$ 347</td>
<td>0.82</td>
<td>0.63</td>
</tr>
</tbody>
</table>

August 2008: Firm Wind Sensitivities

Additional wind sensitivities were conducted for Portfolios 2 and 3 to determine the impact that the amount of wind assumed in the model would have on the benefits. Benefits were estimated for 700 MW of firm wind in the base case and an additional 1,900 MW of market-based wind in the change case. The results showed a significant increase in production cost savings for both Portfolios 2 and 3. The changes in benefits from adding the market-based wind without transmission upgrades were calculated to show the impact of trapped generation. Stakeholders supported the inclusion of all existing wind in the portfolios even though wind without firm transmission service would lower the B/C ratios.
September 2008: Introduction of Portfolio Variations 3-A and 3-B

SPP staff developed two modified portfolios based on Portfolio 3. Adjustments to Portfolio 3 included an upgrade of the Wichita – Reno Co - Summit line and carried through the addition of Spearville-Knoll-Axtell. From this modification of Portfolio 3 two variations were developed and labeled 3-A and 3-B. These portfolios are shown pictorially below.

Since many sections of Portfolio 3 included transmission paths that are also in the proposed EHV Overlay Plan, the CAWG decided to consider these common corridor projects for 765 kV construction in the balanced portfolio. The purple lines in the following maps illustrate this construction.

Portfolio 3, with Spearville – Knoll – Axtell (SKA)
Portfolio 3-B with Wichita – Reno Co - Summit
Modeling assumptions for the dispatch of wind were still an issue in these results where SPP staff used a wind offer price of $20/MWh. Given this caveat, the results showed that both Portfolios 3-A and 3-B had B/C ratios greater than one using 345 kV costs, but were marginal when 765 kV costs were used in the calculations. Portfolio 3-B is a sensitivity of Portfolio 3-A used to test whether or not the Tolk-Potter upgrades would increase the B/C ratio. Since they did, the SPP staff recommended going forward with Portfolio 3-A, as well as subsequent consideration of additional variations of Portfolio 3.

Initial Results for Portfolios 3-A and 3-B

<table>
<thead>
<tr>
<th>Project</th>
<th>Cost ($M)</th>
<th>Proj 10 Year SPP Benefit ($M)</th>
<th>SPP B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>345 kV Construction</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 3-A</td>
<td>$585</td>
<td>$776</td>
<td>1.33</td>
</tr>
<tr>
<td>Portfolio 3-B</td>
<td>$545</td>
<td>$693</td>
<td>1.27</td>
</tr>
<tr>
<td>765 kV Construction</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 3-A</td>
<td>$761</td>
<td>$776</td>
<td>1.02</td>
</tr>
<tr>
<td>Portfolio 3-B</td>
<td>$721</td>
<td>$693</td>
<td>0.96</td>
</tr>
</tbody>
</table>

October 2008: Portfolio 3 (High Wind) and 3-A (Current Wind)

Two different types of analyses were considered for Portfolios 3 and 3-A. Since Portfolio 3 has upgrades similar to those on the western portion of the proposed EHV system, the SPP staff evaluated Portfolio 3 using a high wind (7 GW) scenario with specific wind locations for wind capacity above the current 2008 level of 2.6 GWs. In particular, the B/C ratio was calculated for both 345 kV and 765 kV costs to get a feel for whether or not Portfolio 3 could support a portion of the EHV upgrades in the western SPP region.

High Wind (7 GW) for Portfolio 3

<table>
<thead>
<tr>
<th>Scenario</th>
<th>SPP 10 Yr Benefit</th>
<th>Cost ($M)</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 3 - 345 kV</td>
<td>$1,920,593,438</td>
<td>$292</td>
<td>2.32</td>
</tr>
<tr>
<td>Portfolio 3 - 765 kV</td>
<td>$1,920,593,438</td>
<td>$1,213</td>
<td>1.58</td>
</tr>
</tbody>
</table>

SPP staff used Portfolio 3-A to test the sensitivity of a carbon tax on the estimate of benefits from savings in the adjusted production costs. The results indicated that keeping wind at its current levels and imposing a carbon tax would, as expected, result in a significant decrease in benefits for Portfolio 3-A.

Carbon Tax Sensitivity Results for Portfolio 3-A at Current Wind (2.6 GW)

<table>
<thead>
<tr>
<th>Project</th>
<th>Total Adjusted Production Cost</th>
<th>SPP NON-OATT</th>
<th>SPP OATT</th>
<th>TIER1</th>
<th>Cost ($M)</th>
<th>SPP B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio - P3A - Base</td>
<td>($119,180,000)</td>
<td>($2,454,920)</td>
<td>($111,931,080)</td>
<td>($4,794,000)</td>
<td>$597</td>
<td>1.27</td>
</tr>
<tr>
<td>Portfolio - P3A - $15 Carbon Tax</td>
<td>($360,140,000)</td>
<td>($4,000)</td>
<td>($32,699,000)</td>
<td>($5,543,000)</td>
<td>$597</td>
<td>0.60</td>
</tr>
<tr>
<td>Portfolio - P3A - $40 Carbon Tax</td>
<td>($7,992,000)</td>
<td>($317,000)</td>
<td>($16,926,000)</td>
<td>($1,630,000)</td>
<td>$597</td>
<td>0.19</td>
</tr>
</tbody>
</table>
December 2008: Portfolio 3-C (Modify Portfolio 3)

Portfolio 3-C was developed as a hybrid of Portfolios 3 and 3-A by removing the Tolk - Potter upgrades but adding the Spearville – Knoll - Axtell and Wichita – Reno Co - Summit lines. The following graph pictorially represents Portfolio 3-C.

Portfolio 3-C

It should be noted that by this time SPP staff had resolved a problem with its application of the PROMOD that had resulted in dispatching wind on a small number of days, resulting in what appeared to be a significant “trapped generation” problem. With the resolution of that issue, wind was now being dispatched from specified injection points at $0.05/MWh. Note that this was an offer price for the wind injection into the market since using an offer price of $0/MWh which caused problems in the modeling. The final clearing price of wind is at the marginal zonal market price for each hour, which is significantly higher than the offer price; i.e. wind in the actual production cost models is priced at the marginal zonal market price.
SPP staff used Portfolio 3-C to perform an analysis of an integration plan for the EHV Overlay. For this effort, scenarios were conducted at 3,300 MW of wind injection in 2012, 7,000 MW of wind injection in 2017, and 13,500 MW of wind injection in 2023, with 765 kV transmission being added to the analysis to accommodate the higher wind levels assumed for wind. The following table shows the B/C ratio that would apply had the results of year 2012 been distributed uniformly over a ten-year period and compared to the ten-year cost. In addition, the results are shown using ten years of Annual Transmission Revenue Requirements (ATRR) for the EHV projects contained in the study periods 2012, 2017 and 2023.

<table>
<thead>
<tr>
<th>Portfolio 3-C + EHV Build Out</th>
<th>Total B/C</th>
<th>SPP B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 yr vs E&amp;C (P3-C)</td>
<td>0.74</td>
<td>0.66</td>
</tr>
<tr>
<td>10 yr vs E&amp;C (P3-C+West EHV)</td>
<td>0.79</td>
<td>0.72</td>
</tr>
<tr>
<td>10 yr vs E&amp;C (P-3C+West &amp; Central EHV)</td>
<td>2.43</td>
<td>1.45</td>
</tr>
<tr>
<td>10 yr vs ATRR</td>
<td>0.71</td>
<td>0.49</td>
</tr>
<tr>
<td>Annual B/C (final year)</td>
<td>1.99</td>
<td>1.19</td>
</tr>
</tbody>
</table>

SPP staff reran portfolio 3-A at 3,300 MW of wind to determine the impact of adding 700 MW of market-based wind to the benefits of this portfolio. The following table gives the results for Portfolio 3-A using 765 kV costs.

<table>
<thead>
<tr>
<th>Portfolio 3-A</th>
<th>Benefit - Cost</th>
<th>Total B/C</th>
<th>SPP B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 yr vs E&amp;C</td>
<td></td>
<td>1.46</td>
<td>1.30</td>
</tr>
<tr>
<td>10 yr vs ATRR</td>
<td></td>
<td>1.19</td>
<td>1.06</td>
</tr>
<tr>
<td>Annual B/C (final year)</td>
<td></td>
<td>1.46</td>
<td>1.29</td>
</tr>
</tbody>
</table>

In addition to the adjusted production cost and cost benefit analysis, SPP Staff analyzed the impacts of the portfolio options on basic reliability. Portfolios 3-C and 3-A were considered in this analysis. The results of the total Engineering and Construction (E&C) cost impacts on regional reliability are shown in the table below with 3-C yielding the greatest benefits by reducing reliability needs to a net amount of $31M. More detailed impacts are shown in Appendix D.

<table>
<thead>
<tr>
<th>Project</th>
<th>New Violations</th>
<th>Solved Violations</th>
<th>Net</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 3-A</td>
<td>$4,385,000</td>
<td>$4,004,900</td>
<td>-$380,100</td>
</tr>
<tr>
<td>Portfolio 3-C</td>
<td>$4,585,000</td>
<td>$35,265,250</td>
<td>$30,680,250</td>
</tr>
</tbody>
</table>

**January 2009: Further Analysis of Portfolios 3-A and 3-C With Nebraska**

At the December 2008 CAWG meeting, further analysis of Portfolios 3-A and 3-C was requested, including the addition of the three pricing zones in Nebraska as a result of the Nebraska entities decision to join the Southwest Power Pool. The emphasis on Portfolio 3-A was in regard to the balance of this portfolio when the Nebraska zones were added, and to compare this balance when Portfolio 3-A upgrades are priced at 345 kV versus 765 kV costs. With the addition of Nebraska, the B/C ratio for Portfolio 3-A at 765 kV increased from 1.06 to 1.11, and at 345 kV from 1.27 to 1.50. The higher costs at 765 kV resulted in significant levels of cost transfers needed to balance the portfolio compared to the lower costs at 345 kV.
### Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

<table>
<thead>
<tr>
<th>#</th>
<th>Zone</th>
<th>Benefits $</th>
<th>Costs $</th>
<th>Transfer Allocation $</th>
<th>Transfer Out $</th>
<th>Transfer Net $</th>
<th>Net Benefit $</th>
<th>B/C Ratio</th>
<th>Original B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AEPW</td>
<td>20,880,672</td>
<td>24,939,597</td>
<td>14,640,350</td>
<td>-18,699,275</td>
<td>-4,058,925</td>
<td>0</td>
<td>1.00</td>
<td>0.84</td>
</tr>
<tr>
<td>2</td>
<td>EMDE</td>
<td>5,828,820</td>
<td>2,923,755</td>
<td>1,716,339</td>
<td>0</td>
<td>1,716,339</td>
<td>1,188,726</td>
<td>1.26</td>
<td>1.99</td>
</tr>
<tr>
<td>3</td>
<td>GRDA</td>
<td>1,797,527</td>
<td>2,170,293</td>
<td>1,274,032</td>
<td>-1,646,796</td>
<td>-372,766</td>
<td>0</td>
<td>1.00</td>
<td>0.83</td>
</tr>
<tr>
<td>4</td>
<td>KCPL</td>
<td>8,337,354</td>
<td>8,571,771</td>
<td>5,031,907</td>
<td>-5,266,324</td>
<td>-234,417</td>
<td>0</td>
<td>1.00</td>
<td>0.97</td>
</tr>
<tr>
<td>5</td>
<td>MIDW</td>
<td>1,590,879</td>
<td>798,241</td>
<td>468,593</td>
<td>0</td>
<td>468,593</td>
<td>324,045</td>
<td>1.26</td>
<td>1.99</td>
</tr>
<tr>
<td>6</td>
<td>MIPU</td>
<td>1,598,074</td>
<td>4,491,010</td>
<td>2,636,368</td>
<td>-5,529,303</td>
<td>-2,892,935</td>
<td>0</td>
<td>1.00</td>
<td>0.36</td>
</tr>
<tr>
<td>7</td>
<td>MKEC</td>
<td>5,294,897</td>
<td>1,243,893</td>
<td>730,206</td>
<td>0</td>
<td>730,206</td>
<td>3,320,798</td>
<td>2.68</td>
<td>4.26</td>
</tr>
<tr>
<td>8</td>
<td>OKGE</td>
<td>44,982,968</td>
<td>15,731,003</td>
<td>9,234,607</td>
<td>0</td>
<td>9,234,607</td>
<td>20,017,358</td>
<td>1.80</td>
<td>2.66</td>
</tr>
<tr>
<td>9</td>
<td>SPRM</td>
<td>-29,773</td>
<td>1,719,556</td>
<td>1,009,435</td>
<td>-2,758,764</td>
<td>-1,749,329</td>
<td>0</td>
<td>1.00</td>
<td>-0.02</td>
</tr>
<tr>
<td>10</td>
<td>SUNC</td>
<td>389,069</td>
<td>1,185,151</td>
<td>695,722</td>
<td>-1,491,804</td>
<td>-796,082</td>
<td>0</td>
<td>1.00</td>
<td>0.33</td>
</tr>
<tr>
<td>11</td>
<td>SWPS</td>
<td>43,102,775</td>
<td>12,809,661</td>
<td>7,519,685</td>
<td>0</td>
<td>7,519,685</td>
<td>22,773,429</td>
<td>2.12</td>
<td>3.36</td>
</tr>
<tr>
<td>12</td>
<td>WEFA</td>
<td>11,792,345</td>
<td>3,508,023</td>
<td>2,059,323</td>
<td>0</td>
<td>2,059,323</td>
<td>6,224,999</td>
<td>2.12</td>
<td>3.36</td>
</tr>
<tr>
<td>13</td>
<td>WRI</td>
<td>23,072,688</td>
<td>12,818,241</td>
<td>7,524,722</td>
<td>0</td>
<td>7,524,722</td>
<td>2,729,725</td>
<td>1.13</td>
<td>1.80</td>
</tr>
<tr>
<td>14</td>
<td>NPPD</td>
<td>-608,956</td>
<td>8,996,109</td>
<td>5,222,303</td>
<td>-14,727,368</td>
<td>-9,505,065</td>
<td>0</td>
<td>1.00</td>
<td>-0.07</td>
</tr>
<tr>
<td>15</td>
<td>OPPD</td>
<td>-472,047</td>
<td>6,896,029</td>
<td>4,048,192</td>
<td>-11,416,267</td>
<td>-7,368,075</td>
<td>0</td>
<td>1.00</td>
<td>-0.07</td>
</tr>
<tr>
<td>16</td>
<td>LES</td>
<td>-145,808</td>
<td>2,130,072</td>
<td>1,250,421</td>
<td>-3,526,301</td>
<td>-2,275,880</td>
<td>0</td>
<td>1.00</td>
<td>-0.07</td>
</tr>
</tbody>
</table>

Total: $167,411,485 | $110,832,404 | $65,062,205 | $0 | 56,579,080 | 1.51 | 1.51

All numbers in the above table represent annualized costs for Portfolio 3-A over a ten-year period.

Transfers out of a zone represent the dollars that must be moved from the zonal rates to a region-wide rate in order to achieve balance. Two measures of the degree of balance of a portfolio include: a) the number of zones with positive net benefits after the transfers (in this case: 7 of 16 total zones); and b) the ratio of the transfers out to the costs of the upgrades (in this case: 58.7%).

Additional analysis of the EHV upgrades in Portfolio 3-C were performed with and without Portfolio 3-A to determine whether or not portfolio 3-A added more benefits than costs to a zone that would include parts of the EHV (765 kV) overlay. The results indicated that Portfolio 3-A did add more benefits than costs.

Analysis of Portfolio 3-C showed a B/C ratio of 0.58 using 765kV costs and a ratio of 0.94 using 345 kV costs.

### CAWG Response

Due to the difficulty in balancing a portfolio that includes 765 kV projects, as well the high level of uncertainty concerning the level of wind available to the SPP footprint on the planning horizon, it was decided in February 2009 that the Balanced Portfolio should include only existing wind generation in service or under construction. The CAWG directed SPP staff to update the economic models to reflect these changes and to work through the EMMTF to ensure that the models were vetted through the stakeholder process to ensure that all member data was represented accurately. Additionally, the CAWG requested that the Nebraska modeling parameters be updated to include a better, more expansive representation for utilities beyond Nebraska to better account for the economic interchange of energy beyond the Nebraska zones. Lastly, the CAWG requested that SPP Staff work with the EMMTF to update all costs associated with the construction of portfolio projects. The E&C costs had shown a significant degree of variability throughout the course of the Balanced Portfolio effort to date due to changes in the economic climate, leading the CAWG to seek an accurate, updated account of these associated construction costs from each respective constructing member.
SPP Staff Action Plan

SPP staff, in response to the CAWG, developed an action plan to address the issues raised and also developed a timeline for the completion of the Balanced Portfolio analysis that would conclude with a staff recommendation in April 2009. This action plan detailed how SPP staff would work with the EMMTF to address any outstanding modeling and cost issues for the simulation of the Balanced Portfolio. Additionally, the action plan, corresponding to the suggestion by the CAWG, defined that the analysis would consider only existing wind resources. SPP staff worked with stakeholders to determine the exact levels of existing wind resources on the system in the process of facilitating the modeling refinements through the EMMTF. Also, as the RSC directed, Portfolios 3, 3-A and 3-C were used as a starting point for these additional analyses. Lastly, Portfolio 3-D (shown below) was developed and included in the analysis. This action plan was presented to the CAWG at the end of January 2009.

Portfolio 3-D
March 2009: Final Balanced Portfolio Analysis

Further material pertaining to the Balanced Portfolio was not presented until the March 2009 CAWG meeting. Staff and stakeholders spent the majority of February working through the EMMTF on updating process and refining the engineering models used for the analysis. Additionally, the EMMTF members reviewed their respective output data and provided feedback to SPP staff. The data was checked for the reasonableness of the output results as well as the accuracy of the input into the production cost modeling. These changes were included in the Balanced Portfolio analysis.

During the March 2009 CAWG meeting, the results from the analysis described above were presented. SPP staff started with a screening analysis on Portfolios 3, 3-A, 3-C, and 3-D. This analysis was conducted on the 2012 model and taken as an annual benefit to cost basis. The results are shown in the following exhibits.

1 Year (2012) Screening Results

<table>
<thead>
<tr>
<th>Project</th>
<th>Total APC Benefit ($M)</th>
<th>SPP OATT Benefit ($M)</th>
<th>Tier 1 Benefit ($M)</th>
<th>Annual Total Portfolio Cost ($M)</th>
<th>B/C</th>
<th>Transfer %</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-3</td>
<td>$124</td>
<td>$122</td>
<td>$2.6</td>
<td>$120</td>
<td>1.02</td>
<td>242%</td>
</tr>
<tr>
<td>P-3A</td>
<td>$117</td>
<td>$114</td>
<td>$2.7</td>
<td>$121</td>
<td>0.94</td>
<td>n/a</td>
</tr>
<tr>
<td>P-3C</td>
<td>$159</td>
<td>$159</td>
<td>($0.4)</td>
<td>$166</td>
<td>0.96</td>
<td>n/a</td>
</tr>
<tr>
<td>P-3D</td>
<td>$148</td>
<td>$149</td>
<td>($1.3)</td>
<td>$139</td>
<td>1.08</td>
<td>158%</td>
</tr>
</tbody>
</table>

1 Year (2012): Results

<table>
<thead>
<tr>
<th>Project</th>
<th>B/C</th>
<th>Transfer %</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-3</td>
<td>1.02</td>
<td>242%</td>
</tr>
<tr>
<td>P-3A</td>
<td>0.94</td>
<td>N/A</td>
</tr>
<tr>
<td>P-3C</td>
<td>0.96</td>
<td>N/A</td>
</tr>
<tr>
<td>P-3D</td>
<td>1.08</td>
<td>158%</td>
</tr>
</tbody>
</table>
The Benefit to Cost ratio per zone is shown for the respective portfolios in the following pictures. The B/Cs shown here are before transfers have been conducted to balance the respective portfolios.
Portfolio 3-D had the highest B/C ratio of the four portfolios screened and was selected for further development. In this analysis, each of the individual projects in the Portfolio was removed to determine the impact of the project on the portfolio as a whole. These results are shown in the following table. The table is divided into total Adjusted Production Cost (APC) benefit, benefit for SPP Open Access Transmission Tariff (OATT) members as well as benefits to areas outside the region, shown here as Tier 1 benefits. The transfer percentage (%) shown is the percentage of the total portfolio cost in dollars that must be transferred, following tariff provisions, to balance the respective portfolios shown below. Ideally, the goal is a lower transfer percentage is desirable with a higher B/C.
### Portfolio 3-D Refinement Analysis

<table>
<thead>
<tr>
<th>Project</th>
<th>Total APC Benefit ($M)</th>
<th>SPP Benefit ($M)</th>
<th>Tier 1 Benefit ($M)</th>
<th>Annual Total Portfolio Cost ($M)</th>
<th>B/C</th>
<th>Transfer %</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-3D</td>
<td>$148</td>
<td>$149</td>
<td>($1.3)</td>
<td>$139</td>
<td>1.08</td>
<td>158%</td>
</tr>
<tr>
<td>no WRS (P-3E)</td>
<td>$137</td>
<td>$132</td>
<td>$4.3</td>
<td>$107</td>
<td>1.24</td>
<td>121%</td>
</tr>
<tr>
<td>no SKA</td>
<td>$127</td>
<td>$128</td>
<td>($0.8)</td>
<td>$114</td>
<td>1.12</td>
<td>111%</td>
</tr>
<tr>
<td>no TW</td>
<td>$121</td>
<td>$116</td>
<td>($1.1)</td>
<td>$105</td>
<td>1.10</td>
<td>324%</td>
</tr>
<tr>
<td>no Ches</td>
<td>$146</td>
<td>$148</td>
<td>($1.4)</td>
<td>$136</td>
<td>1.09</td>
<td>156%</td>
</tr>
<tr>
<td>no SM</td>
<td>$116</td>
<td>$122</td>
<td>($6.6)</td>
<td>$115</td>
<td>1.06</td>
<td>183%</td>
</tr>
<tr>
<td>no IN</td>
<td>$143</td>
<td>$142</td>
<td>$0.5</td>
<td>$132</td>
<td>1.08</td>
<td>168%</td>
</tr>
<tr>
<td>no WGard</td>
<td>$152</td>
<td>$149</td>
<td>($1.6)</td>
<td>$138</td>
<td>1.08</td>
<td>160%</td>
</tr>
<tr>
<td>no ADK</td>
<td>$146</td>
<td>$147</td>
<td>($0.9)</td>
<td>$137</td>
<td>1.07</td>
<td>159%</td>
</tr>
<tr>
<td>no SC</td>
<td>$120</td>
<td>$122</td>
<td>($1.2)</td>
<td>$135</td>
<td>0.90</td>
<td>n/a</td>
</tr>
</tbody>
</table>

The projects that were the best candidates for removal from Portfolio 3-D were (1) Wichita – Reno Co. – Summit, (2) Spearville – Knoll – Axtell and (3) the Chesapeake Transformer. SPP staff recommended during the March 2009 CAWG meeting that the Wichita – Reno Co. – Summit line be removed from the portfolio, but also recommended Spearville – Knoll – Axtell and Chesapeake stay in the portfolio to maintain balance. This Portfolio was labeled Portfolio 3-E and is shown in the following map.

**Portfolio 3-E**
Portfolio 3-D and 3-E were selected as the candidates for the full 10-year analysis of portfolios as required by the Tariff. The following tables demonstrate the results of the 10-year analysis, with interpolation between simulated years, 2012, 2017 and 2022. The results are discounted back to present worth, using an 8% discount rate. Levelized annual values were also calculated. The annual cost of the each portfolio is given such that the host utility carrying charge rate is assumed to be used for the construction of the project.

Portfolio 3-D: 10 Year Benefit vs. Costs

<table>
<thead>
<tr>
<th>Year</th>
<th>8.00% Discount Factor</th>
<th>Discounted Annual Benefits</th>
<th>Discounted Annual Costs</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>1.00</td>
<td>$149</td>
<td>$139</td>
<td>1.08</td>
</tr>
<tr>
<td>2013</td>
<td>0.93</td>
<td>$161</td>
<td>$139</td>
<td>1.16</td>
</tr>
<tr>
<td>2014</td>
<td>0.86</td>
<td>$173</td>
<td>$148</td>
<td>1.25</td>
</tr>
<tr>
<td>2015</td>
<td>0.79</td>
<td>$185</td>
<td>$147</td>
<td>1.33</td>
</tr>
<tr>
<td>2016</td>
<td>0.74</td>
<td>$197</td>
<td>$145</td>
<td>1.42</td>
</tr>
<tr>
<td>2017</td>
<td>0.68</td>
<td>$209</td>
<td>$142</td>
<td>1.50</td>
</tr>
<tr>
<td>2018</td>
<td>0.63</td>
<td>$219</td>
<td>$138</td>
<td>1.58</td>
</tr>
<tr>
<td>2019</td>
<td>0.58</td>
<td>$229</td>
<td>$134</td>
<td>1.65</td>
</tr>
<tr>
<td>2020</td>
<td>0.54</td>
<td>$240</td>
<td>$129</td>
<td>1.73</td>
</tr>
<tr>
<td>2021</td>
<td>0.50</td>
<td>$250</td>
<td>$125</td>
<td>1.80</td>
</tr>
<tr>
<td>2022</td>
<td>0.46</td>
<td>$260</td>
<td>$121</td>
<td>1.88</td>
</tr>
</tbody>
</table>

Ten Year Totals: Yrs 1-10

<table>
<thead>
<tr>
<th>Total Benefit</th>
<th>Total Cost</th>
<th>SPP OATT</th>
<th>ATRR</th>
<th>Incremental Cost</th>
<th>Cost (E&amp;C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$1,405</td>
<td>$1,385</td>
<td>$1,004</td>
<td>1.40</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Per Year Levelized

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Benefits</th>
<th>Annual Costs</th>
<th>Discounted Benefits</th>
<th>Discounted Costs</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>$149</td>
<td>$139</td>
<td>$149</td>
<td>$139</td>
<td>1.08</td>
</tr>
<tr>
<td>2013</td>
<td>$161</td>
<td>$139</td>
<td>$149</td>
<td>$139</td>
<td>1.16</td>
</tr>
<tr>
<td>2014</td>
<td>$173</td>
<td>$148</td>
<td>$149</td>
<td>$149</td>
<td>1.25</td>
</tr>
<tr>
<td>2015</td>
<td>$185</td>
<td>$147</td>
<td>$149</td>
<td>$149</td>
<td>1.33</td>
</tr>
<tr>
<td>2016</td>
<td>$197</td>
<td>$145</td>
<td>$149</td>
<td>$149</td>
<td>1.42</td>
</tr>
<tr>
<td>2017</td>
<td>$209</td>
<td>$142</td>
<td>$149</td>
<td>$149</td>
<td>1.50</td>
</tr>
<tr>
<td>2018</td>
<td>$219</td>
<td>$138</td>
<td>$149</td>
<td>$149</td>
<td>1.58</td>
</tr>
<tr>
<td>2019</td>
<td>$229</td>
<td>$134</td>
<td>$149</td>
<td>$149</td>
<td>1.65</td>
</tr>
<tr>
<td>2020</td>
<td>$240</td>
<td>$129</td>
<td>$149</td>
<td>$149</td>
<td>1.73</td>
</tr>
<tr>
<td>2021</td>
<td>$250</td>
<td>$125</td>
<td>$149</td>
<td>$149</td>
<td>1.80</td>
</tr>
<tr>
<td>2022</td>
<td>$260</td>
<td>$121</td>
<td>$149</td>
<td>$149</td>
<td>1.88</td>
</tr>
</tbody>
</table>
A reliability impact analysis was conducted on the portfolio projects to determine the impact of the Balanced Portfolio on the STEP reliability analysis as well as on Tier 1 entities, third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2008 STEP 10 year reliability analysis. The analysis was conducted for the entire collection of portfolio projects considered for the March CAWG meeting. The results are broken into (1) advanced projects, those projects that would be moved up in the reliability timeline due to the Balanced Portfolio; (2) new projects, projects which are now needed that were not identified in the original 10 year reliability planning horizon, but may have been needed beyond that horizon; (3) third party impacts or projects needed on neighboring systems due to the Balanced Portfolio; and (4) deferred projects, projects which are either deferred beyond the planning horizon or mitigated entirely due to the portfolio. A summary of these results is shown in the table below.

Reliability Impact (E&C Dollars)

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Advanced Projects</th>
<th>New Projects</th>
<th>3rd Party Impacts</th>
<th>Deferred Projects</th>
<th>Net Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-3</td>
<td>$ 1.0</td>
<td>$ 3.4</td>
<td>$ 10.2</td>
<td>$ 42.1</td>
<td>$ 27.5</td>
</tr>
<tr>
<td>P-3A</td>
<td>$ 1.0</td>
<td>$ 3.4</td>
<td>$ 10.2</td>
<td>$ 42.1</td>
<td>$ 27.7</td>
</tr>
<tr>
<td>P-3C</td>
<td>$ 1.0</td>
<td>$ 3.4</td>
<td>$ 10.2</td>
<td>$ 42.1</td>
<td>$ 27.5</td>
</tr>
<tr>
<td>P-3D</td>
<td>$ 1.0</td>
<td>$ 19.2</td>
<td>$ 10.2</td>
<td>$ 42.1</td>
<td>$ 11.7</td>
</tr>
<tr>
<td>P-3E</td>
<td>$ 1.0</td>
<td>$ 19.2</td>
<td>$ 10.2</td>
<td>$ 42.1</td>
<td>$ 11.7</td>
</tr>
</tbody>
</table>
April 2009: Balanced Portfolio Summit

The material from the March 2009 CAWG meeting was presented at an open meeting in Dallas, TX, April 1, 2009 as an SPP open stakeholder summit. Stakeholder comments and feedback were collected during this summit and incorporated in the final analysis used in the subsequent recommendation to the CAWG on an April 10th conference call.

Feedback from stakeholders and the CAWG included a request to consider the inclusion of a portion of the Wichita – Reno Co – Summit in the final recommendation, if it was feasible, and to include the project given its benefit and costs. Additionally, Empire District Electric Company staff requested that the Chesapeake transformer project be removed from the Balanced Portfolio recommendation due to the complex nature of the project and the associated third party impacts. Also, the CAWG directed SPP to further refine cost estimates of the projects in the portfolio to include greater granularity in the itemization of project costs associated with the portfolio projects, including but not limited to material costs, right of way requirements, labor, etc. Lastly, SPP staff was directed to determine the appropriate carrying charge rates to be used for each host zone to ensure that consistent values were being applied to all projects so that they could be considered on a consistent and reasonable basis.

April 2009: CAWG Conference Call

The work presented during the April SPP open stakeholder summit was refined to reflect the stakeholder feedback and comments and presented to the CAWG on April 10 via conference call.

The first portfolio change was to consider the removal of the Chesapeake transformer. The results are shown in the following tables.

<table>
<thead>
<tr>
<th>Portfolio 3-E No Ches</th>
<th>Million of Dollars</th>
<th>ATRR</th>
<th>SPP OATT</th>
<th>Incremental Cost</th>
<th>Cost (E&amp;C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year</td>
<td>8.00% Discount Factor</td>
<td>Annual Benefits</td>
<td>Discounted Benefits</td>
<td>Annual Costs</td>
<td>Discounted Costs</td>
</tr>
<tr>
<td>2012</td>
<td>1.00</td>
<td>$132.3</td>
<td>$132</td>
<td>$94</td>
<td>$94</td>
</tr>
<tr>
<td>2013</td>
<td>0.93</td>
<td>$145</td>
<td>$134</td>
<td>$94</td>
<td>$87</td>
</tr>
<tr>
<td>2014</td>
<td>0.86</td>
<td>$158</td>
<td>$135</td>
<td>$94</td>
<td>$80</td>
</tr>
<tr>
<td>2015</td>
<td>0.79</td>
<td>$171</td>
<td>$136</td>
<td>$94</td>
<td>$74</td>
</tr>
<tr>
<td>2016</td>
<td>0.74</td>
<td>$184</td>
<td>$135</td>
<td>$94</td>
<td>$69</td>
</tr>
<tr>
<td>2017</td>
<td>0.68</td>
<td>$181</td>
<td>$123</td>
<td>$94</td>
<td>$64</td>
</tr>
<tr>
<td>2018</td>
<td>0.63</td>
<td>$191</td>
<td>$120</td>
<td>$94</td>
<td>$59</td>
</tr>
<tr>
<td>2019</td>
<td>0.58</td>
<td>$201</td>
<td>$117</td>
<td>$94</td>
<td>$55</td>
</tr>
<tr>
<td>2020</td>
<td>0.54</td>
<td>$210</td>
<td>$114</td>
<td>$94</td>
<td>$51</td>
</tr>
<tr>
<td>2021</td>
<td>0.50</td>
<td>$220</td>
<td>$110</td>
<td>$94</td>
<td>$47</td>
</tr>
<tr>
<td>2022</td>
<td>0.46</td>
<td>$229</td>
<td>$106</td>
<td>$94</td>
<td>$43</td>
</tr>
<tr>
<td>Ten Year Totals</td>
<td></td>
<td>$1,792</td>
<td>$1,257</td>
<td>$937</td>
<td>$679</td>
</tr>
<tr>
<td>Per Year Levelized</td>
<td></td>
<td>$173</td>
<td>$94</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
SPP Balanced Portfolio Report

The transfer analysis for portfolio 3-E without Chesapeake is shown in the following table. The analysis concluded that $32M of transfers were required to balance this portfolio.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Portfolio Benefits</th>
<th>Portfolio Costs</th>
<th>Zonal ATRR Transfers Out (Col. 5 Attach H)</th>
<th>Regional Allocation of Zonal ATRR Transfers</th>
<th>Net of Zonal Transfers and Transfer Allocation</th>
<th>Net Benefit</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AEPW</td>
<td>$30.8</td>
<td>$2.11</td>
<td>$0.9</td>
<td>$7.2</td>
<td>$2.5</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>EMDC</td>
<td>($0.4)</td>
<td>$2.5</td>
<td>($3.7)</td>
<td>$0.8</td>
<td>($2.8)</td>
<td>0.0</td>
</tr>
<tr>
<td>3</td>
<td>GRDA</td>
<td>$0.8</td>
<td>$1.8</td>
<td>($1.6)</td>
<td>$0.6</td>
<td>($1.0)</td>
<td>0.0</td>
</tr>
<tr>
<td>4</td>
<td>KCPL</td>
<td>$8.3</td>
<td>$7.2</td>
<td>($1.4)</td>
<td>$2.5</td>
<td>$1.1</td>
<td>0.0</td>
</tr>
<tr>
<td>5</td>
<td>MDW</td>
<td>$12.8</td>
<td>$0.7</td>
<td>$0.0</td>
<td>$0.2</td>
<td>$0.2</td>
<td>1.1</td>
</tr>
<tr>
<td>6</td>
<td>MPU</td>
<td>($5.0)</td>
<td>$3.8</td>
<td>($6.7)</td>
<td>$1.3</td>
<td>($5.5)</td>
<td>0.0</td>
</tr>
<tr>
<td>7</td>
<td>MKEC</td>
<td>$11.7</td>
<td>$1.4</td>
<td>$0.0</td>
<td>$0.4</td>
<td>$0.4</td>
<td>1.0</td>
</tr>
<tr>
<td>8</td>
<td>OKGE</td>
<td>$26.5</td>
<td>$13.3</td>
<td>$0.0</td>
<td>$4.6</td>
<td>$4.6</td>
<td>0.0</td>
</tr>
<tr>
<td>9</td>
<td>SPRM</td>
<td>($0.3)</td>
<td>$1.5</td>
<td>($2.1)</td>
<td>$0.5</td>
<td>($1.6)</td>
<td>0.0</td>
</tr>
<tr>
<td>10</td>
<td>SUNC</td>
<td>$3.2</td>
<td>$1.0</td>
<td>$0.0</td>
<td>$0.3</td>
<td>$0.3</td>
<td>1.0</td>
</tr>
<tr>
<td>11</td>
<td>SWPS</td>
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<td>$3.7</td>
<td>$3.7</td>
<td>1.0</td>
</tr>
<tr>
<td>12</td>
<td>WPCA</td>
<td>$7.9</td>
<td>$3.0</td>
<td>$0.0</td>
<td>$1.0</td>
<td>$1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>13</td>
<td>WRI</td>
<td>$14.2</td>
<td>$10.8</td>
<td>($0.4)</td>
<td>$3.7</td>
<td>$3.4</td>
<td>1.0</td>
</tr>
<tr>
<td>14</td>
<td>NPPD</td>
<td>$5.5</td>
<td>$7.5</td>
<td>($4.8)</td>
<td>$2.6</td>
<td>($2.6)</td>
<td>0.0</td>
</tr>
<tr>
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<td>OPPD</td>
<td>$2.2</td>
<td>$5.8</td>
<td>($5.7)</td>
<td>$2.0</td>
<td>($5.7)</td>
<td>0.0</td>
</tr>
<tr>
<td>16</td>
<td>LES</td>
<td>($2.5)</td>
<td>$1.8</td>
<td>($5.9)</td>
<td>$0.6</td>
<td>($5.9)</td>
<td>0.0</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>$174</td>
<td>$94</td>
<td>-$32</td>
<td>$32</td>
<td>$0</td>
<td>80</td>
</tr>
</tbody>
</table>

Next, the inclusion of the Reno Co – Summit portion of the Wichita – Reno Co. – Summit Project was considered for inclusion after the removal of the Chesapeake transformer. These results are shown below.

Portfolio 3-E No Ches, with Reno Co. - Summit: 10 Year Benefit vs. Costs

<table>
<thead>
<tr>
<th>Year</th>
<th>8.00% Year #</th>
<th>Discount Factor</th>
<th>Annual Benefits</th>
<th>Discounted Benefits</th>
<th>Annual Costs</th>
<th>Discounted Costs</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>1</td>
<td>1.00</td>
<td>$178</td>
<td>$178</td>
<td>$106</td>
<td>$106</td>
<td>1.69</td>
</tr>
<tr>
<td>2013</td>
<td>2</td>
<td>0.93</td>
<td>$191</td>
<td>$177</td>
<td>$106</td>
<td>$98</td>
<td>1.81</td>
</tr>
<tr>
<td>2014</td>
<td>3</td>
<td>0.86</td>
<td>$204</td>
<td>$175</td>
<td>$106</td>
<td>$90</td>
<td>1.93</td>
</tr>
<tr>
<td>2015</td>
<td>4</td>
<td>0.79</td>
<td>$216</td>
<td>$172</td>
<td>$106</td>
<td>$84</td>
<td>2.05</td>
</tr>
<tr>
<td>2016</td>
<td>5</td>
<td>0.74</td>
<td>$229</td>
<td>$169</td>
<td>$106</td>
<td>$78</td>
<td>2.17</td>
</tr>
<tr>
<td>2017</td>
<td>6</td>
<td>0.68</td>
<td>$242</td>
<td>$165</td>
<td>$106</td>
<td>$72</td>
<td>2.29</td>
</tr>
<tr>
<td>2018</td>
<td>7</td>
<td>0.63</td>
<td>$252</td>
<td>$159</td>
<td>$106</td>
<td>$67</td>
<td>2.38</td>
</tr>
<tr>
<td>2019</td>
<td>8</td>
<td>0.58</td>
<td>$261</td>
<td>$153</td>
<td>$106</td>
<td>$62</td>
<td>2.48</td>
</tr>
<tr>
<td>2020</td>
<td>9</td>
<td>0.54</td>
<td>$271</td>
<td>$146</td>
<td>$106</td>
<td>$57</td>
<td>2.57</td>
</tr>
<tr>
<td>2021</td>
<td>10</td>
<td>0.50</td>
<td>$281</td>
<td>$140</td>
<td>$106</td>
<td>$53</td>
<td>2.66</td>
</tr>
<tr>
<td>2022</td>
<td>11</td>
<td>0.46</td>
<td>$290</td>
<td>$135</td>
<td>$106</td>
<td>$49</td>
<td>2.75</td>
</tr>
</tbody>
</table>

Ten Year Totals: Yrs 1-10 | 7.25 | $2,325 | $1,632 | $1,056 | 765 | 2.13|
Per Year Levelized | $225 | $106 | 2.13|
The transfer analysis for portfolio 3-E without Chesapeake but including with Reno Co. - Summit is shown in the following table. The analysis concluded that $62M of transfers were required to balanced this portfolio.

### Attachment H Transfer Adjustments - Portfolio 3E no Ches with RS - Annualized

<table>
<thead>
<tr>
<th>#</th>
<th>Zone</th>
<th>Portfolio Benefits</th>
<th>Portfolio Costs</th>
<th>Zonal ATRR Transfers Out (Col. 5 Attach H)</th>
<th>Regional Allocation of Zonal ATRR Transfers</th>
<th>Net of Zonal Transfers and Transfer Allocation</th>
<th>Net Benefit</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AEPW</td>
<td>$25.8</td>
<td>$23.7</td>
<td>($11.8)</td>
<td>$13.9</td>
<td>$2.1</td>
<td>0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>2</td>
<td>EMDE</td>
<td>$0.1</td>
<td>$2.1</td>
<td>($3.2)</td>
<td>$1.2</td>
<td>$1.0</td>
<td>0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>3</td>
<td>KCPL</td>
<td>$8.7</td>
<td>$8.2</td>
<td>($4.2)</td>
<td>$4.8</td>
<td>$0.5</td>
<td>0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>4</td>
<td>MIDW</td>
<td>$12.8</td>
<td>$0.8</td>
<td>$0.0</td>
<td>$0.4</td>
<td>$0.4</td>
<td>0.0</td>
<td>1.0</td>
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<tr>
<td>5</td>
<td>MIPU</td>
<td>$15.9</td>
<td>$4.3</td>
<td>($12.6)</td>
<td>$2.5</td>
<td>($8.0)</td>
<td>0.0</td>
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<tr>
<td>6</td>
<td>MKEC</td>
<td>$11.3</td>
<td>$1.2</td>
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<td>$0.7</td>
<td>$0.7</td>
<td>9.4</td>
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<td>7</td>
<td>OKGE</td>
<td>$36.8</td>
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<td>$8.8</td>
<td>13.0</td>
<td>1.5</td>
</tr>
<tr>
<td>8</td>
<td>SPRM</td>
<td>($0.3)</td>
<td>$1.6</td>
<td>($2.9)</td>
<td>$1.0</td>
<td>($1.9)</td>
<td>0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>9</td>
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<td>$3.6</td>
<td>$11.1</td>
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<td>$0.7</td>
<td>$0.7</td>
<td>13.0</td>
<td>3.0</td>
</tr>
<tr>
<td>10</td>
<td>SWPS</td>
<td>$55.9</td>
<td>$12.2</td>
<td>$0.0</td>
<td>$7.1</td>
<td>$7.1</td>
<td>36.6</td>
<td>2.9</td>
</tr>
<tr>
<td>11</td>
<td>WEFA</td>
<td>$11.8</td>
<td>$3.3</td>
<td>$0.0</td>
<td>$2.0</td>
<td>$2.0</td>
<td>6.5</td>
<td>2.2</td>
</tr>
<tr>
<td>12</td>
<td>WRI</td>
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<td>$12.2</td>
<td>$0.0</td>
<td>$7.1</td>
<td>$7.1</td>
<td>40.8</td>
<td>3.1</td>
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<tr>
<td>13</td>
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<td>$5.0</td>
<td>($3.0)</td>
<td>0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>14</td>
<td>WRED</td>
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<td>$5.6</td>
<td>($7.3)</td>
<td>$3.9</td>
<td>($3.4)</td>
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<td>1.0</td>
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<td>15</td>
<td>LES</td>
<td>($3.9)</td>
<td>$2.0</td>
<td>($7.1)</td>
<td>$1.2</td>
<td>($5.9)</td>
<td>0.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>$225</td>
<td>$106</td>
<td>-$62</td>
<td>$66</td>
<td>$0</td>
<td>$126</td>
<td>2.1</td>
</tr>
</tbody>
</table>

An analysis was conducted to determine the impact on total Annual Transmission Revenue Requirement (ATRR) for each zone in the tariff. The results are shown for portfolio 3-E, “3-E no Chesapeake” and “3-E no Chesapeake with Reno Co – Summit”. These results are shown in the following table.

### Total ATRR for Proposed Balanced Portfolios

<table>
<thead>
<tr>
<th>Zone</th>
<th>BP 3E Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR</th>
<th>3E no Ches Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR</th>
<th>BP 3E no Ches w RS Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEPW</td>
<td>$175,484,688</td>
<td>$177,104,393</td>
<td>$174,641,806</td>
</tr>
<tr>
<td>SPRM</td>
<td>$8,934,262</td>
<td>$8,659,884</td>
<td>$8,524,079</td>
</tr>
<tr>
<td>EMDE</td>
<td>$14,660,746</td>
<td>$14,007,997</td>
<td>$14,294,209</td>
</tr>
<tr>
<td>GRDA</td>
<td>$25,891,875</td>
<td>$26,032,862</td>
<td>$25,312,950</td>
</tr>
<tr>
<td>KCPL</td>
<td>$43,660,746</td>
<td>$44,709,872</td>
<td>$45,060,781</td>
</tr>
<tr>
<td>OKGE</td>
<td>$118,952,010</td>
<td>$116,849,771</td>
<td>$122,735,245</td>
</tr>
<tr>
<td>MIDW</td>
<td>$5,277,346</td>
<td>$5,170,672</td>
<td>$5,469,320</td>
</tr>
<tr>
<td>MIPU</td>
<td>$19,618,726</td>
<td>$19,420,118</td>
<td>$15,471,824</td>
</tr>
<tr>
<td>SWPA</td>
<td>$9,431,500</td>
<td>$9,431,500</td>
<td>$9,431,500</td>
</tr>
<tr>
<td>SWPS</td>
<td>$104,700,870</td>
<td>$102,989,030</td>
<td>$107,781,536</td>
</tr>
<tr>
<td>SUNC</td>
<td>$16,092,722</td>
<td>$15,934,343</td>
<td>$16,377,746</td>
</tr>
<tr>
<td>WRED</td>
<td>$5,277,346</td>
<td>$5,170,672</td>
<td>$5,469,320</td>
</tr>
<tr>
<td>LES</td>
<td>$128,845,823</td>
<td>$129,135,340</td>
<td>$134,286,149</td>
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<tr>
<td>MKEC</td>
<td>$7,723,574</td>
<td>$7,557,124</td>
<td>$8,022,505</td>
</tr>
<tr>
<td>NPPD</td>
<td>$8,687,057</td>
<td>$8,718,252</td>
<td>$8,313,564</td>
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<tr>
<td>OPD</td>
<td>$38,645,990</td>
<td>$38,681,265</td>
<td>$39,227,136</td>
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</table>

$805,484,404 $802,641,325 $814,465,382
Portfolio 3-E “Adjusted”

Portfolio 3-E with Reno Co – Summit, without Chesapeake
Recommendation

The CAWG endorsed portfolio 3-E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3-E “Adjusted” provides a significant benefit vs. cost to the SPP region, as well as having lower balance transfer requirements. Portfolio 3-E “Adjusted” contains a comprehensive group of economic projects addressing many of the top constraints in the SPP. The projects associated with portfolio 3-E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M
- Total E&C Costs: $692M

The supporting material for portfolio 3-E was presented to the Markets and Operations Policy Committee (MOPC) in April 2009. The MOPC reviewed and discussed the portfolio options and the impact on the footprint. After discussion, the MOPC endorsed the recommendation for Balanced Portfolio 3-E “Adjusted” pending issuance of the final report, according to the SPP Tariff.

Portfolio 3-E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58. Additionally, it should be noted that the Portfolio could incur a construction cost increase of up to 113%, or more than double the estimated construction cost, and still provide a benefit to cost ratio of 1.0 for the region. Therefore, the Balanced Portfolio could have a total E&C final cost of over $1.4B and still provide benefits greater than costs.

Estimated SPP average customer impact (based on 1,000 kWh/month usage)

<table>
<thead>
<tr>
<th>Existing Zonal ATRR</th>
<th>Base Plan</th>
<th>New Base Plan NTCs</th>
<th>P-3E Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1/3</td>
<td>2/3</td>
<td>1/3</td>
</tr>
<tr>
<td>$688M</td>
<td>$7M</td>
<td>$14M</td>
<td>$33M</td>
</tr>
<tr>
<td>Total: $808M</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Avg. Cost Per Customer Per Month: $7.58

P-3E “Adjusted” Benefit = $1.66

The CAWG and MOPC recommendation of Portfolio 3-E “Adjusted” was presented to the SPP Regional State Committee (RSC) during their April 27, 2009 meeting in Oklahoma City where Portfolio 3-E “Adjusted” was endorsed by the RSC. Staff then presented to the MOPC and RSC the recommended Portfolio during the SPP Board of Directors meeting on April 28th. The SPP Board approved the projects in Balanced Portfolio 3-E “Adjusted” for inclusion in the SPP Transmission Expansion Plan. The SPP Board went on to direct staff to finalize the Balanced Portfolio Report in accordance with the SPP tariff. Furthermore, the Board directed that Notification To Construct letters for the Projects in the Balanced Portfolio be issued once the required Balanced Portfolio Report is
finalized after CAWG review and MOPC approval.
Balanced Portfolio Stakeholder Process
The SPP Regional State Committee (RSC) requested the Cost Allocation Working Group (CAWG) to consider alternative cost allocations for economic upgrades.

Cost Allocation Working Group (CAWG)
The CAWG has been the primary stakeholder group overseeing development of the Balanced Portfolio. The CAWG created the Economic Concepts whitepaper. Many representatives from other SPP stakeholder groups attend the CAWG’s monthly meetings.

Trapped Generation Task Force (TGTF)
This CAWG Task Force determined wind assumptions in the Adjusted Production Cost (APC) models.

Economic Modeling and Methods Task Force (EMMTF)
The EMMTF focused on the planning process and development of additional economic benefit metrics. It initially worked to acquire detailed data on generation units in the model. The EMMTF addressed confidential issues. The EMMTF is currently the Economic Studies Working Group (ESWG)

Regional Tariff Working Group (RTWG)
The RTWG facilitated acquiring FERC approval of Attachment O language for the Balanced Portfolio process.

Markets and Operations Policy Committee (MOPC), Board of Directors (BOD), Regional State Committee (RSC)
These groups will review and approve the Balanced Portfolio.

Planning Summits
Proposed Balanced Portfolios and related concepts were shared at planning summits in May and August.

Posting
Portfolios and associated information are posted on SPP.org:
http://www.spp.org/section.asp?pageID=120
Appendix

Final Benefit to Cost Results for the Balanced Portfolio

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Portfolio 3-E “Adjusted” 10 yr B/C with Reliability Impact

<table>
<thead>
<tr>
<th>Year</th>
<th>8.00% Discount Factor</th>
<th>Annual Benefits</th>
<th>Discounted Benefits</th>
<th>Annual Costs</th>
<th>Discounted Costs</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>1.00</td>
<td>$131</td>
<td>$131</td>
<td>$94</td>
<td>$94</td>
<td>1.40</td>
</tr>
<tr>
<td>2013</td>
<td>0.93</td>
<td>$144</td>
<td>$133</td>
<td>$94</td>
<td>$87</td>
<td>1.53</td>
</tr>
<tr>
<td>2014</td>
<td>0.86</td>
<td>$156</td>
<td>$134</td>
<td>$94</td>
<td>$80</td>
<td>1.66</td>
</tr>
<tr>
<td>2015</td>
<td>0.79</td>
<td>$168</td>
<td>$134</td>
<td>$94</td>
<td>$74</td>
<td>1.80</td>
</tr>
<tr>
<td>2016</td>
<td>0.74</td>
<td>$181</td>
<td>$133</td>
<td>$94</td>
<td>$69</td>
<td>1.93</td>
</tr>
<tr>
<td>2017</td>
<td>0.68</td>
<td>$193</td>
<td>$131</td>
<td>$96</td>
<td>$66</td>
<td>2.01</td>
</tr>
<tr>
<td>2018</td>
<td>0.63</td>
<td>$202</td>
<td>$128</td>
<td>$96</td>
<td>$61</td>
<td>2.10</td>
</tr>
<tr>
<td>2019</td>
<td>0.58</td>
<td>$212</td>
<td>$123</td>
<td>$96</td>
<td>$56</td>
<td>2.20</td>
</tr>
<tr>
<td>2020</td>
<td>0.54</td>
<td>$221</td>
<td>$119</td>
<td>$96</td>
<td>$52</td>
<td>2.29</td>
</tr>
<tr>
<td>2021</td>
<td>0.50</td>
<td>$230</td>
<td>$115</td>
<td>$96</td>
<td>$48</td>
<td>2.39</td>
</tr>
<tr>
<td>2022</td>
<td>0.46</td>
<td>$239</td>
<td>$111</td>
<td>$96</td>
<td>$45</td>
<td>2.48</td>
</tr>
</tbody>
</table>

Ten Year Totals: Yrs 1-10 $1,837 $1,281 $950 $687 1.87
Per Year Levelized $177 $95 1.87

The following three tables break out the benefits from the economic analysis. These tables do not include the reliability benefits. The numbers represent a change between the change and base cases, with the change case including the Balanced Portfolio. A negative number denotes a reduction in cost which is considered a benefit. Likewise a positive number is a cost increase.
### 2012 Balanced Portfolio 3E "Adjusted" Benefits

<table>
<thead>
<tr>
<th>Zone</th>
<th>SumOfChange in Production Cost</th>
<th>SumOfDelta Purchases</th>
<th>SumOfDelta Sales</th>
<th>Adjusted Production Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEPW</td>
<td>$21,285,000</td>
<td>($14,003,000)</td>
<td>$31,439,000</td>
<td>($24,155,000)</td>
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<tr>
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<td>$2,990,000</td>
<td>($2,096,000)</td>
<td>$207,000</td>
<td>$687,000</td>
</tr>
<tr>
<td>GRDA</td>
<td>$72,000</td>
<td>$159,000</td>
<td>$982,000</td>
<td>($751,000)</td>
</tr>
<tr>
<td>KCPL</td>
<td>$4,273,000</td>
<td>($637,000)</td>
<td>$9,994,000</td>
<td>($6,358,000)</td>
</tr>
<tr>
<td>LES</td>
<td>$1,297,000</td>
<td>$1,226,000</td>
<td>$0</td>
<td>$2,523,000</td>
</tr>
<tr>
<td>MIDW</td>
<td>($350,000)</td>
<td>($8,783,000)</td>
<td>$0</td>
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</tr>
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<td>$6,027,000</td>
<td>($3,968,000)</td>
<td>($5,000)</td>
<td>$2,064,000</td>
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<td>($2,015,000)</td>
<td>($925,000)</td>
<td>($8,653,000)</td>
</tr>
<tr>
<td>NPPD</td>
<td>$6,519,000</td>
<td>($28,000)</td>
<td>$11,726,000</td>
<td>($5,235,000)</td>
</tr>
<tr>
<td>OKGE</td>
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<td>$52,737,000</td>
<td>($9,386,000)</td>
<td>($23,664,000)</td>
</tr>
<tr>
<td>OPPD</td>
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<td>$160,000</td>
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<td>($42,000)</td>
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<td>$24,000</td>
</tr>
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<td>($2,096,000)</td>
<td>($5,171,000)</td>
<td>($2,131,000)</td>
</tr>
<tr>
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<td>($70,516,000)</td>
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<td>($519,000)</td>
<td>($38,228,000)</td>
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<td>$4,105,000</td>
<td>($375,000)</td>
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<td>WRI</td>
<td>($5,257,000)</td>
<td>($359,000)</td>
<td>$2,131,000</td>
<td>($7,747,000)</td>
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</table>

### 2017 Balanced Portfolio 3E "Adjusted" Benefits

<table>
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<tr>
<th>Zone</th>
<th>SumOfChange in Production Cost</th>
<th>SumOfDelta Purchases</th>
<th>SumOfDelta Sales</th>
<th>Adjusted Production Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEPW</td>
<td>$55,943,000</td>
<td>($17,738,000)</td>
<td>$71,548,000</td>
<td>($33,344,000)</td>
</tr>
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<td>$3,525,000</td>
<td>($3,272,000)</td>
<td>$100,000</td>
<td>$153,000</td>
</tr>
<tr>
<td>GRDA</td>
<td>($28,000)</td>
<td>$163,000</td>
<td>$889,000</td>
<td>($754,000)</td>
</tr>
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<td>KCPL</td>
<td>$6,229,000</td>
<td>($3,576,000)</td>
<td>$11,897,000</td>
<td>($9,244,000)</td>
</tr>
<tr>
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<td>$2,019,000</td>
<td>$1,970,000</td>
<td>$0</td>
<td>$3,989,000</td>
</tr>
<tr>
<td>MIDW</td>
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<td>$0</td>
<td>($14,810,000)</td>
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<td>($793,000)</td>
<td>($12,767,000)</td>
</tr>
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<td>$10,741,000</td>
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<td>($2,357,000)</td>
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<td>($60,000)</td>
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<td>$292,000</td>
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<tr>
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<td>($2,386,000)</td>
<td>($6,776,000)</td>
<td>($3,185,000)</td>
</tr>
<tr>
<td>SWPS</td>
<td>($80,497,000)</td>
<td>$18,914,000</td>
<td>($924,000)</td>
<td>($60,659,000)</td>
</tr>
<tr>
<td>WEFA</td>
<td>($22,863,000)</td>
<td>$14,785,000</td>
<td>($468,000)</td>
<td>($7,610,000)</td>
</tr>
<tr>
<td>WRI</td>
<td>($14,392,000)</td>
<td>($1,073,000)</td>
<td>$1,674,000</td>
<td>($17,139,000)</td>
</tr>
</tbody>
</table>
The following table demonstrates the benefits, costs and transfers on an annualized basis after the resulting reliability impacts, both the advancement and deferral, are accounted for. The net B/C impact of the reliability projects was an approximate marginal increase of .01 of the total Portfolio.

### Portfolio 3-E “Adjusted” Annualized Benefits, Costs and Transfers, including Reliability Impacts

#### Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

| # | Zone | Portfolio Benefits | Portfolio Costs | Zonal ATRR Transfers Out (Col. 5 Attach H) | Regional Allocation of Zonal ATRR Transfers | Net of Zonal Transfers and Transfer Allocation | Net Benefit | B/C |
|---|---|---|---|---|---|---|---|
| 1 | AEPW | $30.9 | $21.3 | $0.0 | $7.0 | $7.0 | $2.6 | 1.1 |
| 2 | EMDE | ($0.3) | $2.5 | ($3.7) | $0.8 | ($2.8) | $0.0 | 1.0 |
| 3 | GRDA | $0.9 | $1.9 | ($1.6) | $0.6 | ($1.0) | $0.0 | 1.0 |
| 4 | KCPL | $8.4 | $7.3 | ($1.3) | $2.4 | $1.1 | $0.0 | 1.0 |
| 5 | MIDW | $12.8 | $0.7 | $0.0 | $0.2 | $0.2 | $11.9 | 14.1 |
| 6 | MIPU | ($1.3) | $3.8 | ($6.4) | $1.3 | ($5.2) | $0.0 | 1.0 |
| 7 | MKEC | $11.8 | $1.1 | $0.0 | $0.3 | $0.3 | $10.4 | 8.3 |
| 8 | OKGE | $26.6 | $13.4 | $0.0 | $4.4 | $4.4 | $87.7 | 1.5 |
| 9 | SPRM | ($0.1) | $1.5 | ($2.1) | $0.5 | ($1.6) | $0.0 | 1.0 |
| 10 | SUNC | $3.7 | $1.0 | $0.0 | $0.3 | $0.3 | $2.3 | 2.7 |
| 11 | SWPS | $56.1 | $10.9 | $0.0 | $3.6 | $3.6 | $41.5 | 3.9 |
| 12 | WEFA | $8.0 | $3.0 | $0.0 | $1.0 | $1.0 | $4.0 | 2.0 |
| 13 | WRI | $14.2 | $11.0 | ($0.4) | $3.6 | $3.2 | $0.0 | 1.0 |
| 14 | NPPD | $5.5 | $7.6 | ($4.6) | $2.5 | ($2.1) | $0.0 | 1.0 |
| 15 | OPPD | $2.3 | $5.9 | ($3.6) | $1.9 | ($3.6) | $0.0 | 1.0 |
| 16 | LES | ($3.1) | $1.6 | ($5.5) | $0.6 | ($4.9) | $0.0 | 1.0 |
| **Total** | **$176** | **$35** | **-$31** | **$31** | **$0** | **$81** | **1.86** |

The spreadsheet which was used to calculate the transfers in the above table can be found on the [Balanced Portfolio section of the SPP Website](http://www.spp.org/section.asp?pageID=120)††
The table shown below demonstrates the MW-mi impact of the deferred reliability projects. This impact is used to determine who receives the benefit for the deferral of each reliability project from the portfolio.

### Portfolio 3-E – Reliability Impact MW-mi analysis

<table>
<thead>
<tr>
<th>Project Description</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>HUNTSVILLE - HEC 115KV CKT 1 - Rebuild</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CLEARWATER-GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EL RENO- EL RENO SW 69KV CKT 1 - Upgrade</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LONGVIEW-WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetrap</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Date</td>
<td>2015</td>
<td>2016</td>
<td>2017</td>
<td>2018</td>
</tr>
<tr>
<td>AEPW</td>
<td>1.6%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EMDE</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GRDA</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KCPL</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MIDW</td>
<td>46.7%</td>
<td>16.2%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MIPU</td>
<td></td>
<td></td>
<td>100.0%</td>
<td></td>
</tr>
<tr>
<td>MKEC</td>
<td>19.4%</td>
<td>36.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OKGE</td>
<td>1.3%</td>
<td>5.3%</td>
<td>24.7%</td>
<td></td>
</tr>
<tr>
<td>SPRM</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SUNC</td>
<td>9.9%</td>
<td>10.9%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SWPS</td>
<td>4.4%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WEFA</td>
<td></td>
<td></td>
<td>75.3%</td>
<td></td>
</tr>
<tr>
<td>WRI</td>
<td>22.6%</td>
<td>22.1%</td>
<td>100.0%</td>
<td></td>
</tr>
<tr>
<td>NPPD</td>
<td>3.6%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPPD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LES</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Reliability Results

The reliability results for the Portfolio 3E “Adjusted” are shown in the following table. The projects are broken into “deferred” and “mitigated” issues and “new” issues. Additionally, projects are shown for potential third party impacts. Note that a project highlighted in yellow (e.g. EARLSBORO – FIXICO) indicates that the project is merely advanced in time and not an entirely new issue.

<table>
<thead>
<tr>
<th>Issue Type</th>
<th>Project Name</th>
<th>Area</th>
<th>STEP Date</th>
<th>Deferred costs to TO: STEP projects solved by BP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overload</td>
<td>CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild</td>
<td>WERE</td>
<td>16SP</td>
<td>$3,324,375</td>
</tr>
<tr>
<td>Overload</td>
<td>EL RENO - EL RENO SW 69KV CKT 1 - Upgrade</td>
<td>WFEC</td>
<td>17SP</td>
<td>$1,950,000</td>
</tr>
<tr>
<td>Overload</td>
<td>HUNTSVILLE - HEC 115KV CKT 1 - Rebuild</td>
<td>WERE</td>
<td>15SP</td>
<td>$12,487,500</td>
</tr>
<tr>
<td>Overload</td>
<td>HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild</td>
<td>MIDW</td>
<td>15SP</td>
<td>$7,965,000</td>
</tr>
<tr>
<td>Overload</td>
<td>LONGVIEW - WESTERN ELECTRIC 161KV CKT 1 - Replace Wave traps</td>
<td>MIPIU</td>
<td>18SP</td>
<td>$50,000</td>
</tr>
<tr>
<td>Voltages</td>
<td>None</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Cost of potential mitigation for New issues due to implementation of portfolio improvements

<table>
<thead>
<tr>
<th>Description</th>
<th>Project Name</th>
<th>Area</th>
<th>Date of Needed Mitigation</th>
<th>SPP New Issues, Cost</th>
<th>Third Party Issues: Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overloads-SPP</td>
<td>EARLSBORO - FIXICO 69KV CKT 1 - Increase limits (trap, CT ratio)</td>
<td>OKGE</td>
<td>13SP</td>
<td>$150,000</td>
<td></td>
</tr>
<tr>
<td>Overloads-SPP</td>
<td>MED LODGE-PRATT, ST.JOHN- GREATBENDTAP 115 KV LINE REBUILD</td>
<td>MKEC</td>
<td>16SP</td>
<td>$15,840,000</td>
<td></td>
</tr>
<tr>
<td>Overloads-Third Party</td>
<td>PLATTE CITY 161/69KV TRANSFORMER CKT 1 - Replace AECl XFMR</td>
<td>MIPIU-AECI</td>
<td>13WP</td>
<td>$7,500,000</td>
<td></td>
</tr>
<tr>
<td>Voltages</td>
<td>None</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Totals $25,776,875

It should be noted that the third party impact of Platte City 161/69 kV transformer was coordinated with Associated Electric Cooperative, Inc. (AECI) staff. AECI staff did not see the same issue in their analysis.
The graphic shown above represents the top flowgates in the SPP EIS Market as they exist today. Congestion here is shown as an orange highlight. Portfolio projects, shown on the map as bold red highlight lines, relieve or mitigate much of the congestion that exists today. The congestion relief provided by the portfolio is shown as a green circle. Projects in the 10-year STEP plan that provide additional congestion relief are shown in light blue.
The diagram above demonstrates the B/C ratio of the Balanced Portfolio divided by state boundaries. While it should be noted that the portfolio of projects provides broad, regional benefits to all SPP members, this diagram is a good representation of the balance aspect of the portfolio broken into the respective state boundaries. This picture represents the balance of the portfolio after transfers have taken place in order to balance all zones. As can be seen from the diagram, all states have a B/C ratio greater than 1.
## SPP Balanced Portfolio Report

<table>
<thead>
<tr>
<th>Zone</th>
<th>OKGE</th>
<th>ORGE</th>
<th>SPS</th>
<th>KCP</th>
<th>NPPO</th>
<th>ITC</th>
<th>KCPL</th>
<th>ORGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project</td>
<td>Socorro - Cleveland</td>
<td>Seminole - Muskogee</td>
<td>Tuco - Woodward</td>
<td>Tuco - Woodward</td>
<td>Aztec - Nashua</td>
<td>Knoll - Axtell</td>
<td>Spearville - Knoll - Axtell</td>
<td>Swissville - Stilwell Tap</td>
</tr>
</tbody>
</table>

### Costs

<table>
<thead>
<tr>
<th>Cost Type</th>
<th>Total Cost</th>
<th>Cost Per Mile</th>
<th>Miles</th>
<th>Substation Cost</th>
<th>Fixed Charge Rates</th>
<th>Conductor Size</th>
<th>Design</th>
<th>Electrical Capacity</th>
<th>Other</th>
<th>Materials</th>
<th>Structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>$33,530,000</td>
<td>$129,000,000</td>
<td>36</td>
<td>$1,130,000</td>
<td>15.1%</td>
<td>2 Conductor</td>
<td>Single Circuit</td>
<td>2578 Amps</td>
<td>Fiber-optic Shield wire</td>
<td>Steel</td>
<td>Single Pole</td>
</tr>
<tr>
<td>Cost Per Mile</td>
<td>$900,000</td>
<td>$1,250,000</td>
<td>100</td>
<td>$4,000,000</td>
<td>15.1%</td>
<td>Bundle</td>
<td>Single Circuit</td>
<td>1800 MVA at 345kV</td>
<td>Wire</td>
<td>Steel</td>
<td>H-frame</td>
</tr>
<tr>
<td>Miles</td>
<td>$900,000</td>
<td>$900,000</td>
<td>72</td>
<td>$15,000,000</td>
<td>15.1%</td>
<td>Bundle</td>
<td>Single Circuit</td>
<td>2578 Amps</td>
<td>Wire</td>
<td>Steel</td>
<td>H-frame</td>
</tr>
<tr>
<td>Substation Cost</td>
<td>$26,130,000</td>
<td>$18,000,000</td>
<td>178</td>
<td>$6,827,000</td>
<td>12.1%</td>
<td>Bundle</td>
<td>Single Circuit</td>
<td>468 Amps</td>
<td>Wire</td>
<td>Steel</td>
<td>H-frame</td>
</tr>
<tr>
<td>Fixed Charge Rates</td>
<td>$6,287,000</td>
<td>$16,800,000</td>
<td>30</td>
<td>$16,800,000</td>
<td>12.0%</td>
<td>Bundle</td>
<td>Single Circuit</td>
<td>2,324 amps</td>
<td>Wire</td>
<td>Steel</td>
<td>H-frame</td>
</tr>
</tbody>
</table>

### Additional Information

- **SPP Balanced Portfolio Report**: The report provides detailed information on various projects, including their projected in-service dates, total costs, cost per mile, and other relevant details.
- **Zone**: The projects are categorized by their respective zones, such as OKGE, ORGE, SPS, KCP, NPPO, ITC, KCPL, and ORGE.
- **Project Details**: Each project includes the name of the project, the zone it belongs to, and its projected in-service date.
- **Total Cost**: The total cost of each project is provided, including both capital and operational costs.
- **Cost Per Mile**: The cost per mile is calculated to give an idea of the project's cost efficiency.
- **Miles**: The total miles for each project are specified to indicate the project's geographical extent.
- **Substation Cost**: The cost associated with substations is listed, providing insights into the infrastructure investments.
- **Fixed Charge Rates**: The fixed charge rates are provided to reflect the financial implications of the projects.
- **Conductor Size**: The conductor size and type are specified to outline the technical specifications of the project.
- **Design**: The design details, including the type of circuit, electrical capacity, and substation costs, are provided to give a comprehensive view of the project's design.
- **Materials**: The materials used in the project, such as steel or fiber-optic wire, are listed to show the project's construction components.
- **Structure**: The structure details, including the type of pole and the support materials, are provided to illustrate the project's architectural aspects.
- **Transformers and Breakers**: The specifications of transformers and breakers are provided, including their models and capacities.
- **Substations**: The details of substations, including the cost, type, and loadings and overheads, are listed to show the project's power management aspects.
- **Eng Design, Project Management, Permitting**: The costs associated with engineering design, project management, and permitting are detailed to reflect the project's administrative costs.
- **Other Cost Factors and Notes**: Additional cost factors and notes are included to provide further insights into the project's financial and operational aspects.

This report is a comprehensive resource for understanding the financial and technical aspects of the SPP Balanced Portfolio, offering a detailed breakdown of each project's costs and specifications.
Study Assumptions

Fuel Price Assumptions – Fuel price assumptions are taken from EIA forecasts and updated according to member specific data for particular plants. For the purpose of this study, the average gas price is $6.50/MMBtu starting in 2012. The price is then escalated for inflation for the years 2017 and 2022 at the rate of 1.81%.

Environmental Costs - Carbon sensitivities have been conducted, but were not included in the portfolio selection process. A price of $15 and $40 per metric ton was used in these sensitivities. No sensitivity analysis was conducted for higher SO₂ or NOₓ prices. SO₂ and NOₓ were priced at $466.50 and $1742.16 per ton respectively.

Plant Outages – Stakeholders provided outage and maintenance rates to SPP staff through the EMMTF data collection effort. Forced outages were taken as a single draw and locked for the change and the base case. Similarly, maintenance outages were also locked down from a single scheduled pattern. These outage rates were plant specific and provided by each member.

Load Forecast – Load forecasts for the region were provided by each stakeholder in early 2009 for the projected years of 2012, 2017 and 2022 through the EMMTF update effort. These non coincident peak loads for the region were, in aggregate, as follows: 2012 - 43,068MW, 2017 – 47,109 MW, 2022 – 51,530 MW. The zonal shares of the 2012 load submittals were used to allocate the costs on a load ratio share basis.

Resource Forecast – The CAWG and EMMTF determined the criteria for inclusion of new resources into the Balanced Portfolio analysis. It was determined that only plants with firm transmission service and signed agreements or plants that were currently under construction would be included in the analysis. The following units are those which were included as a future resource.

- Turk (618 MW)
- Whelan Energy Center 2 (220 MW)
- Iatan 2 (900 MW)
- Central Plains (99 MW)
- Cloud County (201 MW)
- Flat Ridge (100 MW)
- Red Hills (120 MW)
- Smoky Hills (359 MW)

Hurdle Rates – A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW was used to commit resources across regional boundaries.

Demand Side Management – Interruptible load was modeled as supplied by the LSE’s.

Market Structure – The simulation was conducted considering a single balancing authority and a day-ahead market structure for the SPP region.

Flowgate Assumptions – The NERC Book of Flowgates was used as the source for flowgates used in the analysis.
**DC Tie Profiles** - Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

**Wind Profiles** – Historical wind profiles were used to simulate the wind output at each wind farm.

**Load Profiles** – Load profiles were simulated as supplied by each LSE through the EMMTF effort.

**RMR Requirements** – Each Balancing Authority submitted their respective Reliability Must Run (RMR) requirements to be simulated in the analysis.

**Operating Reserves** – SPP’s current reserve sharing program (as of 2008) was used in the simulation for operating reserves.
Waivers
Helping our members work together
to keep the lights on...
today & in the future

Requested Waivers
Waivers

- Westar Waiver Request 1346837 – Meridian Way
- Westar Waiver Request 1346842 – Flat Ridge Wind
- City of Coffeyville, Kansas Request 1352193 – Coffeyville Waiver II

Westar - Meridian Way

- 96 MW from Meridian Way Wind farm
- 10 year reservation
- Meets requirement of 20% wind DR capacity cap
**Westar - Meridian Way**

- Safe Harbor Base Plan Funding cap: 96MW x $180,000 = $17,280,000
- Direct Assignment = $55,185
- Safe Harbor Cap – Direct Assignment = Base Plan Funding Cap for Request
  - $17,280,000 - $55,185 = $17,224,815 E & C that can be base plan funded
- Allocated E & C Request is $380,166. Direct Assignment is $55,185 so E & C potentially BPF is $324,981 for this request.

**Westar – Flat Ridge Wind**

- 100 MW from Flat Ridge Wind farm
- 10 year Reservation
- Meets requirement of 20% wind DR capacity cap
Westar – Flat Ridge Wind

- Safe Harbor Base Plan Funding cap: 100MW x $180,000 = $18,000,000
- Direct Assignment = $5,519,616
- Safe Harbor Cap – Direct Assignment = Base Plan Funding Cap for Request
  - $18,000,000 - $5,519,616 = $12,480,384 E & C that can be base plan funded
- Allocated E & C Request is $17,158,681. Direct Assignment is $5,519,616 so E & C potentially BPF is $11,639,065 for this request.

Coffeyville Amended Waiver

- Amended waiver covers Coffeyville’s owned facilities that are proposed to be brought under the SPP Tariff.
- Facilities are not presently under the SPP OATT.
- City of Coffeyville is taking steps to become a transmission owning member of SPP and to release its transmission facilities under the SPP OATT and file a formula rate.
Coffeyville Amended Waiver

- 29 year commitment
- The city has provided an estimated E & C cost of $3.1 million for their ownership of upgrades required in 2007-AG3.
- 2007-AG3-AFS-7 Allocated Cost of SPP facilities is $9.3 Million estimated E & C.

Waiver Approval

- Westar – Meridian Way
  - SPP Staff recommended a waiver of Attachment J language for a BPF cap of $17,280,000 less the direct assignment of upgrades as allocated in final study.
  - The CAWG recommended the MOPC approve the WR waiver for such amount to Base Plan fund the project. The MOPC approved the request at their June 12, 2009 meeting

- Westar – Flat Ridge
  - SPP Staff recommends a waiver of Attachment J language for a BPF cap of $18,000,000 less the direct assignment of upgrades as allocated in final study.
  - The CAWG recommended the MOPC approve the WR waiver for such amount to Base Plan fund the project. The MOPC approved the request at their June 12, 2009 meeting.
Waiver Approval

- Coffeyville Amended Waiver

- Coffeyville estimates completion of steps should coincide with a vote at the July 2009 SPP Board of Directors meeting.

- SPP recommended approval of the amended waiver request to fully fund the project including the CMLP-owned direct assignment upgrades at such time that the city owned facilities are brought under the OATT.

- Coffeyville estimates the completion of these tasks should coincide with a vote at the July 2009 SPP Board of Directors meeting.

- The MOPC approved the request at their June 12, 2009 meeting.
Organizational Roster
The following members represent the Southwest Power Pool:

Les Dillahunty, Sr. Vice President, Engineering & Regulatory Policy
Pat Bourne, Director, Transmission Policy
Heather Starnes, Manager, Regulatory Policy
Bruce Rew, Vice President, 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.

SPP recently received the following waiver requests:

1. On March 25, 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 Service Corporation (AEPSC) for a new Designated Resource for 15 MW from the Sleeping Bear wind farm. 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 is eligible for Base Plan funding. SPP’s 120 day deadline under Attachment J is July 23, 2009.

2. On March 27, 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 Western Farmers Electric Cooperative (WFEC) for new Designated Resource for 19 MW from the Edison Mission Buffalo Bear wind farm. WFEC seeks approval of this waiver request based on the following: (i) WFEC has an executed power purchase agreement for an initial term of 25 years, (ii) this request meets or exceeds the qualifying criteria as outlined in Section III.C of Attachment J of the SPP OATT, and (iii) the required upgrades will support the long-term needs for additional wind resources within the Western region of SPP. SPP’s 120 day deadline under Attachment J is July 25, 2009.

3. On March 27, 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 for Westar Energy (WR) for a new Designated Resource for 96 MW from the Meridian Way wind farm. WR seeks approval of this waiver request based on the New Attachment J criteria for wind farms. WR acknowledges that this may expose them to direct assigned transmission costs when changing costs allocation methodologies from the previously filed method to the recently approved RSC methodology. SPP’s 120 day deadline under Attachment J is July 25, 2009.

4. On March 27, 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 Westar Energy (WR) for a new Designated Resource for 100 MW from the Flat Ridge wind farm. WR seeks approval of this waiver request based on the New Attachment J criteria for wind farms. WR acknowledges that this may expose them to direct assigned transmission costs when changing costs allocation methodologies from the
previously filed method to the recently approved RSC methodology. SPP’s 120 day deadline under Attachment J is July 25, 2009.

Analysis:

1. AEPSC requested a waiver based upon Section III.C.2. ii of Attachment J, commitment to a long term contract for the new designated resource. This waiver request was discussed in the April 29th meeting of the Cost Allocation Working Group (CAWG). Based on the discussion held in this meeting, the CAWG will recommend that the Markets and Operations Policy Committee (MOPC) approve the AEPSC waiver for such amount to Base Plan fund the projects involved according to Section III.A of Attachment J.

2. WFEC requested a waiver based upon Section III.C.2. ii of Attachment J, commitment to a long term contract for the new designated resource. This waiver request was discussed in the April 29th meeting of the Cost Allocation Working Group (CAWG). Based on the discussion held in this meeting, the CAWG will recommend that the Markets and Operations Policy Committee (MOPC) approve the WFEC waiver for such amount to Base Plan fund the projects involved according to the Section III.A of Attachment J.

3. WR requested a waiver based upon Section III.C.2. ii of Attachment J, commitment to a long term contract for the new designated resource. This waiver request was discussed in the April 29th meeting of the Cost Allocation Working Group (CAWG). Based on the discussion held in this meeting, the CAWG will recommend that the Markets and Operations Policy Committee (MOPC) approve the WR waiver for such amount to Base Plan fund the projects involved according to Section III.A and of Attachment J.

4. WR requested a waiver based upon Section III.C.2. ii of Attachment J, commitment to a long term contract for the new designated resource. This waiver request was discussed in the April 29th meeting of the Cost Allocation Working Group (CAWG). Based on the discussion held in this meeting, the CAWG will recommend that the Markets and Operations Policy Committee (MOPC) approve the WR waiver for such amount to Base Plan fund the projects involved according to the Section III.A of Attachment J.

Recommendation

The recommendation of SPP Staff is to approve all waivers for such amount to be Base Plan funded in accordance with Attachment J as filed April 24th, 2009.
March 27, 2009

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

Subject: Request for Waiver for OASIS Request #1346837

Dear John:

Westar Energy hereby formally submits a request for a waiver, as provided for in Attachment J, Section III.C of the SPP OATT, pertaining to the transmission upgrade costs associated with SPP OASIS Request #1346837. Westar Energy specifically is requesting that the cost allocation for this request be administered in line with the recently approved RSC methodology for Wind Resources. Westar Energy respectfully requests that this waiver be evaluated on, but not limited, to the following facts and circumstances as allowed pursuant to Attachment J Section III. C. 2. ii & iv of the SPP OATT.

Transmission request #1346837 will facilitate Westar Energy’s request to designate 96 MW of the new Meridian Way Wind Farm, recently installed in north central Kansas, as a Designated Network Resource (DNR) under our Network Integrated Transmission Service (NITS). For informational purposes only, Westar Energy has a 20-year Purchase Power Agreement (PPA) for output from this wind farm. The initial term for this NITS request is 10 years, which exceeds the five (5) year minimum commitment for base plan funding eligibility. Also based on our long-term PPA, we will be taking output from this facility far beyond the initial term of this request.

Based on the latest results of SPP study AG3-2007-AFS-7, this transmission service request has an allocated Engineering and Construction (E&C) cost of $1,616,090 with a potential base plan funding allocation of $1,728,000, based on a 10% nameplate capacity allocation times the safe harbor cost limit. Westar Energy is requesting this waiver even though the estimated E&C costs does not exceed the allocation and technically would not meet the conditions set forth in Attachment J Section B.3. We are concerned that when SPP Criteria, Section 12.1.5.3 (g) is applied retrospectively to determine our actual accredited capacity and therefore the final allocation amount, the E&C costs will exceed the $1,800,000 base plan funding allocation.

Section 12.1.5.3 (g) of the SPP Criteria specifies that the actual accredited capacity for a wind farm will be based on the hourly net power output values that can be expected more than 85% of the time occurring during the top 10% of Westar Energy’s monthly peak load. Westar Energy believes the resulting accredited capacity value for our wind farm will be less than the 10% default value used as a placeholder for determining the initial wind farm funding allocation. Once the actual accreditation value is known for this wind farm, we anticipate the base plan funding allocation will be significantly less than the amount of the projected E&C cost.
Based on the information known today, Westar Energy acknowledges that this waiver request may expose us to direct assigned transmission cost when changing costs allocation methodologies from the previously filed method to the recently approved RSC methodology. However, we prefer the new RSC cost allocation methodology for wind resources. Also this will also provide Westar Energy, assuming our waiver for Transmission Request #1346842 is approved, similar treatment for all three wind farms for which we are the off-taker.

Sincerely,

John P. Olsen
Executive Director,
Bulk Power Marketing
Waiver Request
Westar Energy
Meridian Way Wind

April 2009
Summary of Waiver Request

- Westar reservation 1346837 studied in 2007-AG3
- Westar requesting 96 MW from Meridian Way Wind farm
- Base Plan Funding (BPF) potential calculated in AFS-7: $9.6 \times \$180,000/MW = \$1,728,000$ based on 10% nameplate net dependable capacity
- E & C upgrade allocation in AFS-6 study posting is \$1,616,090.
- E & C upgrade allocation in AFS-7 study posting is \$380,166.
- Upgrades are Fully Base Plan funded in both studies however Westar is concerned that accredited capacity may result in a lower value than 10% of nameplate and a resultant smaller Safe Harbor calculation.
- March 27, 2009 Letter – Westar requests waiver following posting of AFS-6
  - Recommendation to SPP Board of Directors within 120 days per the tariff required not later than July 24, 2009.
  - SPP staff recommended MOPC acknowledge unusual circumstances per Attachment J III. 2
  - Next SPP Board of Directors meeting for action is July 28, 2009

Waiver Request Discussion

- Attachment J, Section C.2.ii - Allows all or part of excess above Safe Harbor Cost Limit to be classified as Base Plan Upgrade Cost, taking into account extent to which commitment to new or changed DR exceeds five-year commitment
  - Westar reservation 1346837 is a 10 year reservation
Attachment J changes to Base Plan funding for Wind Farms

- Attachment J Revisions approved by BOD and SPP filed with FERC requesting an April 25, 2009 effective date
- New language caps BPF for wind DR capacity at 20% of peak load in year of start of service
- Intent is to limit Base Plan Funding for wind resources to 20% of Customer's peak load responsibility due to operational concerns
- Westar request meets this test
- Requested capacity used in Safe Harbor calculations
- Safe Harbor BPF cap would be 96MW x $180,000 = $17,280,000

Attachment J changes to Base Plan funding for Wind Farms

- If upgrade associated with Wind Generation located in same zone as Customer's POD
  - 33% Regional 67% Zonal
- If upgrade associated with Wind Generation located in different zone than Customer's POD
  - 67% Regional 33% Direct assigned to customer
Attachment J changes to Base Plan funding for Wind Farms

• If upgrade associated with Wind Generation located in same zone as Customer’s POD
  • 33% Regional equates to $161,061 RR
  • 67% Zonal equates to $322,122 RR

Attachment J changes to Base Plan funding for Wind Farms

• If upgrade associated with Wind Generation located in different zone than Customer’s POD
  • 67% Regional equates to $291,008 RR
  • 33% Direct Assigned equates to $145,504 RR or $55,185 E & C
Base Plan funding allocation

- Safe Harbor Cap – Direct Assignment = Base Plan Funding Cap for Request
- $17,280,000 - $55,185 = $17,224,815 E & C that can be base plan funded
- The allocated E & C Request for 1346837 is $380,166. Direct Assignment E & C is $55,185 so E & C potentially base plan funded is $324,981 for this request.

SPP Conclusions and Waiver Recommendation

- Conclusion:
  - Original Base plan funding cap was $1,728,000
  - New Base plan funding cap this study $17,224,815
- Recommends a Waiver based on
  - Commitment in Excess of Five Years.
  - Application of Attachment J language for a Base Plan funding cap of $17,280,000 less the direct assignment of upgrades as allocated in final study.
March 27, 2009

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

Subject: Request for Waiver for OASIS Request #1346842

Dear John:

Westar Energy hereby formally submits a request for a waiver, as provided for in Attachment J Section III.C of the SPP OATT, pertaining to the transmission upgrade costs associated with SPP OASIS Request# 1346842. Westar Energy specifically is requesting that the cost allocation for this request be administered in line with the recently approved RSC methodology for Wind Resources. Westar Energy respectfully requests that this waiver be evaluated on, but not limited to, the following facts and circumstances as allowed pursuant to Attachment J Section III. C. 2. ii & iv of the SPP OATT.

Transmission request #1346842 will facilitate Westar Energy’s request to designate 100 MW of the new Flat Ridge Wind Farm, recently installed in south central Kansas, as a Designated Network Resource (DNR) under our Network Integrated Transmission Service (NITS). For informational purposes only, Westar Energy owns 50% of this wind farm facility and has agreed to purchase the other 50% under a 20-year Purchase Power Agreement (PPA). The initial term for this NITS request is 10 years. Westar Energy will be taking output from this facility far beyond the initial 10-year transmission request based on our ownership interest and the long-term PPA.

Based on the latest results of the SPP study AG3-2007-AFS-7, this transmission service request has an allocated Engineering and Construction (E&C) cost of $17,417,601. The current cost allocation method would provide a potential base plan funding allocation of $1,800,000 based on a 10% nameplate capacity allocation times the safe harbor cost limit, exposing us to a direct assigned cost of $15,617,601. Our understanding of the recently approved RSC methodology would reduce the direct assigned cost to $5,679,345 put $379,396 in the Westar Energy zonal rate and the remainder uplifted to the footprint.

Sincerely,

John P. Olsen  
Executive Director,  
Bulk Power Marketing
Waiver Request
Westar Energy
Flat Ridge Wind

April 2009
Summary of Waiver Request

- Westar reservation 1346842 studied in 2007-AG3
- Westar requesting 100 MW from Flat Ridge Wind farm
- Base Plan Funding (BPF) potential calculated in AFS-7: 10 MW x $180,000/MW = $1,800,000 based on 10% nameplate net dependable capacity
- E & C upgrade allocation in AFS-6 study posting is $17,417,601.
- E & C upgrade allocation in AFS-7 study posting is $17,158,681.
- March 27, 2009 Letter – Westar requests waiver following posting of AFS-6 based on new Attachment J language
- Recommendation to SPP Board of Directors within 120 days per the SPP.org
- SPP staff recommended MOPC acknowledge unusual circumstances per Attachment J III. 2
- Next SPP Board of Directors meeting for action is July 28, 2009

Waiver Request Discussion

- Attachment J, Section C.2.ii - Allows all or part of excess above Safe Harbor Cost Limit to be classified as Base Plan Upgrade Cost, taking into account extent to which commitment to new or changed DR exceeds five-year commitment
  - Westar reservation 1346842 is a 10 year reservation
Attachment J changes to Base Plan funding for Wind Farms

- Attachment J Revisions approved by BOD and SPP filed with FERC requesting an April 25, 2009 effective date.
- New language caps BPF for wind DR capacity at 20% of peak load in year of start of service
- Intent is to limit Base Plan Funding for wind resources to 20% of Customer’s peak load responsibility due to operational concerns
- Westar request meets this test
- Requested capacity used in Safe Harbor calculations
- Safe Harbor BPF cap would be 100MW x $180,000 = $18,000,000

Attachment J changes to Base Plan funding for Wind Farms

- If upgrade associated with Wind Generation located in same zone as Customer’s POD
  - 33% Regional 67% Zonal
- If upgrade associated with Wind Generation located in different zone than Customer’s POD
  - 67% Regional 33% Direct assigned to customer
Attachment J changes to Base Plan funding for Wind Farms

• If upgrade associated with Wind Generation located in same zone as Customer’s POD
  • 33% Regional equates to $429,755 RR
  • 67% Zonal equates to $859,511 RR

Attachment J changes to Base Plan funding for Wind Farms

• If upgrade associated with Wind Generation located in different zone than Customer’s POD
  • 67% Regional equates to $26,418,818 RR
  • 33% Direct Assigned equates to $13,209,409 RR or $5,519,616 E & C
Base Plan funding allocation

- Safe Harbor Cap – Direct Assignment = Base Plan Funding Cap for Request
- $18,000,000 - $5,519,616 = $12,480,384 E & C that can be base plan funded
- The allocated E & C Request for 1346842 is $17,158,681. Direct Assignment E & C is $5,519,616 so E & C potentially base plan funded is $11,639,065 for this request.

SPP Conclusions and Waiver Recommendation

- Conclusion:
  - Original Base plan funding cap was $1,800,000
  - New Base plan funding cap this study $12,480,384
- Recommends a Waiver based on
  - Commitment in Excess of Five Years.
  - Application of Attachment J language for a Base Plan funding cap of $18,000,000 less the direct assignment of upgrades as allocated in final study.
May 15, 2009

John E. Mills, P.E.
Manager, Tariff Studies
Southwest Power Pool
415 North McKinley, #140 Plaza West
Little Rock, AR 72205-3020

RE: Base Plan Funding Waiver Amendment Request for Reservation Request #1352193

Dear John,

The City of Coffeyville, Kansas (CMLP) hereby requests to amend its waiver submitted September 11, 2008, regarding transmission network facility upgrade costs in excess of the Safe Harbor Cost Limits of the Southwest Power Pool (SPP) Open Access Transmission Tariff for its existing network transmission reservation request currently under study by the SPP in the 2007-AG3. The purpose of this amended waiver is to request similar treatment of those CMLP facilities that will be placed under the SPP Tariff.

The City of Coffeyville, Kansas is taking the necessary steps to become a transmission owning member of the Southwest Power Pool. It is the intent that the City of Coffeyville, Kansas will release its transmission facilities under the SPP Open Access Transmission Tariff and file a formula rate. The timing of these events is in close correspondence with the writing of this document, and the completion of these tasks should coincide with a vote at the July 2009 SPP Board of Directors meeting.

The City of Coffeyville, Kansas requested, and was granted, the original waiver for a portion of the upgrades required for their service. In their analysis the Southwest Power Pool determined that there were existing nonjurisdictional facilities, transmission lines owned by the City of Coffeyville, Kansas that would require upgrades and could not include those facilities' costs in the base plan funding. These lines are the COFFEYVILLE FARMLAND – DELAWARE 138KV CKT 1 and COFFEYVILLE FARMLAND – SOUTH COFFEYVILLE CITY 138KV CKT 1. This amended waiver seeks to incorporate those previously nonjurisdictional transmission network facilities
into the SPP facilities studies and allow them to be included in engineering and construction costs for the base plan funding calculations.

The Kansas Municipal Energy Agency (KMEA) will be working with the City of Coffeyville Kansas in the implementation of processes required of a Transmission owning member in SPP and have executed an agreement between the two parties. Please feel free to contact KMEA for any issues regarding implementation.

Please don’t hesitate to contact me if you have any questions regarding this base plan funding waiver amendment request, or require additional information. Thank you for your assistance in this matter.

Sincerely,

Bernard A. Cevera
Electric Utility Director
7th and Walnut
P.O. Box 1629
Coffeyville, KS 67337-0949

cc: Robert Pennybaker, AEP
    Kevin Easley, GRDA
    Jeff Morris, City of Coffeyville, Kansas
    Jim Widener, KMEA
Amended Waiver Request –
City of Coffeyville, Kansas

June 2009
Summary of Amended Waiver Request

- The City of Coffeyville, Kansas (CMLP) reservation 1352193 studied in 2007-AG3-AFS-7
- 2007-AG3-AFS-7 Allocated Cost of SPP facilities is $9.3 Million estimated E&C
- September 11, 2008 – CMLP requests original waiver
- October 28, 2008 - Board of Directors Approved 1st Waiver
- May 15, 2009 Letter – CMLP requests amendment of original waiver
- The amended waiver covers Coffeyville's owned facilities that are proposed to be brought under the SPP Tariff

Summary of Amended Waiver Request

- City of Coffeyville owns just over 5 miles of transmission from the city substation to the Kansas/Oklahoma state line
- The city has provided an estimated E&C cost of $3.1 million for their ownership of upgrades required in 2007-AG3
- Recommendation to SPP Board of Directors is due within 120 days per the Tariff or not later than September 12, 2009
  - Next SPP Board of Directors meeting July 28, 2009
Amended Waiver Request Discussion

- Attachment J, Section III.C.2.ii - Allows all or part of excess above the Safe Harbor Cost Limit to be classified as Base Plan Upgrade Costs, taking into account the extent to which commitment to the new or changed DR exceeds the five-year commitment

- These facilities for which a waiver is being sought are not presently under the SPP OATT

- The city is taking the necessary steps to become a transmission owning member of the Southwest Power Pool and to release its transmission facilities under the SPP Open Access Transmission Tariff and file a formula rate.

- Coffeyville estimates the completion of these tasks should coincide with a vote at the July 2009 SPP Board of directors meeting.

SPP Amended Waiver Recommendation

- SPP recommends approval of the amended waiver request to fully fund the project including the CMLP-owned direct assignment upgrades at such time that the city owned facilities are brought under the OATT.

  - Based on the commitment in excess of five years (29 years)
  - Based on all assigned facilities being SPP jurisdictional
Implications of Federal Transmission Planning and Siting on the Southwest Power Pool (“SPP”) Transmission Expansion Planning (“STEP”) Process

I. Introduction

The siting of transmission facilities within the SPP region is generally a matter that lies within the jurisdiction and authority of the states and their regulatory commissions. While certain limited “backstop” transmission siting authority was granted to the Federal Energy Regulatory Commission (“FERC”) by the Energy Policy Act of 2005, it only applies where the Secretary of the Department of Energy (“Secretary” or “Department of Energy”) has designated a “national interest electric transmission corridor.” No area within the SPP footprint currently has such a designation.

While SPP, through the STEP process, has the authority to direct transmission owners to construct facilities necessary to provide transmission service to customers, ensure reliability of the transmission system, or take advantage of economic opportunities, the states, through their certification and siting processes, play a critical role in determining where and how transmission expansion will occur. State certification and siting laws continue to have full force and effect. Moreover, SPP’s transmission planning process, outlined in Attachment O of the SPP Tariff, envisions participation by state regulatory commissions throughout the planning process.

To understand the role of state and federal siting laws in this process, this paper first provides a broad overview of the transmission siting process at the state level, then discusses FERC’s currently limited “backstop” siting authority under EPAct 2005, and concludes with a discussion of legislation currently under active consideration by the U.S. Congress that may modify federal transmission planning and siting authorities and thus impact the SPP planning process.

II. Summary of Conclusions

In reviewing state and federal transmission siting requirements, SPP reviewed the following issues, concerns, and policies:

Question: What is the role of state siting in the SPP planning process?

SPP Conclusion: States retain primary authority for approving the siting of transmission facilities, even following the passage of EPAct 2005. Because state siting is critical to bringing SPP transmission planning and construction plans to fruition, coordination with state regulatory authorities will continue to be a significant aspect of SPP’s transmission planning efforts.

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2 There is significant Congressional activity underway regarding energy legislation as this paper is being written. The discussion of pending legislation is accurate as of July 17, 2009.
Question: What is the role of federal siting in the SPP planning process?

SPP Conclusion: Currently, federal transmission siting authority does not impact SPP because no area within the SPP region has been designated a “national interest electric transmission corridor” by the Secretary of the Department of Energy. To the extent that the Secretary designates an area within the SPP region to be a national interest corridor, federal transmission siting authority could only arise where a state fails to act on an application for the siting of a transmission project within one year of submission of the application (except possibly in Oklahoma or Louisiana where the relevant state utility commissions currently do not exert authority over transmission siting).

Question: What are the procedures for federal “backstop” transmission siting authority?

SPP Conclusion: Federal “backstop” transmission siting authority arises in designated “national interest electric transmission corridors” only if a state that has authority to act on an application for the siting of a transmission facility has failed to act on the application within one year after its submission. In considering an application, FERC considers any findings of state regulators, coordinates environmental reviews with the affected state(s), and permits state regulator involvement throughout the pre-filing and application processes. FERC also coordinates system analyses with Regional Transmission Organizations (“RTO”) and Independent System Operators (“ISO”) and affords “due weight” to the findings and conclusions of RTOs and ISOs.

Question: How might pending federal legislation impact transmission siting in SPP?

SPP Conclusion: Current legislation pending before the U.S. Congress modifies the transmission siting authority granted to FERC by EPAct 2005. The U.S. Senate is considering legislation that would extend FERC siting authority throughout the United States when a state fails to act or denies an application. This siting authority no longer would be limited to national interest electric transmission corridors, although it would apply only to Extra High-Voltage (“EHV”) facilities (defined as facilities operating at or 345-kV for alternating current or at or above 300-kV for direct current). The Senate legislation also would expressly allow FERC to allocate costs of EHV facilities broadly across a region, but only to customers who derive “measurable economic and reliability benefits” from a transmission project. The U.S. House of Representatives has also passed legislation that would provide
FERC with siting authority, but only in the Western Interconnection, if a state fails to act or denies a siting application. It is difficult to predict the outcome of these legislative efforts at this time.

III. State Siting Laws and Procedures in the SPP Region

The SPP Membership Agreement and Open Access Transmission Tariff (“OATT” or “SPP Tariff”) explicitly recognize the role of the states in transmission siting. Under the Membership Agreement, Transmission Owners are required to:

use due diligence to construct transmission facilities as directed by SPP in accordance with the OATT and this Agreement, subject to such siting, permitting, and environmental constraints as may be imposed by state, local and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals, including, as necessary, the Member’s governing board where it serves as that authority.3

Thus, state siting proceedings are a critical part of bringing the results of the SPP planning process to fruition. Nothing in the SPP Membership Agreement or Tariff preempts the applicability of state siting laws. To the contrary, the governing SPP documents explicitly recognize the states’ roles.

Generally, but with the notable exceptions of Oklahoma and Louisiana, entities planning to construct new transmission facilities in the SPP region must apply for and obtain a certificate of public convenience and necessity in the state(s) where the facility will be located. While each state has distinct application requirements and unique criteria for granting a certificate of convenience and necessity, some common attributes exist. Most states require an applicant to submit information regarding the proposed route or location of the transmission facility, and many require information regarding the cost of construction, economic and environmental impacts, impact on other utility services, and impact on landowners. Two states (Arkansas and Kansas) also provide for assessment of the impact and benefits to other states from the proposed transmission project (for Arkansas, this arises specifically in the context of a project proposed in a national interest electric transmission corridor, as discussed in more detail in the attached Appendix). State laws vary regarding whether and to what extent an extension or upgrade to an existing facility requires a new certificate of convenience and necessity.

Hearing requirements also vary, but most states will conduct an evidentiary hearing prior to issuing a certificate of convenience and necessity for a proposed transmission project, although some state commissions are permitted to waive hearing requirements in certain circumstances.4 Most state statutes prescribe the time limit for the state commission to hold a hearing and issue an order, which vary from as short as two months from the submission of an

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3 Southwest Power Pool, Inc., Membership Agreement, Original Volume No. 3 § 3.3(a) (emphasis added).

4 It also is the custom in certain states, such as Kansas and Oklahoma, to hold community meetings along the proposed route of a transmission line prior to official hearings regarding proposed transmission projects.
application to the issuance of an order, up to one year or longer. State utility commissions in most of the states in the SPP region are required to act on an application for a certificate of convenience and necessity within one year, which, as discussed below, is critical to determining whether FERC “backstop” siting authority may be triggered. FERC may only act on a siting application under its “backstop” authority if a state commission has failed to act within one year from the time the application was submitted to the state commission.

The SPP planning process and each state’s exercise of its jurisdiction over siting work side by side, as both are crucial to the development of the necessary regional transmission system. State proceedings may occur at any time in the process, at the discretion of state regulatory authorities, but often will follow SPP’s determination of the need for a particular new facility.

A more detailed state-by-state summary of transmission siting approval procedures is attached as Appendix 1.

IV. Existing Federal Transmission Siting Laws and Regulations

EPAct 2005, enacted on August 8, 2005, grants authority to FERC to approve the siting and construction of electric transmission facilities located in “national electric transmission corridors,” as established by the U.S. Department of Energy, if states “withhold approval” of a project for longer than one year or are not authorized to consider the project or certain aspects of the project. States can avoid the exercise of federal transmission siting authority by acting on a siting application within one year of its submission or by creating “interstate compacts” for the siting of electric transmission facilities.

To date, the Department of Energy has not designated any area within the SPP footprint as a national interest electric transmission corridor; however, the Department of Energy is required to publish an updated congestion study in 2009 that may designate new national interest electric transmission corridors. Although not currently a national interest corridor, the Department of Energy’s 2006 congestion study named portions of Kansas and Oklahoma as a “Conditional Congestion Area” where future congestion would result if large amounts of new generation were to be developed without simultaneous development of associated transmission capacity.

A. National Corridor Projects

EPAct 2005 required the Secretary of Energy to conduct a study of electric transmission congestion within one year of enactment of EPAct 2005 and every three years thereafter.5 In the report, the Secretary is authorized to designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a “national interest electric transmission corridor.”6 The Secretary is required to consult with affected

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6 In determining whether to designate a national interest electric transmission corridor, the Secretary may consider whether: (a) the economic vitality and development of the corridor or the end markets served by the corridor may be constrained by lack of adequate or reasonably priced electricity; (b) economic growth in the
states, FERC, transmission organizations approved by FERC, and electric reliability organizations and regional entities established under electric reliability organizations. It is only this designation of a “national interest electric transmission corridor” by the Secretary that triggers FERC “backstop” siting authority – EPAct 2005 did not grant FERC any siting authority for projects outside of designated national interest electric transmission corridors.

The Department of Energy issued its initial congestion study for comment on August 6, 2006. The congestion study identified and classified the most significant congestion areas in the country. Two “Critical Congestion areas” (i.e., areas where the current and/or projected effects of congestion are especially broad and severe) were identified: the Atlantic coastal area from metropolitan New York through northern Virginia (the Mid-Atlantic Critical Congestion Area); and southern California (the Southern California Critical Congestion Area). Four “Congestion Areas of Concern” (i.e., areas where a large-scale congestion problem exists or may be emerging but more information and analysis were needed to determine the magnitude of the problem) were identified: New England; the Phoenix-Tucson area; the San Francisco Bay area; and the Seattle-Portland area. A number of “Conditional Congestion Areas” (i.e., areas where future congestion would result if large amounts of new generation were to be developed without simultaneous development of associated transmission capacity) were identified, including: Montana-Wyoming; Dakotas-Minnesota; Kansas-Oklahoma; Illinois, Indiana and upper Appalachia; and the Southeast.

On October 5, 2007, the Department of Energy issued an order designating two “national interest electric transmission corridors” including: (1) the Mid-Atlantic Area National Corridor, consisting of all or part of Delaware, Ohio, Maryland, New Jersey, New York, Pennsylvania, Virginia, West Virginia, and Washington, D.C.; and (2) the Southwest Area National Corridor, comprising southern California and western Arizona. At present, these are the only areas where FERC has “backstop” authority to approve siting of transmission projects.

The Department of Energy’s next Congestion Study is due to be released in August 2009.

corridor or in the end markets served by the corridor may be jeopardized by reliance on limited sources of energy and a diversification of supply is warranted; (c) the energy independence of the United States would be served by the designation; (d) the designation would be in the interest of national energy policy; and (e) the designation would enhance national defense and homeland security. Id. §§ 824p(a)(4)(A)–(E).

Id. § 824p(a)(1).

Id. § 824p(h)(9)(B).


Id. at 57,025–026.
B. Federal “Backstop” Siting

EPAct 2005 granted FERC authority to issue permits for construction or modification of electric transmission facilities located in a national interest electric transmission corridor designated by the Secretary of Energy.\(^\text{12}\) However, FERC is only authorized to act on a transmission siting application where FERC determines that:

1. A state in which the transmission facilities are to be constructed or modified does not have authority to: (a) approve the siting of the facilities;\(^\text{13}\) or (b) consider the interstate benefits expected to be achieved by the proposed construction or modification of transmission facilities in the state;

2. the applicant for a permit is a transmitting utility under the Federal Power Act but does not qualify to apply for a permit or siting approval for the proposed project in a state because the applicant does not serve end-use customers in the state; or

3. a state commission or other entity that has authority to approve the siting of facilities has: (a) withheld approval for more than one year after the filing of an application seeking approval pursuant to applicable law or one year after the inclusion of the area at issue as a national interest electric transmission corridor, whichever is later; or (b) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.\(^\text{14}\)

In order to issue a permit for siting and construction or modification of transmission facilities, FERC must also determine that: (1) the proposed facilities will be used for the transmission of energy in interstate commerce; (2) the proposed construction or modification is in the public interest; (3) the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers; (4) the proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and (5) the proposed modification will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers and structures.\(^\text{15}\) EPAct 2005 also specifically indicates that federal transmission siting authority does not preclude an entity from constructing or modifying transmission facilities in accordance with state laws.\(^\text{16}\) FERC’s siting authority is merely a “backstop” where a state cannot or does not act on a siting application within one year.

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\(^{12}\) 16 U.S.C. § 824p(b).

\(^{13}\) There is some ambiguity regarding FERC’s authority to entertain siting applications for facilities located in states like Oklahoma and Louisiana, where state commissions do not exert authority over transmission facility siting. This provision may provide FERC with some jurisdiction over transmission siting authority in these states in the event that any territory in these states becomes designated as part of a national interest electric transmission corridor.


\(^{15}\) Id. §§ 824p(b)(2)–(6).

\(^{16}\) Id. § 824p(f).
Once FERC issues a permit, the permit holder can acquire rights-of-way over private property by exercising eminent domain rights in either the state courts or federal district court in the district where the property is located.\footnote{Id. § 824p(e).}

Significantly, in considering applications for siting permits, FERC must “afford each State in which a transmission facility covered by the permit is or will be located . . . a reasonable opportunity to present their views and recommendations with respect to the need for and impact of a facility covered by a permit.”\footnote{Id. § 824p(d)}. Additionally, three or more contiguous states may enter into interstate compacts (subject to Congressional approval) to establish regional transmission siting agencies to: (1) facilitate siting of future electric energy transmission facilities within the states involved; and (2) carry out the electric energy transmission siting responsibilities of the states involved.\footnote{16 U.S.C. § 824p(i)(1).} Such regional transmission siting agencies must have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest electric transmission corridors, except for the siting of facilities on federal government property.\footnote{Id. § 824p(i)(3).} Where an interstate compact is in place, FERC’s siting authority arises only if the members of the compact are in disagreement and the Secretary of Energy finds that the states involved have failed to act on the siting application for one year or lack the authority to do so.\footnote{Id. § 824p(i)(4).}

In its Order adopting regulations to implement its EPAct 2005 siting authority, FERC initially interpreted its siting authority to include situations where a state \textit{denied} a siting application, finding that the use of the language “withheld approval” by Congress contemplated not only situations where a state commission has not been able to act within one year of an application, but also where the state has rejected an application.\footnote{Order No. 689 at P 31.} However, the United States Court of Appeals for the Fourth Circuit rejected this statutory interpretation, finding that FERC’s siting authority effectively arises in five circumstances:

1. a state in which the transmission facilities are to be constructed or modified does not have authority to approve the siting;
2. a state does not have the authority to consider the expected interstate benefits to be achieved by the proposed project;
3. a permit applicant is a transmitting utility under the Federal Power Act but does not qualify for a permit in a particular state;

(4) a state commission has withheld approval for more than one year after the filing of an application or the designation of the relevant national interest corridor; or

(5) a state commission has conditioned its approval in such a manner that the proposed construction or modification is not economically feasible or will not significantly reduce transmission congestion in interstate commerce. 23

The Fourth Circuit Court held that Congress intended to confer siting authority on FERC “only when a state commission is unable to act on a permit application in a national interest corridor, fails to act in a timely manner, or acts inappropriately by granting a permit with project-killing conditions,”24 but not where a state commission has duly exercised its siting authority and denied a permit application within one year of submission.25

Thus, under current law, a state commission possessing transmission siting authority may effectively prevent the exercise of federal “backstop” siting authority by acting on a state siting application within one year.

To the extent FERC’s limited “backstop” authority comes into play, Part 50 of FERC’s regulations sets forth the procedure for reviewing siting applications for transmission facilities located in national interest electric transmission corridors.26 Before formally filing an application, applicants are required to engage in a pre-filing process, the purpose of which is to identify all potential issues and gather all necessary information in order for FERC to process the formal application once it is filed. In situations where states have primary authority to site the facility, the applicant cannot pre-file its application until the one-year state approval period has completed.27 In other instances (i.e., where the state does not have jurisdiction to act or consider the interstate benefits or the applicant does not qualify to apply for a permit in the state because it does not serve end use customers in the state), the applicant may pre-file the application at any time.28 Where states have primary jurisdiction, applicants must act in good faith to seek state approval within the one-year period,29 and FERC retains the discretion to allow the state proceeding to continue after the one-year period before FERC allows an applicant to commence the pre-filing process.30 FERC characterizes its process as allowing two years for state approval, 23 Piedmont Envtl. Council v. FERC, 558 F.3d 304, 313–314 (4th Cir. 2009).
24 Id. at 315.
25 Id. at 313.
26 18 C.F.R. Part 50.
27 Order No. 689 at P 21.
28 Id. at P 21 n.14.
29 Id. at P 22.
30 Id. at P 31.
the initial one-year period plus the period of time for FERC review of the pre-filed materials and the application.\textsuperscript{31}

During the pre-filing stage, the applicant must inform FERC about the status of the state process(es), and FERC will hold a scoping meeting with the applicant and applicable state commission(s) to discuss coordination of environmental and other reviews.\textsuperscript{32} Given the extensive, independent environmental review required by the National Environmental Policy Act (“NEPA”),\textsuperscript{33} FERC encourages project sponsors and states to work together in an attempt to site the facilities at the state level.\textsuperscript{34} Importantly, FERC also has indicated that it expects to use the information developed in state proceedings “to the maximum extent possible” and that it will consider state findings in rendering a decision on an application.\textsuperscript{35} However, FERC also has said that its decision in siting a facility that is deemed to benefit a broad region will not rest on whether the facility benefits individual states crossed by the facility,\textsuperscript{36} and FERC will not defer to state siting requirements and procedures for siting a facility.\textsuperscript{37}

For projects spanning multiple states, FERC’s jurisdiction may arise only over the portion(s) of the proposed project that qualify for federal siting authority (i.e., a state commission has failed to act or cannot act on the application); however, in such circumstances, FERC will analyze the impact of the entire project, including those parts of the project that are under state jurisdiction, in rendering its permitting decision.\textsuperscript{38} FERC will not determine whether a project triggers its jurisdiction prior to the application process, but will instead rule on jurisdiction in its subsequent order on the merits of the proposed project.\textsuperscript{39}

As part of the pre-filing process, the applicant is required to submit a “participation plan” to facilitate participation from all stakeholders during the FERC process.\textsuperscript{40} “Stakeholder” is

\textsuperscript{31} Id. at P 31. The Commission has estimated that, at least for extensive projects, the pre-filing process for federal siting of transmission projects could take a year to complete, followed by the formal application review period. Id. at P 112.

\textsuperscript{32} Id. at PP 23, 45, 92.

\textsuperscript{33} 42 U.S.C. § 4321, et seq.

\textsuperscript{34} Order No. 689 at P 115 (characterizing the state siting process as “the most expeditious way to site the facilities.”).

\textsuperscript{35} Id. at PP 124–25. Applicants are permitted to use any information developed during state application proceedings to satisfy the Commission’s application filing requirements. Id. at P 181. FERC has not yet revised regulations in light of Piedmont. As a result of Piedmont’s holding that FERC may not act where a state has timely acted, it is not clear how FERC could consider state findings on an application.

\textsuperscript{36} Id. at P 132.

\textsuperscript{37} See, e.g., id. at P 139. Piedmont’s holding calls into question the continuing force of these earlier FERC statements.

\textsuperscript{38} Id. at P 35.

\textsuperscript{39} Id. at P 32.

\textsuperscript{40} Id. at P 46. Applicants are required to notify all stakeholders, including affected state commissions, within 14 days of commencing the pre-filing process. Id. at P 60. The Commission requires notification of any
broadly defined as a federal, state, multistate, tribal, or local agency, any affected non-
governmental organization, or other interested person.\footnote{18 C.F.R. § 50.1. The Commission will consider any interested entity or individual to be a “stakeholder.” Order No. 689 at P 61.} Once an applicant commences the pre-
filing process, FERC will begin its scoping and environmental review processes, and will seek comments and recommendations from interested stakeholders,\footnote{Order No. 689 at P 47.} including scheduling scoping meetings to be held by FERC at various locations along the route of the proposed project.\footnote{Id. at P 80.} FERC will assign a docket number to a pre-filed application;\footnote{Id. at PP 79, 200.} however, interested parties will not be permitted to intervene until the application is formally filed at the conclusion of the pre-
filing process.\footnote{Id. at P 48.} Stakeholders will be able to participate at several stages of the siting process, including during the applicant’s initial outreach activities,\footnote{Id. at P 84, 201. The Commission has not established a time-frame for the pre-filing process. Id. at P 112.} during FERC’s environmental review processes under NEPA during the pre-filing and application processes,\footnote{Id. at P 74.} and once the application has been filed.\footnote{Id. at P 83.} The applicant is also required to name a point of contact within the company to answer general inquiries,\footnote{18 C.F.R. § 50.4(b).} and it must make all documents related to the project available for public inspection, either in central locations in each county along the project route or electronically on the project’s website.\footnote{Id. at P 85.} Once the Director of FERC’s Office of Energy Projects determines that sufficient information has been collected in the pre-filing process to commence review, the pre-filing process ends and the applicant will file an application,\footnote{Id. at P 48.} at which point interested parties may formally intervene in the proceeding.\footnote{Id. at P 84, 201.} After the application has been filed, FERC will issue a

\begin{itemize}
\item \footnote{Order No. 689 at PP 84, 201. The Commission has not established a time-frame for the pre-filing process. Id. at P 112.} the applicant’s initial outreach activities, \footnote{Id. at P 80.} during FERC’s environmental review processes under NEPA during the pre-filing and application processes, \footnote{Id. at P 74.} and once the application has been filed. \footnote{Id. at P 83.} The applicant is also required to name a point of contact within the company to answer general inquiries, \footnote{18 C.F.R. § 50.4(b).} and it must make all documents related to the project available for public inspection, either in central locations in each county along the project route or electronically on the project’s website.\footnote{Id. at P 85.} Once the Director of FERC’s Office of Energy Projects determines that sufficient information has been collected in the pre-filing process to commence review, the pre-filing process ends and the applicant will file an application,\footnote{Id. at P 48.} at which point interested parties may formally intervene in the proceeding.\footnote{Id. at P 84, 201. The Commission has not established a time-frame for the pre-filing process. Id. at P 112.} After the application has been filed, FERC will issue a
draft environmental document and invite stakeholder comment.\textsuperscript{53} Once FERC has considered all comments and issues a final environmental document, it will issue an order on the merits of the project, including the proposed project route, and issue or deny a permit to construct the proposed facilities. Parties disagreeing with FERC’s findings may seek rehearing using the rehearing procedures outlined in FERC’s rules of practice and procedure.\textsuperscript{54}

Order No. 689 also describes the role of RTOs in the federal transmission siting process. FERC is required to afford “due weight” to the findings of independent entities such as RTOs in determining whether the statutory criteria for approval of a project have been met.\textsuperscript{55} FERC has also indicated that much of the information to be included in a system analysis for the proposed project will be developed in consultation with any applicable RTO during the pre-filing process.\textsuperscript{56} Applicants are required to submit information for FERC to assess the impact of the proposed facilities on existing transmission system performance, including congestion, power flows, stability and short circuit analyses, and information regarding how long-term regional planning is impacted and how congestion will be impacted.\textsuperscript{57} In considering an application, FERC will consider environmental impacts, reliability and transmission system impacts, and alternatives to the project, among other things.\textsuperscript{58}

Once a permit is issued, if the applicant cannot otherwise obtain necessary rights-of-way through contract or agreement with the owner of the property, it may exercise the right of eminent domain in either federal or state court.\textsuperscript{59} Proceedings in federal court are required to conform as nearly as practicable to the rules and procedures applicable to similar proceedings in the state court of the state in which the property is located.\textsuperscript{60}

FERC thus has extensive regulations delineating in detail how it will process applications under its “backstop” siting authority, including provision for extensive participation by the states and other stakeholders. Nonetheless, in light of the \textit{Piedmont} case, under current law there is unlikely to be any significant use of FERC’s “backstop” authority. As noted, timely siting decisions by the states can effectively eliminate any exercise of federal authority. As discussed below, however, pending legislation could alter the effect of \textit{Piedmont} and bring FERC’s “backstop” authority and these regulations back into play.

\textsuperscript{53} \textit{Id.} at P 88.
\textsuperscript{54} Order No. 689 at P 89.
\textsuperscript{55} \textit{Id.} at P 44.
\textsuperscript{56} \textit{Id.} at P 99. The Commission will review all stakeholder processes conducted by the applicant, including applicable RTOs and ISOs, in determining whether to issue a construction permit. \textit{Id.} at P 189.
\textsuperscript{57} \textit{Id.} at P 188.
\textsuperscript{58} \textit{Id.} at P 191.
\textsuperscript{59} 16 U.S.C. § 824p(e)(1).
\textsuperscript{60} \textit{Id.} § 824p(e)(3).
V. Pending Federal Legislation

Several significant pieces of energy legislation have been introduced in the 111th Congress; however, legislative efforts in both chambers have focused on creating a single, comprehensive energy bill. The principle House bill, H.R. 2454, currently contains limited provisions addressing federal transmission planning and provides FERC with transmission siting authority in the Western Interconnection only. It was passed by the House by a vote of 219-212 on June 26, 2009. The Senate measure, which addresses not only transmission planning but also federal transmission siting authority throughout the United States, has been approved by the Senate Energy and Natural Resources Committee and is proceeding to the full Senate. Both pending bills address matters that could significantly impact transmission planning in SPP.61

A. Senate Legislation – American Clean Energy Leadership Act of 2009
(Senate Energy and Natural Resource Committee Draft)

The main legislative vehicle for energy reform in the Senate is the American Clean Energy Leadership Act of 2009, which has not yet been formally introduced but was crafted from several individual bills by the Senate Energy and Natural Resources Committee. The Senate energy bill addresses, among other things, enhanced federal electric transmission planning and siting authority and cost allocation. The legislation authorizes FERC to approve applications for siting of “high-priority national transmission projects” (operating at or above 345-kV for alternating current and at or above 300-kV for direct current) that are included in an “Interconnection-wide transmission plan.” The bill requires FERC to coordinate regional and sub-regional plans into Interconnection-wide plans for the Eastern Interconnection and the Western Interconnection.

Under the measure, states would have the first opportunity to site a high-priority national transmission project; however, if after one year the state fails to act, rejects an application, or places unreasonable conditions on its siting approval, FERC would have authority over siting of the transmission facility. This bill would therefore modify the Piedmont holding and permit FERC to site a facility that a state has rejected. The bill requires the planning processes to take renewable generation and location-constrained resources into consideration, but does not require national transmission projects to be specifically designated to serve renewable resources. The bill would require FERC to adopt national electricity grid planning principles addressing coordination among planning entities and requiring consideration of location-constrained resources (including renewable generation), demand side resources, and costs to consumers, among other factors.

61 Proposed legislation has covered the gamut of energy issues including renewable energy generation, federal transmission siting authority, climate change, increased domestic energy and fuel production, and other issues. For instance, while not directly applicable to the issue of transmission siting, Arkansas Rep. Mike Ross recently introduced H.R. 3009, legislation to diversity U.S. energy sources by: (1) encouraging domestic exploration and production of oil and natural gas by opening up more domestic U.S. territory to exploration, including the Arctic National Wildlife Refuge and Outer Continental Shelf; and (2) using lease and royalty payments from the sale of oil and gas leases to create an “American-Made Energy Trust Fund” to provide incentives for alternative and renewable energy projects. Given the significant differences between the main legislation in the House and Senate, it is unclear which aspects of other pending bills, such as Congressman Ross’s bill, may be included in any comprehensive energy measure.
Under the Senate bill, FERC also is required to establish by rule an appropriate methodology for cost allocation for high-priority national transmission projects, including allocation of costs to all load-serving entities within all or part of a region. Costs cannot be socialized in this manner, however, “unless the costs are reasonably proportionate to measurable economic and reliability benefits.”

The Senate bill also includes language creating a national renewable electricity standard requiring utilities to supply 15% of their power by renewable energy resources by 2021, and provides greater market oversight authority to FERC including the ability to issue cease and desist orders and to temporarily modify electricity rates and terms in “emergency” circumstances (where disturbances in wholesale electric markets could disrupt service or result in excessive price fluctuations), among other things. The legislation also would require FERC to develop interconnection rules for small-scale distributed generation, including residential distributed generation.

Other provisions of the bill include appliance efficiency, energy efficiency building code standards, “green” work force training, development of a clean energy bank, encouragement of and indemnity from liability for carbon sequestration demonstrations, creation of a refined products reserve, expanded Department of Energy authority in energy markets, incentives for distributed generation and small-scale energy production, expanded data collection authority for the Energy Information Agency, and other matters.

The bill was approved 15-8 by the Senate Energy and Natural Resources Committee and is expected to be introduced on the floor of the Senate this summer. The Senate Democratic leadership has expressed its intent to combine comprehensive energy legislation along with climate change legislation; however, to date, no comprehensive climate change legislation has advanced through the committee process. Most likely, these efforts will not culminate until this fall.


Comprehensive energy and climate change legislation passed the House of Representatives on June 26, 2009 by a vote of 219-212. H.R. 2454, “The American Clean Energy and Security Act of 2009,” is designed to: (1) promote renewable energy, carbon capture and sequestration technologies, low-carbon fuels, clean electric vehicles, and smart grid and electricity transmission infrastructure; (2) increase efforts to promote energy efficiency across all sectors of the economy, including electric and natural gas distribution utilities, buildings, appliances, transportation, and industry; (3) establish a cap-and-trade system for greenhouse gases to reduce emissions of heat-trapping pollutants; (4) provide financial assistance to protect consumers and industry from the costs imposed by the legislation and promote green jobs during the transition to a clean energy economy; and (5) grant FERC transmission siting authority in the Western Interconnection.

While the main focus of H.R. 2454 is to address global warming, the bill contains several provisions directly applicable to the energy industry. At present, H.R. 2454 does not contain any
language granting expanded federal transmission siting authority to FERC or any other federal entity in the Eastern Interconnection (including SPP); however, the bill does provide FERC with authority to issue permits for the siting of transmission facilities in the Western Interconnection if a state commission does not issue a decision on or denies an application seeking siting approval for a facility within one year of submission or imposes conditions that unreasonably interfere with the development of the facility. In order to qualify for federal siting authority, the proposed facility must be identified as part of a regional or Interconnection-wide electric grid plan that was submitted to FERC and developed in accordance with national grid planning principles adopted by FERC, the facility must be “identified as needed in significant measure to meet demand for renewable energy in such plans,” and the facility must be multistate in nature.

Additionally, the bill requires FERC to establish national transmission planning principles and to review transmission plans from regional planning entities that agree to incorporate national electricity grid planning principles in their electric grid planning, and also requires FERC to coordinate with the U.S. Department of Interior, the National Oceanic and Atmospheric Administration, and coastal states to study the siting of offshore renewable energy facilities and related transmission lines.

The legislation also creates an office of consumer advocate within FERC to: (1) represent (and appeal on behalf of) energy customers on matters concerning rates or service of public utilities and natural gas companies before FERC, other federal agencies, and the courts; (2) monitor and review energy customer complaints and grievances concerning rates and services for companies under FERC’s jurisdiction; (3) investigate services provided by and rates charged by utilities under FERC’s jurisdiction; (4) develop means to ensure that the interests of consumers are represented before FERC to the maximum extent practicable; and (5) collect and analyze data, prepare reports, and issue recommendations. H.R. 2454 also creates a national renewable energy standard requiring utilities to meet 20% of their load with renewable energy by 2020, to be overseen by FERC, among other things.

C. Potential Impacts of Federal Legislation on SPP Planning

While it is premature to predict the final outcome of the ongoing legislative debate, the pending legislation, some form of which may be enacted this year, indicates that new federal authorities could have implications for the SPP planning process. These include:

- Potential for FERC involvement in high-voltage transmission planning or Interconnection-wide planning, at least to the extent of “coordinating” regional plans to develop “Interconnection-wide” plans;
- Greater emphasis on renewable generation through a national renewable electricity standard, giving rise to greater transmission planning emphasis on connecting location-constrained renewable generation to load centers;
- Potential regulations for cost allocation of national interest transmission projects or Interconnection-wide projects, which could impact existing SPP cost allocation methodologies; region-wide socialization of transmission costs could require demonstration of “measurable” region-wide benefits; and
• Modification of the Piedmont holding and expansion of federal “backstop” siting authority where states reject transmission siting applications for high-voltage transmission projects of national interest.

There are significant differences between the House and Senate versions of the legislation (such as whether federal authority will be limited to the Western Interconnection or will more broadly encompass the Eastern Interconnection as well), and at this time it is unclear how the differences may be resolved. The transmission aspects of the legislation also are secondary to the more controversial “cap-and-trade” provisions. Whether new transmission legislation emerges may depend on the outcome of the cap-and-trade debate.

VI. Conclusion

SPP’s governing documents explicitly recognize the role of state and federal siting laws and regulations in the transmission planning process. Implementation of the STEP is “subject to” the “siting, permitting, and environmental” constraints imposed by “state, local and federal laws and regulations.”

Under current law, siting of electric transmission facilities remains primarily under the jurisdiction of state regulatory commissions. While EPAct 2005 granted FERC “backstop” authority to approve siting of transmission facilities, FERC’s authority is limited to designated “national interest electric transmission corridors,” and arises only when a state is unable to consider a project or fails to act on an application within one year. In situations where FERC’s authority is triggered, EPAct 2005 and Order No. 689 require FERC to consider the findings and conclusions of states throughout the transmission siting approval process. States have the ability to avoid federal involvement by acting on a transmission siting application within one year of its submission.

Congress is considering legislation that potentially will expand FERC’s transmission siting authority over high-voltage projects, including possibly authorizing FERC to modify the outcomes of state decisions regarding these facilities. However, if Congress grants broader transmission siting authority to FERC, FERC may use its existing but dormant siting regulations under EPAct 2005 to consider new transmission siting applications. These regulations already recognize the importance of state participation in the transmission siting process including: (1) requiring applicants to involve state commissions in the pre-filing and application process; (2) coordinating environmental reviews with state commissions; and (3) inviting state regulatory commissions to intervene and offer comment throughout the process. Pending legislation also preserves the ability of states to consider siting applications before FERC authority is triggered, preserving to a significant extent the primary authority that states have traditionally had over transmission siting. FERC’s order adopting the siting regulations that likely will be used for any federal applications indicates FERC’s intent to use information from state proceedings “to the maximum extent possible” and that FERC will consider state findings in its decisions.

Under pending legislation, SPP’s decisions in the STEP process, which take into account the views of stakeholders including state commissions, likely will carry significant weight. It appears the legislation also may adopt a “bottom up” approach, coordinating regional plans such
as the STEP into Interconnection-wide plans. FERC’s existing siting regulations already afford “due weight” to the findings of RTOs and that likely will continue.

Wright & Talisman, P.C.
July 20, 2009
APPENDIX 1
State-by-State Siting Laws and Requirements

A. Arkansas

For transmission siting authorizations, Arkansas Law distinguishes between “major utility facilities” (transmission lines and associated facilities with a design voltage of at least 100-kV if the transmission line is more than 10 miles in length, or transmission lines and associated facilities with a design voltage of at least 170-kV for lines more than one mile in length)\(^1\) and other, non-major transmission facilities, with major transmission facilities undergoing more rigorous review than non-major projects. Modifications to existing facilities to replace, upgrade, or modernize existing lines and associated equipment do not require additional authorizations if they do not exceed existing rights-of-way.\(^2\)

Applicants are required to submit information showing: (1) that the proposed construction is or will be required by the public convenience and necessity; (2) the proposed location or route; (3) the manner in which the facilities will be constructed; (4) maps specifying the route to be followed in constructing the new transmission line, the location of nearby airports, and applicable allocation boundaries; (5) cost estimates and related data; and (6) the proposed method of financing.\(^3\) Applicants seeking to construct major utility facilities are also required to submit information regarding: (1) a general description of the location and type of transmission line and associated facilities; (2) a general description of any reasonable alternative locations or routes considered; (3) the need and reasons for construction of the transmission line and associated facilities; (4) the estimated construction cost; (5) the method of financing and reasonable alternative methods of financing, including the comparative merits and demerits of each alternative financing method; (6) a discussion of the merits and demerits of financing the project through the issuance of state or federal tax-exempt bonds (if applicable); (7) the projected economic and financial impact on the applicant and the local community; (8) the estimated effects on energy costs to the consumer; (9) an environmental impact statement setting forth the environmental impact, any adverse environmental effects that cannot be avoided, a statement of the reasons why the proposed location and production processes were chosen over the identified alternatives, and any irreversible and irretrievable commitments of resources that would be involved in the proposed construction; and (10) such other information of an economic or environmental nature that the applicant may consider relevant.\(^4\) Applicants seeking to construct transmission lines and related facilities in a national interest electric transmission corridor are also required to submit a discussion of the interstate benefits to be achieved by the proposed construction.\(^5\)

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\(^2\) Id. §§ 23-3-201(a)(2), 23-18-510(a).

\(^3\) Arkansas Public Service Commission Rules of Practice and Procedure § 7.04 (Certificates of Public Convenience and Necessity – Electric Utilities).


\(^5\) Id. § 23-18-511(9).
In approving an application for siting and construction of a major utility facility, the Arkansas Public Service Commission (“APSC”) is required to make findings and issue an order determining: (1) the basis of the need for the transmission project; (2) that the transmission line will serve the public interest, convenience, and necessity; (3) the nature of probable environmental impacts; (4) that construction and the location of the proposed transmission line represents an acceptable adverse environmental impact; (5) the nature and extent of probable economic impact of the construction and siting of the proposed transmission line and associated facilities; (6) that construction of the proposed project is not inconsistent with the filed and known plans of other electric utilities serving the state; (7) that the proposed location or route conforms as closely as practicable to applicable state, regional, and local laws; and (8) that the transmission facilities to be constructed will meet or exceed applicable construction standards. For projects proposed in national interest electric transmission corridors, the APSC is also required include in its order an assessment: (1) of the interstate benefits expected to be achieved by the proposed construction or modification of the major electric transmission facility; and (2) that any conditions attached to a certificate for construction or modification of transmission facilities to be located within a national interest electric transmission corridor do not interfere with the reduction of electric transmission congestion in interstate commerce and do not render the project economically infeasible.

The APSC is required hold a public hearing on an application no sooner than 40 days and no later than 180 days after the filing of the application; and is required to issue an order on the application “as expeditiously as practicable.”

B. Kansas

Applicants for construction of transmission facilities in Kansas are required to submit an application to the Kansas Corporation Commission (“KCC”) prior to beginning site preparation or construction, detailing: (1) the proposed location; (2) the names and addresses of the landowners of record whose land is proposed to be acquired in connection with the construction of or is located within 660 feet of the center line of the easement where the line is proposed to be located; and (3) such other information as may be required by the KCC. The KCC is required to conduct a public hearing in one of the counties through which the proposed transmission line is expected to traverse within 90 days after receiving an application, to determine the necessity for and reasonableness of the location of the proposed electric transmission line. The KCC

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6 Id. § 23-18-519(b).
7 Id. §§ 23-18-519(b)(11)–(12).
8 Id. § 23-18-516(a)(1).
9 The Kansas Siting Act does not apply to: (1) portions of any electric transmission line to be constructed on an easement where there currently exists one or more electric transmission lines if the easement is not within the corporate limits of any city; (2) portions of any electric transmission line to be constructed on property adjacent to a right-of-way along a four-lane controlled access highway; or (3) any electric utility that complies with the provisions of the National Environmental Policy Act of 1969 regarding the siting of electric transmission lines. KSA § 66-1, 182 (2008).
10 Id. § 66-1, 178(a).
11 Id. § 66-1, 178(b).
must issue a final order on the application within 120 days of the filing of the application,\textsuperscript{12} taking into consideration the benefit to both consumers in Kansas and consumers outside the state, as well as economic development benefits in Kansas.\textsuperscript{13}

C. Louisiana

Louisiana state law does not require a utility to obtain siting approval from the Louisiana Public Service Commission (“LPSC”) prior to constructing a transmission facility in the state, and, while state courts have determined that the LPSC has broad “plenary” authority over electric utilities,\textsuperscript{14} the LPSC has not issued regulations requiring utilities to seek approval for transmission siting. However, construction of electric public utility facilities is limited by the statutory “three hundred foot rule,” which indicates that electric public utilities cannot construct or extend facilities, or furnish or offer to furnish electric service, to any point of connection which is being served by another electric public utility or within three hundred feet of an existing electric line of another electric public utility.\textsuperscript{15}

Additionally, public utilities are prohibited from constructing new facilities or extending existing facilities in cities “unless and until the governing authority of the city certifies that public convenience and necessity require the same.”\textsuperscript{16} Utilities are required to obtain property or rights-of-way either from landowners through voluntary agreement or eminent domain, which could further involve state and local government agencies in the process.

D. Missouri

The Missouri Public Service Commission (“MoPSC”) is empowered with issuing certificates of convenience and necessity for the construction of electric plants, including electric transmission facilities (“line certificate authority”),\textsuperscript{17} and for electric utility franchise areas (“area certificate authority”).\textsuperscript{18} Line certificates may be granted without a local franchise being granted, and area certificates entitle the electric utility to construct transmission lines within the certificated franchise area without having to obtain separate line certificates or additional approval from the MoPSC.

\textsuperscript{12} \textit{Id.} § 66-1, 178(d).
\textsuperscript{13} \textit{Id.} § 66-1, 180. The KCC may issue or withhold the permit or condition the permit to protect the rights of all parties and the general public. \textit{Id.}
\textsuperscript{15} \textit{La. Rev. Stat. Ann.} § 45:123 (2009). Under the statute, “electric line” means both transmission and distribution lines. \textit{Id.} § 45:123(B). Given that the three hundred foot rule applies to electric service furnished to “points of connection,” it generally does not preclude the building of transmission lines located within three hundred feet of other existing transmission lines.
\textsuperscript{16} \textit{Id.} § 33:4406. City approval for extensions of existing facilities are only required where the extension “will cost over two percent of the rate-making value of the property at the time the extension or addition is made.” \textit{Id.}
\textsuperscript{17} Mo. Rev. Stat. § 393.170(1) (2009).
\textsuperscript{18} \textit{Id.} § 393.170(2).
Upon application for a certificate of convenience and necessity, the MoPSC is authorized to grant approval if, after due hearing, it determines that the construction or exercise of the right, privilege, or franchise sought is necessary or convenient for the public service.\footnote{Id. § 393.170(3).} MoPSC may also impose conditions upon the certificate as it may deem reasonable and necessary.\footnote{Id.} The Missouri Revised Statutes do not specify any criteria for the MoPSC to consider or define what is “necessary or convenient,”\footnote{Missouri courts, however, have determined that a finding that a facility or franchise is “necessary and convenient” requires at least a determination that the facility or franchise is “adequate,” which includes assessing the relative experience of competing suppliers of the service. \textit{State ex rel. Ozark Elec. Cooper. v. Pub. Serv. Comm’n of the State of Mo.}, 527 S.W.2d 390, 394 (Mo. Ct. App. 1975).} nor do they impose any deadline for MoPSC action on an application.

The MoPSC’s procedural rules outline certain criteria an applicant must include in its application for an area or line certificate. For area certificates, the applicant must include: (1) a statement regarding other similar utility service provided in the area; (2) information regarding the identity of landowners and residents in the proposed franchise area; (3) a legal description of the area to be certificated; (4) a plat of the proposed area; (5) a feasibility study containing plans and specifications for the utility system and estimated cost of the construction of the utility system during the first three years of construction; (6) plans for financing; and (7) proposed rates and charges and an estimate of the number of customers, revenues and expenses during the first three years of operations.\footnote{Mo. Code Regs. Ann. tit. 4, § 240-3.105(1)(A) (2003).} For line certificates, the MoPSC requires: (1) a description of the route of construction and a list of all electric and telephone lines, railroad tracks, and underground facilities that the proposed construction will cross; (2) construction cost information and specifications; and (3) plans for financing.\footnote{Id. § 240-3.105(1)(B).} Applications for both area and line certificates also must present facts demonstrating that the granting of the application is required by the public convenience and necessity.\footnote{Id. § 240-3.105(1)(E).}

\hspace{1em}E. Nebraska

Nebraska electric service is provided exclusively by public power entities and there is no process or authority for private electric utilities to build transmission facilities in the state. Two entities, the Nebraska Power Review Board (“NPRB”) and the Nebraska Public Service Commission (“NPSC”) have jurisdiction over certain aspects of transmission facility siting. A utility seeking to construct new transmission facilities in Nebraska must first reach agreement with other affected transmission owners regarding what facilities are needed.\footnote{Neb. Rev. Stat. § 70-1002.03 (2009).} The builder must
then seek approval from the NPRB by applying for a certificate of convenience and necessity.\textsuperscript{26} The NPRB Rules of Practice and Procedure outline the application requirements including: (1) a map showing all transmission and distribution lines within one mile of the proposed facility; (2) a statement of how the applicant will provide service at its “low [sic] overall cost as possible consistent with sound business practices;” and (3) construction cost information, whether the cost will be paid in part by any customer, and if so, the amount of the customer’s contribution.\textsuperscript{27}

The NPRB must schedule a hearing within 30 days (or within 90 days if the applicant requests an extension and demonstrates good cause), and must render its decision within 30 days of the hearing.\textsuperscript{28} To issue a certificate, the NPRB must determine that the facilities will serve the public convenience and necessity, and that the applicant can most economically and feasibly supply the electric service without unnecessary duplication of facilities or operations.\textsuperscript{29}

NPSC approval is required for all transmission lines located outside of incorporated cities where the line crosses a highway or railroad track or is to be located within a certain distance (depending on the voltage of the proposed line) of existing electrical, communication, or railroad signal lines or airports.\textsuperscript{30} In such instances, the applicant is required to provide maps and engineering specifications regarding the proposed facility.\textsuperscript{31}

\textbf{F. New Mexico}

Under New Mexico statute and the rules of the New Mexico Public Regulation Commission (“PRC”), utilities seeking authorization to construct transmission lines operating at or above 230-kV and related facilities are required to obtain a certificate of public convenience and necessity,\textsuperscript{32} a location permit,\textsuperscript{33} and a right-of-way width determination (where the necessary right-of-way is wider than 100 feet).\textsuperscript{34} When reviewing an application for a location permit, the PRC may consider: (1) existing plans of the state, local government, and private entities for other developments at or in the vicinity of the proposed location; (2) impacts on fish, wildlife, and plant life; (3) potential noise emission levels and interference with communication signals; (4) the proposed availability of the location to the public for recreational purposes, consistent with safety considerations and regulations; (5) existing scenic areas, historic, cultural, or religious

\begin{itemize}
  \item \textsuperscript{26} \textit{Id.} § 70-1012. Utilities are not required to apply for certificates to extend facilities within the supplier’s own service area or within one-half mile outside its service area if all of the other owners of transmission facilities within one-half mile consent to the extension in writing. \textit{Id.}
  \item \textsuperscript{27} 285 Neb. Admin. Code § 2-004 (2008).
  \item \textsuperscript{28} Neb. Rev. Stat. § 70-1013 (2009).
  \item \textsuperscript{29} \textit{Id.} § 70-1014. The NPRB is responsible for approving the siting of transmission facilities but has no jurisdiction over rates. \textit{Id.} § 70-1002.03.
  \item \textsuperscript{30} \textit{Id.} §§ 75-701–724.
  \item \textsuperscript{31} 291 Neb. Admin. Code § 7-002.02 (2009)
  \item \textsuperscript{33} \textit{Id.} § 62-9-3(B).
  \item \textsuperscript{34} \textit{Id.} § 62-9-3.2.
\end{itemize}
sites and structures or archaeological sites at or in the vicinity of the proposed location; and (6) additional factors that require consideration under applicable federal and state laws pertaining to the location.\textsuperscript{35}

The PRC is required to act on an application for a certificate of public convenience and necessity and a location permit within nine months of submission of the application, but may grant itself a six-month extension for good cause shown.\textsuperscript{36} Utilities are required to comply with all local permitting requirements; however, if the local authority does not act within 240 days or does not approve the permit application, the applicant may file for approval with the PRC.\textsuperscript{37} The PRC cannot approve a permit for a project that violates existing state, county, or municipal land use statutes or administrative regulations unless the PRC finds that the regulation is unreasonably restrictive and compliance with the regulation is not in the interest of the public convenience and necessity.\textsuperscript{38}

G. Oklahoma

The Oklahoma Corporation Commission (“OCC”) does not have authority over the siting of transmission facilities in the state. Under Oklahoma law, companies authorized to furnish electricity service in the state have the same right of eminent domain as applies to railroads operating in the state.\textsuperscript{39} A party seeking to exercise eminent domain must petition the district court for the district in which the property is located,\textsuperscript{40} and must include in its petition a statement indicating: (i) that it is authorized to exercise the power of eminent domain and it has been unable to make a voluntary purchase of the property or right-of-way in question; (ii) the owner of the property and the specific property in question; and (iii) that the specific property sought to be taken is necessary for a purpose for which the power of eminent domain may be exercised.\textsuperscript{41}

In a recent case involving an application by a transmission-only electric utility to provide wholesale bulk electricity transmission services within the state of Oklahoma, the OCC adopted an Administrative Law Judge’s recommendations that the OCC “find that no determination by the [OCC] that additional transmission capacity is needed in Oklahoma is required, prior to any company building transmission lines in Oklahoma,” and that “SPP will make the decision regarding which entity will install and maintain transmission lines necessary for the efficient and

\textsuperscript{35} Id. § 62-9-3(M).
\textsuperscript{36} Id. §§ 62-9-1(C) and 62-9-3(K). If the location permit application is filed while the application for a certificate of public convenience and necessity is pending, the PRC must act on the location permit within ninety days after the certificate of public convenience and necessity is granted. Id. § 62-9-3(K)(3).
\textsuperscript{37} Id. § 62-9-3(H).
\textsuperscript{38} Id. § 62-9-3(G).
\textsuperscript{39} Okla. Stat., tit. 27, § 7 (2009).
\textsuperscript{40} Id. at tit. 66, § 53.
cost effective distribution of electricity for the use of [Oklahoma Gas & Electric Company’s] customers.”

H. Texas

The Public Utilities Regulatory Act (“PURAA”) prohibits electric utilities from directly or indirectly providing service to the public unless the utility first obtains a certificate of public convenience and necessity from the Public Utility Commission of Texas (“PUCT”). Utilities are not required to obtain a certificate for: (1) extensions into contiguous territories that do not receive similar service from another electric utility and are not in another electric utility’s certificated area; (2) extension in or to territory that the utility serves or is authorized to serve; or (3) operation, extension, or service in progress on September 1, 1975.

In reviewing a certificate application, the PUCT considers: (1) the adequacy of existing service; (2) the need for additional service; (3) the effect of granting the certificate on the recipient and any electric utility service in the proximate area; (4) impacts to community values, recreation and park areas, historic and aesthetic values, and environmental integrity; (5) the probable improvement of service or lowering of costs to consumers; and (6) the effect of granting the certificate on the ability of the state to meet renewable energy goals. Under its Substantive Rules, the PUCT also considers the needs of the interconnected transmission system to support a reliable and adequate network and to facilitate robust wholesale competition, and gives “great weight” to recommendations from “essential organizations” (i.e., independent system operators) or written documentation that the proposed facility is needed to connect a new transmission service customer. PUCT transmission line routing decisions are based on whether the proposed route: (1) utilizes existing compatible rights-of-way, including vacant positions on existing multiple-circuit transmission lines; (2) parallels existing compatible rights-of-way; (3) parallels property lines or other natural or cultural features; and (4) conforms with the policy of prudent avoidance, which seeks to limit exposure to electric and magnetic fields.

The PUCT is required to render its certificate decision within one year of the application; however, the PUCT has reserved the right to extend the one-year period for good


44 Id. § 37.052(a). Extensions of service are only allowed to interconnect to existing facilities or solely to transmit electric utility services from an existing facility to a customer of retail electric utility service. Id. § 37.052(b).

45 Id. § 37.056(c).


47 Id. § 25.101(b)(3)(B). These considerations are tempered where grid reliability or security dictate otherwise. Id.

cause. Projects that have been formally designated by an “essential organization” as critical for the reliability of the transmission system must be considered on an expedited basis, with the PUCT issuing a decision within 180 days of receiving a completed application. Expedited proceedings are also afforded to transmission lines serving “competitive renewable energy zones” designated by the PUCT and to uncontested applications.

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49 PUCT Subst. R. § 25.101(b).
50 Id. § 25.101(b)(3)(D).
52 PUCT Subst. R. § 25.101(b)(3)(C). The PUCT must act on an uncontested application that is complete and meets all filing criteria within 80 days of filing.
The Synergistic Planning Project

New, Proactive Efforts to Improve Transmission Planning and Cost Allocation for the SPP Region

*Draft: Excerpts from “ITP Roadshow” for state regulators*

Purpose

- Communication/discussion tool for Synergistic Planning Project
- Condensed version of longer presentation
- Will vet with members and CAWG before use
- Contents will continue to evolve
Overview

- SPP’s current transmission planning processes
- Synergistic Planning Project:
  - Integrated Transmission Planning
  - Priority Projects
  - Cost Allocation and Cost/Benefit Analysis
- Role of regulators

Synergistic Planning Project Team (SPPT)

- SPP recommended formation of SPPT to:
  - Look for opportunities to improve transmission planning and cost allocation
  - Think creatively – unencumbered by Tariff or other limitations
Synergistic Planning Project Team Members

- **Paul Suskie**; Chairman, Arkansas Public Service Commission
- **Barry Smitherman**; Chairman, Public Utility Commission of Texas
- **Kelly Harrison**; Vice President – Transmission Operations and Environmental, Westar Energy
- **Ricky Bittle**; Vice President - Planning, Rates and Dispatching, Arkansas Electric Cooperative Corporation
- **Rob Janssen**, President and General Manager, Dogwood Energy
- **Ric Abel**; Managing Director, Prudential Capital Group
- **Carl Monroe**; Executive Vice President and COO, SPP
- **Mark Rossi**, Accenture, facilitation and administration

Components of SPPT Report

- Integrated Transmission Plan
- Priority Projects
- Cost Allocation
What is Integrated Transmission Planning?

- **Major Objective**: Design transmission backbone to connect load centers to low-cost generation
- **Other Objectives**:
  - Improve connections between SPP’s east and west regions
  - Make transmission an enabler rather than constraint
  - Strengthen ties to Eastern and Western Interconnections

ITP Milestones

- August: ESWG approves Priority Projects economic metrics
- August - October: SPP visits with state regulators
- September: ESWG/TWG reach consensus on ITP process
- October: CAWG completes and RSC approves cost allocation methodology
- October: BOD approves ITP process and Priority Projects
- January 2010: BOD approves Tariff language for ITP and cost allocation
- 1Q 2010: FERC approves Tariff language for ITP and cost allocation
The Road to Financial Transmission Congestion Cost Hedging in SPP

The Recommendation

- On June 17th the Congestion Hedging Task Force (CHTF) made a recommendation to Market Working Group (MWG) that SPP adopt a financial mechanism for hedging transmission congestion costs in the future markets.
- MWG adopted this approach
- MOPC has been informed
Who Is the CHTF?

- CHTF representatives included:
  - State regulatory staff
  - Load-serving members
  - Transmission Owning members
  - Power Marketers
  - Merchant Generators
  - SPP Staff
  - Industry consultants

Why Do Anything?

- The future market cost/benefit study shows an opportunity for significant savings through an SPP-wide centralized unit commitment
  - Estimated at $100M/yr = $BIG$
  - Reminder: Unit commitment must be a DA process due to physical plant characteristics
Decision Process - Is Change Necessary?

- To realize the $BIG$ benefits SPP will implement a DA energy market, with centralized unit commitment

But…
- Existing process impedes full use of a centralized commitment process
- Today, MPs use their own Day Ahead (DA) commitment and schedules as a hedge against cost to serve load – “my unit serves my load, so I know the cost”

Change IS Necessary

- Realizing the $BIG$ savings will require change –
- Specifically, generation owners must turn the commitment decisions for their own units over to the market.
Change is Necessary – HOW?

How do we convince the MP to let someone else make commitment decisions for their resources, and them live with the results?

By indemnifying them from the cost impact of those decisions.

Change is Necessary – HOW?

Developing and settling a financially binding Energy solution and Congestion hedge in the DA time frame will provide price assurance.

That price assurance will allow Load Serving Entities to turn over the generation commitment decision and economically offer into the DA market.
Wide Range of Initial Positions in CHTF

- FTRs - No way – Never!
- Hedges must be physical
- FTRs - the only way to go – why don’t we already have them?
- Everywhere in between
- All meeting participants displayed an open mind and shared a desire to learn, understand and make the best decision

What was the CHTF Decision Process?

- Thorough, reasoned approach
- Reviewed the decisions of other RTOs
- Analyzed numerous complex examples
  - Engaging in these discussions and extensive “what-ifs” provided the most learning
- Asked questions like:
  - How would your company evaluate a recommendation?
  - What would the ultimate impact be to rate payers?
Decision Process - Areas of Concern

- How comparable is it to your hedge today?
- What is the availability period (Hourly, Daily, Monthly, Yearly)?
- Does the mechanism:
  - promote full use of the transmission system?
  - increase the capability to trade energy bilaterally?
  - support the concept of energy trading hubs?
  - allow a participant to place a value on the right?
  - allow the rights to be traded?
  - require the scheduling of Native Load?
  - Minimize the need for uplift?
  - Provide transparent results?
- How complex is it?
- What are the system changes necessary with each mechanism?
- Does the mechanism provide any incentive or disincentive for transmission expansion?

Decision Process

Inescapable Conclusion…

- There is no single perfect solution
- Every option involves compromise and tradeoffs
Congestion Hedging Examples

Review Fundamental Elements of LMP Market

- ALL load pays the LMP at its location
  - Regardless of any other arrangements

- ALL Generation is paid the LMP at its location
  - Regardless of any other arrangements

Congestion Hedging Examples

Simple “System” Description:

- One Market Participant with...
  - One Load Location: 500 MW
  - One Cheap Generator: 500 MW @ $20
  - One Expensive Generator: 500 MW @ $70
Simple “System” Diagram

Two generators and one load

- **g E**: 500 MW, $70 / MWh
- **g C**: 500 MW, $20 / MWh

Load = 500 MW

All generation and load is offered into the DA market

---

Scenario N

DA, **No congestion**, All of gen C is deployed

- **g E**: 500 MW, $70 / MWh
- **g C**: 500 MW, $20 / MWh

LMP = $X

No Congestion → LMP at all locations is the same

Regardless of LMP magnitude, the dollars paid at load equal dollars received at generation

Net transaction with market = zero

Cost to serve load is just the fuel cost at gen C

The effect is as if gen C energy was delivered to the load.
Scenario C (Congestion)

DA, WITH congestion, Gen C is Limited

LMPs are assumed for illustration purposes

Load=500 MW

LMP = $70

LMP = $20

LMP varies by location

$ paid at load = 500 x $70 = $35,000

$ received at gen E = 100 x $70 = $7,000

$ received at gen C = 400 x $20 = $8,000

Net market transaction is to PAY (35 - 8 - 7) = $20,000

Cost to serve load is own fuel cost PLUS $20,000 in Congestion Cost.

A hedge is needed.

Hedges can take three basic forms.

- Pro-Rata
- Transactional (Physical)
- Independent (Financial)
Ruled out **Pro-rata** approach early

- In the **Pro-rata** method congestion over-collection is returned to the MPs through some static formula.
  - Consistent with postage stamp transmission cost allocation
- The hedge has no relation at all to the commitment or operational decisions
- All congestion costs are spread as uplift (RNU in today’s EIS market)

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**Analysis Review – ** **Transactional**
(aka physical)

- Tied to actual operations
- Value as a credit against the congestion charge on a schedule (transaction)
  - Similar to EIS today – schedules avoid Imbalance
- Could apply to both firm and non-firm schedules
- Simultaneous Feasibility is assured in near real-time
  - Schedules are cut if infeasible
Analysis Review – **Independent** (aka financial)

- Not necessarily tied to actual operations
- Value as a credit against the congestion charge between two locations
- Value can reverse (becomes a charge) if structured as an Obligation
- Can be structured as an Option
- Supports the ability for Auctions (easily tradable)
- Simultaneous Feasibility still assessed but much further in advance of operating day

Reviewed Other RTOs

- Midwest ISO
- PJM
- ISO New England
- New York ISO
- California ISO (future market design)
- ERCOT Nodal Market
Basic Identical Traits

All 6 transmission congestion hedging models...

- are financial rights models *independent* of physical transactions
- conduct Annual and Monthly Auctions of transmission hedges
- allow non-utility entities to participate in the transmission hedge auctions and to hold transmission hedges
- have a secondary trading system to facilitate tracking ownership for “outside the auction” trades of transmission hedges.

Thoroughly Considered Transactional

- Requires use of Schedules to receive congestion credits
  - Similar to today, so not intimidating
- Drawbacks
  - NLS difficult to manage, especially during CAT cuts
  - Imbalance Offset method was developed to automatically create schedules, and remove those MW from the congestion calculations
    - Had its own problems
Thoroughly Considered Transactional - 2

- Don’t know hedge until DA, then too late to react
- Tried a hybrid method with some portion monthly commitments, and some DA
  - Unwieldy and ran into problems of competing priorities - Which firm is firmer in SFT analysis?
- The level of complexity, competing priorities in different timeframes and transparency issues ultimately ruled out the imbalance offset and the hybrid approach

Evaluations of Transactional and Independent Mechanisms

- A financial hedge gives participants the ability to handle many of these concerns within the market system

- Transmission Service is still required to be purchased per the requirements of the Tariff for NITS and PtP service.

- That service will be the basis for determining an initial allocation of the financial rights
Developed Consensus

- Could make either work
- Some stated a preference for Transactional (physical)
  - That is the business we are in
- Most stated that their choice was not overwhelming in either direction, but preferred Independent (financial)

Primary Reasons Given for Independent

- In the end, the majority were in favor of the independent financial transmission hedge mechanism as providing more flexibility for trading and reconfiguring the hedges, removing the requirement to manage Native Load Schedules and better supporting the establishment and use of trading hubs within SPP
A Word About the Acronym “FTR”

- The term “Financial Transmission Rights” is misleading at best
- FTR (as CHTF has used it) conveys **NO RIGHTS AT ALL** to transmission service
  - Transmission service will be acquired as in the past
- An FTR on a path is **NOT** a right to move power over the path.
- An FTR is a right to the receive the congestion cost on a path
- Perhaps we should use another term, like *Transmission Congestion Right*

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Scenario C - Repeated

**DA, WITH congestion, Gen C is Limited**

*LMPs are assumed for illustration purposes*

<table>
<thead>
<tr>
<th>LMP ($70)</th>
<th>500 MW</th>
<th>$70 / MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>100</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td><strong>Pays LMP</strong></td>
</tr>
<tr>
<td>LMP= $20</td>
<td>500 MW</td>
<td>$20 / MWh</td>
</tr>
<tr>
<td></td>
<td>400</td>
<td></td>
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<td></td>
<td></td>
<td><strong>Load=500 MW</strong></td>
</tr>
</tbody>
</table>

With Congestion → LMP varies by location

- $ paid at load = 500 x $70 = $35,000
- $ received at gen E = 100 x $70 = $7,000
- $ received at gen C = 400 x $20 = $8,000

Net market transaction is to PAY (35 - 8 - 7) = $20,000

Cost to serve load is own fuel cost **PLUS $20,000** in Congestion Cost.

A hedge is needed.
Scenario C

DA, WITH congestion, Gen C is Limited

Use TCR-like Hedge

LMP= $70

200 MW $70 / MWh

g E

LMP= $20

500 MW $20 / MWh

g C

Paid LMP

Load=500 MW

LMP = $70

Pays LMP

No change in energy charges

$ paid at load = 500 x $70 = $35,000

$ received at gen E = 100 x $70 = $7,000

$ received at gen C = 400 x $20 = $8,000, netting to a cost of $20,000

TCR (E to Load) revenue = ($70 - $70) X 100 = zero

TCR (C to Load) revenue = ($70 - $20) X 400 = $20,000

The Net market transaction is ZERO

Cost to serve load is own fuel cost

Simultaneous Feasibility is Required for Revenue Neutrality

- TCRs must be aligned with the physical capability of the system
- Failure will result in a mismatch between the amount of congestion charges collected and paid back, leaving SPP either long or short
- SPP must remain revenue neutral
- Any mismatch is eliminated through uplift
Scenario C
What if TCR (C to load) had been for 500 MW?

No change in energy charges
$ paid at load = 500 x $70 = $35,000
$ received at gen E = 100 x $70 = $7,000
$ received at gen C = 400 x $20 = $8,000, netting to a cost of $20,000

TCR (E to Load) revenue = ($70 - $70) X 100 = zero
TCR (C to Load) revenue = ($70 - $20) X 500 = $25,000

The Net market transaction is $5,000 paid by SPP to MP

Without Sim Feas, SPP is now short $5,000, and must collect that amount through uplift

Potential Cost Obligation

One of the primary concerns with TCRs is the possibility of cost obligation.

- Because the proposed TCRs are of an obligation type, when congestion costs reverse, the holder is obligated to pay that difference.
- In the next example, the load is now served by the higher cost resource of the Load MP but congestion is reversed
- The TCR increases the overall cost to serve above and beyond the marginal cost at the Load.
**Scenario CH w/Outage – Cost Obligation**

DA, With Congestion reversed, Gen C unavailable, gen F and gen E are deployed. TCR from gen C to load. Gen F not owned by Load

- **Gen C**
  - LMP = $80
  - 500 MW
  - Pays LMP

- **Gen F**
  - LMP = $100
  - 500 MW

- **Load**
  - 500 MW
  - LMP = $80

- **Fuel Costs**
  - $ paid at load = 500 x $80 = $40,000
  - $ received at gen E = 500 x $80 = $40,000
  - $ received at gen C = 0 x $100 = $0
  - TCR C-Load now = 400 x -$20 = -$8,000

- **Net market Settlement for Load**
  - (40 - 40 + 8) = $8,000

- **Cost to serve load**
  - is fuel cost of E plus counterflow obligation.

- **TCR is now a cost obligation with unit out and congestion reversed.**

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**Risk is Different, But Not New**

- Today we all deal with the possibility of loosing a critical resource during peak times
  - May not be able to find replacement power
  - May not be able to get transmission service
  - Price exposure may be significant!

- But, utilities have always had to deal with these issues

- We are familiar with these risks

- We are unfamiliar with the financial hedge risks
Region’s Recent History of Concerns

- Fear of being forced into FERC’s Standard Market Design
- Concerns that LSE would lose the guarantee of using own resources to serve load, and be forced to buy from the market
  - Remember California?
- Retail Access initiatives
- Misunderstanding of confusing terms

Responding to the Concerns - Who Plays?

- One of the design elements the CHTF is recommending is that the initial allocation of hedge rights is based on existing firm transmission reservations
  - Only parties that can own firm transmission rights will be allocated financial rights
  - ONLY rights that the holder CHOOSES to not accept and convert to TCRs will be available in an auction
What is the Goal?

- The goal is to create a hedge against transmission congestion that allows the MP to offer resources into the centralized commitment and DA market with a reasonable assurance that they will derive a benefit.
- Creating a deep, liquid TCR market is not the goal.

Develop Independent Hedge Design

- CHTF recognizes that the RSC has authority over the allocation of, and any transition mechanism to, financial transmission congestion hedging rights.
- Last several weeks of CHTF activity were devoted to developing as much detail as possible on TCR design.
Summary

- CHTF believes the Day 2 markets will be cost-beneficial
- The comparative analysis of transactional versus TCRs shows both can be made to work. TCRs get the nod because...
  - More flexibility for trading and reconfiguring
  - Removes the requirement to manage Native Load Schedules
  - Better supporting the establishment and use of trading hubs
- Allocation should be restricted to holders of firm transmission rights

References

- CHTF Report describes the details of design that CHTF suggests get adopted, and provides a thorough description of the CHTF decision process

- Generally, there are numerous FTR papers available publicly on most RTO websites. See the CHTF meeting minutes and material for references, links and examples reviewed
Questions?
Wind Integration Task Force

The SPP WITF was developed by MOPC to determine the impact of integrating wind generation into the SPP transmission system and energy markets.

WITF Timeline Update

- Jan 14  MOPC Approval to complete RFP
- Feb 6  WITF Meeting to finalize RFP and Vendors
- Feb 15  RFP Submitted to Vendors
- Mar 16  RFP Responses due from Vendors
- Mar 25  WITF Meeting to select Vendor short-list
- Apr 8  WITF Meeting – Vendor presentations
- Apr 13  WITF Meeting – Final Vendor selection
- Apr 14  MOPC Update – Approval for study
- May 5  WITF Study Kickoff Meeting with CRA International
- June 30  WITF Status Update Meeting
- July 31  WITF Status Update Meeting
- August 25  WITF Status Update Meeting
- Dec 1  Vendor study complete
- Jan 2010  MOPC Presentation of Wind Integration Study
Wind Integration Task Force Study Scope

- Study scope definition
  - Base Case models
    1. 2010 models published in 2008 STEP
    2. CAWG/CBTF/MWG assumptions
  - Change Case definition
    1. 10% wind penetration with existing system
    2. 20% wind penetration with existing system
  - Wind Profiles
    1. NREL wind data profiles from 2004-2006

Original Study Issues

- Issues
  - Data requirement issues
    1. 10 minute load data
    2. Flowgate data
    3. 2010 hourly load data
    4. Others
  - Modeling issues
    1. 10% case power flows
    2. 20% case power flows
    3. Dynamic models
    4. Others
**Mitigation Plans**

- On-site visits to SPP by CRA to assist in issue resolution
  - June 22 (3 days)
  - June 30 (1 day)
  - Additional visits being planned, as needed/required
- Study scope revision reasons
  - It proved to be more difficult to solve at 10-20% than expected
    1. Required 345kV and some 765kV upgrades to solve 20% models – this was unexpected
  - Too many unknowns in 30%-40% models
    1. Decided to forgo 30-40% studies for now

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**CRA Project Methodology**

Task 1: Formulation of Analytical Methodology with Stakeholders

- **Transmission Impact Study**
  - Task 2: Power Flow
  - Binding Flowgates, TR Expansion Plan

- **Operational Impact Study**
  - Task 3: Reserve Requirements
  - Task 4: Unit Commitment

- **Market Impact Study**
  - Task 5: Economic Dispatch
  - Task 6: Forecast Errors
  - Task 7: Best Practices
  - Task 8: Policy Changes

- Task 9: Final Report
Study Schedule - Milestones

Task 1: Analysis Formulation
Task 2: Power Flow
Task 3: Reserve Req.
Task 4: Unit CMT
Task 5: Economic DSP
Task 6: Forecast Errors
Task 7: Best Practices
Task 8: Policy Changes
Task 9: Final Report
Summary

• Revised study scope
  • Still meets study objectives
  • Still meets timeline objective
  • Allows greater focus on 10-20% cases

Questions?
ORDER

In Order No. 1 opening the inquiry in this docket, issued on October 7, 2008, the Arkansas Public Service Commission ("Commission") defined Sustainable Energy Resources ("SER") as including Demand Response ("DR"). Ten days later, on October 17, 2008, the Federal Energy Regulatory Commission ("FERC") issued its Final Rule in *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, III FERC Stats. & Regs. Preambles ¶ 31,281 (2008), as amended 126 FERC ¶61,261 (2009). The Final Rule ("Order No. 719") (FERC Docket Nos. RM07-19 / AD07-7), which is now pending a FERC ruling on various petitions for rehearing, was issued to improve the operation of organized wholesale electric markets in the areas of demand response, long-term power contracting, market monitoring, and Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISO") responsiveness. This Commission understands that there is no date certain by which the FERC will rule on the rehearing requests.

Order No. 719 mandates that RTOs and ISOs, in consultation with stakeholders, submit a compliance filing to explain how existing FERC Tariff language and practices comply with the reforms adopted in Order No. 719 or to specify plans to attain compliance. (*Id.* at p. 8).

On April 28, 2009, the Southwest Power Pool, Inc. ("SPP") submitted a filing revising the RTO's Open Access Transmission Tariff ("Tariff" or "OATT") in order to
comply with the FERC's requirements established in Order No. 719. (Southwest Power Pool, Inc., Docket No. ER09-1050-000, Submission of Order No. 719 Compliance Filing Revising Tariff). The SPP notes that its filing was developed through its stakeholder process, which is described in some detail. The 44-page SPP filing is accompanied by two exhibits showing changes to the RTO's OATT in both clean and red-line form.

This Commission believes that several issues of public interest in our SER inquiry are raised by FERC's Order No. 719 and the SPP's compliance filing in Docket No. ER09-1050-000 and thus may warrant consideration and the opportunity for comment by parties to this docket. This Commission directs the parties to file comments in this Docket within 30 days after the FERC rules on SPP's Compliance Filing in FERC Docket No. ER09-1050-000.

The issue of particular interest to the Commission is the FERC's requirement that all RTOs and ISOs accept bids from DR resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. (Order No. 719 at 49). The FERC also required RTOs and ISOs to amend their market rules as necessary to permit an Aggregator of Retail Customers (“ARC” – a new term apparently coined by FERC in its rulemaking docket) to bid demand response on behalf of retail customers directly into the RTO’s or ISO’s organized markets, “unless the laws or

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1 Copies of both documents can be downloaded from the FERC’s eLibrary website at www.ferc.gov/docs-filing/clipboard.asp.
regulations of the relevant electric retail regulatory authority do not permit a retail
customer to participate.” (Id. at 154).

The Commission hereby notifies the parties to this docket that this issue is before
the FERC. In the event that the FERC takes action on SPP's Compliance Filing in FERC
Docket No. ER09-1050-000, this Commission may need to take appropriate action to
determine the impact, if any, on its jurisdictional authority. Accordingly, the Commission
orders and directs as follows:

1. The Commission directs the parties to file comments in this Docket within 30
days after the FERC rules on SPP's Compliance Filing in FERC Docket No.
ER09-1050-000.

2. The Secretary of the Commission forthwith shall serve a copy of this order by
electronic mail on counsel for all parties to this proceeding.

BY ORDER OF THE COMMISSION.

This 22nd day of May, 2009.

Paul Suskie, Chairman

Colette D. Honorable, Commissioner

Diana K. Wilson
Secretary of the Commission
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN INQUIRY INTO
ELECTRIC TRANSMISSION ISSUES WITHIN
THE AREAS SERVED BY THE SOUTHWEST
POWER POOL REGIONAL TRANSMISSION
ORGANIZATION AND THE ENTERGY
CORPORATION AS SUCH ISSUES AFFECT
ELECTRIC SERVICE WITHIN ARKANSAS

DOCKET NO. 08-136-U
ORDER NO. 10

ORDER

On April 6, 2009, the Arkansas Public Service Commission ("Commission") conducted a public hearing on the subject of the February 12, 2009, filing by the Southwest Power Pool, Inc. ("SPP"), acting as the Independent Coordinator of Transmission ("ICT") for the Entergy Services, Inc. ("Entergy") transmission system, in the above-styled Docket, of the ICT's Annual Performance Report for November 17, 2007 to November 17, 2008 (the "ICT’s Annual Performance Report"). By Order No. 8 in this Docket the Commission directed the parties to submit post-hearing comments and respond to a set of questions propounded in the Order.

The Commission conducted the hearing on the ICT’s Annual Performance Report and received additional comments to inform written comments that it intends to file with the Federal Energy Regulatory Commission ("FERC") in response to the Report, which was filed by the ICT with the FERC in Docket No. ER05-1065-000 on February 11, 2009. On April 24, 2009, written comments and responses to the
Commission's questions were filed by Entergy Arkansas Inc. ("EAI"); the Attorney General ("AG"), Arkansas Electric Cooperative Corporation ("AECC"); Southwest Electric Power Company ("SWEPCO"), Oklahoma Gas & Electric Company ("OG&E"), and Empire District Electric Company ("Empire District") (collectively the "Interested Parties"); Entegra Power Group LLC ("Entegra"), and Suez Energy Marketing, NA ("Suez"). The General Staff of the Commission ("Staff") filed a letter notifying the Commission that they did not intend to file comments.

Having considered the initial and post-hearing comments and the responses of the witnesses of the parties at the April 6th hearing, as well as Entergy's informational filing on the Weekly Procurement Process ("WPP") filed with the FERC on April 16, 2009, (and included as Attachment 1 to Order No. 8 in this Docket), the Commission makes the following findings.

General Findings on the Status of the ICT Experiment and the WPP

The Commission finds that the ICT experiment has to date failed to deliver significant benefits to EAI customers, owing largely to the extensive delays that were experienced in developing the software for and launching the WPP, thus depriving customers of the production cost savings associated with the vaunted third-party suppliers' displacement of more costly Entergy generation. What was expected to be the primary benefit of the ICT was only implemented on March 23, 2009, more than 28

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1 The Commission notes that the testimony at the non-adversarial public hearing on April 6, 2009 was provided by a representative of the Transmission Business Unit ("Entergy Transmission"), which refers to the organization that plans, constructs, and operates the Entergy Transmission System. The "Entergy Transmission System" refers to the collective transmission facilities owned by the Operating Companies and operated on behalf of the Operating Companies by the Transmission Business Unit. EAI as an Operating Company did not put forward any witnesses of its own during the proceeding. Because it is often difficult to distinguish between the decisions of EAI, the Entergy Operating Companies, and the operators of Entergy's Transmission System this Order refers to EAI when referring to Entergy's Arkansas operating Company and "Entergy" when referring to other Entergy entities.
months into the 48-month duration of the experiment approved by the FERC. It is far too soon to tell whether the WPP will succeed in producing sufficient benefits to justify the costs incurred to date in implementing the process -- $24.4 million according to Entergy's Informational Filing on the WPP. It is also noted that the WPP costs are only a part of the total costs of implementing the ICT, which according to Entergy's filings with the FERC cited by AECC have amounted to almost $100 million since 2006 ($69.5 million in 2006; $11.5 million in 2007; and $16.5 million in 2008)\(^2\). It is not clear to what extent the recently reported WPP costs are embedded in the total costs. And as noted by other parties, these are just Entergy's costs and do not include expenditures made by stakeholders and the state commissions participating in and monitoring the ICT's activities.

On the positive side, the Commission finds that the ICT has provided increased transparency on the Entergy System, enhanced transmission access, and helped to address transmission congestion. Based on the evidence in this Docket, however, the Commission is unable at this time to quantify these benefits and awaits with interest the assessment of the FERC later this year expressing its view of how the experiment has measured up to the metrics set forth by the FERC for judging its success. In the meantime, the Commission directs the ICT to file monthly reports on the results of the WPP including the costs and benefits of the experiment as it proceeds. If such reports are already being filed with the FERC pursuant to its order approving the start-up of the WPP, the Commission will accept such reports as compliant with this requirement.

\(^2\) Application in Entergy Services, Inc., FERC Docket No. ER07-93-000, dated October 30, 2006; Settlement Agreement filed on August 21, 2007, in Entergy Services, Inc., FERC Docket No. ER07-93-000; and Application of Entergy Services, Inc., FERC Docket No. ER08-1057, Section F.2.
Transmission Planning and Entergy's Use of “Note B”

The Commission notes that most of the parties agree that the ICT arrangement has brought some measure of transparency to the transmission planning process and improvements in the ICT’s day-to-day operational action on requests for transmission service for competitors of Entergy that use its Open Access Transmission Tariff (“OATT”). In particular, most agree that the planning processes administered by the ICT to develop both the Base Plan and the ICT Strategic Transmission Expansion Plan (“ISTEP”) are beginning to identify reliability and economic expansion projects beneficial to the Entergy transmission system. However, the Commission finds that the general consensus regarding improved transparency of the planning process for the Base Plan and ISTEP does not exist for Entergy’s process of developing the Construction Plan. In order to explain the lack of transparency in Entergy’s process of developing the Construction Plan, it is important to first summarize the differences between the Base Plan, the ISTEP, and the Construction Plan. In short, and as further explained below, the Base Plan addresses reliability concerns, the ISTEP identifies economic upgrades, and the Construction Plan represents Entergy Transmission’s determinations regarding what projects will be built during the next three years to meet both reliability and economic concerns. Stakeholders are invited to participate and submit comments in the development processes of each of the three plans but, as noted more fully below, the stakeholders and the ICT are not involved in the ultimate selection process used by Entergy and its Operating Companies in finalizing the Construction Plan. Therefore, this Commission finds the process used by Entergy to finalize the Construction Plan lacks both independence and transparency.
The Base Plan is developed by the ICT and represents the set of transmission upgrades that the ICT believes are required in order to meet Entergy Planning Criteria and the ICT’s planning criteria enhancements. Base Plan projects are further described in Attachment T to Entergy’s OATT as those needed to maintain reliable service to existing and future native load, to maintain existing firm transmission service reservations, and to maintain network integration of existing Network Resource Interconnection Service (“NRIS”) and Network Integration Transmission Service (“NITS”).

The ISTEP, under Attachment K to the Entergy OATT, is developed by the ICT to identify potential economic upgrades on the Entergy Transmission System. An economic upgrade is defined as accelerating an upgrade that is needed for reliability (i.e., an upgrade that is included in the Base Plan), modifying a Base Plan facility to relieve one or more economic constraints, or constructing a new facility or upgrade that is not included in the Base Plan. The ICT identifies such upgrades based on screening criteria that it develops and provides specified information about the potential benefits of the upgrades. It is important to note that the process outlined in Attachment K does not contemplate that any party will proceed directly with constructing upgrades identified by the ICT. Rather, § 14.6 of Attachment K provides that stakeholders will conduct their own economic analyses of the costs and benefits of the upgrades. In addition, Attachment K specifically provides that neither the ICT nor the Entergy System guarantees that any upgrade identified through the ICT study process will provide economic benefits to the funding customer or to any other party. To meet its obligation under Attachment K, in December 2007 the ICT issued its Phase I ISTEP
report, a high-level screening analysis of potential economic transmission upgrades across the entire Entergy Transmission System and on surrounding transmission systems. Entergy notes that this phase of the report was developed without analysis regarding the potential cost, construction timeline, or levels of production cost savings resulting from these transmission upgrade. (Initial Comments of EAI at 21). The ICT then sought stakeholder input on which of the projects identified in the Phase I ISTEP report should be the subject of a more detailed analysis. In April 2008, in response to stakeholder input, the ICT ranked the sets of upgrade projects. The top five projects, based on stakeholder input, were those indicated on page 16 of the Annual Report. After further study, the ICT concluded that three of the five projects showed potential economic benefits. These included (1) South Louisiana Bulk, (2) Central Arkansas 230 kV, and (3) Acadiana Area.

Entergy's Construction Plan, developed after stakeholder comments between April 30, 2008 and March 3, 2009, and revised downward earlier this year to reflect reduced demand resulting from the current and on-going economic downturn, includes all transmission projects that Entergy expects to construct or initiate to construct over the 2009-2011 time period. It includes projects that Entergy believes are necessary to satisfy Entergy’s Planning Criteria as well as other economic upgrade projects identified by Entergy.

All of the active parties to this Docket, with the lone exception of EAI, agree that transparency is lacking with the selection process used by Entergy in developing the Construction Plan and in determining the ranking and subsequent benefit of reliability.

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projects. It is not clear, for example, how the ISTEP projects become part of the Construction Plan as Base Plan projects that Entergy commits to build. Entergy responded to the comments of parties raising the transparency issue by pointing out that under Attachment K stakeholders are provided an opportunity to provide input, including written comments, regarding “data gathering and the study process” associated with development of the Construction Plan; “other inputs, assumptions, and methodologies relied on in developing the plan; the projects included in the plan; and why projects may not be included” (EAI Post-Hearing Comments at 20). This process, Entergy asserts, is both transparent and participatory. Entergy goes on to explain that under the OATT it is the Operating Companies that are the transmission provider, that are obligated to provide reliable service at a reasonable cost, and that are responsible for meeting the requirements to make comparable and non-discriminatory open-access transmission service available and for meeting all applicable NERC and SERC requirements. Entergy concludes that “the Operating Companies thus should decide what facilities are or are not included in the Construction Plan.” (EAI, Post-Hearing Comments at 25). Entergy consistently made clear at the Commission’s April 6, 2009 hearing as well as in its pre- and post-hearing filings that Entergy — and only Entergy — decides what facilities are built under the Construction Plan.

Finally, Entergy points out that the ICT must prepare a report identifying and explaining the differences between the ICT-developed Base Plan and the Entergy Transmission-developed Construction Plan.4 Entergy offers to conduct a technical

4 Entergy and the ICT submitted such a report to the FERC on May 8, 2009, and the ICT filed the report with the Commission on May 11, 2009. See Differences Report Between ICT Base Plan and Entergy Construction Plan, Entergy Services, Inc., Docket No. ER05-1065-000. This report is discussed more fully below.
conference to address transmission planning issues and questions, including issues and questions related to the development of the Base Plan and the Construction Plan. (Id. at 26). The Commission accepts Entergy’s proposal to conduct such a technical conference, under conditions specified in more detail below.

What is missing in the above picture, the Commission finds, is a direct response by Entergy to the request of the parties for insight into the selection process used by the Operating Companies. If the Operating Companies are “the decider,” it is reasonable to ask how they reach their decisions on what facilities will be included in the Construction Plan. Notwithstanding the improvements in transparency resulting from the ICT planning process, this lack of transparency in what the Operating Companies “decide” to build raises serious questions as to the independence of the Entergy Transmission System from influence by the Entergy System over what transmission is constructed in the Entergy footprint and why.

As the ICT expresses it, while the development of the draft Construction Plan shares some of the transparent elements of the ICT’s Base Plan development process, “there are elements that are less transparent.” (SPP, Post-hearing Comments at 3.) The ICT goes on to note that “...Entergy’s methodology for incorporating non-reliability considerations into its cost/benefit analysis and, in turn, its determinations regarding the specific projects included in the Construction Plan, are not publicly disclosed.” Similarly, according to the ICT, “there is no publication of the process by which Entergy determines how the differences between the Construction Plan and the Base Plan are incorporated into the Construction Plan.” (Ibid.) Thus, the ICT concludes, “the development of the Entergy Construction Plan is comparatively less transparent than
the process associated with the ICT’s Base Plan.” (Ibid.)

The ICT notes that it is an “understandable source of stakeholder frustration that determinations of what projects are ultimately included in Entergy’s Construction Plan are based on analyses which remain somewhat unclear.” (Id. at 4). Furthermore, according to the ICT, “Inclusion in Entergy’s Planning Criteria of the methodology for determining a project’s cost/benefit score, and how this score is used in making upgrade determinations, could temper some of this frustration.” (Ibid.).

The Commission agrees with the ICT observations regarding the lack of transparency in Entergy’s Construction Plan process. The Commission also agrees with the ICT’s comment that another planning feature that could potentially be improved through greater transparency involves the use of operating guides, and related assumptions, in the development of Entergy’s Construction Plan. As the ICT states, “Currently, little is understood about how these operating guides are factored into Entergy’s construction decisions because relevant support and information is not provided to stakeholders.” (Ibid.). The Commission also agrees with the ICT that while Entergy may have legitimate confidentiality concerns, “sharing of this information (even if on some redacted or coded basis) could improve stakeholder confidence in Entergy’s Construction Plan and permit a more informed evaluation of Entergy’s ultimate planning decisions.” (Id. at 4-5).

The Commission finds reasonable the assertion by Suez that any cost-benefit analysis (“CBA”) currently performed by Entergy to assist in determining the ranking and subsequent benefit of reliability projects in the Construction Plan should be coordinated by the ICT and could be performed by an independent contractor. (Suez,
Post-hearing Comments at 3). Further, the Commission finds reasonable Suez’s recommended course of action:

...The inputs into the CBA and results from the CBA should be shared, at the completion of the Construction Planning Process with those state commissions whose states are a part of the Entergy footprint. There should be an opportunity for consideration and comment on the inputs into the CBA and results from the CBA with the final CBA being shared with regulators and stakeholders. The ICT, stakeholders and state regulators should be provided a clear understanding of the projects to be constructed and their benefits to consumers from a reliability and economic standpoint, as well as the basis for their final ranking.

(Ibid, emphasis in original).

The Commission is aware of no provisions in Attachment K or elsewhere in the OATT that would prohibit Entergy from implementing a process similar to that described above and, given our assent to Entergy’s offer to conduct a technical conference on the Construction Plan and the Base Plan, directs that this issue and others raised by the parties in this Docket regarding the two plans (and the differences between them, as identified by the ICT) be addressed in the conference, which we suggest be coordinated with Entergy’s annual Transmission Summit, now scheduled for August 11, 2009.

Finally, the Commission takes notice of the May 8, 2009, joint filing by Entergy and the ICT of the “SPP Report on the Differences Between the 2009 ICT Base Plan and the 2009-2011 Entergy Construction Plan,” as required by the FERC’s orders approving the establishment of the ICT and Entergy’s OATT. The 14-page report, a copy of which was filed in this Docket on May 14, 2009, provides details concerning Base Plan projects not included in the Construction Plan and Construction Plan projects not included in the Base Plan, as well as other information, and has tables providing Entergy’s
explanation of the differences for the inclusion or exclusion of specific projects. Of concern to the Commission is the fact that of the 20 Base Plan projects not included in the Construction Plan, 13 of them were rejected by Entergy owing to Entergy's apparent determination that Entergy is satisfying the North American Electric Reliability Corporation ("NERC") standards through the use of Note B of NERC Standards TPL-001 and TPL-002. The other 7 projects were rejected either because Entergy determined that redispach will solve the overload (and that NERC standards permit system adjustments as mitigation) or that they had been added to the Base Plan due to the ICT's planning criteria enhancement (the invocation of "the 100 MW Rule," which, as noted below, Entergy does not observe).

In the Annual Report, the ICT raises the issue of differences between itself and Entergy with regard to the interpretation of Note B to NERC standards TPL-001 and TPL-002. (Annual Report at 11). While both Entergy and the ICT allow the interruption of firm load to maintain reliability, the ICT interpretation limits the interruption of firm load to 100 MW in the Base Plan. In short, the new "100 MW Rule" requires Entergy to identify a mitigation plan "apart from load shedding" for any N-1 contingency which results in a thermal or voltage violation, internal or external to the faulted element, in which the breaker-to-breaker contingency relieves the violation and in which the Consequential Load exceeds 100 MW on peak. AECC states that it is Entergy's interpretation that Note B and the FERC discussion of non-consequential load in Order 693 permits the interruption of all load between two breakers for reliability purposes.

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Note B states: "(b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserve) electric power transfers."
This, AECC notes with concern, not only includes the initial interruption but also the continuation of the interruption until the problem is corrected. AECC concludes by stressing the fact that it is Entergy's interpretation that controls actual construction and that its attachments show that Entergy plans on allowing "hundreds of megawatts of its own, as well as AECC's members' loads to be exposed to extended outages for single contingency events." (Initial Comments of AECC at 3-4).

The Commission anticipates that stakeholders will submit comments to the FERC on the Differences Report and Entergy's reliance on Note B, expressing their further views on the degree to which Entergy's explanations of its selection process for the Construction Plan provide additional transparency, or not. For now, the Commission observes that there is little that is new in the Differences Report from what was filed or testified to at the hearing in this Docket. Unless Entergy discloses its methodology and metrics for incorporating non-reliability considerations into the cost/benefit analysis underlying its project selection process, the Commission questions how much will be accomplished at the technical conference Entergy intends to conduct. In the meantime, the Commission invites recommendations from the parties on how the different interpretations of Note B might be resolved by the Commission. Finally, in order to provide openness to Entergy's development of a Construction Plan and Entergy's use of Note B in the development of the Construction Plan, the Commission also directs Entergy to provide the metric or metrics it uses in determining when to use Note B rather than to invest in the transmission facilities.

**Entergy and Possible Membership in the SPP RTO**

The Commission finds that there is strong support among the parties for
examining the costs and benefits of full SPP membership by Entergy versus continuation of the ICT services agreement. An intriguing aspect of the SPP membership option is that EAI has given notice\(^6\) that it will exit the Entergy System Agreement on or before December 19, 2013.\(^7\) Therefore, whether Entergy as a whole or EAI as a stand-alone entity could join the SPP RTO is unclear. Consequently, what happens with Entergy’s transmission planning at the end of EAI’s exit from the System Agreement is a question that must be given careful consideration in the context of the FERC’s pending consideration of EAI’s February 2, 2009 request (joined in by Entergy Mississippi, Inc., now under consideration in FERC Docket No. ER09-636-000) that FERC clarify the terms under which the two companies can withdraw from the cost-sharing system that forces EAI’s ratepayers to pay hundreds millions of dollars each year to the other operating companies.\(^8\)

The Commission adopts the suggestion made by the Interested Parties that SPP conduct, with the assistance of an independent third party, a comprehensive cost/benefit evaluation of the possibility of EAI’s – as well as Entergy’s – full SPP membership versus ICT services arrangements, as opposed to the status quo ante. Such a study would need to address technical barriers and other obstacles to Entergy’s participation in SPP, such as:

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\(^6\) Letter from EAI President and CEO Hugh McDonald to other Operating Company presidents and CEOs, dated December 19, 2005, giving required 96-month notice of withdrawal from the System Agreement, pursuant to Section 1.01 of the Agreement.

\(^7\) On November 7, 2007, Entergy Mississippi, Inc. (EMI) provided the same notice by letter of its intent to exit the system agreement effective on or before November 7, 2015.

\(^8\) The Commission notes that in the first two-years of EAI’s bandwidth payments under the System Agreement Arkansas ratepayers have paid approximately $500 million to Entergy’s other Operating Companies. This number is expected to approach a combined total of $900 million by the end of the third year of bandwidth payments.
• the difference in planning standards (e.g., Entergy's broader interpretation of load-shedding mitigation strategies under Note B from NERC Reliability Standard TPL-002-0 vs. the 100 MW rule employed by the SPP as ICT);

• Entergy's five-year transmission planning horizon vs. SPP's ten-year horizon;

• the need for Entergy and its Operating Companies to accept the authority of the SPP Board to make construction decisions for new transmission;

• the different cost allocation methods used by Entergy and the SPP for new transmission lines;

• the costs and benefits to Entergy customers of moving to the energy imbalance market operated by the SPP and other markets under consideration by the RTO.

The Commission also directs the SPP to provide a report by July 1, 2009, comparing and contrasting the transmission planning horizon used by the SPP as RTO with that of Entergy. Likewise, the report should address the planning horizons used by other RTOs in the United States.

The Commission expects that in developing a Request For Proposal ("RFP") for the selection of an independent third-party consultant to conduct the cost benefit analysis the SPP would specify that at least two cases be examined: (a) the costs and benefits of membership in SPP by EAI as a stand-alone entity; and (b) the costs and benefits of full membership in SPP by the Entergy System as a whole. The Commission directs that the SPP report on or before July 1, 2009, on the progress in establishing a process for conducting such an analysis. The Commission directs the SPP to submit the results of the cost-benefit study by December 31, 2009. EAI is directed to assist the SPP in completing this study as requested by the SPP.

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9 The Commission is aware that the current 10 year planning horizon used by the SPP is expected to change to a much longer planning horizon.
Seams Agreement

There is general consensus among the parties and the ICT, and the Commission agrees, that Entergy should move with dispatch to negotiate and complete a comprehensive seams agreement with the SPP RTO, working with the stakeholders of both SPP and the ICT to develop such an agreement. The Commission believes that this process would be furthered by a FERC decision to require the development of such an agreement by a date certain, ideally prior to the end of the ICT's third year of operations in November 2009. The ICT opines in its Comments (SPP Post-Hearing Comments at 9) that if agreement can be reached on difficult cost allocation issues, it may be possible to finalize and implement a comprehensive seams agreement within six to nine months. The Commission agrees with observations of parties made in this Docket that the need for a seams agreement and the elimination or reduction of “rate-pancaking” would likely be obviated or significantly reduced by Entergy’s full membership in the SPP RTO. In the meantime, however, the Commission urges the ICT and Entergy to redouble their efforts to reach a seams agreement and to update the recent analysis conducted for the ICT by CRA International, “Economic Impact of Eliminating Pancaked Transmission Rates between Entergy and SPP”, dated March 23, 2009, to account for recent changes in the financial and energy markets and the implications that the current economic crisis and proposed energy and environmental legislation and regulation may have for load and energy forecasts within the Entergy System.

The Commission also invites the SPP as an RTO, the ICT, and the parties to make recommendations concerning what needs to be included in a seams agreement and, in particular, for the SPP to develop and share a draft agreement addressing seams issues
for the consideration and comment of the parties. The Commission believes it would be helpful to hear from the SPP concerning seams agreements it already has with other entities and whether such agreements developed by other RTOs can be useful models for resolving issues between Entergy and SPP. The parties should file their recommendations and the information on existing seams agreements the SPP has currently executed should be filed by July 1, 2009.

Cost Allocation and Attachment T

As noted by the ICT, the cost allocation methods for transmission expansion within Entergy and SPP differ substantially. (SPP Post-Hearing Comments at 8). For reliability upgrades, as noted above, Entergy makes the ultimate determination, based upon Entergy’s undisclosed cost-benefit analysis, whether a specific reliability project should be included in Entergy’s Construction Plan, and Entergy is responsible for all costs of the included projects. In contrast, the SPP as an RTO has developed a cost allocation methodology to distribute the costs associated with reliability upgrades among its various members. This methodology is detailed in Attachment J of the SPP FERC Tariff and generally socializes one-third of the cost of any reliability upgrade among SPP members, while allocating the remaining two-thirds of the cost based on the megawatt-mile (“MW-mile”) impact of the upgrade. The Commission interprets the SPP’s comments as suggesting that some derivative of the SPP method “could promote more optimal planning and more closely align the benefits and costs of these upgrades” on the Entergy System.

Regarding economic projects, SPP has two approaches that are available. Recently the SPP developed a Balanced Portfolio methodology which optimizes the
transmission system with respect to economic generation within the region and provides that the cost allocation for such upgrades will be recovered by postage stamp rates across the RTO region. This is in addition to a mechanism that provides that a member of the RTO can voluntarily fund an upgrade and receive credits from future users of the facility. In contrast, the ICT notes, Entergy relies on the ICT's determination regarding whether a particular upgrade should be classified as a reliability upgrade (Base Plan) or an economic upgrade (Supplemental). All Supplemental upgrades under the Entergy cost allocation process (as provided for and approved by FERC in Attachment T to Entergy's OATT) are participant-funded with the requesting customer receiving both long-term and short-term financial payments for any future use of these projects. SPP states its belief that certain aspects of the SPP Balanced Portfolio process could be incorporated into the different long-term planning analyses conducted by the ICT and Entergy that consider economic projects.

The Commission agrees with the ICT that these fundamental differences regarding cost allocation for both reliability and economic upgrades present significant complications to the development of a comprehensive seams agreement and declares our intent to follow closely the analysis we would expect Entergy to make concerning the costs and benefits of a possible move towards planning standards similar to those used by SPP.

The Commission welcomes Entergy's offer to conduct a workshop to address questions relating to Attachment T, which we suggest might reasonably be held in conjunction with the upcoming Transmission Summit in August of this year.

Accordingly, the Commission orders and directs as follows:
1. The Commission directs the ICT to file monthly reports on the results of the WPP including the costs and benefits of the experiment as it proceeds. If such reports are already being filed with the FERC pursuant to its order approving the start-up of the WPP, the Commission will accept such reports as compliant with this requirement.

2. The Commission accepts Entergy's offer to conduct a technical conference on the Construction Plan and the Base Plan, and directs that this issue and others raised by the parties in this Docket regarding the two plans (and the differences between them, as identified by the ICT) and questions regarding Attachment T be addressed in the technical conference, which should be coordinated with Entergy's annual Transmission Summit, now scheduled for August 11, 2009.

3. The Commission invites recommendations from the parties on how the different interpretations of Note B might be resolved and whether and how the Commission might advance the prospects of such resolution, including recommendations regarding possible Commission actions to resolve this difference. The Commission also directs Entergy to provide the metric or metrics it uses to determine when to use Note B than to invest in the transmission facilities. Such recommendations and comments shall be filed by noon on July 1, 2009.

4. The Commission directs the SPP to conduct, with the assistance of an independent third party, a comprehensive cost/benefit evaluation of full SPP membership by both EAI (as a stand alone entity) and Entergy versus the
existing ICT services arrangements, as opposed to the status quo ante. Such study shall address the technical barriers and other obstacles to Entergy's participation in SPP as identified hereinabove. The Commission directs that the SPP report on or before July 1, 2009, on the progress in establishing a process for conducting such an analysis. The Commission directs the SPP to submit the results of the cost-benefit study by December 31, 2009. EAI is directed to assist the SPP in completing this study as requested by the SPP.

5. The Commission also directs the SPP to file a report by July 1, 2009, comparing and contrasting the transmission planning horizon used by the SPP as RTO with that of Entergy. Likewise, the report shall address the planning horizons used by other RTOs in the United States.

6. The Commission directs the ICT and Entergy to redouble their efforts to reach a seams agreement and to update the recent analysis conducted for the ICT by CRA International, “Economic Impact of Eliminating Pancaked Transmission Rates between Entergy and SPP”, dated March 23, 2009, to account for recent changes in the financial and energy markets and the implications that the current economic crisis and proposed energy and environmental legislation and regulation may have for load and energy forecasts within the Entergy System.

7. The Commission also directs the SPP as an RTO, the ICT, and the parties to make recommendations concerning what needs to be included in a seams agreement and, in particular, for the SPP to develop and share a draft agreement addressing seams issues for the consideration and comment of the
parties. The Commission believes it would be helpful to hear from the SPP concerning seams agreements it already has with other entities and whether such agreements developed by other RTOs can be useful models for resolving issues between Entergy and SPP. The parties should file their recommendations and the information on existing seams agreements the SPP has currently executed should be filed by July 1, 2009.

8. The Commission directs its General Counsel to cause an official copy of this Order to be filed in FERC Docket No. ER05-1065-000 as the official comments of the Commission on the ICT's Annual Performance Report.

9. The Secretary of the Commission forthwith shall serve by electronic mail a copy of this Order on counsel for all parties to this Docket.

BY ORDER OF THE COMMISSION,

This 29th day of May, 2009.

Paul Suskie, Chairman

Colette D. Honorable, Commissioner

Olan W. Reeves, Commissioner

Diana K. Wilson, Acting Secretary of the Commission
TEXAS
INFORMATION
Public Utility Commission of Texas

Memorandum

TO: Commissioner Donna L. Nelson
Commissioner Kenneth W. Anderson, Jr.

FROM: Chairman Barry T. Smitherman

DATE: July 1, 2009

RE: July 2, 2009 Open Meeting; Agenda Item No. 33; Discussion and possible action on electric utility reliability, electric utility restructuring, ERCOT oversight, market-development activities in areas outside of ERCOT, and electric reliability standards and organizations arising under federal law

SPP has requested feedback from this Commission regarding implementation of proposed tariff provisions in response to FERC Order No. 719. The tariff provisions require market participants who want to offer controllable load as a resource in the Energy Imbalance Service (EIS) Market on their own behalf or as an Aggregator of Retail Customers (ARC) to obtain a declaration that participation of their resources in the EIS Market is not precluded by the laws or regulations of the relevant electric retail regulatory authority.

By way of background, FERC Order No. 719 required RTOs and ISOs to address certain reforms in four areas: (1) demand response and scarcity pricing; (2) long-term power contracting; (3) market monitoring policies; and (4) RTO and ISO responsiveness. At issue in this memo is the requirement that all RTOs and ISOs accept bids from demand response resources on a basis comparable to any other resources for ancillary services that are acquired in a competitive bidding process, if the demand resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-cleaning price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.

FERC also required amendment to RTO and ISO market rules to allow an ARC to bid demand response on behalf of retail customers directly into the organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit the customers aggregated in the bid to participate. FERC indicated that RTOs and ISOs should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority.

2 The broad term “relevant electric retail regulatory authority” applies to a range of entities, including State Commissions, electric cooperative boards, and municipal authorities.
3 Order No. 719 at P 47.
4 Order No. 719 at P 154, 155.
5 Order No. 719 at P 49 n.78.
but the Order also does not require a retail regulatory authority to make any showing or take any 
action in compliance with the rule.\(^6\)

The SPP Board of Directors approved proposed revisions to Attachment AE of the SPP Tariff, 
which governs the EIS Market, and included the following subsection to Section 1.2.2 – Application and Asset Registration:

(i) A Market Participant wishing to offer controllable load as a resource in the EIS Market must include in its application and registration a certification by means of a declaration by the relevant electric retail regulatory authority, as applicable, that participation in the EIS Market by its controllable load resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Controllable load resources must meet all application, registration and technical requirements applicable to other resources offering imbalance energy in the EIS Market. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the EIS Market in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s). [emphasis added]

This provision generated a great deal of controversy, but the Board voted to approve the language and it is now pending at FERC.\(^7\) Proponents of requiring this “certification by means of a declaration” argue that without it, demand response resources and ARCs would be self-regulating their participation in the EIS Market and that it may place SPP in the untenable position of having to interpret state retail laws and regulations when it acts on a customer’s application to register its controllable load resources in the EIS Market. On the other hand, opponents of requiring this certification argue that it exceeds the intent of Order No. 719, that it places an additional requirement on demand response resources that do not apply to other resources, and that it enacts a barrier to participation by load. Opponents argue that Order No. 719 requires RTOs to treat demand response resources on a comparable basis to other resources in the RTO’s organized ancillary services markets, and requiring demand response resources to petition for a declaration does not provide comparable treatment with generation resources.

Although it is still uncertain whether FERC will accept SPP’s proposed language, SPP has requested the Regional State Committee (RSC) members to report back regarding implementation of this provision at the July 27, 2009 meeting. While I understand the positions of all the parties, this issue is difficult from a procedural standpoint. Clearly, it is a policy of the PUC to promote demand participation in markets, and P.U.C. SUBST. R. 25.507 specifically provides for Emergency Interruptible Load Service (EILS) in ERCOT. In fact, Loads Acting as a Resource are an essential part of the ERCOT market. Regarding aggregators, PURA §39.353

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\(^6\) Order No. 719 at PP 53, 155.
\(^7\) Docket No. ER09-1050, Southwest Power Pool, Inc.
and P.U.C. SUBST. R. 25.111 pertain to aggregators for purposes of purchasing electricity, not for purposes of demand participation as a resource in the market. I think everyone would agree that neither PURA nor the PUC rules preclude controllable load from participating in the market in Texas. The question becomes how to make a “certification by means of a declaration.” I do not believe that a declaratory order would be appropriate since there may not be any controversy and advisory opinions are prohibited. Adopting a formal rule seems inappropriate because we would not be providing any guidance beyond a requirement that participation be in conformance with the relevant rules of the RTO or ISO. Therefore, to satisfy the SPP’s desire to not be held responsible for this legal determination, I propose that we delegate authority to the Executive Director to respond to any such request for certification by issuing a letter to the SPP stating that there are no PUC rules or PURA provisions that preclude controllable loads from participating in the EIS Market, provided that such participation is in conformance with the applicable RTO guidelines. The Executive Director would also have an ongoing responsibility to immediately notify SPP should there be any changes to PURA or PUC rules that would alter this determination. SPP has indicated that it would accept a “certification by means of a declaration” in this form.

The complicating factor comes from the attempt by various utilities to include interpretation of state-approved retail tariffs. As I understand the issue, some utilities are concerned over potential situations where a customer on an interruptible tariff may attempt to participate in the market, thereby receiving double benefit for essentially the same capacity and possibly not being available when called upon by either SPP or the utility. While I think situations like this could be remedied with proper market guidelines, I understand the desire to have the retail regulatory authority make the determination in the event there is disagreement between the market participant and the utility. Although some of those who promoted SPP’s proposed tariff language did not want the burden of seeking affirmative action to disqualify the resource’s participation, I do not see any way to address this matter except on a case-by-case basis given the volume of state-approved retail tariffs, the frequency by which those tariffs are amended, and the ability for customers to change the tariff under which they are receiving service without notice to the PUC. This makes it impractical, if not impossible, for a utility to shift its burden onto this Commission regarding ongoing interpretation of applicable tariff provisions. Therefore, I suggest that within the process of the letter certification by the Executive Director, the affected utility be given the opportunity to object to the specific load resource’s participation in the market under its current tariff. If the utility does not object, then the Executive Director issues the final letter certification noting that there was no objection by the utility. If the utility objects, then that specific fact situation can be addressed by the Commission. Just as the Commission’s Executive Director will have an ongoing responsibility to notify SPP should PURA or PUC rules change, the utility is on notice to continue to evaluate any future changes to the specific terms of the tariff applicable to the resource.

I believe this approach is the best alternative to meet three objectives: (1) satisfy SPP’s desire to not be in the position of having to make legal determinations, (2) not be overly burdensome on load such that market participation is discouraged contradictory to the intent of FERC Order No. 719, and (3) provide an adjudicatory forum in the event there is a real controversy but not require excessive action by the regulatory authority to comply with Order No. 719.

I look forward to discussing this matter at the open meeting.
Statement of Commissioner Michael C. Moffet
to the Southwest Power Pool Regional State Committee

Re: Demand Response and 3rd Party Aggregators in Kansas

July 2009 Quarterly Meetings

At the last quarterly meetings, the various States were asked to review and analyze the demand response issue involving FERC Order 719, which has to do with demand response participation in markets, and to what extent under state laws independent demand aggregators can bid it into the SPP markets. This is an area where the FERC had ordered SPP to allow demand aggregators to plan in their markets, but only to the extent allowed by the laws of the States that have retail jurisdiction. I am reporting on the ongoing analysis of the issue in Kansas.

The major issue in Kansas is that Kansas law prevents competition for retail electric service and has designated certificated territories for specific utilities to provide retail service. The retail electric supplier is the only Load Serving Entity (LSE) that may sell electricity at the retail level. This creates a potential conflict with the premise of allowing retail customers to bypass the LSE to bid demand response in a competitive market -- either through individual demand response or through aggregators of retail customers (ARCs).

The SPP has now put into its proposed compliance filing on the FERC order a requirement that such demand aggregators must obtain a "declaration" from the state regulatory in order to participate in the markets that it is appropriate to do so under state law. How this would be accomplished in Kansas is still ambiguous.

Therefore, the KCC intends to open a general investigation (GIV) docket to seek input from affected parties on what issues should be considered and how Kansas should move forward in light of applicable laws and regulations. First, the interested parties will be asked for input regarding whether Kansas law prohibits participation in such markets and, if so, to what extent. Second, the parties will be asked to assume that Kansas law does not prohibit participation and provide input on the practical implications of such participation such as:

- What are the impacts on the certificated utility and its other retail customers of such a program?
- What would be the effect on utility rate design and revenue collection?
- How would customers' demand rates be estimated?
- How would the demand sales be transacted from an operational standpoint?

- Would existing or planned demand response programs, and the costs associated with implementation of these programs, be undermined by the proposed aggregation causing a loss in benefits to retail ratepayers?

This is not an exclusive list and the KCC will seek input from the participating parties to ensure that a complete list of issues is compiled and addressed before issuing an Order setting forth policy or other directives to parties affected by demand response aggregation.

Michael C. Moffet  
Commissioner  
Kansas Corporation Commission
PROJECT TRACKING, Current SPP Process:
SPP actively monitors and supports the progress of transmission expansion projects, emphasizing the importance of maintaining accountability for areas such as grid regional reliability standards, firm transmission commitments and tariff cost recovery.

Each quarter, SPP staff solicits feedback from the project owners to determine the progress of each approved transmission project. This quarterly report charts the progress of all SPP Transmission Expansion Plan (STEP) projects approved either directly by the Board of Directors or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

Results:

Project Summary:
There are 451 projects with an approximate engineering and construction cost of $3.2 billion currently being tracked. There has been a category added for Balanced Portfolio projects for which Notifications to Construct (NTCs) have been recently issued, with a total estimated cost of $700 million.

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Number of Upgrades</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>264</td>
<td>$1,178,086,228</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>12</td>
<td>$70,825,000</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$13,472,843</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>55</td>
<td>$427,168,763</td>
</tr>
<tr>
<td>Generation Interconnect</td>
<td>12</td>
<td>$92,727,000</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>18</td>
<td>$700,168,500</td>
</tr>
<tr>
<td>Other Sponsored Upgrades</td>
<td>81</td>
<td>$747,888,095</td>
</tr>
<tr>
<td><strong>TOTALS</strong></td>
<td><strong>451</strong></td>
<td><strong>$3,230,336,429</strong></td>
</tr>
</tbody>
</table>

Figure 1: 2009 3rd Quarter Project Summary
Regional Reliability Project Summary:

Regional reliability projects include all tariff signatory projects identified in an SPP study to meet regional reliability criteria for which NTCs have been issued. There are 264 regional reliability upgrades with an approximate engineering and construction cost of $1.2 billion.

There were thirty-four upgrades, with latest Engineering and Construction (E&C) cost estimates at $115 million, completed in the second quarter of 2009. There are ninety upgrades, with latest E&C cost estimates at $381 million on schedule. Transmission owners have provided mitigation plans for ninety-nine upgrades with current E&C estimates of $409 million. There are two upgrades which have been delayed beyond the Regional Transmission Organization (RTO) determined need date without having an interim mitigation plan.

Transmission Service/Generation Interconnection (TSR/GI) Project Summary:

This category contains projects identified as needed to support new Transmission Service (TSR) and Generation Interconnection (GI) service agreements. There are sixty-seven TSR/GI upgrades with an E&C cost of $520 million.
There were seven upgrades with latest estimates at $12 million completed in this category during the second quarter of 2009. There are fifty-five upgrades estimated at $490 million on schedule. Transmission owners have provided mitigation plan for two projects valued at $5.5 million. No upgrade has been delayed beyond the RTO determined need date without having an interim mitigation plan.

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Total</th>
<th>Complete</th>
<th>On Schedule</th>
<th>On Schedule - Later in 10 yr Horizon (NTCs Issued)</th>
<th>Behind Schedule - With Mitigation</th>
<th>Behind Schedule - Without Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>264</td>
<td>41</td>
<td>90</td>
<td>32</td>
<td>99</td>
<td>2</td>
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<td></td>
<td>$1,178,086,228</td>
<td>$140,278,157</td>
<td>$384,147,194</td>
<td>$235,984,254</td>
<td>$408,661,623</td>
<td>$9,015,000</td>
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<td>Transmission Service</td>
<td>55</td>
<td>8</td>
<td>43</td>
<td>2</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$427,168,763</td>
<td>$12,966,800</td>
<td>$397,560,296</td>
<td>$11,100,000</td>
<td>$5,541,667</td>
<td>$0</td>
</tr>
<tr>
<td>Generation Interconnect</td>
<td>12</td>
<td>0</td>
<td>12</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$92,727,000</td>
<td>$0</td>
<td>$92,727,000</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
</tbody>
</table>

Figure 2: Project Status

Conclusions:
The 3rd Quarter Project Tracking saw completion of 41 upgrades worth an estimated $126 million.

There are two regional reliability upgrades and two zonal reliability upgrades for Westar Energy Inc. delayed beyond the RTO Determined need date which did not have SPP Staff approved mitigation plans. SPP will continue to work with Westar in determining necessary mitigations to these reliability issues.
### SPP 3rd Quarter 2009 Project Tracking List - Branch_Xfr

<table>
<thead>
<tr>
<th>PID</th>
<th>RC</th>
<th>US</th>
<th>Area</th>
<th>Project Name</th>
<th>Project Type</th>
<th>Service Date</th>
<th>Estimated Lead Time</th>
<th>Project Cost</th>
<th>Grid Area</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>19984</td>
<td>104</td>
<td>1038</td>
<td>S15</td>
<td>Jun - Springfield - Broklyn 161 kV line</td>
<td>transmission service</td>
<td>06/01/08</td>
<td>06/01/06</td>
<td>$330,000</td>
<td>Prior to BPF cap</td>
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<tr>
<td>19992</td>
<td>115</td>
<td>1035</td>
<td>S20</td>
<td>Jun - Northwood Transmission - Aurora Tap 345 kV</td>
<td>transmission service</td>
<td>03/01/09</td>
<td>03/01/08</td>
<td>$2,160,000</td>
<td>On Schedule beyond 4 Year Horizon</td>
<td></td>
</tr>
<tr>
<td>19967</td>
<td>114</td>
<td>1034</td>
<td>S20</td>
<td>Jun - Northwood Transmission - Bart-T-Bare 138 kV line</td>
<td>transmission service</td>
<td>03/01/08</td>
<td>03/01/07</td>
<td>$35,900</td>
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<tr>
<td>19947</td>
<td>116</td>
<td>1032</td>
<td>S20</td>
<td>Jun - Alumine Tap - Bare</td>
<td>transmission service</td>
<td>03/01/09</td>
<td>03/01/07</td>
<td>$1,180,000</td>
<td>On Schedule beyond 4 Year Horizon</td>
<td></td>
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<tr>
<td>20002</td>
<td>119</td>
<td>1032</td>
<td>S20</td>
<td>GTR - Pegue Junction 138/60 kV line</td>
<td>regional reliability</td>
<td>04/25/08</td>
<td>06/01/09</td>
<td>$1,829,100</td>
<td>Complete</td>
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<tr>
<td>19967</td>
<td>126</td>
<td>1032</td>
<td>S20</td>
<td>Jun - Lowwood to McIntosh Switch 69 kV line</td>
<td>regional reliability</td>
<td>04/25/08</td>
<td>06/01/08</td>
<td>$1,180,000</td>
<td>On Schedule beyond 4 Year Horizon</td>
<td></td>
</tr>
</tbody>
</table>

**Legend:**
- Blue: Complete
- Green: On Schedule 4 Year Horizon
- Green: On Schedule beyond 4 Year Horizon
- Yellow: Behind schedule, require re-evaluation due to anticipated load forecast changes
- Red: Delayed beyond the RTO Determined need date and no mitigation plan provided

**Project types:**
- “Sponsored” and “Regional reliability - non OATT” do not receive NTC’s and are not filed at FERC but are being tracked because they are expected to be built in the near term.

**Notes:**
- PID: Project Identification Number
- Date: Estimated date of service
- Area: Area in which the project is located
- NTC_ID: National Transportation Company Identification Number
- Estimate: Estimated cost of the project
- Need Date: Date by which the project is needed
- Final Cost: Final estimated cost of the project
- Comments: Any additional information or notes about the project
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Source</th>
<th>Line</th>
<th>Project Name</th>
<th>Type</th>
<th>Voltage</th>
<th>Region</th>
<th>Start Date</th>
<th>End Date</th>
<th>Status</th>
<th>Cost</th>
<th>Duration</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>101</td>
<td>10105</td>
<td>10106</td>
<td>Line - Shreveport breaker work</td>
<td>Regional</td>
<td></td>
<td>05/01/09</td>
<td>12/31/09</td>
<td>Completed</td>
<td>$5,000,000</td>
<td>8 months</td>
<td></td>
<td></td>
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<td>10107</td>
<td>10108</td>
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<td>Completed</td>
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<td>8 months</td>
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<td></td>
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<td>10109</td>
<td>10110</td>
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<td>05/01/09</td>
<td>12/31/09</td>
<td>Completed</td>
<td>$5,000,000</td>
<td>8 months</td>
<td></td>
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<td>10112</td>
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<td>05/01/09</td>
<td>12/31/09</td>
<td>Completed</td>
<td>$5,000,000</td>
<td>8 months</td>
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<td>105</td>
<td>10113</td>
<td>10114</td>
<td>Line - Shreveport breaker work</td>
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<td>05/01/09</td>
<td>12/31/09</td>
<td>Completed</td>
<td>$5,000,000</td>
<td>8 months</td>
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<tr>
<td>106</td>
<td>10115</td>
<td>10116</td>
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<td>05/01/09</td>
<td>12/31/09</td>
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<td>8 months</td>
<td></td>
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<td>107</td>
<td>10117</td>
<td>10118</td>
<td>Line - Shreveport breaker work</td>
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<td>8 months</td>
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<td>108</td>
<td>10119</td>
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<td>05/01/09</td>
<td>12/31/09</td>
<td>Completed</td>
<td>$5,000,000</td>
<td>8 months</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- Project IDs are unique identifiers assigned to each project.
- Source columns indicate the origin of the project information.
- Line columns specify the line affected by the project.
- Project Name columns detail the specific work being performed.
- Type columns provide the type of work (e.g., breaker work).
- Voltage columns indicate the voltage level of the line affected.
- Region columns specify the geographic area where the project is located.
- Start Date and End Date columns show the timeline for project completion.
- Status columns indicate whether the project is completed or ongoing.
- Cost columns show the total cost of the project.
- Duration columns specify the duration of the project.
It has been identified that the CBs in this station need to be converted from oil to gas to meet environmental requirements. The CBs will need to be replaced.

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Type</th>
<th>Customer</th>
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<th>Rate</th>
<th>Completion Date</th>
<th>Duration</th>
<th>Cost</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>20028</td>
<td>XFR - Claremore 161 kV autos 1 and 2</td>
<td>Regional</td>
<td>Claremore</td>
<td>20028</td>
<td>161 kV</td>
<td>24 months</td>
<td>COMPLETE</td>
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<tr>
<td>20029</td>
<td>Multi - Arcadia Tap</td>
<td>Regional</td>
<td>Arcadia</td>
<td>20029</td>
<td>69 kV</td>
<td>6 months</td>
<td>COMPLETE</td>
<td></td>
<td></td>
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<tr>
<td>20030</td>
<td>XFR - IODINE - MOORELAND 138KV CKT 1 regional</td>
<td>Regional</td>
<td>IODINE - MOORELAND</td>
<td>20030</td>
<td>138 kV</td>
<td>16 months</td>
<td>COMPLETE as of 6/25/09</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Project delayed due to lower load growth.
kV transformer for the outage of the parallel transformer, start the Carlsbad GT. Shed load to mitigate overload while Carlsbad generation is brought on line, if necessary.

$1,222,843, 24 months

$1,589,164, 26 months

$2,750,000, 18 months

$7,715,262, 24 months

$3,891,288, 48 months

The project was modified to only add a 2nd 230/115 kV transformer to avoid future overloads. Completion is by 12/01/2009.

Mitigation Plan verified by SPP staff. Per project tracking info in this project list, these projects should be complete by 3/13/09.

Project is modified: Rebuild Summit-Northview 115 kV; In-service date 6/1/2009; $6,819,380

Build Summit-Southgate 115 kV; Remove Northview-Southgate 115 kV; Work will be performed when extensive crews are completing Reno County-Summit 345 kV work; Cost for substation work is $1.3 million

Construction is in progress.

Terminal upgrades at Wheatland complete

Transformer will be in service prior to summer peak load conditions

Terminal upgrades is a mitigation on HEC 630.

Increase generation at McPherson and Hutchinson to relieve overloading

Terminal upgrades at Wheatland complete

Terminal upgrades at Wheatland complete

Mitigation Plan verified by SPP staff. Project delay is due to routing difficulties at circle, Carlsbad.

The project was modified to only add a 2nd 230/115 kV transformer to avoid future overloads. Completion is by 12/01/2009.

Mitigation Plan verified by SPP staff. Per project tracking info in this project list, these projects should be complete by 3/13/09.

Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. Gaines to Seminole 115 kV.

The project was modified to only add a 2nd 230/115 kV transformer to avoid future overloads. Completion is by 12/01/2009.

Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. Weesner to Seminole 115 kV.

Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. Multi - Seven Rivers - Pecos - Potash 2 30 kV regional

Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012.

Load reduction is being considered to delay the need of 33 kv/115 kv line. Cost for substation work is $1.3 million

Review of the Line design is in progress, and material procurement is in progress. Mitigation is to reduce generation in area 534 and increase in area 539 as needed to relieve overload.

Transformer in service prior to summer peak load conditions

Increase generation at McPherson and Hutchinson to relieve overloading
<table>
<thead>
<tr>
<th>Line</th>
<th>Summary</th>
<th>Cost</th>
<th>Time</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>262 10245 526</td>
<td>Line - Reno County-Summit 345 kV Line 1</td>
<td>$190,410,014</td>
<td>24 months</td>
<td>Project costs include rebuilding of 115 kV and 230 kV underlying system on same ROW.</td>
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<tr>
<td>262 10246 526</td>
<td>345 kV Reno County 345/115 kV line</td>
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<tr>
<td>26544 001 10264 540</td>
<td>Multi - South Harper 115 kV line</td>
<td>$2,059,675</td>
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<tr>
<td>26544 001 10274 540</td>
<td>Multi - Grandview East - Sampson - Longview 115 kV lines</td>
<td>$28,899</td>
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<tr>
<td>26544 001 10271 540</td>
<td>Line - Galena - Liberty 66 kV</td>
<td>$88,699</td>
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<tr>
<td>115 10249 540</td>
<td>Line - Pope Lane to Smithfield 115 kV</td>
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<td>Complete costs not finalized</td>
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<tr>
<td>275 10254 540</td>
<td>Multi - 161/115 kV Tap of Plate City to Stranger Creek</td>
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<tr>
<td>19967 260 10254 541</td>
<td>Line - College - Craig 161 kV</td>
<td>$1,145,400</td>
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<tr>
<td>19967 10984 541</td>
<td>Line - Construction</td>
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<td>199 10255 541</td>
<td>Multi - Lackman Sub</td>
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<tr>
<td>200 10256 541</td>
<td>Line - Terrace - Westside 161 kV</td>
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<td>Line - Crosstown - Midtown 161 kV</td>
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<tr>
<td>275 10258 541</td>
<td>Line - Cross - Liberty 161 kV</td>
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<tr>
<td>199 10259 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
<td>$2,074,000</td>
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<tr>
<td>199 10260 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
<td>$2,074,000</td>
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<tr>
<td>199 10261 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
<td></td>
<td>6 months</td>
<td></td>
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<tr>
<td>199 10262 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
<td></td>
<td>6 months</td>
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<tr>
<td>199 10263 541</td>
<td>Line - Sub 1226 - Sub 1298 161 kV</td>
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<td>Line - Sub 1251 - Sub 1305 161 kV</td>
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<tr>
<td>199 10266 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
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<tr>
<td>283 10267 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
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<tr>
<td>283 10268 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
<td></td>
<td>6 months</td>
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<tr>
<td>283 10269 541</td>
<td>Line - Sub 1251 - Sub 1305 161 kV</td>
<td></td>
<td>6 months</td>
<td></td>
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<tr>
<td>307 10263 526</td>
<td>345 kV Jericho Hill Substation 115 kV</td>
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<tr>
<td>003 10272 540</td>
<td>Line - NPPD/WERE - Steele City - Kansas Border 115 kV</td>
<td>$5,900</td>
<td>6 months</td>
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<tr>
<td>004 10273 540</td>
<td>Grandview Substation 345/230 kV Transformer</td>
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<tr>
<td>005 10274 540</td>
<td>Blackberry Substation 345/230 kV Transformer</td>
<td>$3,005,700</td>
<td>18 months</td>
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<tr>
<td>006 10275 540</td>
<td>Blackberry Substation 345/230 kV Transformer</td>
<td>$3,005,700</td>
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<tr>
<td>007 10276 540</td>
<td>Substation 345/230 kV Transformer</td>
<td>$3,005,700</td>
<td>18 months</td>
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<tr>
<td>008 10277 540</td>
<td>Substation 345/230 kV Transformer</td>
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<tr>
<td>009 10278 540</td>
<td>Substation 345/230 kV Transformer</td>
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<td>100 10279 540</td>
<td>Blackberry Substation 345/230 kV Transformer</td>
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<tr>
<td>20016 30146 520</td>
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<td>15 months</td>
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<tr>
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<tr>
<td>20016 30150 520</td>
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<td>$2,600,000</td>
<td>15 months</td>
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</tr>
</tbody>
</table>

**Year: 2014**

<table>
<thead>
<tr>
<th>Line</th>
<th>Summary</th>
<th>Cost</th>
<th>Time</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>263 10267 330</td>
<td>Multi - Blaisden - Chouteau - GRDA 1</td>
<td>$57,069,993</td>
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<tr>
<td>263 10268 330</td>
<td>Multi - Blaisden - Chouteau - GRDA 1</td>
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<td>263 10269 330</td>
<td>Multi - Blaisden - Chouteau - GRDA 1</td>
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<tr>
<td>263 10270 330</td>
<td>Multi - Blaisden - Chouteau - GRDA 1</td>
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</tr>
<tr>
<td>263 10271 330</td>
<td>Multi - Blaisden - Chouteau - GRDA 1</td>
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<td>6 months</td>
<td></td>
</tr>
<tr>
<td>263 10272 330</td>
<td>Line - Camp Creek - Lamar 141 kV</td>
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<td>6 months</td>
<td></td>
</tr>
<tr>
<td>611 10273 330</td>
<td>GSF - Lamar 66/141 kV</td>
<td></td>
<td>6 months</td>
<td></td>
</tr>
<tr>
<td>20016 507 10262 526</td>
<td>345 kV ARSENAL HILL - FORT PROGRESS 161 kV</td>
<td>$5,428,300</td>
<td>18 months</td>
<td></td>
</tr>
<tr>
<td>20016 30149 520</td>
<td>ARSENAL HILL - FORT PROGRESS 161 kV Transformer</td>
<td>$276,000</td>
<td>15 months</td>
<td></td>
</tr>
<tr>
<td>20016 30149 520</td>
<td>ARSENAL HILL - FORT PROGRESS 161 kV Transformer</td>
<td>$276,000</td>
<td>15 months</td>
<td></td>
</tr>
<tr>
<td>20016 30149 520</td>
<td>ARSENAL HILL - FORT PROGRESS 161 kV Transformer</td>
<td>$276,000</td>
<td>15 months</td>
<td></td>
</tr>
</tbody>
</table>

The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.
The earliest that any portion of the Wheeler County Interchange project can be in-service will be 6/1/2010. NTC should be

The correction made this line from Sherman to Dallam instead of Sherman to Dalhart. This large project is underway and portions of this project will be complete after the Summer of 2009. Ochiltree Sub 230/115

Loading. Substation cost 12 $1.0 million.

This large project is underway and portions of the project will be complete after the Summer of 2009. Hitchland to Moore County 230 kv Transmission Project.

This large project is underway and portions of the project will be complete after the Summer of 2009. Hitchland - Texas Co. 230 kV and 115 kV project.

The correction made this line from Sherman to Dallam instead of Sherman to Dalhart. This large project is underway and portions of this project will be complete after the Summer of 2009. Hitchland to Moore County 230 kv Transmission Project.

This large project is underway and portions of the project will be complete after the Summer of 2009. Hitchland - Texas Co. 230 kV and 115 kV project.

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<table>
<thead>
<tr>
<th>Project Name</th>
<th>Location</th>
<th>Voltage</th>
<th>Category</th>
<th>Estimated Cost</th>
<th>Duration</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>20006 173 10271 536</td>
<td>Line - Tecumseh Energy Center - Midland 115 kV</td>
<td>regional reliability</td>
<td>06/01/11</td>
<td>$2,100,000</td>
<td>6 months</td>
<td>Planned construction</td>
</tr>
<tr>
<td>20006 173 10229 536</td>
<td>Line - Gill Energy Center West - Hoxie 69 kV</td>
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<td>06/01/12</td>
<td>$3,684,740</td>
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<td>Completed</td>
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<tr>
<td>304 536</td>
<td>Line - Chase - White Junction 141 kV</td>
<td>regional reliability</td>
<td>01/27/09</td>
<td>$2,100,000</td>
<td>6 months</td>
<td>Planned construction</td>
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<tr>
<td>328 536</td>
<td>Line - Tecumseh Energy Center - Midland 115 kV</td>
<td>regional reliability</td>
<td>06/01/12</td>
<td>$1,795,900</td>
<td>6 months</td>
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<tr>
<td>426 536</td>
<td>Line - Chelan - White Junction 69 kV</td>
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<td>01/27/09</td>
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<td>20034 627 10815 540</td>
<td>Line - Alabama - Lake Road 161 kV</td>
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<td>20034 628 10816 540</td>
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<td>01/27/09</td>
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<td>6 months</td>
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<tr>
<td>301 540</td>
<td>Line - Clinton MIPU - Clinton AECI 161 kV</td>
<td>regional reliability</td>
<td>06/01/11</td>
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<td>331 540</td>
<td>Line - Clinton MIPU - Clinton AECI 161 kV</td>
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<td>$2,418,750</td>
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<td>XFR - Sibley 161/69 kV</td>
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<td>07/01/10</td>
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<td>18 months</td>
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<tr>
<td>192 540</td>
<td>Line - Iatan - Platte City 161 kV</td>
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<td>12/31/09</td>
<td>$1,050,000</td>
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<tr>
<td>626 541</td>
<td>Multi - Iatan 345/161 kV Sub</td>
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<td>12/31/09</td>
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<tr>
<td>20010 382 10495 544</td>
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<tr>
<td>421 544</td>
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<tr>
<td>19969 338 10435 544</td>
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<tr>
<td>20016 108 10441 520</td>
<td>Line - North Market - Arsenal 100 kV</td>
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<td>01/16/09</td>
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<td>20016 343 10442 520</td>
<td>Line - Magnolia - Franklin 69 kV</td>
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<td>01/16/09</td>
<td>$2,590,000</td>
<td>26 months</td>
<td>Planned construction</td>
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<tr>
<td>20016 345 10443 520</td>
<td>Line - Forest Hills - Quitman 69 kV</td>
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<td>01/16/09</td>
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<tr>
<td>20016 346 10446 520</td>
<td>Line - Woodlawn - Baldwin 69 kV</td>
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<td>01/16/09</td>
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<td>26 months</td>
<td>Planned construction</td>
</tr>
<tr>
<td>20016 347 10447 520</td>
<td>Line - Dyess - Tontitown 161 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$2,590,000</td>
<td>26 months</td>
<td>Planned construction</td>
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</tbody>
</table>

**Year 2011**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Location</th>
<th>Voltage</th>
<th>Category</th>
<th>Estimated Cost</th>
<th>Duration</th>
<th>Status</th>
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<tbody>
<tr>
<td>20016 108 10441 520</td>
<td>Line - North Market - Arsenal 100 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$6,990,000</td>
<td>26 months</td>
<td>Planned construction</td>
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<tr>
<td>20016 343 10442 520</td>
<td>Line - Wilmot - Magalia Tap 69 kV</td>
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<td>01/16/09</td>
<td>$2,290,000</td>
<td>26 months</td>
<td>Planned construction</td>
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<tr>
<td>20016 345 10443 520</td>
<td>Line - Magnolia - Franklin 69 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$2,290,000</td>
<td>26 months</td>
<td>Planned construction</td>
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<tr>
<td>20016 346 10444 520</td>
<td>Line - Woodlawn - Baldwin 69 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$2,290,000</td>
<td>26 months</td>
<td>Planned construction</td>
</tr>
<tr>
<td>20016 347 10445 520</td>
<td>Line - Dyess - Tontitown 161 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$2,290,000</td>
<td>26 months</td>
<td>Planned construction</td>
</tr>
<tr>
<td>20016 348 10446 520</td>
<td>Line - Woodlawn - Baldwin 69 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$2,290,000</td>
<td>26 months</td>
<td>Planned construction</td>
</tr>
<tr>
<td>20016 349 10447 520</td>
<td>Line - Woodlawn - Baldwin 69 kV</td>
<td>regional reliability</td>
<td>01/16/09</td>
<td>$2,290,000</td>
<td>26 months</td>
<td>Planned construction</td>
</tr>
</tbody>
</table>

The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.
<table>
<thead>
<tr>
<th>Project ID</th>
<th>Description</th>
<th>Cost</th>
<th>Duration</th>
<th>Status</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>349 10447 526</td>
<td>Line - Ashdown - Patterson 138 kV generation</td>
<td>$11,431,000</td>
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<tr>
<td>349 10448 526</td>
<td>Line - MICAR REC - Turk 115 kV generation</td>
<td>$1,773,000</td>
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<tr>
<td>349 10451 526</td>
<td>520 Line - Ashdown - Patterson 138 kV generation</td>
<td>$3,246,000</td>
<td>66 months</td>
<td>Replacement not needed in 2006 due to rerating, but replacement needed in 2011 due to voltage conversion associated with Turk.</td>
<td></td>
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<tr>
<td>349 10452 526</td>
<td>520 Line - Turk 115 - Turk 138 kV generation</td>
<td>$8,170,000</td>
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<tr>
<td>349 10457 526</td>
<td>520 Gibraltar - Turk 138/115 kV R</td>
<td>$7,846,000</td>
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<td>20017 30158 50166 524</td>
<td>XFR - Turk 138/115 kV #1 generation</td>
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<td>20017 30179 50167 524</td>
<td>XFR - Turk 138/115 kV #1 generation</td>
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<tr>
<td>19951 357 10467 525</td>
<td>XFR - Anadarko 138/69 kV transmission</td>
<td>$3,937,500</td>
<td>24 months</td>
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<tr>
<td>20017 30162 50170 524</td>
<td>SUNNYSIDE - UNIROYAL 138 kV transmission</td>
<td>$8,019,000</td>
<td>24 months</td>
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<tr>
<td>20031 632 10823 526</td>
<td>Multi: Legacy Interchange 69 kV Tap - 115/69 MVA rating, or 122.4%. Load shed approximately 9 MVA until the following remedial switching is done.</td>
<td>$3,375,000</td>
<td>24 months</td>
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<tr>
<td>20031 633 10826 526</td>
<td>Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new lines</td>
<td>$3,093,750</td>
<td>24 months</td>
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<tr>
<td>20033 600 10767 536</td>
<td>Line - 27th &amp; Croco - 41st &amp; California 115 kV regional</td>
<td>$4,927,500</td>
<td>24 months</td>
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<tr>
<td>20033 624 10812 536</td>
<td>Line - Fort Junction - West Junction - City 115 kV regional</td>
<td>$4,716,600</td>
<td>24 months</td>
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<tr>
<td>20033 463 10602 536</td>
<td>Line - East Manhattan - McDowell 115 kV to 230 kV conversion</td>
<td>$84,669,696</td>
<td>36 months</td>
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<tr>
<td>20033 491 10636 536</td>
<td>Line - Bismark - COOP 230 kV Distribution Transformer NLTs. Load shedding due to North Dakota school, 410 kVA, 35 MVA, 13.8 kV.</td>
<td>$2,085,000</td>
<td>18 months</td>
<td></td>
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<tr>
<td>19970 352 10730 544</td>
<td>Line - Oronogo Junction - Riverton 161 kV Regional</td>
<td>$5,750,000</td>
<td>36 months</td>
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<td></td>
</tr>
</tbody>
</table>
| 609 10924 645 | Build New 161 kV Substation Sub 1341 regional | $16,300,000 | 36 months | | Change Project Name to "Build New 161 KV Substation Sub 1341"
| Year 2012 | 3016 | 50146 | 525 | SOUTH TEXARKANA - TEXARKANA PLANT 69KV CKT 1 | Interconnection service | 04/01/12 | 04/01/12 | 01/16/09 | $4,750,000 | 24 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50144 | 525 | TEXARKANA - TEXARKANA PLANT 69KV CKT 1 | Interconnection service | 04/01/12 | 04/01/12 | 01/16/09 | $22,000 | 24 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50143 | 525 | DOWTY - TOLEDO 69KV CKT 1 | Interconnection service | 04/01/12 | 04/01/12 | 01/16/09 | $85,000 | 24 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50143 | 525 | MMN - LONGSVORD ORDINANCE 69KV CKT 1 | Interconnection service | 06/01/13 | 06/01/13 | 01/16/09 | $4,025,000 | 24 months | FULL BPF |
| Year 2012 | 3016 | 50143 | 525 | MAGAZINE - NORTH MAGAZINE 10KV CKT 1 | Interconnection service | 06/01/12 | 06/01/12 | 01/16/09 | $100,000 | 12 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50152 | 525 | JAMIESON - FOWELL STREET 138KV CKT 1 | Interconnection service | 06/01/12 | 06/01/12 | 01/16/09 | $465,000 | 15 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50158 | 525 | LANCASTER EASTSIDE (LS R 245) 69KV TRANSFORMER CKT 1 | Interconnection service | 12/31/12 | 12/31/12 | 01/16/09 | $4,560,000 | 24 months | FULL BPF |
| Year 2012 | 3016 | 50157 | 525 | SE TEXARKANA - TEXARKANA PLANT 69 KV CKT 1 transmission | Interconnection service | 04/01/12 | 04/01/12 | 01/16/09 | $22,000 | 24 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50165 | 525 | OKAY - TOLLETTE 69KV CKT 1 | Interconnection service | 06/01/12 | 06/01/12 | 01/16/09 | $4,025,000 | 24 months | FULL BPF |
| Year 2012 | 3016 | 50164 | 525 | NORTH TEXARKANA - TEXARKANA PLANT 69KV CKT 1 | Interconnection service | 04/01/12 | 04/01/12 | 01/16/09 | $4,025,000 | 24 months | FULL BPF |
| Year 2012 | 3016 | 50163 | 525 | SERVICE 04/01/12 04/01/12 01/16/09 $80,000 | Interconnection service | 06/01/12 | 06/01/12 | 01/16/09 | $80,000 | 12 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50162 | 525 | TEXARKANA - TEXARKANA PLANT 69KV CKT 1 | Interconnection service | 04/01/12 | 04/01/12 | 01/16/09 | $100,000 | 12 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50164 | 525 | SERVICE 04/01/12 04/01/12 01/16/09 $100,000 | Interconnection service | 06/01/12 | 06/01/12 | 01/16/09 | $100,000 | 12 months | GREEN | FULL BPF |
| Year 2012 | 3016 | 50155 | 525 | OKAY - TOLLETTE 69KV CKT 1 | Interconnection service | 06/01/12 | 06/01/12 | 01/16/09 | $465,000 | 15 months | GREEN | FULL BPF |

**Note:** The table above represents a summary of various interconnection services and transmission projects for the year 2012, with details including service dates, project descriptions, and associated costs and durations. The table is organized in a clear tabular format for easy readability.
<table>
<thead>
<tr>
<th>Balanced Portfolio</th>
<th>Start Year</th>
<th>End Year</th>
<th>Capex</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>20040 606 10927 S23 Line - Severs – Cleveland 345 kV Balanced Portfolio</td>
<td>12/31/12</td>
<td>06/19/09</td>
<td>$17,000,000</td>
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<tr>
<td>20041 605 10928 S24 Line - Severs - Cleveland 345 kV Balanced Portfolio</td>
<td>12/31/12</td>
<td>06/19/09</td>
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<tr>
<td>20041 700 10929 S24 Line - Seminole - Muskogee 345 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20041 700 10930 S24 MFR - Seminole 345/138 kV Balanced Portfolio</td>
<td>12/31/13</td>
<td>06/19/09</td>
<td>$4,859,930</td>
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</tr>
<tr>
<td>20041 701 10931 S24 Line - Tuco to Woodward 345 kV lines Balanced Portfolio</td>
<td>06/18/14</td>
<td>06/19/09</td>
<td>$64,000,000</td>
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<tr>
<td>20041 701 10932 S24 XFR - Seminole 345/138 kV Balanced Portfolio</td>
<td>06/18/14</td>
<td>06/19/09</td>
<td>$15,000,000</td>
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<td>20041 702 10933 S24 Line - Tuco to Woodward 345 kV Balanced Portfolio</td>
<td>06/19/14</td>
<td>06/19/09</td>
<td>$64,000,000</td>
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<tr>
<td>20041 702 10934 S24 XFR - Woodward 345 kV and a 50 MVAR reactor bank Balanced Portfolio</td>
<td>06/19/14</td>
<td>06/19/09</td>
<td>$15,000,000</td>
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<tr>
<td>20041 705 10935 S24 Sub - Anadarko Balanced Portfolio</td>
<td>12/31/11</td>
<td>06/19/09</td>
<td>$6,800,000</td>
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</tr>
<tr>
<td>20041 706 10936 S24 Line - WFEC Anadarko – OKGE Anadarko 138 kV Balanced Portfolio</td>
<td>12/31/11</td>
<td>06/19/09</td>
<td>$2,000,000</td>
<td></td>
</tr>
<tr>
<td>20042 704 10937 S24 Line - Tuco to Woodward 345 kV lines Balanced Portfolio</td>
<td>06/18/14</td>
<td>06/19/09</td>
<td>$122,577,500</td>
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</tr>
<tr>
<td>20042 705 10938 S24 XFR - Tuco transformer and Mid-point Reactor Station Balanced Portfolio</td>
<td>06/18/14</td>
<td>06/19/09</td>
<td>$26,120,000</td>
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<tr>
<td>20042 706 10939 S24 Line - Knoll - Axtell 345 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 707 10940 S24 XFR - Knoll 345/230 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 708 10941 S24 Line - Knoll - Axtell 345 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<td>20042 709 10942 S24 XFR - Knoll 345/230 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 710 10943 S24 Line - Spearville - Knoll 345 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 711 10944 S24 XFR - Spearville - Knoll 345 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 712 10945 S24 Tap - Swainsco - Stilwell Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 713 10946 S24 Line - Iatan - Nashua 345 kV Balanced Portfolio</td>
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<td>06/19/09</td>
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<tr>
<td>20042 714 10947 S24 XFR - Nashua 345/161 kV Balanced Portfolio</td>
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<td>20042 715 10948 S24 Line - Iatan - Axtell Balanced Portfolio</td>
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<td>PID</td>
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<td>Project Name</td>
<td>Project Type</td>
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<td>524 Device - Rush Springs 69 kV</td>
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<td>525 Device - Maltairee Cap 138 kV</td>
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<td>529 Device - Pied Cap 115 kV</td>
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<td>30178</td>
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<td>30180</td>
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<td>529 Rapid Load</td>
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<td>544 Device - Riverbig Sub Cap 10 kV</td>
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**Year 2009**

**Year 2010**
### Year 2011

<table>
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<th>Year</th>
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<th>Duration</th>
<th>Notes</th>
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<tbody>
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<td>2008</td>
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<td>2008</td>
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<tr>
<td>20004</td>
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### Year 2012

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<th>Year</th>
<th>Cost</th>
<th>Duration</th>
<th>Notes</th>
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</thead>
<tbody>
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<tr>
<td>20006</td>
<td>30107</td>
<td>2009</td>
<td>$350,000</td>
<td>12 months</td>
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<tr>
<td>20007</td>
<td>30098</td>
<td>2008</td>
<td>$750,000</td>
<td>12 months</td>
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<td>20008</td>
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<td>20009</td>
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### Year 2013+

<table>
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<th>Year</th>
<th>Cost</th>
<th>Duration</th>
<th>Notes</th>
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<tbody>
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<td>2013</td>
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<td>20012</td>
<td>30076</td>
<td>2009</td>
<td>$409,900</td>
<td>12 months</td>
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</table>

### Notes
- Some projects may be deferred due to violations in models that didn't use system transformer LTCs, when voltage regulation is validated it starts the project.
- This project will be deferred because the violations occurred in models that didn't use system transformer LTCs, when voltage regulation is validated it starts the project.
- Greene Co. will move ahead with project in 4th quarter of 2010. Construction to begin in 1st quarter of 2011.
- Engineering work to begin in 4th quarter of 2010. Construction to begin 1st quarter of 2011.
- Green Co. is moving ahead with project in 4th quarter of 2010. Construction to begin in 1st quarter of 2011.
- BE templates are used to provide a consistent approach to voltage problems. Short-term mitigation cannot be used to solve the long-term voltage issues. Transformation from 345 kV Substation to Empire and Duncan Substations.
- BE templates are used to provide a consistent approach to voltage problems. Short-term mitigation cannot be used to solve the long-term voltage issues.
- Green Co. is moving ahead with project in 4th quarter of 2010. Construction to begin 1st quarter of 2011.