SPP Priority Projects Phase II Report

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SPP Engineering/Planning

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Executive Summary

At the April 28, 2009 SPP Board of Directors (BOD) meeting, Southwest Power Pool, Inc. (SPP) staff was charged with restructuring its regional transmission expansion planning process to be consistent with the Synergistic Planning Project Team (SPPT) report. This restructuring effort is comprised of three major components. First, an Integrated Transmission Planning (ITP) process was established to improve and integrate SPP's existing planning processes. The second major effort was to identify, evaluate, and recommend Priority Projects to improve the transmission system based on specifics in the SPPT report. Finally, a new cost allocation methodology is being created by the Regional State Committee (RSC) and its Cost Allocation Working Group (CAWG). This document reports on results of the Priority Project analysis and associated recommendations.

Stakeholders provided input throughout the Priority Project submittal and scope development via numerous conference calls and meetings. The Transmission, Economic Studies, and Cost Allocation Working Groups provided significant support to this effort, and the Market and Operations Policy Committee (MOPC) reviewed and consented to the final list of 10 projects chosen for further screening and detailed evaluation.

Phase I Analysis of these 10 Priority Projects included multiple value metrics including adjusted production cost, loss impacts, reliability assessment, local and environmental impacts, and deliverability of capacity and energy to load. SPP used internal staff and outside consultants, including Quanta Technologies, Brattle Group, KEMA, and Brown Engineers, to perform engineering and economic analysis. The phase I study included two different wind levels. Level one is a 10-year growth level in which 20% of the energy in SPP is supplied by renewable wind. Level two is a slower growth projection with the same 10-year growth, but to only a 10% level of wind.

In October, 2009, the SPP BOD directed the SPP staff should take six of the 10 projects and do further analysis, which is documented in this phase II report. These recommended projects were studied to determine the benefit to SPP's current Generation Interconnection (GI) and Aggregate Transmission Service Study (AS) processes, address known congestion, and better integrate the west and east portions of SPP's transmission system. Phase II analysis was conducted with the oversight of the SPP Strategic Planning Committee. The study was performed in two groups and with a future wind level of approximately 7 GW or 10% level of wind.

The estimated engineering and construction cost for the six projects is $1.26 billion for group 1, which includes two of the six projects constructed at 765 kV but operated at 345 kV. Group 2 estimated costs are $1.11 billion with those two projects constructed and operated as double-circuit 345 kV. The Priority Projects were identified to have substantial quantifiable benefits complimentary to the SPPT requirements. The specific quantifiable benefits included Adjusted Production Costs, reliability, wind benefit, fuel diversity and losses. These Priority Projects will also provide significant qualitative benefits to the SPP region providing for improved reliability, enhanced economic opportunities, and an opportunity to better meet the challenges facing the electric industry.

Based on the study results SPP staff recommends approval of the six Priority Projects as defined in group 2. Group 2 includes projects 1 and 2 below constructed and operated as double circuit 345 kV with an estimated cost of $1.11 billion. The following is a list of the grouping for approval:

1. Spearville – Comanche – Medicine Lodge – Wichita, double circuit construction and operated at 345 kV

2. Comanche – Woodward District EHV, double circuit construction and operated at 345 kV

3. Hitchland – Woodward District EHV, double circuit construction and operated at 345 kV

4. Valliant – NW Texarkana, constructed and operated at 345 kV

5. Cooper – Maryville – Sibley, constructed and operated at 345 kV

6. Riverside Station – Tulsa Power Station 138 kV reactor addition

SPP staff believes the list of recommended projects achieve the strategic goals set forth in the "Report of the Synergistic Planning Project" dated April 23, 2009. These recommended projects will provide for improvements in the GI and AS queues and relieve know congestion while also improving west to east transmission system capabilities.

Construction of these projects will result in large local economic benefits, including thousands of jobs created during both construction and operating phases. Initially the projects 1 and 2 would be constructed and operated with a double circuit 345 kV line. After completion of the SPP ITP 20 Year Assessment in January 2011, these two projects may be changed to reflect future grid needs. These recommended projects are discussed in detail in the Conclusions and Recommendations section.

Introduction

With the ever-increasing prominence that electric transmission is receiving in energy policy debates at the federal level, the SPP Board of Directors formed the Synergistic Planning Project Team to develop recommendations to help SPP to prepare for and quickly respond to national energy priorities. This high-level policy team was charged with providing sufficient direction for SPP and its members to address comprehensive transmission planning and cost allocation methodologies. Members of the SPPT included:

- 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, Southwest Power Pool
- Mark Rossi, Accenture, facilitation and administration

In April 2009, the SPPT submitted its report and recommendations to the MOPC, BOD, and RSC. The report recommended that SPP implement an Integrated Transmission Planning (ITP) process to create a robust, flexible, and cost-effective transmission network for the SPP footprint. The ITP process was developed by SPP and its stakeholders and approved by the MOPC, BOD, and RSC in October 2009.

In transitioning to the new ITP process, the SPPT recommended that SPP evaluate and recommend to the RSC a list of Priority Projects within six months for approval by the BOD. The Priority Projects are intended to capture near-term opportunities associated with the heightened focus on electric transmission expansion. This process should result in projects that enhance West to East transfers, improve the Generator interconnects and Aggregate studies queues, and relieve congestion. In conjunction with the evaluation of Priority Projects, the SPPT recommended the RSC select an existing cost allocation methodology or a new "highway-byway" cost allocation methodology to be used for approved Priority Projects.

This report describes the development of the Priority Projects in the phase II study, the scope of analysis performed on the projects by SPP and consultants, and results of that analysis. SPP respectfully submits this report to stakeholders and the MOPC, RSC, and BOD for consideration.

Scope of Priority Projects Phase II Analysis

List of Priority Projects for Analysis

Staff presented the results of the initial Priority Projects effort to the MOPC, RSC, and BOD in October 2009. The BOD directed staff to perform additional analysis on a group of six projects. This analysis was guided by the Strategic Planning Committee (SPC) to be presented to stakeholders and the BOD for review in April 2010. The list of projects the BOD requested staff to study in Phase II of the Priority Projects effort is referred to as Group 1 throughout this report and is listed below and illustrated in Figure 1:

Group 1

- Spearville – Comanche – Medicine Lodge – Wichita (765 kV construction and 345 kV operation)
- Comanche – Woodward District EHV (765 kV construction and 345 kV operation)
- Hitchland – Woodward District EHV (345 kV DCT[1])
- Valiant – NW Texarkana (345 kV)
- Cooper – Maryville – Sibley (345kV)
- Riverside – Tulsa Reactor (138 kV)

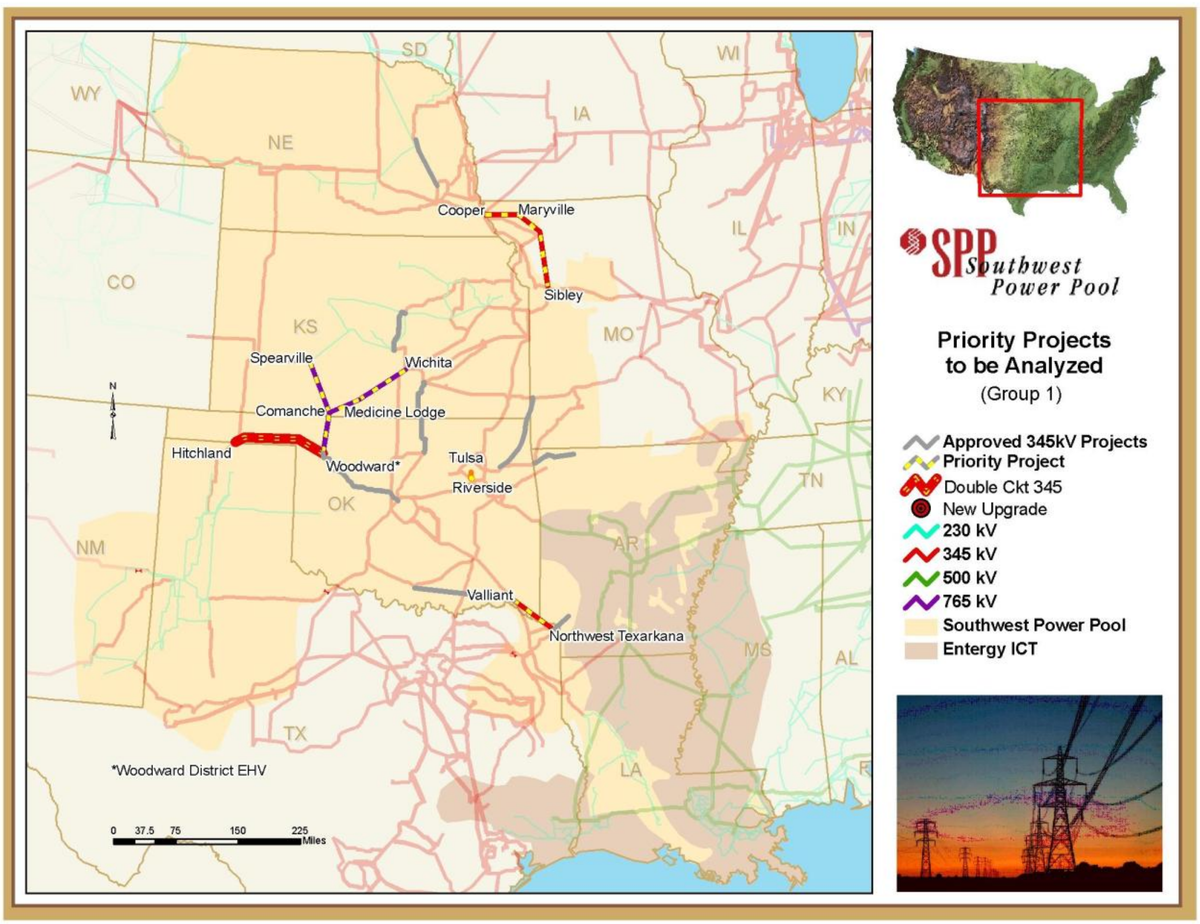


Figure 1: Priority Projects (Group 1)

[1] DCT refers to double-circuit

The SPC also requested staff to study an alternative 345 kV double-circuit construction for the Group 1 proposed 765 kV constructed projects. This grouping of projects will be referred to as Group 2 throughout the report and are listed below and illustrated in Figure 2.

Group 2

- Spearville – Comanche – Medicine Lodge – Wichita (345 kV DCT)
- Comanche – Woodward District EHV (345 kV DCT)
- Hitchland – Woodward District EHV (345 kV DCT)
- Valiant – NW Texarkana (345 kV)
- Cooper – Maryville – Sibley (345kV)
- Riverside – Tulsa Reactor (138 kV)

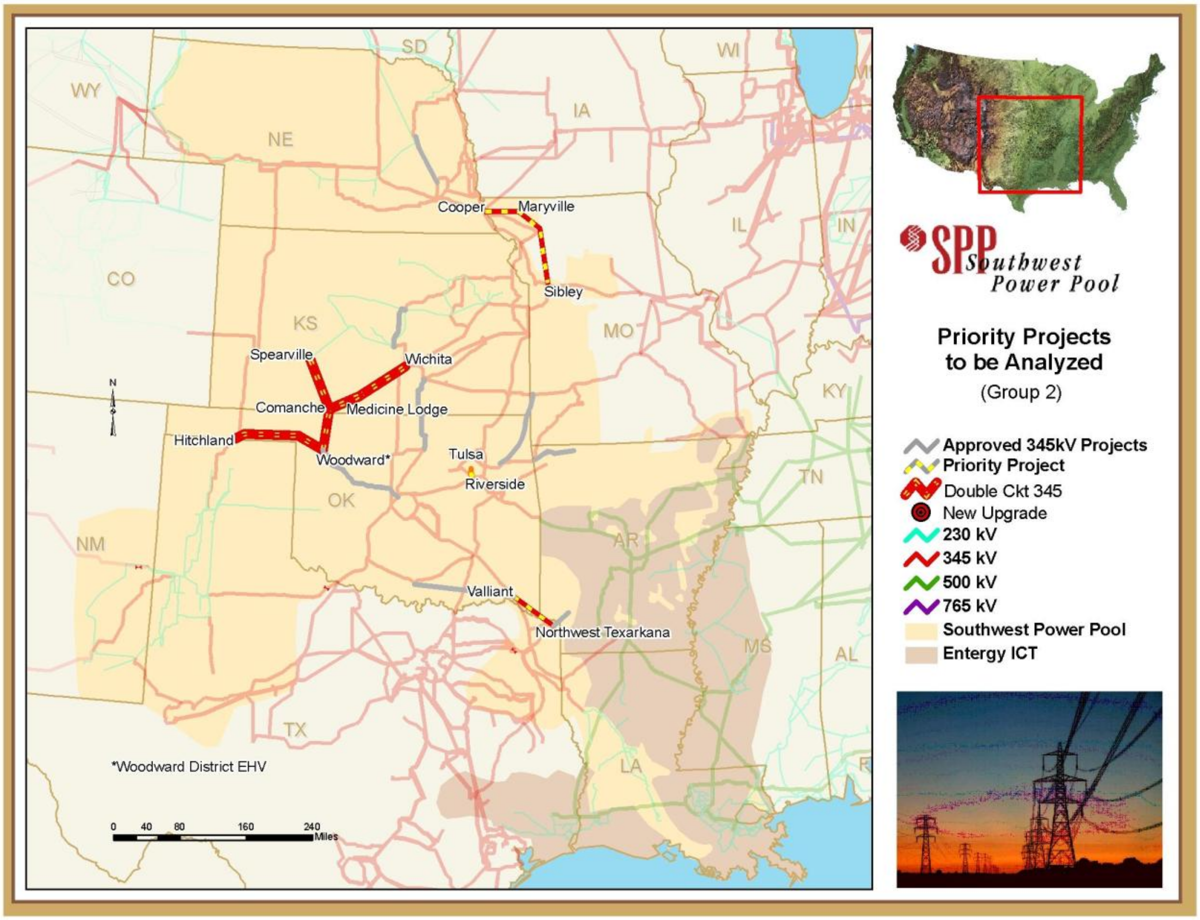


Figure 2: Priority Projects (Group 2)

Study Assumptions

Assumptions used in Priority Projects modeling and analysis were vetted through the SPP stakeholder process and amended by the Strategic Planning Committee (SPC) at its November 19 meeting. The majority of assumptions were developed by the Benefits Analysis Techniques Task Force (BATTF) and approved by the Economic Studies Working Group (ESWG) and reviewed by the Markets and Operations Policy Committee (MOPC). For the Priority Projects analysis, PROMOD software was utilized to model 8,760 hours representing a full year of system-wide commitment and dispatch of resources.

- **Time Frame** – The BATTF directed that a ten-year time frame be used to analyze benefits for Priority Projects. Three years were modeled, and the benefits for the years in between were calculated using a linear progression. The total of the ten-year benefit was then used to create the Net Present Value (NPV). The three modeled years were 2009, 2014, and 2019. Additionally, a terminal value was used to represent the final B/C of the project from the last year of analysis (i.e. 2019). Considering the scope and lifetime of some of the projects, a 20- and 40-year financial result is shown as extrapolated from the data used in the 10-year analysis.

- **Fuel Prices** – The gas price was determined by using the Henry Hub NYMEX ten-year forecast with an additional adder for fuel distribution differences across the footprint. Staff used the 2010 forecast as the starting point since it was the first year in which an entire year's forecast was available. The starting price for the 2009 model runs was $5.20/MMBtu. Other fossil fuel prices used generic assumptions and publicly-available data.

- **Wind Modeling –** SPP staff was directed by the Strategic Planning Committee (SPC) to study the Priority Projects using a total of 7 GW of nameplate wind generation in the SPP footprint and to study the same wind in both the base and change cases. The Priority Projects model contained 3.8 GW of existing wind that was identified as in-service or under construction. Wind plants with a signed interconnection agreement (IA) and that have given SPP authorization to proceed with the construction of the required network upgrades were considered "under construction". To reach the 7 GW target, staff added an additional 3.2 GW of generic wind generation.

  The additional wind was not selected to represent specific future wind plants but was instead used as proxies for wind development in Kansas, Missouri, Nebraska, Oklahoma, and Texas. Staff used the geographic locations of the Priority Projects and the generation interconnection (GI) queue as a guide to determine the general locations of likely wind development to help determine the injection sites for the additional wind. These sites were also vetted through the ESWG. The injection sites are as follows:

  - Fairport (Missouri)
  - Gentlemen Station (Nebraska)
  - Hitchland (Oklahoma/Texas)
  - Hoskins (Nebraska)
  - Spearville (Kansas)

- Woodward (Oklahoma)

With the injection sites determined, staff then worked to select the amount of generation that would be at each site. SPP staff approximated the load in the footprint for each state for the year 2019. Using information gathered by the CAWG regarding each state's renewable standard or target, staff determined a target wind level for each state corresponding with that state's estimated load. While information regarding the level of renewable target each state has was considered in distributing the additional wind, the level of wind being studied in the Priority Projects analysis did not permit any state to actually achieve its target. Staff's approximation of the wind injection amounts is outlined below in Table 1 and illustrated in Figure 3.

State	Peak Load (MW)	Existing Wind and Under Construction (MW)	Additional Wind (MW)	Total Wind (MW)
Kansas	9,809	960	605	1,565
Missouri	7,707	0	600	600
Nebraska	7,207	243	392	635
New Mexico	1,574	120	0	120
Oklahoma	13,789	1431	522	1,953
Texas	7,066	1041	1,077	2,118
Total	46,203	3795	3,196	6,990

Table 1: Wind Injection Amounts

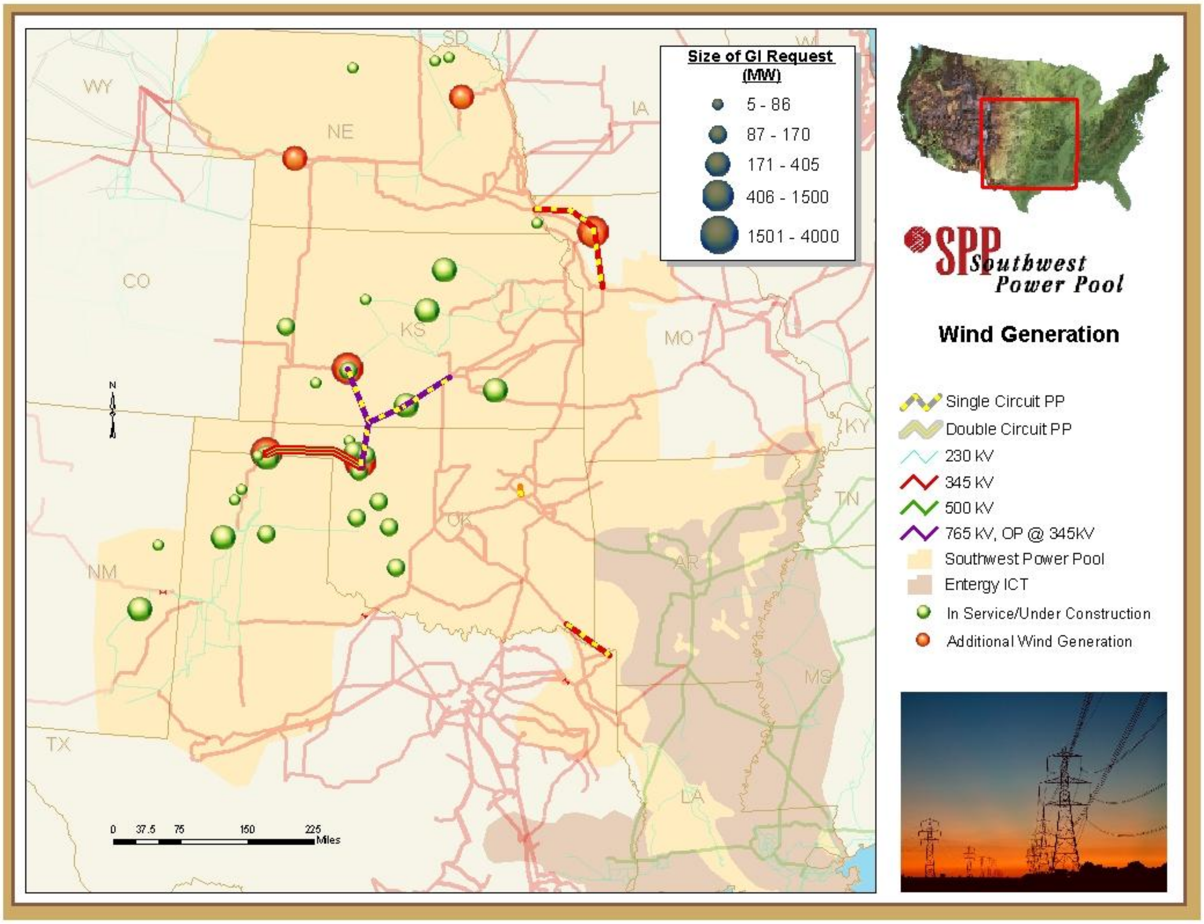


Figure 3: Wind Generation Modeled

The values in the table above do not represent any other renewable resources such as hydroelectric, biomass, etc which may be used to meet an RPS. Wind allocation and placement was determined without consideration to entitlement of resources outside that entities zone.

- **Study Footprint** – The study footprint contains SPP, Entergy, TVA, MAPP, MISO (Ameren, MEC, et al), PJM, Southern Companies, WAPA, Basin Electric, Big Rivers Electric Company, Associated Electric Cooperative Inc. (AECI), E.ON, and East Kentucky Power Cooperative.

- **DC Ties** – Historical DC Tie profiles were used to simulate profiles for all DC Ties in the SPP region. The DC ties modeled[2] for the SPP region are located at:

[2] The Stegall DC tie in Nebraska was not modeled in this planning assessment because Tri-State/Basin would not grant SPP permission to use the historical data.

- Oklaunion
- Welsh
- Lamar
- Eddy County
- Blackwater
- Sidney

- **Environmental Costs** – Estimates of emission cost for SO_2 and NO_x were approximated using data from the Chicago Climate Exchange. All CO_2 analysis was done as a post-processing technique according to the amount of carbon deferred from the transmission plans modeled. As prescribed by the BATTF, the analysis used both low and high carbon pricing as an approximation for the magnitude of potential benefits resulting from a reduction in CO_2. The costs used to represent carbon emissions are $26 and $49 per ton[3] (real dollars) as determined for the year 2030 by the U.S. Environmental Protection Agency in its October 2009 report. Mercury was not addressed due to the lack of valid market information.

- **Non-Wind Resource Model Additions** – Only plants with a signed interconnection agreement (IA) and that have given SPP authorization to proceed with the construction of the required network upgrades were considered "under construction".

- **Plant Outages** – Data for outages and maintenance was taken from the ESWG data collection and review process throughout 2009 as part of the Balanced Portfolio and Priority Projects Phase I efforts. This data was originally provided by stakeholders, and stakeholders had the opportunity to provide updated outage and maintenance information in October and November 2009. Forced outage rates were taken as a single draw and locked for the change and the base cases to eliminate biased results due to different outage schedules. Similarly, maintenance outages were also locked from a single scheduled pattern. These outages were plant specific.

- **Operating Reserves** – SPP's current reserve sharing program (as of 2009) was used in the operating reserves simulation.

- **Hurdle Rates –** Specific hurdle rates are applied in the modeling for both generating unit commitment and security-constrained economic dispatch. SPP attempts to quantify the hurdle rates within the base models so as to reasonably represent the transactions that have occurred or will occur in the market.

  A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW were used to commit resources across regional boundaries. These values are similar to values

[3] U.S. Environmental Protection Agency, *Economic Impacts of S. 1733: The Clean Energy Jobs and American Power Act of 2009*, http://www.epa.gov/climatechange/economics/pdfs/EPA_S1733_Analysis.pdf, October 23, 2009

applied within various studies of the Eastern Interconnection and represent recommended rates as described in the Transmission Network Economic Modeling & Methods document prepared by the Economic Modeling and Methods Task Force (EMMTF) in 2006. There were no hurdle rates for internal SPP market transactions.

- **Load Forecasts** – In early 2009, stakeholders submitted load forecasts for 2012, 2017, and 2022. To determine load for the study years of 2009, 2014, and 2019, an escalation rate of 1.29% per year was used. This escalation rate is the default used in PROMOD and represents a reasonable approximation of load growth within SPP.

- **Market Structure** – The simulation was conducted considering a consolidated balancing authority and a day-ahead market structure for the SPP region. The economic model simulates a consolidated balancing authority by economically dispatching all resources within the SPP footprint. The day-ahead market is the PROMOD default operation and means that the resources in the footprint are dispatched economically based on the calculated future prices for each resource. This market structure is starkly different than the way SPP currently operates, so the study results should not be compared to how each individual balancing authority currently operates.

Stakeholder Data Review Process

The data used in the development of the Priority Projects analysis went through an extensive data review process. The ESWG determined that certain data fields would be reviewed and updated by stakeholders while other data fields would use only publically available data. The publically available data included any generation cost data as well as heat rate information. By using only publically available data the ESWG attempted to ensure that Tier 1 entities were treated the same as SPP members in the model and to limit the amount of proprietary information contained in the model.

The following data fields were reviewed by the SPP members: Maximum Capacity, Unit Type, Commission Date, Retirement Date, Bus, Minimum Capacity, Maintenance Required Hours, Forced Outage Rate, Forced Outage Duration, Minimum Downtime, Minimum Run Time, Must Run Status, Ramp Rates, and demand data. The members also reviewed the data to ensure that all units were being accounted for and were being modeled in the correct zone.

The data review process included two iterations. After the initial PROMOD run, the stakeholders were provided the model inputs as well as load and generation output data. At this time they were able to update the inputs to correct any errors which could be causing their units to dispatch unrealistically. Once these corrections were applied to the model staff ran PROMOD again to produce new dispatch results and to provide the members with an opportunity to review how their changes had impacted the unit dispatch. The members were again able to suggest changes to the model for the second iteration. Once the PROMOD run for the second iteration was complete, staff provided this data to the stakeholders for approval. All Transmission Owners indicated their approval on the input and output data by Thursday, January 14.

Value Metrics

The BATTF developed or approved the use of the following quantifiable value metrics to be used in the calculation of financial benefit from the Priority Projects analysis.

Adjusted Production Cost

Adjusted Production Cost (APC) is a measure of the impact on production cost savings by Locational Imbalance Price (LIP), accounting for purchases and sales of economic energy interchange. This benefit metric is typically simulated by a production cost modeling tool accounting for 8,760 hourly profiles yearly of commitment and dispatch modeling, taken over the course of the study period.

Nodal modeling is aggregated on a zonal basis using weighted LIPs. There is concern that modeling the border points will not be accurate without additional Eastern Interconnection points. For example, the border LIPs will have significant impact on the APC within SPP. If there are lower LIP prices outside SPP, there will be no transfers from the western portion of SPP. The BATTF recommended the modeled footprint be broadened to include Southern Companies, Basin Electric, WAPA, TVA, PJM, MISO (Ameren, MEC, et al), and the DC ties (using the recent historic patterns) at a minimum when running the model to assess the impact on the borders.

The nodal analysis was aggregated on a zonal basis using the following formulation. The calculation, performed on an hourly basis:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases
Where:
Revenues from Sales = MW Export x Zonal $LIP_{\text{Gen Weighted}}$
and
Cost of Purchases = MW Import x Zonal $LIP_{\text{Load Weighted}}$

The tools used for this analysis include standard assumptions and modeling utilizing PROMOD.

The rationale for using this methodology is as follows:

- This formula was previously used by stakeholders, the MOPC, RSC, and BOD as part of the approval of the Balanced Portfolio analysis.

- The formulation represents the broad impact of new transmission projects in changing LIP costs (energy, congestion and losses cost) to rate payers within the SPP footprint. It represents much of the savings/benefits or additional cost to rate payers for specific transmission projects.

The total APC for the projects was calculated using the APC value for the projects in three different years. The years that were studied, and subsequently had an APC value, are 2009, 2014, and 2019. The benefits of the in-between years (i.e. 2010, 2011, etc.) were calculated linearly using the benefit values from the two years that were studied (i.e. 2009 and 2014). The sum of the APC benefits for each of the 10 years is the total APC. This same methodology was utilized in the recently adopted Balanced Portfolio.

Impact on Losses - Energy

Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings is captured as part of the APC analysis. It is possible that losses will increase since generation sources will be remotely located from load centers.

Impact on Losses – Capacity

While the energy component of losses is captured in the APC analysis, the capacity component is not. Capacity savings associated with a loss change are determined by looking at the selected hourly loadflow models to determine the loss change associated with a transmission upgrade. The BATTF established standard capacity prices to capture capacity savings. Calculations were based on a Combustion Turbine (CT) replacement, currently priced at $750 per kW installed (based on the expected cost to install various types of machines used by BATTF members).

There is a fixed Operations and Maintenance (O&M) cost component base of $650,000 per year (average expected cost experienced by BATTF members). This is an additive benefit for capturing the capacity component of that energy typically passed on to ratepayers through Ancillary Service charges. This is the variance in quantity of energy (capacity). The capacity component of losses is captured in the formulation below:

- Capacity Savings at Coincidental Peak = ((Capacity requirement at Peak (base case) – Capacity requirement at Peak (with projects upgrades included)) x (CT replacement cost)).

  This would be a savings estimate of the capacity, since the CT installation would be a one-time cost when the upgrade was energized.

- There is a fixed O&M cost savings associated with this calculation, captured in the Ancillary Services fee.

  It is calculated as Fixed Cost Benefit = (Capacity savings (as determined from above per 150 MW) x $ 650,000/yr), escalated by the rate of inflation as reported by the Bureau of Economic Analysis.

- The price differential was calculated on an annual basis from the point the proposed upgrade is energized to the end of the defined 20-year period. There were no additional accommodations for savings after 20 years, because a CT has an estimated 20-year life span.

- This formulation is the estimated benefit or cost impact of losses.

Environmental Impacts

The pricing for SO_2 and NO_X was approximated using data from the Chicago Climate Exchange; this represents the best estimate of current market prices. The BATTF discussed at length the merits of CO_2. The BATTF determined that the CO_2 calculation is viewed as a less definitive, but still quantitative, formulation. As described previously, an approximation for the impact of CO_2 was determined by calculating the change in CO_2 output between the base and change cases. The change in CO_2 tons was then used to calculate the potential savings or costs using a price of $26 and $49 per ton as estimated by the October 2009 EPA report.

The BATTF discussed running two carbon scenarios with a low- and a high-carbon value; both of which are needed to see what the impact will be on generation dispatch to provide the best determination of the impact of carbon on transmission projects. Without this type of modeling run, the CO_2 benefits for transmission projects will cause any transmission project to have benefits in excess of its cost if it displaces coal or gas generation. Due to the time constraints for this type of modeling and simulations, and given the current state of the model and the input and model development required, the BATTF determined this analysis would not be a part of the Priority Projects effort.

Reliability Impact

Power Flow Analysis

As part of the Priority Project Phase II evaluation, SPP conducted a study to evaluate the impact of the Priority Projects on the reliability plan of the SPP transmission system and on first tier third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2009 SPP Transmission Expansion Plan (STEP) 10 year reliability analysis, but did not include 2009 STEP projects. It is expected that evaluation of these projects would result in even greater reliability benefits when evaluated with Priority Projects.

This study is not intended to justify any Priority Project based on deferred project cost alone; it is only intended to show the effects of the Priority Projects on the SPP reliability plan. At this time the in-service dates for the Priority Projects are not definite. For this study the projects are included in the 2014 models. If a project identified for deferment has a STEP date before 2014 it may or may not actually be deferred. It may be possible to mitigate these issues for a short period of time before the Priority Project is in service. Therefore, these projects and their costs are provided for assessment purposes.

An AC N-1 contingency analysis was performed using PSS/E. The analysis was performed using the 2009 STEP Build 3 models. Build 3 models were created in July 2009 to include revised load forecast information due to the recent economic downturn. Using the STEP models allows re-evaluation of STEP projects to determine if they can be deferred or eliminated due to the Priority Projects. These models are different from the models used in the economic analysis, since they do not include the anticipated wind generation. As a result, this study did not address the additional resources and load that are evaluated in the economic portion of the Priority Projects Report. Details of the analysis are as follows:

- Monitoring of Facilities
    - All facilities in the SPP footprint were monitored at 69 kV and above.
    - Entergy Services Inc. (EES) and AECI facilities were monitored at 100 kV and above.
    - All other first tier control areas were monitored at 230 kV and above.

- Cases
    - 2014 Summer Peak
    - 2014/15 Winter Peak
    - 2019 Summer Peak
    - Including all transaction cases

- Normal conditions and contingency analysis
    - Normal conditions
    - All N-1 single-element contingencies 69 kV and above in the SPP footprint were evaluated. These contingencies did not include manual transfer of load or manual switching.
    - All N-1 single-element contingencies 100 kV and above in EES, AECI, and all other first-tier control areas were evaluated.
    - SPP verified that all normal conditions and N-1 violations identified have corrective plans.

- Use of Transmission Operating Directives (TOD)
    - Transmission Operating Directives were applied in the same manner they have been applied in the 2009 STEP.

FCITC Analysis

As part of the Priority Projects Phase II evaluation, SPP conducted an FCITC analysis to determine impacts of the Priority Projects on the SPP transmission system. Using a DC transfer analysis, FCITC values were first calculated on each base SPP model without the Priority Projects. Additional calculations were then performed on models containing Priority Projects Group 1 upgrades then calculated on a third set of models containing Priority Project Group 2 upgrades. The models used were:

- 2014 Summer, Scenario 0
- 2014 Winter, Scenario 0
- 2019 Summer, Scenario 0

The cases include previously approved expansion plan upgrades. 2009 STEP projects were not included because they were not approved at the time of this analysis. The MUST settings and procedures used in the analysis are included in Appendix C.

Reactive Requirements

The consideration of long distance EHV transmission upgrades (e.g., > 50 miles) may require additional reactive compensation to maintain voltage during normal operating conditions and reduce voltage rise during line switching. During light load conditions the high voltage issue may be exacerbated, as there are less transmission line real power losses to offset capacitive line charging. The additional line charging increases voltage on the bulk electric system. In order to address this issue, shunt line reactors are typically used to counter or offset excessive line charging during light load conditions.

This high level screening study provides a calculated value for line shunt reactors required to support the addition of EHV transmission in Priority Projects Groups 1 and 2 under normal (no outage) and selected single contingency events.

The study method determines reactive power (Q) requirements for different line voltages (V) to determine the magnitude of reactive compensation to maintain system voltages within acceptable limits. This analysis technique is commonly called “QV Analysis”.

A QV, reactive compensation verses voltage analysis, was conducted on each proposed grouping of Priority Projects to determine the impact of these projects on the SPP interconnection points and the amount of shunt compensation each segment of the project would require to maintain acceptable transmission voltages.

The light load base cases representing 2014 light load conditions were prepared using Power System Simulator for Engineering (PSS/E). The steps used to build each model are listed below.

Model building steps:

1. Add Balanced Portfolio Projects to the base case
2. Add Priority Project Group
3. Add line breakers as needed
4. Solve model

PowerWorld Corporation Simulator was used to perform an AC QV analysis. The total amount of line reactance to keep the system voltages around 1.01 p.u.[4] was determined for each group of Priority Projects. Each line segment was also tested for voltage rise at the open end while the other end remained closed into the network.

The following key study assumptions were applied:

1. This study does not include the effects of Sub synchronous Resonance (SSR). SSR is an electric power system condition where the electric network exchanges energy with a turbine generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system[5].
2. A light load conditions is the worst case scenario for high voltage conditions.
3. The STEP 2010 Spring Peak model is included in the base case.
4. Balanced Portfolio Projects are added to the base case.
5. Priority Projects Groups 1 and 2 are analyzed to determine the number of line shunts per line segment.
6. Line reactors are sized by opening one end of each line segment to determine reactive support to keep line end voltage around 1.01 p.u.
7. Actual line reactors may be a combination of smaller units or Flexible AC Transmission System (FACTS) devices to cover multiple system load conditions and operating points.
8. The study has not included additional shunts required to maintain safe voltage levels on locations other than the Priority Project line segments.
9. The study is not a short circuit analysis and does not include the effects of reactors on line switching.

Revenues to Wind Resources

Traditionally SPP's economic analysis has not considered the revenues paid to transactionally-modeled (wind) resources. Because the states within SPP's footprint continue to progress towards additional renewable energy targets and with the ever increasing likelihood of a federal renewable standard, it becomes much more appropriate to consider the affect these targets will have on SPP's transmission expansion. Under a renewable target, each zone within the SPP footprint is essentially required to commit to a certain level of renewable energy – whether by outright ownership or through a power purchase contract.

For the purposes of evaluating Priority Projects, the assumption is made that all wind resources in the model are not designated to the zone in which the resource is located, but instead the energy output of those resources will be committed by the Transmission Owners across SPP. Each Transmission Owner has a fixed cost associated with the purchase of the

[4] All EHV lines (345 kV+) are operated between 0.98 and 1.04PU. For the study purpose, an average 1.01 pu operating voltage was chosen.

[5] Sub synchronous Resonance in Power Systems, Paul M. Anderson, B. L. Agrawal, J. e. Van Ness, IEEE Press, 1990

energy output from the renewable resources. This fixed cost will be recovered through the sales of that energy into the SPP market. Since the renewable resources being studied in the Priority Projects analysis is included in the base and change cases, the benefit to the region from the wind resources can be calculated by multiplying the increased energy output by the generation-weighted LIP for each resource.

SEAMS Coordination

A letter was sent to AECI, CLECO, ERCOT, ESI, MISO, TVA, and WECC on December 16, 2009 to inform them of the projects being proposed as Priority Projects. The letter also encouraged the respective companies to engage in the process through the various stakeholder working groups.

Breakeven Analysis

The ESWG met on November 3, 2009 to provide their recommendations to the Strategic Planning Committee (SPC) regarding Priority Projects. One of the recommendations was for staff to determine what level of wind would be required to produce a benefit to cost ratio (B/C) of 1 for the subject groups of Priority Projects. Staff agreed this analysis would be performed as time permitted. An evaluation will be made after the January 2010 BOD meeting as to what time-frame staff will be able to perform this assessment.

Economic Modeling Tools

PROMOD

PROMOD IV is a detailed nodal and zonal market simulation tool offered by Ventyx. It provides users a way to assess the economic impacts of changes to the transmission system. For the Priority Projects study, staff primarily utilized the Locational Imbalance Price (LIP) forecasting and unit dispatch capabilities of PROMOD IV.

The Transmission Analysis Module (TAM) utilized by PROMOD IV performs a detailed simulation of market operations considering any inefficiencies across seams. PROMOD IV TAM is an hourly chronological simulation of electric market operations using a detailed transmission grid topology which can include up to 46,000 buses and 56,000 transmission lines. PROMOD IV TAM uses an hourly forecast of loads at each bus, along with detailed descriptions of generators to commit and dispatch under an LIP market.

LIPs are calculated for both the generation-weighted and load-weighted average hub LIPs for the footprint. Prices are provided in full hourly detail (8760 hours) and can be summarized into monthly periods. The net production cost is calculated hour-by-hour, and the formula is variable generation costs (fuel costs, variable O&M costs, emission costs, startup-costs), plus the cost of external purchases (if generation is less than demand) minus external sales revenues (if generation exceeds load) on an hourly basis. The cost of external purchases is computed as the MW purchase level times the load-weighted sub-region's LIP. The external sales' revenues are computed as the MW sale level times the generation-weighted sub-region's LIP.

The Adjusted Production Cost (APC) benefit of a project is determined by using the metrics described above. PROMOD IV also provides detailed price components of transmission congestion for market hubs while identifying areas of potential improvement.

PROMOD IV LIP utilizes a Security-Constrained Unit Commitment (SCUC) algorithm, recognizing the following bids and constraints:

- Generation:
    - Minimum capacity with no-load energy bid
    - Segmented energy bids with ramp up and ramp down limits
    - Startup cost bid
    - Minimum runtime and minimum downtime (hours)
    - Operating reserve contribution

- Transmission:
    - Individual transmission flow limits (including DC ties)
    - Flowgate limits on interfaces
    - Phase Angle Regulator (PAR) angle limits

- Dynamically determined transmission loss penalty factors

- Market:
  - Load balance with market net interchange limits and hurdle rates
  - Regional operating reserves (both spinning and non-spinning)

LIP is calculated for individual nodes and hubs with congestion price (broken out by flowgate) and loss price components.

PROMOD Analysis Tool (PAT)

The PAT (also known as the PROMOD Analysis Tool) is an interactive program that forms and solves a transmission-constrained economic dispatch model. All of the input data for the PAT analysis for Priority Projects comes from Ventyx's PROMOD program, which is a large, complex batch program used by SPP for long-term transmission and generation planning studies. The PAT uses the same mathematical model, and provides an intuitive tool for studying and temporarily modifying the underlying details of the transmission and generation systems, and computing the resulting changes in dispatch and locational bus pricing information that result from the optimization. Specifically in the Priority Projects analysis PAT was used to research congested bottlenecks and indentify their causes. This provided staff with additional contingencies which were added for PROMOD to monitor.

Priority Projects Phase II Analysis Results

Summary of Results

A multi-faceted and detailed analysis has been performed using the study assumptions and definitions of the value metrics to derive APC, impact on losses (energy and capacity), reliability impact (in relation to deferral and advancement of existing STEP NTC projects), and increased revenues to wind plants. The results are presented both with and without considering the wind revenues metric.

All of the value metric results are further described in this report in relation to the two study groupings of projects. Further, this financial analysis is provided in three timeframes including the first ten years, the second ten years, and the last twenty years due to the scope and lifetime of the projects. Benefits not counted in this assessment include but are not limited to environmental benefits and benefits related to deferral of 2009 STEP projects. As a result of the CAWG survey, it is important to note that the 7 GW level of renewable resources studied in this analysis will not be enough for each member to meet their existing renewable mandates/targets.

The impact of transmission expansion on a typical residential customer electric bill is approximately 33.5 cents per month per kW of demand for $1 billion of investment. At the August 26, 2009 CAWG meeting, there was general consensus among the regulators, transmission owners, marketers, and wind developers with the conclusion of a customer impact of approximately $1/mo. per $1 billion of investment assuming a residential demand of 3 kW. Additional detail on calculating customer bill impact can be found in Appendix F.

Study Group	APC (Years 1-40)	Reliability (Years 1-40)	Losses (Years 1-40)	Wind Benefit	KEMA Other Benefits	Total Benefit (w/ Wind)	Total Cost (Years 1-40)	Net Benefit	B/C (w/ Wind)
Group 1	$786,001,884	($20,175,666)	$26,627,100	$403,940,404	$361,073,329	**$1,557,467,052**	**$2,246,851,575**	**($689,384,523)**	**0.69**
Group 2	$819,705,924	($20,175,666)	$26,888,067	$443,104,684	$399,916,159	**$1,669,439,168**	**$2,012,293,729**	**($342,854,562)**	**0.83**

Table 2: Benefits and Costs with Wind Revenue and KEMA Other Benefits

Study Group	APC (Years 1-40)	Reliability (Years 1-40)	Losses (Years 1-40)			Total Benefit	Total Cost (Years 1-40)	Net Benefit	B/C
Group 1	$786,001,884	($20,175,666)	$26,627,100			**$792,453,318**	**$2,246,851,575**	**($1,454,398,257)**	**0.35**
Group 2	$819,705,924	($20,175,666)	$26,888,067			**$826,418,325**	**$2,012,293,729**	**($1,185,875,404)**	**0.41**

Table 3: Benefits and Costs without Wind Revenue and KEMA Other Benefits

Years 0 -10

Study Group	Priority Projects Built	Benefit Detail					Cost and Benefit Summary			
		APC (in Millions)	Wind Benefit (in Millions)	Fuel Diversity (in Millions)	Reliability (in Millions)	Losses (in Millions)	Total Benefit (in Millions)	Total Cost (in Millions)	Net Benefit (in Millions)	B/C
1	**• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (765 kV @ 345 kV) • Comanche – Woodward District EHV (765 kV @ 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station**	$291.74	$139.06	$145.09	($14.61)	$24.27	**$585.54**	**$1,264.32**	**($678.78)**	**0.46**
2	**• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (DCT 345 kV) • Comanche – Woodward District EHV (DCT 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)**	$300.93	$158.65	$161.28	($14.61)	$24.48	**$630.74**	**$1,132.33**	**($501.60)**	**0.56**

Table 4: Years 0-10 Benefits and Costs with Wind Revenue and Other KEMA Benefits

Years 11 - 20

Study Group	Priority Projects Built	Benefit Detail					Cost and Benefit Summary			
		APC (in Millions)	Wind Benefit (in Millions)	Fuel Diversity (in Millions)	Reliability (in Millions)	Losses (in Millions)	Total Benefit (in Millions)	Total Cost (in Millions)	Net Benefit (in Millions)	B/C
1	**• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (765 kV @ 345 kV) • Comanche – Woodward District EHV (765 kV @ 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station**	$267.23	$140.45	$118.18	($5.84)	$2.36	**$522.37**	**$585.63**	**($63.25)**	**0.89**
2	**• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (DCT 345 kV) • Comanche – Woodward District EHV (DCT 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)**	$280.06	$151.75	$130.65	($5.84)	$2.40	**$559.03**	**$524.49**	**$34.54**	**1.07**

Table 5: Years 11-20 Benefits and Costs with Wind Revenue and Other KEMA Benefits

Years 21 - 40

Study Group	Priority Projects Built	Benefit Detail: APC (in Millions)	Wind Benefit (in Millions)	Fuel Diversity (in Millions)	Reliability (in Millions)	Losses (in Millions)	Cost and Benefit Summary: Total Benefit (in Millions)	Total Cost (in Millions)	Net Benefit (in Millions)	B/C
1	**• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (765 kV @ 345 kV) • Comanche – Woodward District EHV (765 kV @ 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station**	$227.03	$124.43	$97.81	$0.28	$0.00	**$449.55**	**$396.90**	**$52.65**	**1.13**
2	**• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (DCT 345 kV) • Comanche – Woodward District EHV (DCT 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)**	$238.71	$132.70	$107.99	$0.28	$0.00	**$479.67**	**$355.47**	**$124.21**	**1.35**

Table 6: Years 21-40 Benefits and Costs with Wind Revenue and Other KEMA Benefits

Without Wind Revenue and Fuel Diversity Benefit

Years 0 -10

Study Group	Priority Projects Built	Benefit Detail: APC (in Millions)	Benefit Detail: Reliability (in Millions)	Benefit Detail: Losses (in Millions)	Cost and Benefit Summary: Total Benefit (in Millions)	Cost and Benefit Summary: Total Cost (in Millions)	Cost and Benefit Summary: Net Benefit (in Millions)	Cost and Benefit Summary: B/C
1	• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (765 kV @ 345 kV) • Comanche – Woodward District EHV (765 kV @ 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)	$291.74	($14.61)	$24.27	**$301.39**	**$1,264.32**	**($962.93)**	**0.24**
2	• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (DCT 345 kV) • Comanche – Woodward District EHV (DCT 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)	$300.93	($14.61)	$24.48	**$310.80**	**$1,132.33**	**($821.53)**	**0.27**

Table 7: Years 0-10 Benefits and Costs without Wind Revenue and Other KEMA Benefits

Years 11 - 20

Study Group	Priority Projects Built	Benefit Detail: APC (in Millions)	Benefit Detail: Reliability (in Millions)	Benefit Detail: Losses (in Millions)	Cost and Benefit Summary: Total Benefit (in Millions)	Cost and Benefit Summary: Total Cost (in Millions)	Cost and Benefit Summary: Net Benefit (in Millions)	B/C
1	• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (765 kV @ 345 kV) • Comanche – Woodward District EHV (765 kV @ 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)	$267.23	($5.84)	$2.36	**$263.75**	**$585.63**	**($321.87)**	**0.45**
2	• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (DCT 345 kV) • Comanche – Woodward District EHV (DCT 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)	$280.06	($5.84)	$2.40	**$276.63**	**$524.49**	**($247.86)**	**0.53**

Table 8: Years 11-20 Benefits and Costs without Wind Revenue and Other KEMA Benefits

Years 21 - 40

Study Group	Priority Projects Built	Benefit Detail: APC (in Millions)	Benefit Detail: Reliability (in Millions)	Benefit Detail: Losses (in Millions)	Cost and Benefit Summary: Total Benefit (in Millions)	Cost and Benefit Summary: Total Cost (in Millions)	Cost and Benefit Summary: Net Benefit (in Millions)	B/C
1	• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (765 kV @ 345 kV) • Comanche – Woodward District EHV (765 kV @ 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)	$227.03	$0.28	$0.00	**$227.31**	**$396.90**	**($169.59)**	**0.57**
2	• Hitchland – Woodward District EHV • Spearville – Comanche - Medicine Lodge – Wichita (DCT 345 kV) • Comanche – Woodward District EHV (DCT 345 kV) • Valliant – NW Texarkana • Cooper – Maryville – Sibley • Riverside Station – Tulsa Power Station (Add Reactor)	$238.71	$0.28	$0.00	**$238.98**	**$355.47**	**($116.48)**	**0.67**

Table 9: Years 21-40 Benefits and Costs without Wind Revenue and Other KEMA Benefits

Adjusted Production Cost

The table below indicates the results of the adjusted production cost analysis. For each group of projects studied, the APC was calculated between the base and change case for each year of study. The results for 2009, 2014, and 2019 were then linearly interpolated between the years and extrapolated for the next ten years. After the twentieth year, benefits were held constant until the fortieth year at which time benefits were assumed to cease. Finally, a net present value (NPV) was calculated for each study group using the full forty years of benefits and an 8% discount rate. This is the value shown in the benefits summary tables above.

	2009	*2014*	*2019*
Group 1	$22,170,000	$45,230,000	$64,673,000
Group 2	$22,040,000	$46,950,000	$67,301,000

Table 10: Regional APC Results

Impact on Losses – Capacity

The capacity savings and fixed cost benefit calculations were calculated using the methods suggested by the BATTF in the Benefit Analysis for Priority Projects Report (Attachment 1). The change in losses was calculated for each study period and interpolated between each year. Additionally, the results were extrapolated to capture the last ten years of benefits. Per the BATTF recommendations, loss savings were assumed to terminate after twenty years due to the expected life of a combustion turbine. A net present value was then calculated for the losses, and the results are provided in the table below.

Group 1			
Zone	**2010 - 2019 NPV**	**2020 - 2029 NPV**	**Total**
AEPW	$9,877,767	$945,533	$10,823,300
EMDE	$227,817	$27,300	$255,117
GRDA	($152,600)	($18,200)	($170,800)
KCPL	$1,180,683	$98,367	$1,279,050
LES	$77,383	$9,100	$86,483
MIDW	$3,724,150	$341,467	$4,065,617
MIPU	($174,267)	$5,633	($168,633)
MKEC	$6,346,300	$574,600	$6,920,900
NPPD	$691,250	$86,667	$777,917
OKGE	($4,350,833)	($509,167)	($4,860,000)
OPPD	$702,950	$58,067	$761,017
SPRM	$76,300	$9,100	$85,400
SUNC	$240,600	$22,533	$263,133
SWPS	$2,029,117	$302,900	$2,332,017
WEFA	$2,587,267	$323,700	$2,910,967
WRI	$1,186,317	$79,300	$1,265,617
Total	**$24,270,200**	**$2,356,900**	**$26,627,100**

Table 11: Impact on Losses - Group 1

Group 2			
Zone	**2010 - 2019 NPV**	**2020 - 2029 NPV**	**Total**
AEPW	$10,184,917	$977,167	$11,162,083
EMDE	$227,817	$27,300	$255,117
GRDA	($152,600)	($18,200)	($170,800)
KCPL	$1,336,317	$111,800	$1,448,117
LES	$77,383	$9,100	$86,483
MIDW	$4,033,250	$368,333	$4,401,583
MIPU	($97,967)	$14,733	($83,233)
MKEC	$6,417,400	$588,467	$7,005,867
NPPD	$692,333	$86,667	$779,000
OKGE	($3,891,083)	($459,333)	($4,350,417)
OPPD	$781,200	$62,400	$843,600
SPRM	$76,300	$9,100	$85,400
SUNC	$165,383	$13,433	$178,817
SWPS	$1,720,017	$276,033	$1,996,050
WEFA	$2,510,967	$314,600	$2,825,567
WRI	$403,167	$21,667	$424,833
Total	**$24,484,800**	**$2,403,267**	**$26,888,067**

Table 12: Impact on Losses - Group 2

Environmental Impacts

Initially carbon benefits were to be included in the report; however the prescribed method of modeling the 7 GW of wind in the base and change cases do not support the previously developed calculations needed for carbon benefit estimates. In the base case, the calculated wind generation is trapped within the zone where it is generated due to the existing base case transmission grid. This trapped wind is therefore used to supply the load within that zone; causing the output for the carbon units within that zone to decrease.

In the change case, a more robust transmission system results in the model exporting the wind outside the zone where it is generated. As the wind disperses, the fossil units that were being displaced by wind in the base case increase to balance the load. Because the wind is modeled in both the base and change cases, using the methods previously described for calculating the impact of the Priority Projects on carbon emissions shows an increase in emissions.

Reliability Impact

The reliability analysis is summarized in the table below showing the revenue requirements associated with advancements, deferments and overall net impact for each of Priority Project study groupings. Results are broken into (1) advanced projects — projects that would be moved up in the reliability timeline due to the Priority Project; (2) new SPP 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) new third party projects — projects needed on neighboring systems due to the Priority Projects; (4) deferred projects — projects which are either deferred beyond the planning horizon or mitigated entirely due to the Priority Projects; and (5) Net Impact – the net cost or benefit of reliability projects related to the Priority Projects. Amounts shown for reliability impact in the overall benefits and costs summary tables are in terms of NPV of the Annual Transmission Revenue Requirements. This Net Present Value is limited to a 40 year project life.

Priority Project Group	Advanced Projects	New SPP Projects	New 3rd Party Projects	Deferred Projects	Net Impact
Group 1 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita 765 kV @ 345 kV Comanche – Woodward District EHV 765 kV @ 345 kV Cooper – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$2.6M	$14.0M	$11.6M	$2.2M	-$26.0M
Group 2 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita Double 345 kV Comanche – Woodward District EHV Double 345 kV Cooper – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$2.6M	$14.0M	$11.6M	$2.2M	-$26.0M

Table 13: Reliability Impact Results

Revenues to Wind Resources

Traditionally SPP's economic analysis has not considered the revenues paid to transactionally-modeled (wind) resources. Because the states within SPP's footprint continue to progress towards additional renewable energy targets and with the ever increasing likelihood of a federal renewable standard, it becomes much more appropriate to consider the affect these targets will have on SPP's transmission expansion. Under a renewable target, each zone within the SPP footprint is essentially required to own a certain level of renewable energy – whether by outright ownership or through a power purchase contract.

For the purposes of evaluating Priority Projects, the assumption is made that all wind resources in the model are not designated to the zone in which the resource is located, but instead the energy output of those resources will be owned by the utilities across SPP. Each owner has a fixed cost associated with the purchase of the energy output from the renewable resources. This fixed cost will be recovered through the sales of that energy into the SPP market.

Since the renewable resources being studied in the Priority Projects analysis is included in the base and change cases, the benefit to the region is a result of the incremental additional energy output from the wind resources. This benefit is calculated by multiplying the increased energy output by the average generation-weighted LIP for each wind resource in each case. The ESWG gave staff its support in calculating this benefit metric at its meeting on January 5, 2009.

The change in revenue between the base and change cases is shown in the table below. As with the other benefit metrics, the values below were interpolated between the study years and extrapolated out to forty years and discounted at 8%. The net present value of the forty years of benefits is shown in the benefit summary tables above.

	2009	*2014*	*2019*
Group 1	$ 11,771,328	$ 17,699,661	$ 27,823,453
Group 2	$ 15,763,419	$ 22,512,798	$ 35,304,387

Table 14: Increased Revenues to Wind

The chart below shows the percentage of dispatched wind generation relative to maximum capacity of the wind generators. The potential capacity factor column indicates how much wind energy would be dispatched without any curtailment. The next three columns are the total capacity factor percentages for each of the study groups. The columns displayed are aggregates of the three study years 2009, 2014, and 2019. As expected, the addition of the two study groups resulted in less wind curtailment in comparison to the base case model. While study Group 1 produces fewer additional wind revenues than Group 2 due to lower LIP prices, Group 1 allows more wind to be dispatched.

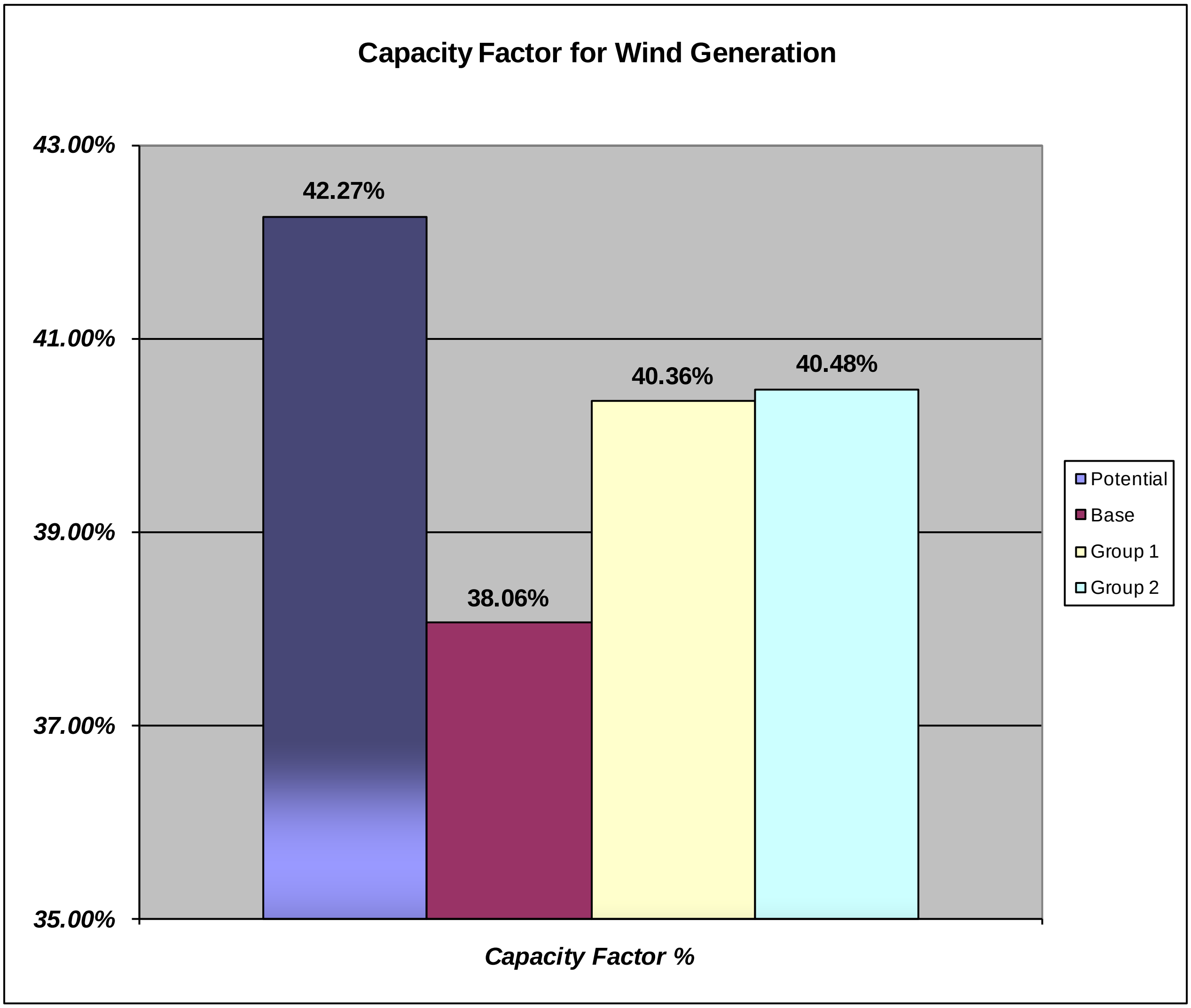


Figure 4: Wind Capacity Factor Changes

Priority Project Cost Calculations

The tables below show the Annual Transmission Revenue Requirement (ATRR) by project for study group 1 and 2. The Engineering and Construction (E&C) cost estimates were provided by the Transmission Owners (TO's). The ATRR for each transmission line was calculated by multiplying the Engineering E&C cost estimates by the levelized Fixed Charged Rate (FCR) for each company. The ATRR was carried out for forty years (the assumed life of the projects) and a net present value was determined by discounting the ATRR back using 8%. These NPV costs are what is represented in the summary benefit and cost tables above.

Project	Voltage	Breakout of project by TO	Owner	Levelized FCR	E & C Cost	ATRR
Spearville (ITC GP) - Comanche (ITC GP) - Medicine Lodge (ITC GP)/ (WR) - Wichita (WR)	765 @ 345 kV	Spearville-Comanche-Medicine Lodge	ITC	12.0%	$301,003,320	$36,120,398
		Wichita - Medicine Lodge	Prairie Wind	12.2%	$177,000,000	$21,552,693
Comanche (ITC GP)- Woodward District EHV (OGE)	765 @ 345 kV	Comanche - KS/OK border towards WD EHV	Westar	12.2%	$12,500,000	$1,522,083
		WD EHV- KS/OK border towards Comanche	OGE	15.1%	$119,647,059	$18,066,706
Hitchland (SPS) - Woodward District EHV (OGE)	345 kV DCT	OK Stateline - Woodward District EHV	OGE	15.1%	$233,026,000	$35,186,926
		Hitchland - OK Stateline	SPS	12.1%	$5,096,033	$ 616,620
Valliant - NW Texarkana (AEP)	345 kV	100% AEP	AEP	14.7%	$131,451,250	$19,297,044
Cooper (NPPD) - Maryville (KCPL) - Sibley (KCPL)	345 kV	Cooper-NE/MO border towards Maryville (NPPD), Maryville-NE/MO border towards Cooper and Maryville -Sibley (KCPL-GMO)	KCPL	15.1%	$278,000,000	$41,978,000
Riverside Station - Tulsa Power Station (Reactor) (AEP)	138 kV	100% AEP	AEP	14.7%	$842,847	$123,730

Table 15: Project Cost Calculations – Group 1

Project	Voltage	Breakout of project by TO	Owner	Levelized FCR	E & C Cost	ATRR
Spearville (ITC GP) - Comanche (ITC GP) - Medicine Lodge (ITC GP)/ (WR) - Wichita (WR)	765 @ 345 kV	Spearville-Comanche-Medicine Lodge	ITC	12.0%	$205,600,000	$24,672,000
		Wichita - Medicine Lodge	Prairie Wind	12.2%	$150,700,000	$18,350,231
Comanche (ITC GP)- Woodward District EHV (OGE)	765 @ 345 kV	Comanche - KS/OK border towards WD EHV	Westar	12.2%	$10,800,000	$1,315,080
		WD EHV- KS/OK border towards Comanche	OGE	15.1%	$97,427,500	$14,711,553
Hitchland (SPS) - Woodward District EHV (OGE)	345 kV DCT	OK Stateline - Woodward District EHV	OGE	15.1%	$233,026,000	$35,186,926
		Hitchland - OK Stateline	SPS	12.1%	$5,096,033	$616,620
Valliant - NW Texarkana (AEP)	345 kV	100% AEP	AEP	14.7%	$131,451,250	$19,297,044
Cooper (NPPD) - Maryville (KCPL) - Sibley (KCPL)	345 kV	Cooper-NE/MO border towards Maryville (NPPD), Maryville-NE/MO border towards Cooper and Maryville -Sibley (KCPL-GMO)	KCPL	15.1%	$278,000,000	$41,978,000
Riverside Station - Tulsa Power Station (Reactor) (AEP)	138 kV	100% AEP	AEP	14.7%	$842,847	$123,730

Table 16: Project Cost Calculations – Group 2

Strategic and Other Benefits of EHV Transmission

This economic assessment of Priority Project focuses on the following Value Metrics: Adjusted Production Cost (Savings), Impact on Losses – Energy and Capacity, Environmental Impacts, Reliability Impact(s), and Revenues to Wind Resources. These metrics do not capture the value of transmission as enabling assets that facilitate markets while maintaining reliability. Some of the strategic and other benefits of EHV transmission which are difficult to quantify include:

- Enabling future markets
- Storm hardening
- Improving operating practices/maintenance schedules
- Lowering reliability margins
- Improving dynamic performance and grid stability during extreme events
- Societal economic benefits

The ESWG has already discussed many of these metrics and generally agreed that these benefits, while at this time difficult to quantify, have the potential to provide significant value for the region. It is anticipated that further development of these metrics for the ITP will result in quantifiable benefits resulting from a robust transmission system.

KEMA Results

The SPP Board understands the challenges, yet the importance, of quantifying the benefits of enabling transmission facilities and requested that SPP staff work with consultants in late 2009 on this critical topic. SPP retained KEMA to prepare a white paper to outline other benefits of major EHV transmission projects, estimate Fuel Diversity Benefits and Dynamic Benefits for the Priority Projects and the ITP, and provide recommendations on additional steps for SPP to quantify other benefits of major transmission expansion.

KEMA was contracted to help SPP because these other benefits are not easily captured in static models, given the interdependencies of variables/parameters and the affect of competition which can be expected to occur as a result of enabling assets like EHV transmission. For example, the price elasticity of fuels is dependent upon supply and demand yet PROMOD fuel forecasts are static. KEMA also quantified some of the Dynamic Benefits associated with EHV transmission expansion in terms of savings/reductions from a strengthened transmission system in terms of reduced installed capacity, reduced operating capacity to mitigate intermittent resource variability's, reduced energy costs from lower energy prices.

A tool was developed to assist SPP staff and stakeholders understanding of the interdependencies of changes in assumptions and parameters of not only production costs, but other benefits that can be expected as a result of major EHV transmission expansion.

KEMA used the scenarios from the 2008 EHV Overlay Report posted 12/26/08 to create models for staff and stakeholder review. Preliminary results indicated that other benefits of EHV transmission expansion are at least equivalent to, if not an order of magnitude higher, than APC values derived by measuring congestion relief in static models like PROMOD. . These findings are consistent with efforts by Brattle to quantify the value of the Palo Verde – Devers EHV tie which concluded that inclusion of other benefits would double the calculated APC savings for that project.

KEMA Assumptions and Application to Priority Projects

KEMA assumptions for fuel diversity benefits in SPP are based on PROMOD results for the Priority Projects with 7 GW of wind in the base and change cases. Recent research efforts by Lawrence Berkley Labs and Rand Corp provide similar results regarding the range of price elasticity that can be expected for natural gas consumption in the range of 0.9 to 1.2. The Rand Study found a value of 0.97. KEMA has proposed that SPP use a value of 1.2 in the economic analyses associated with the fuel diversity benefits of the Priority Projects. This means that a 1.0% change in natural gas usage would reduce natural gas prices on a per unit basis by 1.2%. The U.S. DOE EIA data for 2007 shows that natural gas generation provides 22.5% of the total gas use in the states of KS, LA, NE and OK. Using this data, a 1% reduction in gas use for electricity would result in a 0.225% change in regional usage, which would produce 0.27% (0.225 * 1.2) change in gas prices. Therefore a 1% change in gas electric use would lower gas prices by 0.27%.

The PROMOD results with 7 GW of wind in the base and change cases indicate that the addition of the Priority Projects will reduce natural gas consumption as a boiler fuel by 4.1 – 5.4 percent which equates to a lower gas price in the range of 1.1 – 1.5%. While these price elasticity impacts are small, the resulting impact to gas costs is large in SPP. The following table shows the expected savings associated with 7 GW of wind in the base and change cases:

	2009	*2014*	*2019*
Group 1	$13.3M	$22.5M	$29.7M
Group 2	$14.4M	$26.0M	$32.4M

Table 17: Expected Savings from Reduced Gas Consumption

The net present value of these expected savings over forty years results in an aggregate fuel diversity benefit for Group 1 and Group 2 of $361.1M and $399.9M, respectively.

Other Dynamic Benefits Quantified

The benefits of competition which result from enabling infrastructure on margins should translate to lower prices to consumers. KEMA has defined these benefits in terms of reduced internal congestion, lower north to south energy differences, and lower on-peak prices. These values are projected to provide annual savings to SPP's markets in the range of $2M – $7.5M each with an aggregate value of $12.3M per year in 2010 dollars. The net present value of these other benefits is $146.7M in 2009 dollars.

Brattle Group Analysis

In 2009 The Brattle Group estimated the potential economic benefits associated with enabling and expanding the build out of wind power generation in the SPP region. The Brattle Group uses the Job and Economic Development Impact (JEDI) Wind model developed for the U.S. Department of Energy to estimate the potential economic impact of wind projects in the SPP footprint.

The JEDI Wind model separates a wind project's life into construction and operation phase. In each phase, the model estimates direct, indirect, and induced job and economic impacts. Direct jobs construct or operate the wind facilities. Indirect jobs provide services or materials to enable construction or operation. Induced jobs provide food, housing, day care, etc. to direct and indirect employees. The Brattle Group analysis found that investment of 4 GW of wind projects in 2014 would have the following economic benefits:

- Economic output during construction: ~ $2.1 billion
- Cumulative value of economic output during 20 operating years: ~ $1.7 billion (in 2009 dollars)
- Combined earnings during construction: ~$687 million
- Construction phase would create ~2,400 direct, 13,500 indirect jobs, 5,000 induced jobs
- Operating years would create ~225 direct, 300 indirect, 300 induced jobs

Future Considerations and Next Steps

Traditional resource planning tools do not capture the entire value of enabling assets such as EHV transmission. They are limited due to the use of normalized, typical and synchronized load profiles; standardized profiles for key variables such as HVDC ties or intermittent resources such as wind plants; optimized generation maintenance schedules; and no planned or forced outages of transmission facilities, to list a few.

While APC savings are determined based on a set of assumptions, they can be considered conservative projections of the value of a transmission system. Man-made and natural events happen that drastically affect grid topology and resource availabilities. For instance, extreme cold weather in early 2010 set all time peak demands for some SPP members and neighboring systems, which traditionally occurs in the summer months. This event also affected the availability and performance of 17 thermal units in SPP due to equipment problems or fuel supply disruptions. Although these unusual and extreme events happen with regularity, they are difficult to predict. The value of enabling infrastructure such as a robust EHV network, which provides competitive options in resource procurement and delivery during unusual and extreme events, can be very large. As we transition to value-based planning concepts with long horizons, the option to address unusual and extreme events will provide tremendous benefits above the minimum capacity/capability based on historical standards and markets.

The value of a robust EHV transmission network that facilitates competition provides significant benefits over the long term as market participants reposition themselves to capitalize on new opportunities that arise as a result of enabling infrastructure. The long lead time for EHV transmission assets is a challenge and barrier which impedes optimizing resource planning decisions which are not available due to constraints. It is paramount to capture the value of a robust and flexible EHV transmission network that enables markets in terms of unusual and extreme events, as well as competitive markets and future resource options.

Sensitivity Analysis

SPP staff has attempted to provide enough information based on the feedback we received from stakeholders during phase I analysis to help stakeholders better understand the benefits of the Priority Projects. In addition to the analysis directed by the SPC, SPP staff made the following comparisons with the resulting APCs:

Comparison	Base Case	Change Case	Total 40 year APC
1	Current wind in the SPP footprint	7 GW total Wind in the SPP footprint	$800,064,339
2	Current wind in the SPP footprint	Current wind in the SPP footprint plus Priority Project Group 1	$736,888,644
3	7 GW total Wind in the SPP footprint	7 GW total Wind in the SPP footprint plus Priority Projects Group 1	$786,001,884
4	Current wind in the SPP footprint	7 GW total Wind in the SPP footprint plus Priority Projects Group 1	$1,586,053,941

Table 18: APC Comparisons - Group 1

Comparison	Base Case	Change Case	Total 40 year APC
1	Current wind in the SPP footprint	7 GW total Wind in the SPP footprint	$800,064,339
2	Current wind in the SPP footprint	Current wind in the SPP footprint plus Priority Project Group 2	$741,182,127
3	7 GW total Wind in the SPP footprint	7 GW total Wind in the SPP footprint plus Priority Projects Group 2	$819,705,924
4	Current wind in the SPP footprint	7 GW total Wind in the SPP footprint plus Priority Projects Group 2	$1,619,754,006

Table 19: APC Comparisons - Group 2

As can be seen in the preceding charts, addition of wind to the current system results in savings in the form of a larger adjusted production cost. Compare that to addition of the Priority Projects to the current system and approximately the same level of savings is realized as with the addition of wind alone.

From the perspective of APC alone, the minimum value the Priority Projects provide is over $700 M. Comparison 3 - addition of more wind to the cases - results in better utilization of the transmission system and greater savings without biasing the results by changing two variables at once.

Other Supporting Information

WITF Results

The SPP Wind Integration Task Force (WITF) Wind Penetration study's purpose was to determine the operational and reliability impacts of wind integration into the SPP transmission system and energy markets. Three wind penetration levels were studied (10%, 20%, and 40%) and compared to a Base case (current system conditions) of approximately 4% wind penetration. Because SPP wind generation resources are largely located in the western portion of the SPP footprint in transmission-constrained locations away from load generation centers, an increase in wind penetration level causes changes in the power flow patterns requiring upgrades or reconfigurations to the transmission system.

The power flows from western SPP to eastern SPP are increased significantly. To meet the reliability standards of the SPP criteria and to accommodate the increased west-to-east flows, a number of transmission expansions were required. These included new transmission lines totaling 1,260 miles of 345 kV and 40 miles of 230 kV lines for the 10% Case, and an additional 485 miles of 765 kV, 766 miles of 345 kV, 205 miles of 230 kV, and 25 miles of 115 kV lines for the 20% Case.

WITF Study recommendations:

- Major transmission reinforcements are needed to accommodate increased wind penetration levels, starting as low as 10%

- Considering lead times of transmission projects, it is recommended that SPP take definitive steps to reinforce its transmission network, especially west to east

- The addition of high voltage lines requires the installation of voltage control devices to prevent over-voltages under low-flow conditions due to contingencies or low wind power availability

- Dynamic voltage support becomes increasingly important for higher wind penetration levels in which several conventional generators may become displaced in the dispatch order by wind generators

- Add new reactive capability of the same nature as that provided by the displaced thermal units (i.e., continuously and instantaneously controllable) as wind penetration increases.

With all needed transmission upgrades in place, the study found that integrating the levels of wind studies in the 10% and 20% cases could be attained without adversely impacting SPP system reliability. Some localized voltage issues and transmission congestion were observed, but on average, they were around 1% for both the 10% and 20% Cases.

CAWG Survey

On November 6, 2009 the Cost Allocation Working Group (CAWG) distributed a survey to the state commission representatives within SPP requesting information on each state's renewable energy and energy conservation targets. The 7 GW of wind studied in the Priority Project analysis is not enough to meet each state's current mandate or target. The results of the survey indicate over 11 GW of wind is already targeted for the SPP footprint within the next twenty years even without a federal renewable energy mandate. Each state's target for wind energy is included in the table below. With a lower wind unit capacity factor the amount of installed wind would increase.

State	*State Target*	*Energy Targets (MWh)*	*Capacity Assuming 40% CF (MW)*
TX		6,517,491	1,860
MO	15	3,881,404	1,108
KS	20	9,342,546	2,666
OK		12,523,041	3,574
NE	10	4,023,427	1,148
NM	10	473,040	135
AR		1,241,108	354
LA		1,697,000	484
Total		**39,699,057**	**11,330**

Table 20: State Renewable Targets for SPP Footprint (No Federal RPS)

Conclusion and Recommendations

The SPPT report concluded that Priority Projects should improve known congestion, integrate SPP's west and east transmission systems, and be routinely identified as needed in SPP's current AS and GI cluster study processes. Based on these considerations, SPP staff confirms that the benefits provided for Group 2 are consistent with the SPPT requirements. Additional discussion on each of the SPPT measurements is provided. Staff recommends the following Priority Projects for construction:

1. Spearville – Comanche – Medicine Lodge – Wichita, double circuit construction and operated at 345 kV
2. Comanche – Woodward District EHV, double circuit construction and operated at 345 kV
3. Hitchland – Woodward District EHV, double circuit construction and operated at 345 kV
4. Valliant – NW Texarkana, constructed and operated at 345 kV
5. Cooper – Maryville – Sibley, constructed and operated at 345 kV
6. Riverside Station – Tulsa Power Station 138 kV reactor addition

Prior to construction of projects 1 and 2 above, staff recommends that the Priority Projects be evaluated with results of the Integrated Transmission Plan (ITP) study scheduled to be completed in January 2011. The ITP process will result in the development of a 20 year plan for transmission expansion in the next 20 years. The outcome of this analysis should determine if the proposed construction and voltage operation of the Priority Projects is consistent with the 20 year plan requirements.

Known congestion was a major consideration of the initial screening process for Priority Projects. These recommended projects will reduce several long-term congestions points for SPP. Transmission congestion relief is shown in the reduced APC calculations.

The SPP transmission system's GI and AS queues include a large amount of renewable resources. The CAWG survey identified over 11 GW of wind generation required to meet current 20 year renewable commitments. The Priority Projects will provide significant benefit and improvement to the GI and AS queues as required by the SPPT. The analysis shows that these Priority Projects will provide for expanded transmission service and ability to interconnect generation. The approval of these projects will facilitate improvement in both queues.

The WITF study identified transmission expansion as a key component to allowing for a reliable and economic operation of the grid at increased wind levels. The Regional State Committee's, Cost Allocation Working Group identified that the SPP region has current commitments of over 11 GW of wind for the SPP. The WITF report shows that for SPP reliably operate at that high of a wind penetration level, additional transmission is needed. Priority Projects 1, 2, and 3 were specifically identified in the WITF study as needed, important projects for providing and enhancing west to east interconnection of the SPP grid. Without these projects a major Priority Project goal would not be met.

The existing studies such as the SPP EHV Overlay Report conclude that at certain levels of wind there is a clear breakpoint at which 765 kV is needed and cost-justified compared to a 345 kV expansion. Based on prior studies and SPP staff's experience with modeling high levels of wind, the SPP breakpoint is between 8,000 MW and 10,000 MW of installed nameplate capacity. The exact number varies, depending on which wind and transmission facilities are assumed to be in place. Staff recommends that the ITP process evaluation of the 20 year projected needs confirm the appropriate future transmission voltage level to enable the reliable and economic operation of the future transmission grid.

The following table describes the cost and benefits of the Priority Projects. The calculated B/C ratio for the projects is slightly below 1 with the evaluations that were performed.

Study Group	APC (Years 1-40)	Reliability (Years 1-40)	Losses (Years 1-40)	Total Cost (Years 1-40)	Net Benefit	B/C (w/ Wind)
Group 1	$786,001,884	($20,175,666)	$26,627,100	**$2,246,851,575**	**($689,384,523)**	**0.69**
	Wind Benefit	**Fuel Diversity Benefit**	**Total Benefit (w/ Wind)**			
	$403,940,404	$361,073,329	**$1,557,467,052**			
Study Group	**APC (Years 1-40)**	**Reliability (Years 1-40)**	**Losses (Years 1-40)**	**Total Cost (Years 1-40)**	**Net Benefit**	**B/C (w/ Wind)**
Group 2	$819,705,924	($20,175,666)	$26,888,067	**$2,012,293,729**	**($342,854,562)**	**0.83**
	Wind Benefit	**Fuel Diversity Benefit**	**Total Benefit (w/ Wind)**			
	$443,104,684	$399,916,159	**$1,669,439,168**			

The APC and B/C calculates indicate slightly higher results for double circuit 345 construction for projects 1 and 2. While the B/C ratio is slightly below 1.0 for the directly calculated benefits, the SPP Staff recommends the Group 2 projects to accommodate known renewable growth and other benefits such as job creation indentified in the Brattle Group assessment. The regional benefits provided by these facilities are substantial and can strengthen the grid for future. The SPP region is already committed to renewable growth that needs these transmission Priority Projects to operate reliably and economically.

SPP staff will monitor the ITP to determine if there is a need for 765 kV construction to support the future requirements of SPP members. SPP staff recommends the following grouping for approval:

7. Spearville – Comanche – Medicine Lodge – Wichita, double circuit construction and operated at 345 kV

8. Comanche – Woodward District EHV, double circuit construction and operated at 345 kV

9. Hitchland – Woodward District EHV, double circuit construction and operated at 345 kV

10. Valliant – NW Texarkana, constructed and operated at 345 kV

11. Cooper – Maryville – Sibley, constructed and operated at 345 kV

12. Riverside Station – Tulsa Power Station 138 kV reactor addition

SPP staff believes the list of recommended projects achieve the strategic goals set forth in the “Report of the Synergistic Planning Project” dated April 23, 2009. These recommended projects will provide for improvements in the GI and AS queues and relieve know congestion while also improving west to east transmission system capabilities.

Appendices

Appendix A – Priority Project Cost Estimates (E&C)

	Zone	OG&E	SPS	WERE	ITC GP	WERE	ITC GP
	Project	Hitchland - Woodward	Hitchland - Woodward	Spearville - Comanche - Medicine Lodge - Wichita	Spearville - Comanche - Medicine Lodge - Wichita	Spearville - Comanche - Medicine Lodge - Wichita	Spearville - Comanche - Medicine Lodge - Wichita
	Voltage	Double Circuit 345 kV	Double Circuit 345 kV	765 kV Operated at 345 kV	765 kV Operated at 345 kV	Double Circuit 345 kV	Double Circuit 345 kV
Cost	Total Cost	$233,026,000	$5,096,033	$177,000,000	$301,003,320	$150,700,000	$205,600,000
	Total Material Cost	$98,154,000	$1,830,000	$175,000,000	$174,416,660	$28,000,000	$66,000,000
	Cost Per Mile	$817,950	$1,076,471	$2,500,000	$1,585,606	$400,000	$600,000
	Miles	120	1.7	70	110	70	110
	Substation Cost	$4,000,000	$3,164,033	$2,000,000	$26,000,000	$2,000,000	$34,000,000
Conductor	Size	2-1590 ACSR	2-795 ACSS	6 x 795 kcmil ACSR	6x954 ACSR/phase	3 x 954 kcmil ACSR	2-1590 ACSR per phase
	Design	Single with R/W for future twin or single and one 795 kV circuit	*Single Circuit	Single Circuit	Single Circuit	Double Circuit	double circuit
	Electrical Capacity (amps)	3000	3000	4000	4000	3000	3000
	Other						
Structure	Cost	$32,718,000				$42,000,000	
	Type	Single Pole	H-frame		Lattice/H-Frame		single-pole
	Material	Steel	Steel	Steel	Steel	Steel	Steel
	Base	Reinforced Concrete Foundation	Tangents are direct bury, and others in concrete foundation		concrete foundation		concrete foundation
	NESC Assumption	Heavy	Heavy	Heavy	Heavy	Heavy	Heavy
	Dead Ends				36		36
	Underbuild	No		None	None	None	None
Sub	Transformers	none	none	none	2- 1000MVA at Spearville; 400 MVA at Medicine Lodge	none	400 MVA at Medicine Lodge
	Breaker Scheme	1.5 Breaker	1.5 Breaker	1.5 Breaker	Ring	1.5 Breaker	Ring
	Protection Scheme	2 line terminal relay panels		Fiber & Double Primary	fiber/double primary	Fiber & Double Primary	fiber/double primary
	Voltage Control						
	Cost	4	$3,164,033	$2,000,000	$26,000,000	$2,000,000	$34,000,000
Construction Labor	Amount						
	Cost	$93,480,000			$93,920,000	$37,000,000	$99,000,000
Eng. Design, Project Management, Permitting	ROW	150	150	200ft	250ft	150	150
	ROW Condition	rural			rural, combination pasture and cultivated		rural, combination pasture and cultivated
	Permitting/Certifications						
	Escalation Rate	2%		5% per year		5% per year	
	Eng. Design/ Proj. Mang.	$17,704,500					
	Total Cost	$37,392,000	102,000		$6,666,660	$14,000,000	$6,666,660
Loadings and Overheads	Type 1					$18,500,000	
	Type 2					$9,200,000	
Other Cost Factors and Notes			*				

*This estimate is for building approximately two 0.85 mile lines between the existing Hitchland 345 kV Station and the OGE 765/345 kV Stateline Station. These lines are designed for 125 ºC operation, and considerations are given for other line crossings. The estimate is in 2009 dollars.

Project cost estimates (cont'd)

	Zone	WERE	OG&E	WERE	OG&E	AEP
	Project	Comanche - Woodward District EHV	Comanche - Woodward District EHV	Comanche - Woodward District EHV	Comanche - Woodward District EHV	Valiant - NW Texarkana
	Voltage	765 kV Operated at 345 kV	765 kV Operated at 345 kV	Double Circuit 345 kV	Double Circuit 345 kV	345 kV
Cost	Total Cost	$12,500,000	$119,647,059	$10,800,000	$97,427,500	$131,451,250
	Total Material Cost	$12,500,000			$40,897,500	$53,375,000
	Cost Per Mile	$2,500,000			$817,950	$700,000
	Miles	5	50	5	50	76.25
	Substation Cost	$0	$2,000,000	$0	$200,000	$2,800,000
Conductor	Size	6 x 795 kcmil ACSR		3 x 954 kcmil ACSR	2-1590 ACSR	2-954 ACSR
	Design	Single Circuit		Double Circuit	Single with R/W for future twin or single and one 795 kV circuit	Double Ckt
	Electrical Capacity (amps)	4000		3000	3000	2236/3204 (N/E)
	Other					
Structure	Cost				$13,632,500	
	Type				single-pole	Lattice Tower
	Material	Steel		Steel		Steel
	Base				Reinforced Concrete Foundation	Concrete
	NESC Assumption	Heavy		Heavy	Heavy	Heavy
	Dead Ends					
	Underbuild	None		None	No	No
Sub	Transformers	none	none	none	none	none
	Breaker Scheme				1.5 Breaker	ring
	Protection Scheme				2 line terminal relay panels	high speed
	Voltage Control					
	Cost	$0		$0	$2,000,000	$2,800,000
Construction Labor	Amount				$38,950,000	
	Cost					$44,780,000
Eng. Design, Project Management, Permitting	ROW	200ft		150	150	150 ft
	ROW Condition				rural	rural and forested with some pasture
	Permitting/Certifications					CCN
	Escalation Rate	5% per year		5% per year	2%	5%
	Eng. Design/ Proj. Mang.				$7,376,875	Included in Construction Cost
	Total Cost				$15,580,000	$11,056,250
Loadings and Overheads	Type 1					$19,440,000
	Type 2					
Other Cost Factors and Notes						

Project cost estimates (cont'd)

	Zone	NPPD - KCPL	AEP
	Project	Cooper - Maryville - Sibley	Tulsa Power Station Reactor
	Voltage	345 kV	138 kV
Cost	Total Cost	$278,000,000	$842,847
	Total Material Cost		
	Cost Per Mile	$1,500,000	
	Miles	152	
	Substation Cost	$9,000,000	$448,153
Conductor	Size	2 - 1192 38/19 ACSS	
	Design	Single Circuit	
	Electrical Capacity (amps)	4178 @200degC	
	Other		
Structure	Cost	Included in material	
	Type	H-frame	
	Material	steel	
	Base	direct-embedded	
	NESC Assumption	Heavy	
	Dead Ends	32	
	Underbuild	no	
Sub	Transformers	none	none
	Breaker Scheme	ring	
	Protection Scheme	included	
	Voltage Control		
	Cost	$9,000,000	$448,153
Construction Labor	Amount		
	Cost		$140,180
Eng. Design, Project Management, Permitting	ROW	160ft	
	ROW Condition	Mostly rural, some urban near Kansas City, two Missouri River crossings	
	Permitting/Certifications		
	Escalation Rate		
	Eng. Design/ Proj. Mang.		Included in Construction Cost
	Total Cost		$110,765
Loadings and Overheads	Type 1		$143,749
	Type 2		
Other Cost Factors and Notes		*	

*10% contingency for line construction ($23M), NPPD estimate Cooper sub line terminal & river crossing ($16M), KCPL estimates river crossing at Sibley ($2M).

Appendix B – STEP Model Construction

The reliability analysis uses 2014 Summer Peak, 2014/15 Winter Peak and 2019 Summer Peak cases with updates from nearby regions and entities. The STEP load flow cases were built using the 2009 series MDWG Models On Demand (MOD) process. The load and capacity forecast for the load flow cases have included the impact on load of the existing and planned demand response resources. Due to the recent economic downturn, SPP provided an opportunity for its members to update their load forecast information. The 2009 STEP Build 3 models were created to include this new forecast information. These models were completed in June 2009

- Treatment of Transmission Owner-Initiated Projects
  - Transmission Owner-Initiated Projects as determined by the Transmission Owner were included.
    - MOD Type – Reliability
    - MOD Status STEP (with Notification to Construct (NTC))
    - Planned Projects
- Treatment of previous SPP Transmission Expansion Plan Projects
  - All projects that have either a Letter of Authorization (LOA) or NTC are included in the model except projects requested for removal through the stakeholder review process.
    - MOD Type- Reliability
    - MOD Status STEP (with NTC)
    - TO Planned
  - Due to the economic downturn requiring new load forecast and a short lead time to complete the STEP, stakeholders could request projects with NTC letters to be re-evaluated if the request was received by June 1, 2009.
  - Balanced Portfolio projects with NTC letters were included in the June models. Projects with NTC letters that have been identified as impacted by the Balanced Portfolio were re-evaluated.
- Treatment of SPP Aggregate Study (Attachment Z) Projects
  - All projects that have an LOA/NTC are included in the model except projects requested for removal through the stakeholder review process.
    - MOD Type TSR
    - MOD Status w/NTC (Approved)
- Treatment of transmission interconnection facilities of new generation
  - Include the interconnection facilities with executed agreements not on suspension
  - MOD Type LGIP
    - MOD status GIP.
- Include all MOD projects that have been energized
  - MOD Type Network
  - MOD type Energized
- Include all MOD projects that change network topology status
  - Constructed facilities that are out-of-service or normally open

        - MOD Type Outage
        - MOD Status Outage
- Include all MOD projects that update network data
    - MOD Type Network
    - MOD Status Update.
- Scenario cases
    - SPP developed six scenario cases for each season for the steady state evaluation
        - The “Zero case” had the same dispatch as the MDWG cases with the exception that generation that does not have a signed interconnection agreement and generation that does not have transmission service is also removed. The exception to this is in later years when generation load and interchange does not match the shortfall is made up of units that are in-service.
        - The “West to East” scenario 1 case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact West to East flowgates with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS exporting from the Lamar HVDC Tie.
        - The “East to West” scenario 2 case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact East to West flowgates with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC Tie.
        - The “South to North” (Scenario 3) scenario case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact South to North flowgates with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and SPS exporting to the Lamar HVDC Tie.
        - The “North to South” (Scenario 4) scenario case is the same as the zero scenario case with the dispatch changed to capture transmission service that has been sold that impact North to South flowgates with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie.
        - The “All transactions” scenario 5 case is the same as the zero scenario case with the dispatch changed to include all transmission service sold with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie
- Use of Transmission Operating Directives (TOD)
    - The Steady State analysis will identify all violations without the use of TODs.
    - TODs may be used as alternatives to planned projects. Load flow analysis will be performed to determine the effectiveness of the TOD in alleviating the violation(s).

- SPP will determine all reinforcements that are needed to eliminate TODs used in alleviating violation(s). A list of reinforcements that are not required due to TODs will be included in the report.

Appendix C – MUST Settings and Procedures for FCITC Analysis

MUST Solution Settings

- CONSTRAINTS/CONTINGENCY INPUT OPTIONS
  - AC Mismatch Tolerance – 2 MW
  - Base Case Rating – Rate A
  - Base Case % of Rating – 100%
  - Contingency Case Rating – Rate B
  - Contingency Case % of Rating – 100%
  - Base Case Load Flow – PSS/E
  - Convert branch ratings to estimated MW ratings – No
  - Contingency ID Reporting – Labels + Events
  - Maximum number of contingencies to process – 50000

- MUST CALCULATION OPTIONS
  - Phase Shifters Model for DC Linear Analysis – Constant Flow for Base Case and Contingencies
  - Report Base Case Violations with FCITC – Yes
  - Maximum number of violations to report in FCITC table – 50000
  - Distribution Factor (OTDF and PTDF) Cutoff – 0.03
  - Maximum times to report the same elements – 1 {eliminate voluminous repeats}
  - Apply Distribution Factor to Contingency Analysis – Yes
  - Apply Distribution Factor to FCITC Reports – Yes
  - Minimum Contingency Case flow change – 1 MW
  - Minimum Contingency Case Distribution Factor change – 0.0
  - Minimum Distribution Factor for Transfer Sensitivity Analysis – 0.0

Voltage Monitoring

- MUST does not do voltage monitoring for transfer analysis.

Contingency

- Outage of all single branches and ties in the SPP (Area 502-546, 640-650) and NON-SPP (EES,AECI) above 100 kV
- Multi-terminal/Special Contingency Outage

Exclude

- Exclude outage of all invalid single outages. Single outages may be invalid due to system configuration. For example, a breaker to breaker outage may result in multiple elements being removed from service, so testing the loss of the single element is not valid.

- Operating guides implementation

Monitor

- Monitor branches and ties in SPP above 100 kV

Transfer Directions/Transfer Level

- 600 MW transfer from all PORs to PODs (PORs/PODs consist of all zones in SPP's OASIS, excluding IPPs)

Appendix D –Priority Project Benefits and Costs by Zone

For the zonal calculations below, the calculated NPV costs for each project grouping was allocated using load ratio share.

Area	Study Group 1 (765 kV @ 345 kV)						
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Net Benefit (Years 0 - 40)	B/C
AEPW	$505,588,352	$13,595,919	$5,157,860	($2,385,242)	$10,823,300	($491,992,434)	0.03
EMDE	$59,271,865	$39,347,401	$39,371,914	($279,630)	$255,117	($19,924,464)	0.66
GRDA	$43,997,292	($46,711,078)	($46,332,710)	($207,568)	($170,800)	($90,708,370)	(1.06)
KCPL	$173,771,365	$13,427,976	$12,968,737	($819,811)	$1,279,050	($160,343,389)	0.08
LES	$43,181,923	($41,579,181)	($41,461,943)	($203,722)	$86,483	($84,761,104)	(0.96)
MIDW	$16,182,350	($89,173,610)	($93,162,882)	($76,344)	$4,065,617	($105,355,959)	(5.51)
MIPU	$91,044,063	$59,565,594	$60,163,751	($429,524)	($168,633)	($31,478,468)	0.65
MKEC	$25,216,847	($142,686,228)	($147,989,419)	($1,617,709)	$6,920,900	($167,903,075)	(5.66)
NPPD	$180,346,498	$110,497,026	$110,569,940	($850,831)	$777,917	($69,849,472)	0.61
OKGE	$318,906,984	$301,889,703	$308,254,228	($1,504,525)	($4,860,000)	($17,017,280)	0.95
OPPD	$139,799,846	$58,131,159	$58,029,684	($659,541)	$761,017	($81,668,687)	0.42
SPRM	$34,859,727	($19,163,373)	($19,084,313)	($164,460)	$85,400	($54,023,100)	(0.55)
SUNC	$24,025,983	($18,710,322)	($18,860,107)	($113,349)	$263,133	($42,736,305)	(0.78)
SWPS	$259,684,041	$348,209,534	$356,405,764	($10,528,246)	$2,332,017	$88,525,493	1.34
WEFA	$71,116,453	$171,692,325	$167,890,577	$890,781	$2,910,967	$100,575,872	2.41
WRI	$259,857,986	$34,120,473	$34,080,803	($1,225,946)	$1,265,617	($225,737,513)	0.13
Totals	**$2,246,851,575**	**$792,453,318**	**$786,001,884**	**($20,175,666)**	**$26,627,100**	**($1,454,398,257)**	**0.35**

Table 21: Zonal Results – Group 1 without Wind Revenue and Fuel Diversity Benefit

Area	Study Group 2 (DCT 345 kV)						
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Net Benefit (Years 0 - 40)	B/C
AEPW	$452,807,957	$10,236,066	$1,459,224	($2,385,242)	$11,162,083	($442,571,891)	0.02
EMDE	$53,084,237	$42,198,696	$42,223,209	($279,630)	$255,117	($10,885,541)	0.79
GRDA	$39,404,238	($52,168,384)	($51,790,015)	($207,568)	($170,800)	($91,572,622)	(1.32)
KCPL	$155,630,676	$3,651,463	$3,023,157	($819,811)	$1,448,117	($151,979,213)	0.02
LES	$38,673,989	($43,439,300)	($43,322,062)	($203,722)	$86,483	($82,113,290)	(1.12)
MIDW	$14,493,009	($103,350,456)	($107,675,695)	($76,344)	$4,401,583	($117,843,465)	(7.13)
MIPU	$81,539,608	$60,366,795	$60,879,552	($429,524)	($83,233)	($21,172,813)	0.74
MKEC	$22,584,359	($149,875,106)	($155,263,264)	($1,617,709)	$7,005,867	($172,459,465)	(6.64)
NPPD	$161,519,404	$116,615,026	$116,686,857	($850,831)	$779,000	($44,904,378)	0.72
OKGE	$285,615,005	$334,915,703	$340,770,644	($1,504,525)	($4,350,417)	$49,300,698	1.17
OPPD	$125,205,579	$62,238,475	$62,054,417	($659,541)	$843,600	($62,967,104)	0.50
SPRM	$31,220,581	($20,900,615)	($20,821,556)	($164,460)	$85,400	($52,121,196)	(0.67)
SUNC	$21,517,814	($17,272,094)	($17,337,562)	($113,349)	$178,817	($38,789,909)	(0.80)
SWPS	$232,574,583	$351,266,078	$359,798,274	($10,528,246)	$1,996,050	$118,691,495	1.51
WEFA	$63,692,321	$200,336,278	$196,619,930	$890,781	$2,825,567	$136,643,956	3.15
WRI	$232,730,369	$31,599,701	$32,400,814	($1,225,946)	$424,833	($201,130,668)	0.14
Totals	**$2,012,293,729**	**$826,418,325**	**$819,705,924**	**($20,175,666)**	**$26,888,067**	**($1,185,875,404)**	**0.41**

Table 22: Zonal Results – Group 2 without Wind Revenue and Fuel Diversity Benefit

The following tables show the zonal benefits and costs using staff assumptions on how the wind revenue and fuel diversity benefits could potentially be allocated. The change in wind revenue for designated wind farms are allocated to the zone in which they are designated. All wind farms that are not designated by any particular zone are allocated by load ratio share. The fuel diversity benefits calculated by KEMA are allocated by load ratio share as well.

	Study Group 1 (765 kV @ 345 kV)								
Area	**Total Cost (Years 0 -40)**	**Total Benefit (Years 0 - 40)**	**APC**	**Reliability**	**Losses**	**Wind Benefit**	**Fuel Diversity Benefit**	**Net Benefit (Years 0 - 40)**	**B/C**
AEPW	$505,588,352	$137,323,574	$5,157,860	($2,385,242)	$10,823,300	$42,478,644	$81,249,012	($368,264,778)	0.27
EMDE	$59,271,865	$31,012,260	$39,371,914	($279,630)	$255,117	($17,860,242)	$9,525,102	($28,259,604)	0.52
GRDA	$43,997,292	($32,378,531)	($46,332,710)	($207,568)	($170,800)	$7,262,098	$7,070,449	($76,375,823)	(0.74)
KCPL	$173,771,365	$108,777,815	$12,968,737	($819,811)	$1,279,050	$67,424,450	$27,925,389	($64,993,550)	0.63
LES	$43,181,923	($26,685,336)	($41,461,943)	($203,722)	$86,483	$7,954,427	$6,939,417	($69,867,260)	(0.62)
MIDW	$16,182,350	($84,386,345)	($93,162,882)	($76,344)	$4,065,617	$2,186,731	$2,600,534	($100,568,694)	(5.21)
MIPU	$91,044,063	$97,806,754	$60,163,751	($429,524)	($168,633)	$23,610,205	$14,630,954	$6,762,691	1.07
MKEC	$25,216,847	($127,555,610)	($147,989,419)	($1,617,709)	$6,920,900	$11,078,222	$4,052,395	($152,772,458)	(5.06)
NPPD	$180,346,498	$182,954,934	$110,569,940	($850,831)	$777,917	$43,475,882	$28,982,026	$2,608,436	1.01
OKGE	$318,906,984	$379,512,463	$308,254,228	($1,504,525)	($4,860,000)	$26,373,800	$51,248,960	$60,605,479	1.19
OPPD	$139,799,846	$115,689,369	$58,029,684	($659,541)	$761,017	$35,092,109	$22,466,102	($24,110,477)	0.83
SPRM	$34,859,727	($8,299,645)	($19,084,313)	($164,460)	$85,400	$5,261,704	$5,602,025	($43,159,372)	(0.24)
SUNC	$24,025,983	($11,375,792)	($18,860,107)	($113,349)	$263,133	$3,473,509	$3,861,021	($35,401,775)	(0.47)
SWPS	$259,684,041	$459,639,774	$356,405,764	($10,528,246)	$2,332,017	$69,698,519	$41,731,720	$199,955,733	1.77
WEFA	$71,116,453	$142,752,360	$167,890,577	$890,781	$2,910,967	($40,368,515)	$11,428,550	$71,635,907	2.01
WRI	$259,857,986	$192,925,093	$34,080,803	($1,225,946)	$1,265,617	$117,044,946	$41,759,674	($66,932,893)	0.74
Non-Tariff*	N/A	N/A	N/A	N/A	N/A	($246,084)	N/A	N/A	N/A
Totals	**$2,246,851,575**	**$1,557,467,052**	**$786,001,884**	**($20,175,666)**	**$26,627,100**	**$403,940,404**	**$361,073,329**	**($689,384,523)**	**0.69**

Table 23: Zonal Results – Group 1 with Wind Revenue and Fuel Diversity Benefit

Area	Study Group 2 (DCT 345 kV)								
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Wind Benefit	Fuel Diversity Benefit	Net Benefit (Years 0 - 40)	B/C
AEPW	$452,807,957	$145,169,510	$1,459,224	($2,385,242)	$11,162,083	$44,943,988	$89,989,456	($307,638,447)	0.32
EMDE	$53,084,237	$31,958,579	$42,223,209	($279,630)	$255,117	($20,789,891)	$10,549,774	($21,125,658)	0.60
GRDA	$39,404,238	($36,815,611)	($51,790,015)	($207,568)	($170,800)	$7,521,713	$7,831,059	($76,219,849)	(0.93)
KCPL	$155,630,676	$108,953,853	$3,023,157	($819,811)	$1,448,117	$74,372,898	$30,929,492	($46,676,822)	0.70
LES	$38,673,989	($27,474,839)	($43,322,062)	($203,722)	$86,483	$8,278,529	$7,685,932	($66,148,828)	(0.71)
MIDW	$14,493,009	($97,787,719)	($107,675,695)	($76,344)	$4,401,583	$2,682,447	$2,880,290	($112,280,728)	(6.75)
MIPU	$81,539,608	$102,188,318	$60,879,552	($429,524)	($83,233)	$25,616,629	$16,204,894	$20,648,710	1.25
MKEC	$22,584,359	($132,740,184)	($155,263,264)	($1,617,709)	$7,005,867	$12,646,586	$4,488,336	($155,324,544)	(5.88)
NPPD	$161,519,404	$194,410,582	$116,686,857	($850,831)	$779,000	$45,695,759	$32,099,797	$32,891,178	1.20
OKGE	$285,615,005	$422,118,814	$340,770,644	($1,504,525)	($4,350,417)	$30,440,993	$56,762,119	$136,503,810	1.48
OPPD	$125,205,579	$123,900,255	$62,054,417	($659,541)	$843,600	$36,778,865	$24,882,915	($1,305,324)	0.99
SPRM	$31,220,581	($8,821,809)	($20,821,556)	($164,460)	$85,400	$5,874,138	$6,204,668	($40,042,390)	(0.28)
SUNC	$21,517,814	($8,973,703)	($17,337,562)	($113,349)	$178,817	$4,022,017	$4,276,375	($30,491,517)	(0.42)
SWPS	$232,574,583	$480,525,142	$359,798,274	($10,528,246)	$1,996,050	$83,038,012	$46,221,052	$247,950,559	2.07
WEFA	$63,692,321	$166,891,707	$196,619,930	$890,781	$2,825,567	($46,102,558)	$12,657,987	$103,199,386	2.62
WRI	$232,730,369	$205,978,987	$32,400,814	($1,225,946)	$424,833	$128,127,273	$46,252,013	($26,751,382)	0.89
Non-Tariff*	N/A	N/A	N/A	N/A	N/A	($42,715)	N/A	N/A	N/A
Totals	**$2,012,293,729**	**$1,669,439,168**	**$819,705,924**	**($20,175,666)**	**$26,888,067**	**$443,104,684**	**$399,916,159**	**($342,854,562)**	**0.83**

Table 24: Zonal Results – Group 2 with Wind Revenue and Fuel Diversity Benefit

Appendix E – Contour Maps of Priority Projects

The contour maps herein represent the absolute value of the difference in megawatt flow between a model without the identified projects and one with the identified projects. Values below the minimum level (10 MW) are not shown, and values above the maximum level (400 MW) are illustrated at the same color as the maximum level. The maps are generated based on the 2019 STEP models that were used for the reliability analysis of the Priority Projects. These models do not contain any additional wind generation.

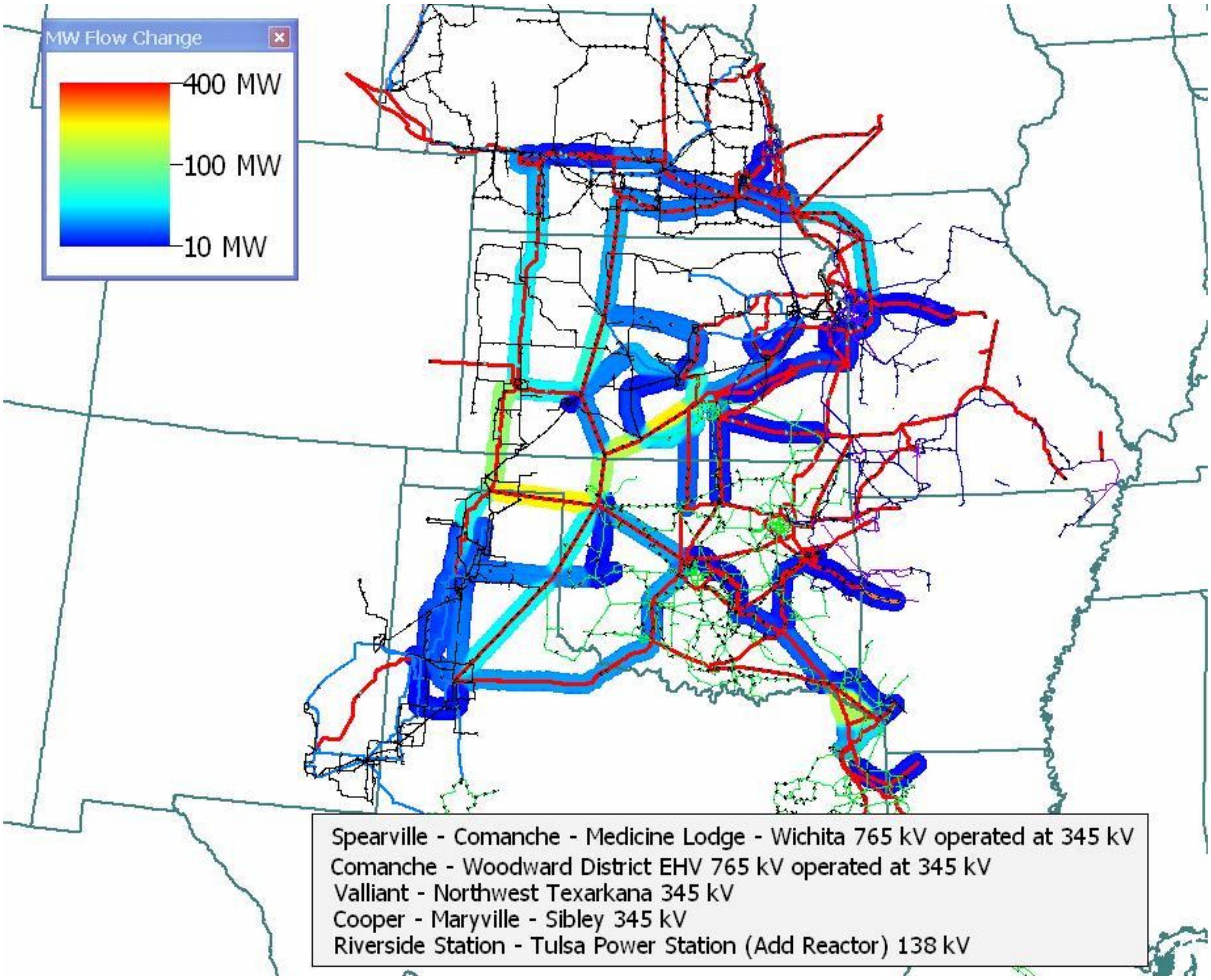


Figure 5: Priority Projects Group 1

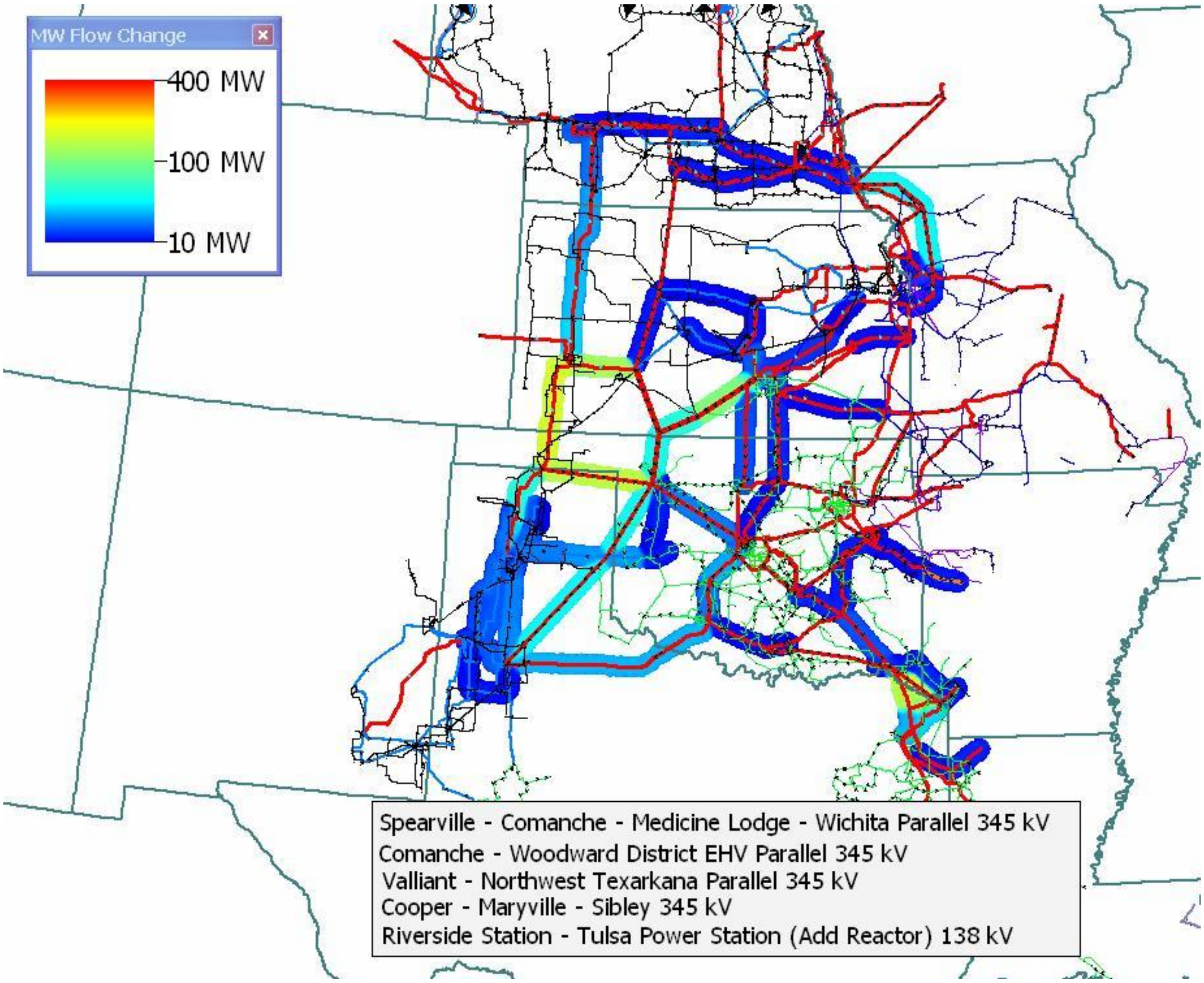


Figure 6: Priority Projects Group 2

Appendix F – Calculating Impact for Average Residential Electric Bill

The cost of $1 billion dollars of incremental transmission investment to the typical residential customer in the SPP transmission footprint may be estimated to be in the neighborhood of $ 1.34 per customer per month. This estimation was performed by multiplying the $1 billion assumed to be invested by a typical levelized fixed charge rate of 16%, generating an annual transmission revenue requirement (ATRR) of $160 million per year. This ATRR is then multiplied by 85%, recognizing that 15% of the SPP transmission service revenue requirements are met by Point to Point Transmission Service sold on the system. This figure is then divided by the total monthly average coincident peak load of the system (12 CP Load) of 33,778 MW generating an indicative rate of $4,026 per MW-year. This rate is divided by 1,000 kW/MW and 12 months/year, thus converting the rate to $0.34 per kW-month. The $0.34 per kW-month is then multiplied by an average residential consumption of 4 kW/month, generating the estimated increase of $1.34 per month per $1 billion of E&C investment. The actual cost to any residential customer depends upon their individual consumption and the rates approved by the appropriate regulatory authorities.

	$160,000,000	Levelized ATRR	
	0.85	ATRR Allocator for NITS	
	33,778	Current Total System Load (12 CP in MW)	
	$4,026.29	Annual Cost per MW	
	$0.34	Cost per kW-month	
	4.00	Typical Res. Customer Diversified Demand (kW)	
	$1.34	Typical Res. Customer Billing Impact	

Appendix G – Frequently Asked Questions

1. Should all areas within SPP be modeled consistently? The DC ties will be modeled on some reasonable historical profile – What is that profile?

   Yes, to the extent possible all areas within SPP were modeled consistently. For the DC ties, staff used 2008 actual historical data for each DC tie to represent the hourly-profiled flows across each tie. In cases where stakeholders did not feel 2008 data was a fair representation for a particular DC tie, they were allowed to submit another year's data that they did feel adequately represented the flows.

2. Should the Priority Projects be studied as individual projects, rather than only groupings of projects?

   The current assessment was performed under the direction of the BOD and SPC.

3. Were there any significant changes in the model validation process?

   During the stakeholder review process for the input and output data, there were a number of modifications to individual utility modeling parameters. Staff would not qualify the changes as significant.

4. Will there be a technical conference to discuss the outcome of this analysis?

   There is a scheduled conference February 10, 2010 at the DFW Hyatt. WebEx will also be available for those unable to attend.

5. Before going to the BOD in April, should we have a Priority Project review in March?

   Staff does intend to assess the need for another stakeholder review in March which will be based on the feedback received at the February 10 meeting.

6. What transmission projects were included in the models? What models were used?

   Only previously BOD approved transmission projects were included in the analysis. As they were not yet approved, the 2009 STEP projects were not included in the analysis. The load flow models used were the most recent models utilized in the 2009 STEP process. See the report section Scope of Priority Projects Phase II Analysis for additional details.

7. Do the wind locations match the WITF?

The wind locations do not directly match those locations used in the WITF. The Priority Projects analysis approximated wind injection locations based on the location of the Priority Projects, the location of wind in the GI queue, and state renewable target and load information. See the report for additional information.

8. Will a full N-1 reliability analysis be done on these Priority Projects? Will the wind be in the models?

   A full N-1 reliability analysis was performed on the Priority Projects, and the impact of this analysis is detailed in Attachment 2. Wind was not included in this reliability assessment.

Attachment 1 – BATTF Report

Benefit Analysis for Priority Projects

July 24, 2009

Disclaimer: This report is for Priority Project evaluation only. No reference for cost allocation is implied or intended.

Southwest Power Pool

Table of Contents

Introduction

By recommendation of the Synergistic Planning Project Team (SPPT), the Economic Studies Working Group (ESWG) was asked to develop benefit analysis techniques for transmission planning with the goal of creating a robust, flexible, and cost-effective transmission system. The ESWG is currently developing the metrics to be used in the Integrated Transmission Planning (ITP) process.

The Benefit Analysis Techniques Task Force (BATTF) was created as a quick response team to address the immediate need to determine the formulation of the metrics to support Priority Project analysis, an interim measure specified by the SPPT until the ITP process is functional.

Significant time is required to fully develop the metrics for the ITP and integrate the existing transmission planning processes. This document and the metrics contained within will be a “living document”, subject to change as the process matures and develops.

This document is presented as a working draft of the benefit metrics to be used primarily for Priority Projects and as a starting point for the ITP benefit metrics calculations. The final list of Priority Projects and the ITP process will be presented to the SPP Board of Directors for approval in October 2009.

Scope of Work and Metrics for Formulation

The scope of the BATTF effort is to standardize formulation and analysis techniques for SPP study metrics so Priority Projects are evaluated on a consistent basis. Another goal of the BATTF is to develop a standard reporting format to maximize market participants' and stakeholders' understanding of the results.

If approved by the ESWG, results of the BATTF's efforts will be utilized as a starting point for future ITP process evaluation and will be incorporated into the ESWG's Economic Studies Manual.

The BATTF was asked to consider and formulate for use with Priority Projects the following metrics:

1. **Adjusted Production Cost** (APC) – Projects will be screened to determine their individual APC benefit for SPP. This benefit metric is typically simulated using a production cost modeling tool accounting for 8760 yearly hourly profiles of system-wide commitment and dispatch modeling taken over the course of the study period.

2. **Environmental Impacts** – SO_2, NO_X, CO_2, and mercury can be modeled in a study for the fuel type used in the generating units. Once stakeholders determine a value per ton for the emissions, the cost of emissions can be calculated for the units. Transmission upgrades can then be used to determine the net impact on emission pricing.

3. **Reliability Impact** – Economic transmission upgrades can have an impact on reliability. This benefit is seen when reliability projects are deferred or displaced through construction of more efficient, regional projects. The advancement of reliability projects must also be considered when determining the total overall impact of a collection of economic expansions.

4. **Deliverability of Capacity and Energy to Load** – Projects will be assessed on their ability to provide or act as enablers for power to be delivered from firm designated resources to respective loads. These projects are typically associated with transmission service requests for new designated resources, but could also be bulk EHV projects for regional transfer capability.

5. **Impact on Losses** – Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings can be captured as part of a production cost analysis tool. Capacity savings associated with a loss reduction can be determined by looking at select hourly models to determine loss reduction.

6. **Local Economic Benefits** – Transmission construction provides local economic development and job creation benefits. These benefits will probably reside in the state where each project is constructed.

Results of the BATTF Efforts

The BATTF recommends using the Net Present Value (NPV) over 10 years with a terminal value rather than a benefit to cost ratio for the Priority Projects. This rationale is based on the following:

- The time frame for determining the Priority Projects is very short and there is currently no existing model that has a greater than 10-year time frame. Unless the Board directs the ESWG and SPP to develop a 20-year or greater model, a current model must be used.

- A positive NPV over 10 years is a fair indicator of determining a project's priority. This is not a decision to implement a project, just an indicator of the priority of a project. A project with a higher NPV may have a higher cost, so other metrics should be used when evaluating whether a Priority Project should be implemented. Conversely, if a project has a negative NPV, it can be eliminated from the list.

- The logical assumption is that after 10 years, if there is a positive NPV, then a BC ratio of more than 1.0 is more probable.

- If a cost benefit indicator over 10 years is used, the ESWG will need to determine what assumptions should be addressed beyond the 10-year horizon. This will require additional study and will not meet the projected delivery date of October 2009.

- The BATTF is unsure whether the cases for evaluation have adequate data and background beyond 10-year analysis, or whether or not they should be vetted with stakeholders before implementing them into a long-term model.

- The BATTF is assuming there is a limit on the amount of money for Priority Projects and will have to choose from projects with positive NPVs (the "low hanging fruit" projects). Other indicators will need to be used to adequately pick the best projects based on the metrics that the group has identified below.

Based on conversations with the ESWG, the BATTF has been asked to concentrate its efforts on the following metrics:

Adjusted Production Cost

Adjusted production cost is a measure of the impact on production cost savings by node (LMP), accounting for purchases and sales of economic energy interchange. This benefit metric is typically simulated by a production cost modeling tool accounting for 8760 yearly hourly profiles of commitment and dispatch modeling, taken over the course of the study period.

Nodal modeling is aggregated on a zonal basis using weighted LMPs. There is concern that modeling the border points will not be accurate without additional Eastern Interconnection points. For example, the border LMPs will have significant impact on the Adjusted Production Cost within SPP. If there are lower LMP prices outside SPP there will be no transfers from the western portion of SPP. Therefore, the BATTF recommends the model should broaden the footprint to include Southern Companies, Ameren, Basin, WAPA, TVA, PJM, MISO, and the DC ties (using the recent historic patterns) at a minimum when running the model to assess the impact on the borders. The group recognizes the increased run time required and the short time for analysis of the Priority Projects.

The BATTF recommends that gas prices should be based on Henry Hub NYMEX ten-year, plus a Panhandle basis difference. For other fossil fuel prices, publicly-available data should be used.

The BATTF recommends that wind in the models be at a rate of $6.00 per MWH, based on the variable Operation and Maintenance (O&M) cost of a wind plant for the first three years of operation. The BATTF recommends using the same rate for other renewables that was used in the Balanced Portfolio analysis.

A nodal analysis will be completed that aggregates on a zonal basis using the following formulation highlighted. The calculation, performed on an hourly basis, will be:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases
Where:
Revenues from Sales = MW Export x Zonal $LMP_{\text{Gen Weighted}}$
and
Cost of Purchases = MW Import x Zonal $LMP_{\text{Load Weighted}}$

Tools used for this analysis will include standard assumptions and modeling using PROMOD, PowerWorld, or equivalent production cost software.

The rationale for using this methodology is as follows:

- This formula was previously approved by stakeholders, the Market and Operating Policy Committee, and the SPP Board as part of the Balanced Portfolio analysis.

- The formulation represents the broad impact of new transmission projects in changing LMP costs (energy, congestion and losses cost) to rate payers within the SPP footprint. It therefore represents much of the savings/benefits or additional cost to rate payers for specific transmission projects.

Impact on Losses

Lower impedance transmission lines provide a loss savings to the transmission grid. The energy component of the loss savings is captured as part of the above production cost analysis tool. It is possible that losses will increase since generation sources will be remotely located from load centers.

Capacity savings associated with a loss change are determined by looking at the selected hourly loadflow models to determine the loss change associated with a transmission upgrade. The BATTF has established standard capacity prices to capture capacity savings. Formulation will be based on an aero derivative Combustion Turbine (CT) replacement, currently priced around $750 per kW installed (based on the expected cost to install of various types of machines used by BATTF members).

There is a fixed O&M cost component based on $650,000 per year (average expected cost experienced by BATTF members). The energy component of losses is captured in the formulation above. This an additive benefit component for capturing the capacity component of that energy typically passed on to rate payers through Ancillary Service charges. This is variance in quantity of energy (capacity).

The calculation:

- Capacity Savings at Coincidental Peak = ((Capacity requirement at Peak (base case) – Capacity requirement at Peak (with projects upgrades included)) x (CT replacement cost)).

  This would be a straight savings estimate of the capacity, since the CT installation would be a one-time cost when the upgrade was energized.

- There is a fixed O&M cost savings associated with this calculation, usually captured in the Ancillary Services fee.

  It should be calculated as Fixed Cost Benefit = (Capacity savings (as determined from above per 150 MW) x $ 650,000/yr), escalated by the rate of inflation as reported in Bureau of Economic Analysis.

- The price differential would be calculated on an annual basis from the point the proposed upgrade would be energized to the end of the defined 20-year period. There should be no additional accommodation for savings after 20 years, because a CT has an estimated 20-year life span.

- This formulation is the estimated benefit or cost Impact of Losses.

Environmental impacts

The BATTF's primary assumption is that SO_2 and NO_X will be approximated using pricing curves from the Chicago Climate Exchange; this represents our best estimate of current market prices. Mercury will not be addressed in this metric due to the lack of valid market information. The BATTF discussed at length the merits for CO_2; our assumption is that the high price in the long term (20 years) is determined by 100% sequestration currently valued at between \$80 and \$102 per ton (\$91 per ton average) from the Mountain Air Plant DOE project. The low price is based on the current price of CO_2 from the Chicago Climate Exchange.

Our assumption is to escalate the current price up to \$91 per ton in year 20, based on unknowns with government regulation. Emissions values should be based in a range that reflects the maximum and minimum from various sources, using a high case and low case probability. Example: the high case could be current prices times 3 and the low case could be current prices times 0.5. The base case should be established using the ESWG's opinion of future scenarios (based on current information). Therefore, the reference future will be based on the latest information from sources such as legislative outlooks, technology improvements, state regulations, and other data sources.

The BATTF determined that this calculation is viewed as a less definitive, but still quantitative, formulation. Since Cap and Trade legislation is under discussion and there is no clear direction - but a higher probability - that that a higher price bias exists, we recommend using a 60-40 weighting. The BATTF believes there will be federal legislation; there is a 40% chance the lower case will happen and 60% chance the high price case will happen. (There is also the possibility of the federal government spearheading transmission construction.) Using this formula, we get (60% x \$91/ton) + (40% x \$0/ton) = \$54/ton

The BATTF discussed whether modeling should reflect year 1, year 5, and year 10 evaluation points. It is the BATTF's opinion that as carbon prices increase, wind resources will increase. Therefore, a linear interpretation of the carbon cost curve is a reasonable cost curve. The BATTF discussed running two carbon scenarios with a low and a high carbon value; we need both of these to see what the impact will be on generation dispatch to provide the best determination of the impact of carbon on transmission projects. Without this type of modeling run, the CO_2 benefits for transmission projects will cause any transmission project to have benefits in excess of its cost if it displaces coal or gas generation. Due to the time constraints for this type of modeling and runs, and given the current state of the model and the input and model development required, this analysis will not be delivered by October 2009. An approximation for the impact of CO_2 can be to have the model produce the amount of tons of CO_2 from the Base Case minus the amount of tons saved from the addition of the transmission projects and show a potential range of CO_2 prices for comparative purposes. A table can be calculated as follows:

Case Description	Tons of CO2 Produced	Reduction from Base Case at \$15/Ton	Reduction from Base Case at \$54/ton
Base Case		N/A	N/A
All Priority Projects Priority Project 1			
Priority Project 2			
Priority Project 3			
Priority Project 4			
Priority Project 5			
Priority Project 6			
Priority Project 7			

Priority Project 8			
Priority Project 9			
Priority Project 10			

Based on the above discussion, the BATTF recommends that SO2 and NOX be evaluated for Priority Projects and CO2 be evaluated as a post analysis based on tons of CO2 produced at $15 and $54 per ton.

Increased Reliability

The advancement/expedition of SPP Board-approved reliability projects must be considered to determine the total overall impact of economic upgrades. The formula would be based on SPP Transmission Expansion Plan (STEP) reliability projects deferred or advanced, and the benefit would be linked to the dollar impact on the NPV of Annual Transmission Revenue Requirements (ATRR) savings for the deferral/advancement.

The recommended benefit calculation should be:

∑ (STEP Projects Deferred ATRR - STEP Projects Advanced ATRR), taken for years deferred/advanced

Note: If a STEP Project is eliminated, the ATRR for the 40-year life of the asset would be calculated based on the year in which the upgrade was scheduled to go into service.

Local Economic Benefits

Local economic development, job creation, etc. fall under the umbrella of local economic benefits. These benefits will most likely reside in the state where the each project is constructed. The task force recommends using an SPP or consultant model for economic studies to describe local economic impact, which can then be endorsed by the ESWG for ITP benefit analysis. Preliminary discussion suggests this calculation will be difficult to qualify on a multi-county or multi-jurisdictional basis. Historically, economic analysis for local economic benefits has taken 7-10 days per construction project. A more realistic calculation would be a formula based on standard economic impact analysis to provide analysis for the SPP region.

The BATTF recommends not using a detailed local economic impact calculation for Priority Project evaluation. The economic impact calculation should be part of the ITP process. This metric should be developed in conjunction with economic experts/consultants to provide the true local economic impact. For Priority Projects, the BATTF recommends using project construction costs instead of the full local economic impact on the project's location. The cost of the project needs to be framed and explained to avoid cost allocation issues.

Deliverability of Capacity and Energy to Load

A change in deliverability should be reflected in more or less variation in the LIP or LMP prices across the SPP footprint. If deliverability is improved, it would be reflected as a decrease in variation. Since variation and its statistical metrics are difficult to explain, the following metric has been developed using the capabilities of PROMOD or a similar nodal modeling tool.

The LMP price at each node is the sum of three price components:
(1) the energy price component
(2) the price component for losses
(3) the congestion price component

All of these component prices are added to make the LMP price at each node. During each hour of the year, each node across the SPP footprint has an associated LMP price and quantity of energy injected (generation) or withdrawn (load) from the system. Generation or injected energy carries a positive sign (+) and loads or withdrawn energy is negative (-).

The congestion component of those LMP nodes will change as a new transmission line is added to relieve congestion. The sum congestion cost within the region will change as new transmission lines are added, providing an effective measure of the impact on deliverability. If the assumption is made that deliverability is the inverse of congestion, we now have a way to measure deliverability in dollars rather than using statistical terminology. These dollars are not additive to the APC metric, since doing so would mean congestion costs are being double counted.

The metric will determine which lines reduce the most congestion. It can also be seen as a variance in price.

The BATTF recommends capture deliverability using the following formulation:

> Congestion Cost at baseline – Congestion Cost with new project = Improved Deliverability Benefit[6]

An alternative formulation:

> Total System Congestion[7] Before Upgrade – Total System Congestion After Upgrade

SPP's PROMOD function has the capability to divide LMP points into energy, congestion, and loss components. The focus of this metric would be on the congestion component.

[6] losses must be fixed and captured separately before congestion cost can be calculated
[7] potentially shown as shadow prices

Additional Recommendations

1. The ESWG needs to determine the assumptions to be used in developing a 20-year model.

2. The ESWG needs to develop, with support of SPP, a 20-year model for the ITP Process.

3. To meet the October 2009 deadline for recommending Priority Projects, assumptions in the modeling and analysis need to be simplified:
   a. Use the existing Balanced Portfolio model as the primary model for benefit analysis.
   b. Assumptions used in the Balanced Portfolio for wind generation, or as recommended by the ESWG, should be used for analysis. This is a critical piece of data to begin modeling.

4. Another possible metric for consideration by the ESWG would be a Return on Investment (ROI) to capture those projects that yield better returns for the footprint.

5. Value at risk concepts can be applied directly to hourly LMP time series. We cannot use this metric to produce a dollar value that has value at risk meaning in a traditional sense. We would need to use Monte Carlo simulation and look at the problem hourly for this to work. However, we can still get a good look at the standard deviation, and make an ordinal decision regarding which project provides more benefit along the variance dimension. Here is how we would work the mathematics:

   a. Calculate LMP's for both the base case and change cases (e.g., run the cases).

   b. Calculate the LOAD weighted LMP for these cases for the entire SPP region for each hour. This will give us 8760 load weighted observations for each case.

   c. Calculate the natural log differences between the sequential hourly weighted LMPs for each case. That is, LN(HR2) - LN(HR1), etc.

   d. Calculate the standard deviation of these log differences for each case.

   e. If a project reduces congestion, the standard deviation of the change case will be lower than the base case. The greater the difference, the better the project is.

We are already using "other" metrics to evaluate our positive NPV projects given a budget constraint. This would be another good one.

Disclaimer: This report is for Priority Project evaluation only. No reference for cost allocation is implied or intended.

Attachment 2 – TWG Reliability Report

PUBLISHED: 12/04/2009
LATEST REVISION: 1/5/2010
Endorsed by TWG on 1/19/2010 (with comments)

Southwest Power Pool

Table of Contents

Revision History

Version	Date	Description
1	12/04/09	Document Creation; Submitted to TWG
2	12/21/09	Added Reactive Requirements and revised STEP date of Huntsville – St. John 115kV line
3	1/5/10	Revised based on TWG comments

Reliability Analysis

In the Phase I evaluation, eleven potential Priority Projects and three additional Priority Projects groupings were evaluated for impacts on the reliability plan on the SPP system. As part of Phase II evaluation, the list of Priority Projects was refined to two groups of projects that are electrically similar. SPP conducted a study to evaluate the impact of the Priority Projects on the reliability plan of the SPP transmission system. The following section summarizes the findings of this study.

An analysis was conducted on two groups of proposed projects to determine the impact of these projects on the SPP reliability plan and on first tier third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in SPP's 2009 STEP 10 year reliability analysis.

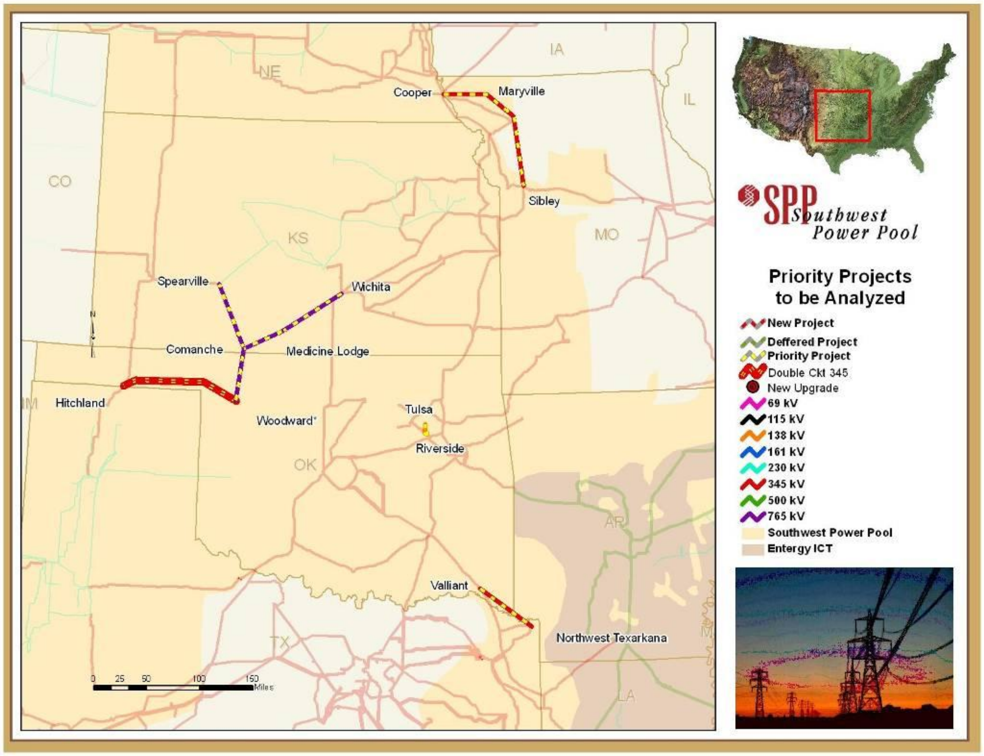
This study is not intended to justify any Priority Project based on deferred project cost alone; it is only intended to show the effects of the Priority Projects on the SPP reliability plan. At this time the in-service dates for the Priority Projects are not definite. For this study the projects are included in the 2014 models. If a project identified for deferment has a STEP date before 2014 it may or may not actually be deferred. It may be possible to mitigate these issues for the short period of time before the Priority Project is in service. Therefore, these projects and their costs are provided for assessment purposes only.

The two groups of proposed projects are composed of the following projects:

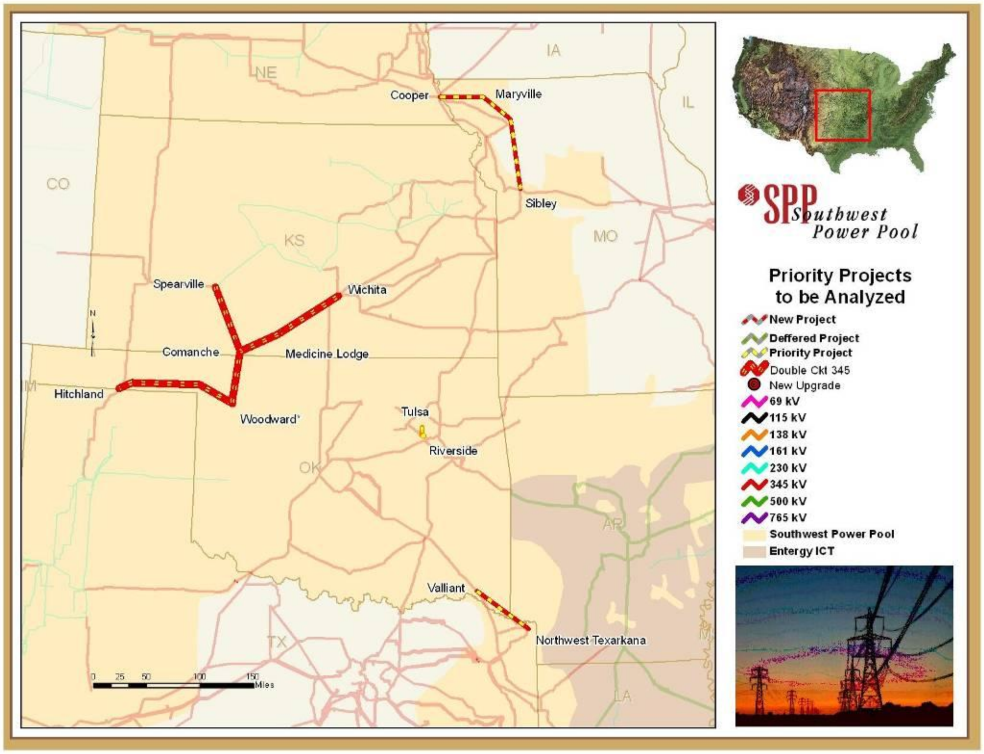
Group 1:
1. Spearville – Comanche – Medicine Lodge – Wichita 765 kV Operated at 345 kV
2. Comanche – Woodward District EHV 765 kV Operated at 345 kV
3. Hitchland – Woodward District EHV Double Circuit 345 kV
4. Valliant – NW Texarkana 345 kV
5. Cooper – Maryville – Sibley 345 kV
6. Riverside Station – Tulsa Power Station 138 kV Reactor

Group 2:
1. Spearville – Comanche – Medicine Lodge – Wichita Double Circuit 345 kV
2. Comanche – Woodward District EHV Double Circuit 345 kV
3. Hitchland – Woodward District EHV Double Circuit 345 kV
4. Valliant – NW Texarkana 345 kV
5. Cooper – Maryville – Sibley 345 kV
6. Riverside Station – Tulsa Power Station 138 kV Reactor

Group 1 Map



Group 2 Map



Study Scope

An AC N-1 contingency analysis was performed using PSS/E. The analysis was performed using the 2009 STEP Build 3 models. Details of these models can be found in the Study Assumptions section. Details of the analysis are as follows:

- Monitoring of Facilities
  - All facilities in the SPP footprint were monitored at 69 kV and above.
  - EES and AECI facilities were monitored at 100 kV and above.
  - All other first tier control areas were monitored at 230 kV and above.
- Cases
  - 2014 Summer Peak
  - 2014/15 Winter Peak
  - 2019 Summer Peak
  - Including all transaction cases
- Normal conditions and contingency analysis
  - Normal conditions
  - All N-1 single-element contingencies 69 kV and above in the SPP footprint were evaluated. These contingencies did not include manual transfer of load or manual switching.
  - All N-1 single-element contingencies 100 kV and above in EES, AECI, and all other first-tier control areas were evaluated.
  - SPP verified that all normal conditions and N-1 violations identified have corrective plans
- Use of Transmission Operating Directives (TOD)
  - Transmission Operating Directives were applied in the same manner they have been applied in the 2009 STEP

The analysis was performed using the 2009 STEP Build 3 models. Build 3 models were created in July 2009 to include revised load forecast information due to the recent economic downturn. Using the STEP models allows re-evaluation of STEP projects to determine if they can be deferred or eliminated due to the Priority Projects. These models are different from the models used in the economic analysis though, since they do not include the anticipated wind generation. As a result, this study did not address the additional resources and load that are evaluated in the economic portion of the Priority Projects Report.

Stakeholder Process

The STEP 10 year reliability analysis is an open and transparent process allowing for stakeholder input. This analysis of Priority Projects shares the study results in stakeholder public meetings using the same methodologies used in the 2009 STEP.

The scope used in this analysis originated from the 2009 STEP scope. The STEP scope was initially approved by the TWG in November 2008 then later updated in May 2009 to allow for changes related to the economic downturn and other developments. These changes included updated load forecasts and incorporation of Balanced Portfolio projects.

The contingency analysis results for the Priority Projects are evaluated using input provided by stakeholders for the 2009 STEP. This allows projects to be evaluated in the same manner as the STEP. Projects are deferred based on the same justification as their original need. Similarly, mitigations are handled in the same manner as the STEP.

Primary Analysis

The analysis was conducted for two groups of Priority Projects. The Priority Project groups can either cause new reliability issues or they can relieve issues that have been identified in either the 2009 or earlier STEP analyses. Therefore, the results are in terms of additions or deferments of reliability projects and the revenue requirements associated with those projects. Results are broken into (1) advanced projects—projects that would be moved up in the reliability timeline due to the Priority Project; (2) new SPP 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) new third party projects—projects needed on neighboring systems due to the Priority Projects; and (4) deferred projects—projects which are either deferred beyond the planning horizon or mitigated entirely due to the Priority Projects. For projects which are deferred past the planning horizon, linear extrapolation of loading was used to estimate how far the project might be deferred. Then, for projects which are not either completely new or completely deferred, the value shown is the Net Present Value of Annual Transmission Revenue Requirements. This Net Present Value is limited to a 40 year project life. The following tables and maps illustrate the reliability projects changed by the Priority Project groups. New or advanced projects are shown in red while deferred projects are shown in green.

Impact on Reliability Plan

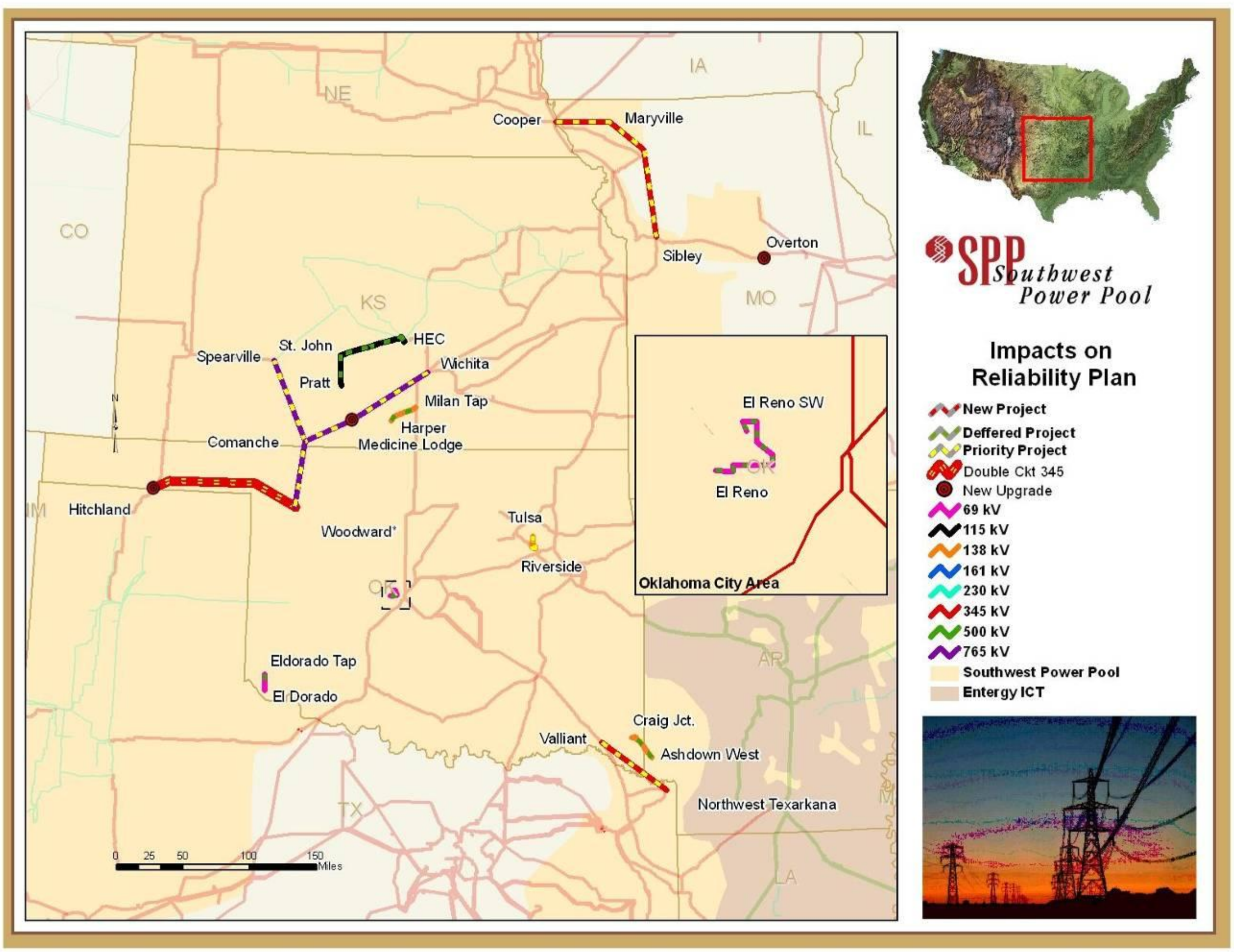
Red = New or Advanced
Green = Deferred

Group 1

Hitchland – Woodward District EHV Double 345 kV
Spearville – Comanche – Medicine Lodge – Wichita 765 kV Operated at 345 kV
Comanche – Woodward District EHV 765 kV Operated at 345 kV
Cooper – Maryville – Sibley 345 kV
Valliant – NW Texarkana 345 kV
Riverside Station – Tulsa Power Station 138 kV (Add Reactor)

Project Name	Area	E&C Cost	Date Needed	STEP Date	Advanced ATRR Cost	New SPP ATRR Cost	New Third Party ATRR Cost	Deferred ATRR Cost
ADD SECOND HITCHLAND 345/230KV TRANSFORMER	SPS	$6,993,438	19SP	None		$13,954,681		
REPLACE MEDICINE LODGE 138/115KV TRANSFORMER CKT 1	MKEC	$3,825,000	14SP	19SP	$2,613,216			
ADD SECOND OVERTON 345/161kV TRANSFORMER*	AMMO	$6,750,000	19SP	None			$11,624,617	
RECONDUCTOR ELDORADO - ELDORADO JCT 69KV CKT 1	WFEC	$3,881,250	23SP	16SP				$1,839,437
REPLACE WAVETRAP ON HARPER - MILAN TAP 138KV CKT 1	MKEC	$225,000	None	19SP				$365,103
REBUILD ASHDOWN WEST - CRAIG JUNCTION 138KV CKT 1**	AEPW	$1,378,125	None	14SP				
RECONDUCTOR EL RENO - EL RENO SW 69KV CKT 1**	WFEC	$1,950,000	17SP	12SP				
REBUILD HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1**	WR/MIDW	$12,487,500	None	13SP				
REBUILD HUNTSVILLE - ST_JOHN 115KV CKT 1**	MIDW	$7,965,000	None	14SP				
REBUILD ST JOHN - PRATT 115KV CKT 1**	MKEC	$9,239,000	None	13SP				
Totals					$2,613,216	$13,954,681	$11,624,617	$2,204,540
Net								-$25,987,975

*Loading of the Overton transformer only increases from 99.8% to 100.6% when adding the upgrade
**Costs for this project are not included because the project may be needed before Priority Projects are in service

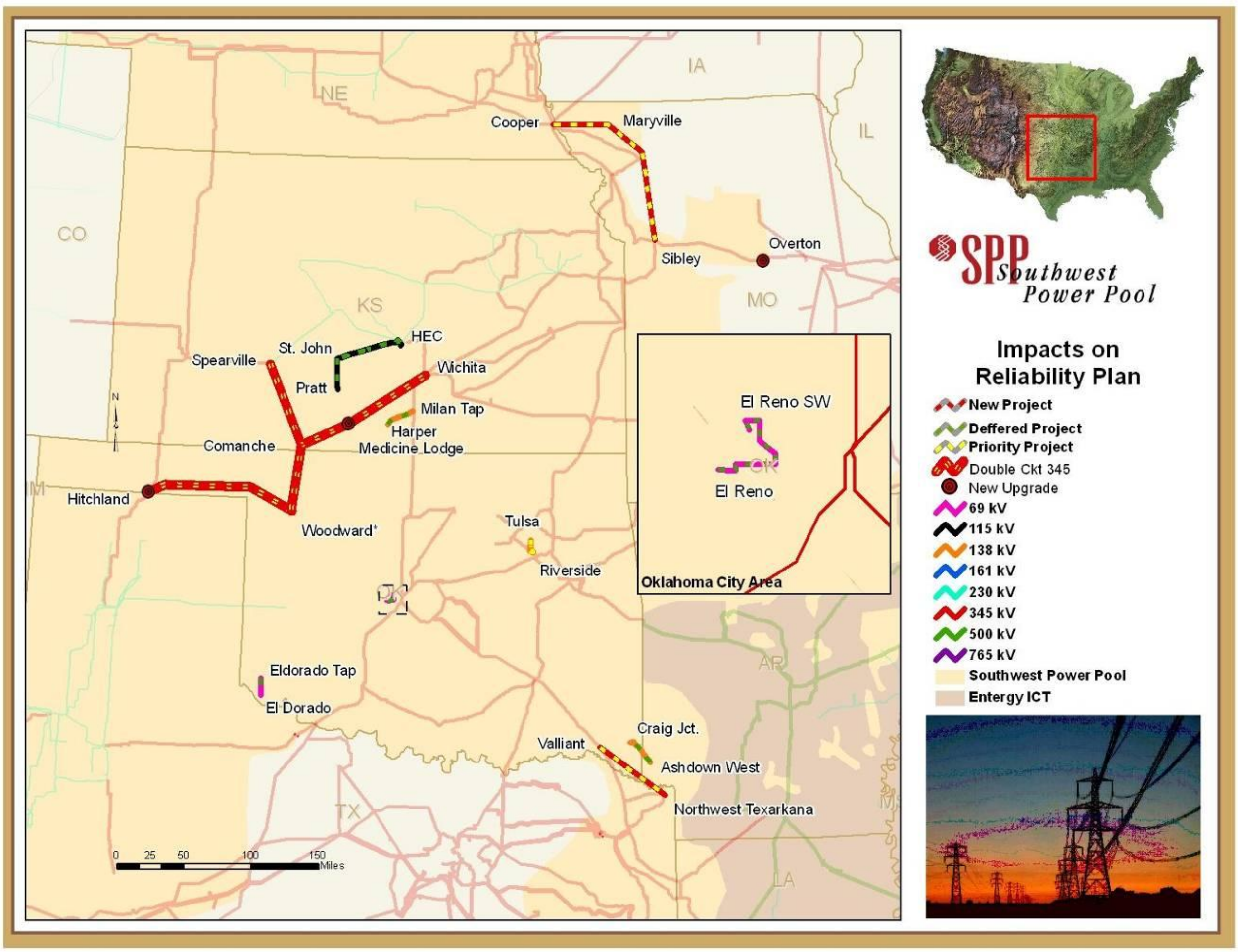


Group 2

Hitchland – Woodward District EHV Double 345 kV
Spearville – Comanche – Medicine Lodge – Wichita Double 345 kV
Comanche – Woodward District EHV Double 345 kV
Cooper – Maryville – Sibley 345 kV
Valliant – NW Texarkana 345 kV
Riverside Station – Tulsa Power Station 138 kV (Add Reactor)

Project Name	Area	E&C Cost	Date Needed	STEP Date	Advanced ATRR Cost	New SPP ATRR Cost	New Third Party ATRR Cost	Deferred ATRR Cost
ADD SECOND HITCHLAND 345/230KV TRANSFORMER	SPS	$6,993,438	19SP	None		$13,954,681		
REPLACE MEDICINE LODGE 138/115KV TRANSFORMER CKT 1	MKEC	$3,825,000	14SP	19SP	$2,613,216			
ADD SECOND OVERTON 345/161kV TRANSFORMER*	AMMO	$6,750,000	19SP	None			$11,624,617	
RECONDUCTOR ELDORADO - ELDORADO JCT 69KV CKT 1	WFEC	$3,881,250	23SP	16SP				$1,839,437
REPLACE WAVETRAP ON HARPER - MILAN TAP 138KV CKT 1	MKEC	$225,000	None	19SP				$365,103
REBUILD ASHDOWN WEST - CRAIG JUNCTION 138KV CKT 1**	AEPW	$1,378,125	None	14SP				
RECONDUCTOR EL RENO - EL RENO SW 69KV CKT 1**	WFEC	$1,950,000	17SP	12SP				
REBUILD HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1**	WR/MIDW	$12,487,500	None	13SP				
REBUILD HUNTSVILLE - ST_JOHN 115KV CKT 1**	MIDW	$7,965,000	None	14SP				
REBUILD ST JOHN - PRATT 115KV CKT 1**	MKEC	$9,239,000	None	13SP				
Totals					$2,613,216	$13,954,681	$11,624,617	$2,204,540
Net								-$25,987,975

*Loading of the Overton transformer only increases from 99.8% to 100.6% when adding the upgrade
**Costs for this project are not included because the project may be needed before Priority Projects are in service



Some facilities have been filtered from the results above. Cutoff levels are used to filter these facilities out of the results because they have very little relation to the Priority Projects. The cutoff filters used are: a normal to N-1 change of 1MW, a normal to N-1 change of 0.005puV, and a base case to change case flow difference of 2%.

Results and Conclusions

The reliability analysis can be summarized into the following table showing the revenue requirements associated with advancements, deferments and overall net impact for each of the Priority Project groups. Results are broken into (1) advanced projects — projects that would be moved up in the reliability timeline due to the Priority Project; (2) new SPP 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) new third party projects — projects needed on neighboring systems due to the Priority Projects; (4) deferred projects — projects which are either deferred beyond the planning horizon or mitigated entirely due to the Priority Projects; and (5) Net Impact – the net cost or benefit of reliability projects related to the Priority Projects. Amounts shown are in terms of Net Present Value of Annual Transmission Revenue Requirements. This Net Present Value is limited to a 40 year project life.

Priority Project Group	Advanced Projects	New SPP Projects	New 3rd Party Projects	Deferred Projects	Net Impact
Group 1 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita 765 kV @ 345 kV Comanche – Woodward District EHV 765 kV @ 345 kV Cooper – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$2.6M	$14.0M	$11.6M	$2.2M	-$26.0M
Group 2 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita Double 345 kV Comanche – Woodward District EHV Double 345 kV Cooper – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$2.6M	$14.0M	$11.6M	$2.2M	-$26.0M

Note that these are groupings of projects with common components; therefore, the net impacts cannot be added together. In addition, none of the likely new STEP projects have been included in these models; therefore, it is possible that the Priority Projects could interact with future STEP projects. Such issues can be addressed in future STEP studies as needed.

The results of the study show limited opportunities to defer existing reliability based projects which were previously identified through STEP. However, this list of deferrals is not complete. This study only covers a 10 year period. Reliability projects that would have been proposed (without the Priority Projects) in the 10-20 year period were not identified or checked for deferrals. One must also keep in mind that this study only evaluates the impact to the STEP 10 year reliability process; it is expected that the Priority Projects may have a greater impact on the Generation Interconnection and

Aggregate Study processes as additional generation resources and transmission service are added to the system. Ultimately, the intent of this study is not to justify any Priority Project based on deferred project cost alone; it is only intended to show the effects of the Priority Projects on the SPP reliability plan and to incorporate known costs or benefits into the overall Priority Project costs.

FCITC Analysis

As part of Phase II evaluation of Priority Projects, SPP conducted an FCITC analysis to determine impacts of the Priority Projects on the SPP transmission system. Using a DC transfer analysis, FCITC values were first calculated on each base SPP model without the Priority Projects then calculated on upgraded models containing Priority Project Group 1 upgrades then calculated on a third set of models containing Priority Project Group 2 upgrades. The models used were:

- 2014 Summer, Scenario 0
- 2014 Winter, Scenario 0
- 2019 Summer, Scenario 0

The cases include approved expansion plan upgrades from the 2008 STEP and Balanced Portfolio.

Below are the MUST settings and procedures for the FCITC analysis:

<u>MUST Solution Settings</u>

- CONSTRAINTS/CONTINGENCY INPUT OPTIONS
  - AC Mismatch Tolerance – 2 MW
  - Base Case Rating – Rate A
  - Base Case % of Rating – 100%
  - Contingency Case Rating – Rate B
  - Contingency Case % of Rating – 100%
  - Base Case Load Flow – PSS/E
  - Convert branch ratings to estimated MW ratings – No
  - Contingency ID Reporting – Labels + Events
  - Maximum number of contingencies to process – 50000

- MUST CALCULATION OPTIONS
  - Phase Shifters Model for DC Linear Analysis – Constant Flow for Base Case and Contingencies
  - Report Base Case Violations with FCITC – Yes
  - Maximum number of violations to report in FCITC table – 50000
  - Distribution Factor (OTDF and PTDF) Cutoff – 0.03
  - Maximum times to report the same elements – 1 {eliminate voluminous repeats}
  - Apply Distribution Factor to Contingency Analysis – Yes
  - Apply Distribution Factor to FCITC Reports – Yes
  - Minimum Contingency Case flow change – 1 MW
  - Minimum Contingency Case Distribution Factor change – 0.0
  - Minimum Distribution Factor for Transfer Sensitivity Analysis – 0.0

<u>Voltage Monitoring</u>

- MUST does not do voltage monitoring for transfer analysis. All transfers are done using DC load flow and then AC verified.

Contingency

- Outage of all single branches and ties in the SPP (Area 502-546, 640-650) and NON-SPP (EES,AECI) above 100 kV
- Multi-terminal/Special Contingency Outage

Exclude

- Exclude outage of all invalid single outages
- Operating guides implementation

Monitor

- Monitor branches and ties in SPP above 100 kV

Transfer Directions/Transfer Level

- 600 MW transfer from all PORs to PODs (PORs/PODs consist of all zones in SPP's OASIS, excluding IPPs)

The Excel document embedded below summarizes the findings of this study. There were a few instances when the addition of the Priority Projects caused the FCITC values to change from positive to negative; this is denoted by a "True" statement in the first column of each workbook. However, the FCITC results found in this study may not be the same as the Available Transfer Capability on the SPP system. All of the positive to negative changes in FCITC occur on facilities that were overloaded prior to the upgrades.

Priority Projects
FCITC_20091201.xls

Reactive Requirements

The consideration of long distance EHV transmission upgrades (i.e. > 50 miles) may require additional reactive compensation to maintain voltage during normal operating conditions and reduce voltage rise during line switching. During light load conditions the high voltage issue may exacerbate as there are less transmission line inductive power losses to offset capacitive line charging. The additional line charging increases voltage on the Bulk Electric System. In order to address this issue, shunt line reactors are typically used to counter or off set excessive line charging during light load conditions.

This high level screening study provides a calculated value for line shunt reactors required to support the addition of EHV transmission in Priority Project groups 1 and 2 under normal (no outage) and selected single contingency events.

The study method determines Reactive power (Q) requirements for different line voltages (V) to determine the magnitude of reactive compensation to maintain system voltages within acceptable limits. This analysis technique is commonly called “QV Analysis”.

A QV, reactive compensation verses voltage analysis was conducted on each proposed grouping of Priority Projects to determine the impact of these projects on the SPP interconnection points and the amount of shunt compensation each segment of the project would require to maintain acceptable transmission voltages.

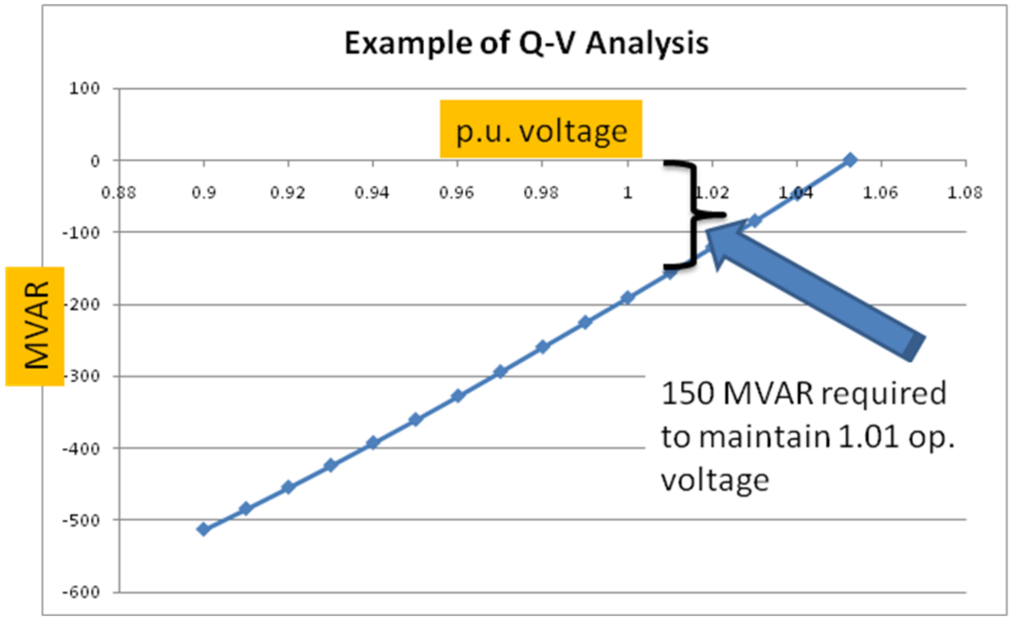
Study Scope

The study base case representing 2014 light load condition was prepared using PSS/E. The steps to build each model are in **Table 1**.

Table 1: Model building steps

5. Add Balanced Portfolio Projects to the base case
6. Add Priority Project group
7. Add line breakers as needed
8. Solve model

PowerWorld Corporation Simulator was used to perform an AC QV analysis. The total amount of line reactance to keep the system voltages around 1.01 p.u.[8] was determined for each project group line segment. The base case was analyzed. Each line segment of a project was also tested for voltage rise at the open end while the other end remained closed into the network.



Key Study Assumptions

10. This study does not include the effects of sub synchronous resonance (SSR). SSR is an electric power system condition where the electric network exchanges energy with a turbine generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system[9].
11. A light load condition is the worst case scenario for high voltage.
12. The July 2009 created STEP 2010 Spring Peak model was used as a starting point and modified to represent a 2014 light load case.
13. Balanced Portfolio Projects are added to the base case.
14. Priority Project groups 1 and 2 are analyzed to determine the amount of line shunts per line segment.
15. Line reactors are sized by opening one end of line segment to determine reactive support to keep line end voltage around 1.01 p.u.
16. Actual line reactors may be a combination of smaller units or Flexible AC Transmission System (FACTS) devices to cover multiple system load conditions and operating points.
17. The study has not included additional shunts required to maintain safe voltage levels on locations other than the priority project group line segments.

[8] EHV lines (>300 kV) are typically operated between 0.98 and 1.04 p.u. For the study purpose, an average 1.01 pu operating voltage was chosen.

[9] Sub synchronous Resonance in Power Systems, Paul M. Anderson, B. L. Agrawal, J. e. Van Ness, IEEE Press, 1990

18. The study is not a short circuit analysis and does not include the effects of reactors on line switching.
19. The study does not consider the effect of unapproved 2009 STEP projects.

Results and Conclusions

Project group line reactors are listed in Table 2. The average line reactor compensation for 345 kV is 1.17 MVar/mile and 1.28 MVar/mile in Groups 1 and 2 respectively. The average line reactor compensation for 765 kV operated at 345 kV is 1.77 MVar/mile in Group 1. Total estimated cost for the line reactor compensation is in the range of $20-$30 million.

A preliminary cost estimate for 100 MVar reactors is in the range of $2 million to $3 million for 345 kV. A detailed facility study will allow us to determine the location, size, and cost estimate of the final reactive requirements.

Future studies should include a more detailed system voltage scan under N-1 analysis with the selected line reactors included in each project.

Table 2 lists the approximate amount of line reactance needed to limit system voltage to around 1.01 p.u. This table also lists the line MVar compensation required for each section of the Priority Project along with an average compensation determined per mile for 345 kV.

Table 2: Project Group Line Reactors

Project	Circuit	From Bus Shunt (MVar)	To Bus Shunt (MVar)	Total Circuit Shunt (MVar)	Line Miles	Line kV
Group 1	Hitchland-Woodward 1	-71	-71	-142	123.2	345
	Hitchland-Woodward 2	-71	-71	-142	123.2	345
	Spearville-Comanche	-40	-40	-80	71.5	765 at 345
	Comanche-Med Lodge	-39	-39	-78	42.9	765 at 345
	Med Lodge-Wichita	-30	-30	-60	73.7	765 at 345
	Comanche-Woodward	-105	-105	-210	53.9	765 at 345
	Cooper-Maryville	-34	-34	-68	44.9	345
	Maryville-Sibley	-55	-55	-110	102.1	345
	Valliant-NW Texarkana	0	0	0	66.0	345
	Total Shunt (MVar)			-890		
	Total Shunt (MVar)/mile (avg.) for 345 kV				-1.01	
	Total Shunt (MVar)/mile (avg.) for 765 kV operated at 345 kV				-1.77	
Group 2	Hitchland-Woodward 1	-70	-70	-140	123.2	345
	Hitchland-Woodward 2	-70	-70	-140	123.2	345
	Spearville-Comanche 1	-27	-27	-54	71.5	345
	Spearville-Comanche 2	-27	-27	-54	71.5	345
	Comanche-Med Lodge 1	-21	-21	-42	42.9	345
	Comanche-Med Lodge 2	-21	-21	-42	42.9	345
	Med Lodge-Wichita 1	-26	-26	-52	73.7	345
	Med Lodge-Wichita 2	-26	-26	-52	73.7	345
	Comanche-Woodward 1	-92	-92	-184	53.9	345
	Comanche-Woodward 2	-92	-92	-184	53.9	345
	Cooper-Maryville	-34	-34	-68	44.9	345
	Maryville-Sibley	-55	-55	-110	102.1	345
	Valliant-NW Texarkana	0	0	0	66.0	345
	Total Shunt (MVar)			-1122		
	Total Shunt (MVar)/mile (avg.) for 345 kV				-1.19	

Attachment 3 – TWG Comments to the Priority Project Reliability Report

SPS Concerns and reason for "no" vote

SPS opposed the SPP Priority Projects Phase II Reliability Report because of several factors, which became apparent through the review of the document and associated discussions. SPS's Transmission Asset Management Department is concerned the reliability analyses were not constructed appropriately and are showing disturbing results.

1. The Reliability Analysis looks for reliability problems caused by the addition of the Priority Projects themselves. It doesn't examine the addition of the proposed Priority Projects with the accompanying incremental wind generation that is being reflected in the economic studies to determine if the proposed Priority Projects are really the best transmission reliability choice to support wind injection at the locations assumed or simulated in the economic models.

2. A FCITC (First Contingency Incremental Transfer Capability) study was conducted to help quantify any potential impacts on inter-area transfer capability between SPP balancing areas. SPS understands it was not a definitive study on import and export capability. This study was extremely helpful, but also disturbing. It can be observed from the studies that minimal transfer capability increases seem to occur from western Kansas to eastern Kansas with the addition of the proposed Priority Projects. For the SPS area, it appeared that SPS import capability may have decreased with the addition of the proposed Priority Projects and SPS export capability saw small or minimal increase. There are clearly existing problems in the models caused by the load growth in the SPS area, and these models do not contain the SPP staff recommended upgrades found in the 2009 STEP. It may be that those upgrades should have been included in the analysis since load increases are reflected in the model. While the FCITC studies were a 'first cut' at this area of study, they raise disturbing questions as to the overall transmission capability that may be a result of the proposed Priority Projects. For example, it seems strange that adding another tie-line (the Hitchland-Woodward double-circuit 345 kV line) to the SPS area as a proposed Priority Project would negatively or minimally impact SPS's transfer capabilities.

Considering the cost of the proposed Priority Projects to ratepayers, SPS felt the reliability analysis raised more questions than it answered and felt compelled to vote no due to the results provided.

NPPD Concerns and reason for abstention

Nearly all of the FCITC limiters flagged in the NPPD system are localized load-serving issues and are not considered valid constraints from a regional transfer capability perspective. Due to these localized load-serving issues, the tested incremental transfer levels were too low to uncover any impacts to existing NPPD flowgates or produce any new potential NPPD regional limiters. Based on the FCITC Analysis results, it is not possible for NPPD to ascertain whether the Priority Project grouping will have an adverse or beneficial impact on transfer capability across the NPPD system.

NPPD also objects to the two alternative Priority Project groups which were chosen to be studied as they had no significant differences from a topology or electrical characteristic perspective. A reliability comparison of double circuit 345 kV to 765 kV operated at 345 kV is a fundamentally flawed exercise which, as shown in the report, yielded no comparison value. NPPD has continually supported the review of competing alternatives in the Priority Project analysis especially regarding the chosen Cooper – Maryville – Sibley project versus Nebraska City - Stranger and the evaluation of 345 kV single circuit versus 765 kV for the Kansas / Oklahoma projects.

KCPL reason for abstention

Harold Wyble, KCPL, has concern that considering all of the investment to be made in the Priority Projects, TWG should be able to have the necessary amount of time and effort to prepare a thorough FCITC analysis of the Priority Projects. He doesn't feel that TWG has had that opportunity due to SPP Staff's work load and aggressive schedule to complete the Priority Project analysis.

EDE reason for "no" vote
Previously stated in TWG minutes (excerpt): "Sam McGarrah, Empire District Electric, expressed concern that the reliability study scope does not allow the results of this study to be combined into the cost benefit analysis of the Priority Projects assessments. He stated 'since the economic assessments considered several levels of wind generation in SPP, the reliability analysis should include these levels of wind to adequately assess benefits of the Priority Projects. The reliability study was not based on similar system conditions as the other economic studies; therefore, the reliability issues associated with these conditions may not be adequately captured. It is likely that the results of this report will be summarized in the Priority Projects Report; consequently, the limitations of the results of the reliability study may not be properly characterized in the summary.'"

Attachment 4 – SEAMS Notification Letter

December 15, 2009

Name
Company
Address
City, State Zip

Dear Name,

This letter is to inform you, as a neighbor to SPP and potential interested party, that SPP is currently studying several proposed transmission projects as part of its Priority Projects effort. Since some of the proposed projects are EHV projects, they could potentially impact areas outside the SPP footprint.

The projects currently being considered are:

1. Spearville – Comanche – Medicine Lodge – Wichita (765 kV construction operated at 345 kV or double-circuit 345 kV construction and operation)
2. Comanche – Woodward District EHV (765 kV construction operated at 345 kV or double-circuit 345 kV construction and operation)
3. Hitchland – Woodward District EHV (345 kV double circuit)
4. Valiant – NW Texarkana (345 kV single circuit)
5. Cooper – Maryville – Sibley (345 kV single circuit)
6. Riverside – Tulsa Reactor (138 kV)

You are invited to participate in this process as your input would prove beneficial. To engage in the Priority Projects effort, you may take part in our open stakeholder process via the Transmission Working Group and Economic Studies Working Group. Information regarding Long Term Transmission Service, Regional Expansion Planning and other planning processes can be found at Engineering & Planning at spp.org. Additional information on the Priority Projects effort can be found at http://www.spp.org/section.asp?group=1573&pageID=27.

For your reference, enclosed you will find two maps showing the location of the proposed projects. Should you have any questions please don't hesitate to contact me.

Sincerely,

Katherine Prewitt
Manager, ITO
(501) 614-3518 • Fax: (501) 664-9553 • kprewitt@spp.org

Enclosure

Attachment 5 – Wind Generation JEDI Metrics

ESTIMATING JOB AND ECONOMIC IMPACT OF WIND POWER DEVELOPMENT IN THE SPP FOOTPRINT

As part of SPP's effort in estimating the economic costs and benefits of the transmission investments, *The Brattle Group* has been asked to estimate the potential economic benefits associated with enabling and expanding the build out of wind power generation in SPP. This subsection of the report discusses our methodology, assumptions, and findings.

Description of Job and Economic Impact Estimation Methodology

The Brattle Group uses the Job and Economic Development Impact (JEDI) Wind model developed for the U.S. Department of Energy to estimate the potential economic impact of wind projects in the SPP footprint.

The JEDI Wind model separates a wind project's life into construction and operation phase. In each phase, the model estimates the "Direct", "Indirect", and "Induced" job and economic impacts. (The JEDI Wind model uses "economic multipliers" from the Input-Output Model called IMPLAN[10] to perform the estimations.) These various levels of job and economic impacts can be best explained in terms of the ways that a wind project might create income, jobs, and economic activities for the state in which the project resides. Using employment as an example, "Direct Employment" refers to those that are directly employed to construct or operate the facility. "Indirect Employment" refers to jobs that provide services or materials to enable the construction or operation of the facility. Finally, "Induced Employment" refers to those who are employed to provide food, housing, transportation, and other services to those who are directly and indirectly employed to construct and operate the wind projects. Similar descriptions apply to "Direct", "Indirect", and "Induced" earnings and economic output.

The JEDI Wind model is designed to estimate the job and economic impact for a particular state. This means that when a wind project is sited in one state, even though some jobs and economic activities might be created and spilled over into a neighboring state, the model does not estimate that "spill-over" effect. This also means that we have not estimated the potential job and economic impact of each wind project on the economies of neighboring states. This omission may make it seem like each project only benefits the state in which it reside, when in reality, the region as a whole could experience benefits. For example, wind projects located in Oklahoma, Texas and Missouri may create some jobs in Arkansas but this effect has not been estimated. Economic theory and intuition, however, suggest that, given its geographical proximity to numerous potential wind projects, Arkansas also will benefit from such economic development.

JEDI reports construction and operating jobs as full-time equivalent jobs that would be needed to complete the construction of the project and operated the facility annually. A full-time equivalent job is equivalent to 2,080 hours of work hours. The estimated employment level is the number jobs (directly, indirectly, and induced) associated with the wind projects assuming that the labor force is not being utilized elsewhere in the economy. If the rate of unemployment is low in a state, then these jobs are not necessarily "additional" jobs, employees are simply shifting jobs from other sectors or other projects to support the wind projects under study.

Depending on how project development is implemented, there might be some economies of scale associated with larger projects. For example, if two or more projects are undertaken in close

10 Although IMPLAN's economic multipliers are used in the JEDI model, *The Brattle Group* does not have access to the precise multipliers used and has not attempted to match them to the IMPLAN model used to estimate the economic impact from transmission projects.

proximity or as a combined venture, some savings in labor, expertise and resources might be achieved, which would reduce the aggregate employment and economic impact compared to undertaking the two projects independently. In our analysis, we have assumed each project in the list provided in the assumption table is a stand-alone project, and have not captured any economies of scale. Thus, the estimated job and economic impact is greater than had the projects been developed in larger aggregations.

Input Assumptions Used to Obtain the JEDI Model Results

The JEDI model utilizes data on project-specific characteristics and costs to estimate the direct, induced and indirect effects on employment, earnings, and output from developing and operating the project. Consequently, the JEDI Wind model requires three general groups of input data—project description, project cost, and wind plant annual operating and maintenance costs. The category of input assumptions is summarized in Table 1 below.

Table 1
Assumption Categories for the JEDI Wind Model

Project Descriptive Data
Project Location
Total Project Size - Nameplate Capacity (MW)
Turbine Size (KW)
Project Cost Data
Construction Costs
Equipment Costs
Turbines, Blades, Towers, Transportation
Balance of Plant
Materials, Labor, Development, Engineering, Legal, and Other Costs
Labor
Wind Farm Annual Operating and Maintenance Costs
Labor
Personnel
Materials and Services
Other Parameters
Financial Parameters
Tax Parameters
Land Lease Parameters
Payroll Parameters

To estimate the job and economic output from the wind projects, we used project-specific data for all wind projects designated as part of the project “tranches” to be analyzed. Specifically, the two tranches are: 4 GW wind investment in phase 1 and an additional 7 GW wind investment in phase 2, adding to a total of 11 GW of new wind investment. The specific projects in the 4 GW and the total 11 GW groups are specified in Tables 2 and 3 below.

Table 2
Wind Project Information for 4GW Tranche

GI REQUEST	MAX CAPACITY (MW)	TURBINE MODEL	STATE	TURBINE CAP (MW)
GEN-2002-025A	49.5	GE 1.5MW	KS	1.5
GEN-2005-012	250	VESTAS V90 1.8MW	KS	1.8
GEN-2005-016	150	GAMESA G87 2.0 MW	KS	2
GEN-2006-006	205.5	GE 1.5MW	KS	1.5
GEN-2006-034	81	GE 1.5MW	KS	1.5
GEN-2006-040	100	ACCIONA AWE 1500	KS	1.5
GEN-2006-049	400	GE 1.5MW	KS	1.5
MADISONCO	120	GE 1.5MW	NE	1.5
BOYDCO1	124.5	GE 1.5MW	NE	1.5
ANTELOPECO	111	GE 1.5MW	NE	1.5
COOKERCO	108	GE 1.5MW	NE	1.5
BUTLERCO	105	GE 1.5MW	NE	1.5
GEN-2006-048	150	ACCIONA AWE 1500	NM	1.5
GEN-2002-006	150	GE 1.5MW	OK	1.5
GEN-2003-005	100	GE 1.5MW	OK	1.5
GEN-2006-043	99	GE 1.5MW	OK	1.5
GEN-2006-046	130	MITSUBISHI MWT 92/95	OK	2.4
GEN-2002-022	80	SIEMENS SWT 2.3MW	TX	2.3
GEN-2003-020	80	Acciona 1.5MW	TX	1.5
GEN-2006-020S	18.9	GE 1.5MW	TX	1.5
GEN-2006-044	400	GE 1.5MW	TX	1.5
GEN-2006-045	240	SUZLON S88 2.1MW	TX	2.1
GEN-2006-047	240	SUZLON S88 2.1MW	TX	2.1
GEN-2007-004	150	GAMESA G87 2.0MW	TX	2
GEN-2007-005	200	FUHRLANDER FL2500 2.5MW	TX	2.5
GEN-2002-008	240	GE 1.5MW	TX	1.5
Total	**4,082.40**			

Table 3
Wind Project Information for the Full 11GW Tranche

GI REQUEST	MAX CAPACITY (MW)	TURBINE MODEL	STATE	TURBINE CAP	TURBINE CAP (kW)
GEN-2002-025A	49.5	GE 1.5MW	KS	1.5	1500
GEN-2005-012	250	VESTAS V90 1.8MW	KS	1.8	1800
GEN-2005-016	150	GAMESA G87 2.0 MW	KS	2	2000
GEN-2006-006	205.5	GE 1.5MW	KS	1.5	1500
GEN-2006-034	81	GE 1.5MW	KS	1.5	1500
GEN-2006-040	100	ACCIONA AWE 1500	KS	1.5	1500
GEN-2006-049	400	GE 1.5MW	KS	1.5	1500
MADISONCO	120	GE 1.5MW	NE	1.5	1500
BOYDCO1	124.5	GE 1.5MW	NE	1.5	1500
ANTELOPECO	111	GE 1.5MW	NE	1.5	1500
COOKERCO	108	GE 1.5MW	NE	1.5	1500
BUTLERCO	105	GE 1.5MW	NE	1.5	1500
GEN-2006-048	150	ACCIONA AWE 1500	NM	1.5	1500
GEN-2002-006	150	GE 1.5MW	OK	1.5	1500
GEN-2003-005	100	GE 1.5MW	OK	1.5	1500
GEN-2006-043	99	GE 1.5MW	OK	1.5	1500
GEN-2006-046	130	MITSUBISHI MWT 92/95	OK	2.4	2400
GEN-2002-022	80	SIEMENS SWT 2.3MW	TX	2.3	2300
GEN-2003-020	80	Acciona 1.5MW	TX	1.5	1500
GEN-2006-020S	18.9	GE 1.5MW	TX	1.5	1500
GEN-2006-044	400	GE 1.5MW	TX	1.5	1500
GEN-2006-045	240	SUZLON S88 2.1MW	TX	2.1	2100
GEN-2006-047	240	SUZLON S88 2.1MW	TX	2.1	2100
GEN-2007-004	150	GAMESA G87 2.0MW	TX	2	2000
GEN-2007-005	200	FUHRLANDER FL2500 2.5MW	TX	2.5	2500
GEN-2007-011	135	ACCIONA AWE 1500	KS	1.5	1500
GEN-2007-012	300	Acciona 1.5 MW	KS	1.5	1500
GEN-2007-013	99	GE 1.5MW	KS	1.5	1500
GEN-2007-015	135	GE 1.5MW	KS	1.5	1500
GEN-2007-019	375	GE 1.5MW	KS	1.5	1500
GEN-2007-025	300	CLIPPER C96 2.5MW	KS	2.5	2500
GEN-2007-028	200	Vestas V90 3.0 MW	KS	3	3000
GEN-2007-036	200	CLIPPER C93 2.5MW	KS	2.5	2500
GEN-2007-037	200	CLIPPER C93 2.5MW	KS	2.5	2500
GEN-2007-038	200	CLIPPER C93 2.5MW	KS	2.5	2500
GEN-2007-040	500	SIEMENS SWT 2.3MW	KS	2.3	2300
GEN-2007-017	100.5	GE 1.5 MW	MO	1.5	1500
PIERCECO	171	GE 1.5MW	NE	1.5	1500
CHERRYCO	272	GE 1.5MW	NE	1.5	1500
HAMILTONCO	301	GE 1.5MW	NE	1.5	1500
GEN-2007-027	60	SUZLON S88 2.1MW	NM	2.1	2100
GEN-2007-034	150	GE 1.5MW	NM	1.5	1500
GEN-2007-006	160	SUZLON S88 2.1MW	OK	2.1	2100
GEN-2007-021	201	GE 1.5MW	OK	1.5	1500
GEN-2007-032	150	Acciona 1.5 MW turbines)	OK	1.5	1500
GEN-2007-041	600	SUZLON S88 2.1MW	OK	2.1	2100
GEN-2007-043	300	GE 1.5MW	OK	1.5	1500
GEN-2007-044	300	GE 1.5MW	OK	1.5	1500
GEN-2007-008	300	SUZLON S88 2.1MW	TX	2.1	2100
GEN-2007-010	200	GE 1.5MW	TX	1.5	1500
GEN-2007-026	130.2	SUZLON S88 2.1MW	TX	2.1	2100
GEN-2007-030	200	FUHRLANDER FL2500 2.5MW	TX	2.5	2500
GEN-2007-033	200	FUHRLANDER FL2500 2.5MW	TX	2.5	2500
GEN-2007-042	360	GE 1.5MW	TX	1.5	1500
GEN-2002-008	240	GE 1.5MW	TX	1.5	1500
Total	**10,882.10**				

We have been asked to assume that the installation years of the two phases differ in three scenarios that SPP calls “Levels”. In “Level 1”, 4 GW of new wind projects are developed in 2014 and additional 7 GW will be developed in 2019. In “Level 2”, only 4 GW of new wind projects are developed in 2019. And in “Level 3”, 4 GW of new wind is developed in 2009, with the additional 7 GW developed in 2014.

The JEDI Wind model provides default parameter values that are state-specific and based on a survey of wind project development experience. However, we have revised the cost of equipment costs, keeping them constant across the states and assumed that none of the turbine and blades are manufactured in the state where the project is located. Overall, the average overnight project cost for wind projects portfolio is approximately $2,020/kW, while the average annual O&M cost is approximately $20/kW-year.

By design, the JEDI Wind model attributes direct employment effects exclusively to construction-related costs. We also have assumed that for all the wind projects' direct expenditure on construction materials (such as cement) is spent 90% locally in the state in which the project resides, while the labor costs related to construction is procured primarily locally from within the state, with some labor costs coming from outside of the state.

The JEDI model provides impact calculations for both the period of construction and the period of operation of the wind project. We have assumed a 20-year lifecycle for each project and have discounted the stream of annual earnings and output values using the currently reported 20-year risk-free real rate of return (from Treasury Inflation Protected Security, or TIPS data) of 2.19%.[11]

Results

The results of each "Level" is organized below, each separated by an input assumption sheet. Level 1 results are contained in Tables 4A and 4B. Level 2 results are in Table 5. Level 3 results are in Table 6. For each set of tables, the economic impacts by state during the construction period are reported in the two tables on the left, while those during the years of operation are reported in the tables on the right.

Taking Level 1 results as an example, during the construction phase, the investment of 4 GW of wind projects in 2014, which amounts to about $8.2 billion (in 2009$), is estimated to create *direct* employment of approximately 2,413 full-time equivalent ("FTE") jobs[12] with additional 13,584 indirect jobs and 5.041 induced jobs associated with the wind projects. (Please refer to the definition of the indirect and induced jobs in Methodology section.) During operating years, we estimate 224 FTE direct jobs, 317 FTE indirect jobs, and 306 FTE induced jobs are associated with the 4 GW of wind projects. The associated earnings amount are also reported in the tables, with a combined earnings during the construction periods for 4GW of wind projects estimated to be approximately $687 million (in 2009$). In addition, the estimated economic overall output associated with the 4 GW new wind project is estimated to be $2.1 billion. During the operating years, the net present value of the cumulative earnings (over 20 years, the assumed economic life of the plant) associated with the 4 GW of new wind project is approximately $503 million (in 2009$) while the economic output during the operating years is estimated to be in the neighborhood of $1.7 billion (in 2009$).

Similarly, assuming another 6,800MW of wind projects will be installed in 2019, more jobs and local economic impact would be associated with the new wind projects. To summarize the combined effect of the 11 GW of new wind projects developed in 2 phases between 2014 and 2019, the estimated full-time equivalent jobs associated with the new wind projects would be approximately 56,600 during construction and 2,200 during the operational phase. In addition, $5 billion in economic value during the construction phase, and $3.9 billion during the operating years (all estimated as net present value in 2009$) are associated with the 11 GW of new wind projects.

[11] 20-yr Treasury Inflation Protected Security (TIPS) rate from http://www.federalreserve.gov/releases/h15/update/

[12] 1 FTE = 2,080 hours

Findings and Caveats

The results from our analysis suggest that:

- There are job and economic benefits to developing wind projects in the SPP footprint.
- The magnitude of associated economic and job benefits are sensitive to the magnitude of local spending.
- The wind project can provide some job and economic spillover benefits for neighboring states, and thereby increase the overall economic development benefits to the entire region. However, the specific breakdown of this spillover effects could increase the regional value.
- The presence of a manufacturing, construction, and other infrastructure-building sectors could increase the local economic benefits. While not captured in this analysis, increasing wind development activities in the SPP region could also further increase the attractiveness of setting additional manufacturing, R&D, and educational facilities that could further increase the economic and job benefits to the region.
- The potential job and economic impact of the cost of the wind projects are not incorporated in this study. This means that the effect of the additional wind development on the local power costs are not assessed in this analysis and when accounted for, the job and economic impact can be significantly altered.

LEVEL 1 SCENARIO

Assumptions:

- 4GW of New Wind Constructed in 2014, online in 2015, lifespan of 20 years
- 11 GW of New Wind Constructed in 2019, online in 2020, lifespan of 20 years
- 20-year risk-free real rate of return: 2.19% from Treasury Inflation Protected Security (TIPS)

TABLE 4A: 4GW of New Wind Constructed in 2014, online in 2015, lifespan of 20 years

EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	71.7	306	1,747	612	**2,665**
Kansas	209.0	723	4,275	1,558	**6,556**
Texas	282.1	931	5,047	1,848	**7,826**
Missouri	*Positive indirect effects from neighboring projects not quantified*				
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	27.4	90	538	239	**867**
Nebraska	97.1	362	1,976	784	**3,123**
Total	***687.3***	**2,413**	**13,584**	**5,041**	***21,037***

ANNUAL EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	TOTAL EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	51.9	27	39	39	**105**
Kansas	136.3	66	99	66	**231**
Texas	224.9	89	115	147	**351**
Missouri	*Positive indirect effects from neighboring projects not quantified*				
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	22.0	9	14	19	**42**
Nebraska	68.1	33	49	36	**118**
Total	***503.2***	**224**	**317**	**306**	***847***

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
		2009$		
Oklahoma	238.3	14.9	169.7	53.7
Kansas	631.7	44.1	445.4	142.2
Texas	867.7	61.5	603.0	203.3
Missouri	*Positive indirect effects from neighboring projects not quantified*			
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	81.8	5.4	56.1	20.2
Nebraska	302.1	20.9	209.4	71.7
Total	***2,121.6***	**146.9**	**1,483.6**	**491.1**

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
		2009$		
Oklahoma	183.1	17.7	111.4	54.0
Kansas	383.5	56.6	230.5	96.4
Texas	857.7	81.8	515.9	259.9
Missouri	*Positive indirect effects from neighboring projects not quantified*			
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	78.7	7.3	45.5	25.8
Nebraska	200.4	26.5	121.0	52.9
Total	***1,703.4***	**190.0**	**1,024.4**	**489.0**

Source and Notes: Results generated with JEDI Model.

Earnings and Output values are millions of dollars in year 2009 dollars.

Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours).

TABLE 4B: 11 GW of New Wind Constructed in 2019, online in 2020, lifespan of 20 years

EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	287.5	1,217	7,983	2,777	**11,977**
Kansas	583.2	2,155	13,418	4,872	**20,445**
Texas	464.0	1,669	9,302	3,398	**14,369**
Missouri	17.8	66	347	152	**566**
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	60.0	238	1,293	577	**2,108**
Nebraska	196.8	745	4,560	1,796	**7,100**
Total	***1,609.4***	**6,090**	**36,904**	**13,572**	***56,566***

ANNUAL EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	TOTAL EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	206.1	118	178	174	**471**
Kansas	381.5	208	310	206	**724**
Texas	371.9	164	212	271	**647**
Missouri	13.1	6	9	8	**23**
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	48.0	21	34	46	**100**
Nebraska	136.3	72	113	82	**267**
Total	***1,156.8***	**588**	**856**	**787**	***2,232***

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
		2009$		
Oklahoma	969.7	55.1	696.2	218.4
Kansas	1,773.1	119.2	1,254.8	399.1
Texas	1,432.2	99.4	997.3	335.5
Missouri	50.6	3.8	33.7	13.1
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	177.4	12.7	120.8	43.9
Nebraska	620.8	39.6	433.8	147.4
Total	***5,023.9***	**329.8**	**3,536.7**	**1,157.4**

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
		2009$		
Oklahoma	742.0	67.7	454.2	220.0
Kansas	1,076.3	158.4	647.3	270.6
Texas	1,418.0	135.6	852.6	429.7
Missouri	38.8	5.2	22.0	11.6
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	170.4	16.0	98.6	55.7
Nebraska	407.5	51.2	248.2	108.1
Total	***3,852.9***	**434.1**	**2,323.0**	**1,095.8**

Source and Notes: Results generated with JEDI Model.

Earnings and Output values are millions of dollars in year 2009 dollars.

Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours).

LEVEL 2 SCENARIO

Assumptions:

- 4GW of New Wind Constructed in 2019, online in 2020, lifespan of 20 years
- 20-year risk-free real rate of return: 2.19% (latest TIPS data)

TABLE 5: 4GW of New Wind Constructed in 2019, online in 2020, lifespan of 20 years

EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	64.4	306	1,747	612	**2,665**
Kansas	187.6	723	4,275	1,558	**6,556**
Texas	253.2	931	5,047	1,848	**7,826**
Missouri	*Positive indirect effects from neighboring projects not quantified*				
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	24.6	90	538	239	**867**
Nebraska	87.1	362	1,976	784	**3,123**
Total	***616.8***	**2,413**	**13,584**	**5,041**	***21,037***

ANNUAL EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	TOTAL EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	46.5	27	39	39	**105**
Kansas	122.3	66	99	66	**231**
Texas	201.8	89	115	147	**351**
Missouri	*Positive indirect effects from neighboring projects not quantified*				
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	19.8	9	14	19	**42**
Nebraska	61.2	33	49	36	**118**
Total	***451.6***	**224**	**317**	**306**	***847***

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
			2009$	
Oklahoma	213.8	13.4	152.3	48.2
Kansas	566.9	39.6	399.7	127.6
Texas	778.7	55.2	541.1	182.4
Missouri	*Positive indirect effects from neighboring projects not quantified*			
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	73.4	4.9	50.3	18.2
Nebraska	271.1	18.8	187.9	64.4
Total	***1,903.8***	**131.8**	**1,331.3**	**440.7**

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
			2009$	
Oklahoma	164.3	15.9	99.9	48.5
Kansas	344.2	50.8	206.9	86.5
Texas	769.6	73.4	463.0	233.2
Missouri	*Positive indirect effects from neighboring projects not quantified*			
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	70.6	6.6	40.9	23.1
Nebraska	179.8	23.8	108.6	47.4
Total	***1,528.5***	**170.5**	**919.2**	**438.8**

Source and Notes: Results generated with JEDI Model.

Earnings and Output values are millions of dollars in year 2009 dollars.

Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours).

LEVEL 3 SCENARIO

Assumptions:

- 4GW of New Wind Constructed in 2009, online in 2010, lifespan of 20 years
- 11 GW of New Wind Constructed in 2014, online in 2015, lifespan of 20 years
- 20-year risk-free real rate of return: 2.19% (latest TIPS data)

TABLE 5A: 4GW of New Wind Constructed in 2009, online in 2010, lifespan of 20 years

EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	79.9	306	1,747	612	**2,665**
Kansas	233.0	723	4,275	1,558	**6,556**
Texas	314.4	931	5,047	1,848	**7,826**
Missouri	*Positive indirect effects from neighboring projects not quantified*				
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	30.5	90	538	239	**867**
Nebraska	108.2	362	1,976	784	**3,123**
Total	***766.0***	**2,413**	**13,584**	**5,041**	***21,037***

ANNUAL EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	TOTAL EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	57.8	27	39	39	**105**
Kansas	151.9	66	99	66	**231**
Texas	250.6	89	115	147	**351**
Missouri	*Positive indirect effects from neighboring projects not quantified*				
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	24.6	9	14	19	**42**
Nebraska	75.9	33	49	36	**118**
Total	***560.8***	**224**	**317**	**306**	***847***

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
			2009$	
Oklahoma	265.5	16.6	189.1	59.8
Kansas	704.0	49.2	496.4	158.5
Texas	967.0	68.5	672.0	226.5
Missouri	*Positive indirect effects from neighboring projects not quantified*			
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	91.1	6.1	62.5	22.6
Nebraska	336.6	23.3	233.4	80.0
Total	***2,364.3***	**163.7**	**1,653.3**	**547.3**

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
			2009$	
Oklahoma	204.1	19.7	124.1	60.2
Kansas	427.4	63.1	256.9	107.4
Texas	955.8	91.2	574.9	289.6
Missouri	*Positive indirect effects from neighboring projects not quantified*			
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	87.7	8.2	50.7	28.7
Nebraska	223.3	29.5	134.9	58.9
Total	***1,898.2***	**211.8**	**1,141.5**	**544.9**

Source and Notes: Results generated with JEDI Model.

Earnings and Output values are millions of dollars in year 2009 dollars.

Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours).

TABLE 5B: 11 GW of New Wind Constructed in 2014, online in 2015, lifespan of 20 years

EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	320.4	1,217	7,983	2,777	**11,977**
Kansas	650.0	2,155	13,418	4,872	**20,445**
Texas	517.1	1,669	9,302	3,398	**14,369**
Missouri	19.8	66	347	152	**566**
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	66.9	238	1,293	577	**2,108**
Nebraska	219.3	745	4,560	1,796	**7,100**
Total	***1,793.6***	**6,090**	**36,904**	**13,572**	***56,566***

ANNUAL EMPLOYMENT EFFECTS (FTE)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	TOTAL EARNINGS *2009$ million*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)			
Oklahoma	229.7	118	178	174	**471**
Kansas	425.2	208	310	206	**724**
Texas	414.5	164	212	271	**647**
Missouri	14.6	6	9	8	**23**
Arkansas	*Positive indirect effects from neighboring projects not quantified*				
New Mexico	53.5	21	34	46	**100**
Nebraska	151.9	72	113	82	**267**
Total	***1,289.2***	**588**	**856**	**787**	***2,232***

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING CONSTRUCTION PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
		2009$		
Oklahoma	1,080.7	61.4	775.8	243.4
Kansas	1,976.0	132.8	1,398.4	444.8
Texas	1,596.1	110.8	1,111.4	373.9
Missouri	56.4	4.3	37.5	14.6
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	197.7	14.1	134.6	48.9
Nebraska	691.8	44.1	483.4	164.3
Total	***5,598.6***	**367.5**	**3,941.3**	**1,289.8**

OUTPUT GENERATED ($ million)
FROM WIND PROJECTS DURING OPERATING PERIOD

STATE	OUTPUT *2009$*	*Direct*	*Indirect*	*Induced*
		2009$		
Oklahoma	826.8	75.5	506.1	245.2
Kansas	1,199.4	176.5	721.4	301.5
Texas	1,580.2	151.1	950.2	478.9
Missouri	43.2	5.8	24.5	13.0
Arkansas	*Positive indirect effects from neighboring projects not quantified*			
New Mexico	189.9	17.9	109.9	62.1
Nebraska	454.1	57.1	276.6	120.4
Total	***4,293.7***	**483.8**	**2,588.7**	**1,221.2**

Source and Notes: Results generated with JEDI Model.

Earnings and Output values are millions of dollars in year 2009 dollars.

Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours).

Attachment 6 – Transmission IMPLAN Metrics

TRANSLATING ECONOMIC IMPACT INTO EMPLOYMENT AND OUTPUT ESTIMATES

We use the IMPLAN®[13,14] model to estimate the employment levels, economic activity, and local tax impacts that will be generated by investments related to transmission line construction in the SPP footprint. We evaluate the impacts of three build out scenarios: for a subset of projects, a 765 kV transmission line and a 765kV transmission line operated at 345 kV, and for all projects, a double circuit 345 kV (3,000 A) transmission line. The results are broken out by project into direct, indirect, and induced effects within the state in which the expenditures occur. We do not measure the spill-over effects outside of the state in which the expenditure is made.

The IMPLAN® model divides the economy into 440 sectors. We identified six sectors that are directly impacted by the construction labor and design work related to the proposed investments. They are listed in Table 1. We assume that all materials used for the proposed investments are manufactured out of state and subsequently do not allocate any expenditures associated with materials in our analysis—to the extent any of the materials used in the transmission lines is manufactured in the state in which the line is built, we are underestimating economic impacts. This information forms the basic input into the IMPLAN® model. We apply the expenditures by category associated with the proposed investments at the state level.

Table 25: IMPLAN Cost Categories

1	Electric power generation, transmission, and distribution
2	Construction of other new nonresidential structures
3	Maintenance and repair construction of nonresidential maintenance and repair
4	Architectural, engineering, and related services
5	Environmental and other technical consulting services
6	Scientific research and development services

Source: www.implan.com

The stimulus from a given expenditure is broken down into direct, indirect, and induced effects.[15] Direct effects represent the changes in employment and economic activity in the industries to which the final demand change was made. Indirect effects measure the changes in inter-industry purchases generated from the new demand. Induced effects reflect changes in household spending resulting from income changes due to production changes.[16] The impacts on employment and output are reported in Tables 2 and 3. The state and local government tax revenues from each of the projects is reported in Table 4.

[13] IMPLAN® stands for IMpact Analysis for PLANing. See www.implan.com for more information on the IMPLAN® model.

[14] IMPLAN® is a standard input-output model that estimates the relationships between economic expenditures, incomes and employment, both within sectors of the economy and between them. It tracks the effect of demand for goods and services (expenditures) on inputs, including labor, needed to meet those demands.

[15] MIG Inc., *Implan Pro™ User's Guide* (Minnesota: Minnesota Implan Group, Inc., 2004), 102.

[16] We do not capture trade flows between states, and thus, the out of state impacts generated from a given expenditures within a state. For example, an expenditure made in Texas could result in trade flows that result in jobs in New Mexico (i.e. in another state in our study) or elsewhere, neither of which are captured.

Table 26: Employment Effects (Full-Time Equivalent Jobs)

PROJECT NAME	STATE	*765*				*765 @ 345*				*Double Circuit 345 (3000 A)*			
		Direct	*Indirect*	*Induced*	*Total*	*Direct*	*Indirect*	*Induced*	*Total*	*Direct*	*Indirect*	*Induced*	*Total*
		Full-Time Equivalent Jobs (FTE)				*Job Years*				*Full-Time Equivalent Jobs (FTE)*			
Hitchland - Woodward	Oklahoma	1,314	395	467	2,176	1,134	345	411	1,890	888	264	315	1,467
Spearville - Comanche - Medicine Lodge - Wichita	Kansas	1,429	396	602	2,428	1,005	278	423	1,706	1,194	342	522	2,058
Comanche/Medicine Lodge - Woodward	Kansas	99	27	42	168	81	22	34	137	103	29	45	178
Comanche/Medicine Lodge - Woodward	Oklahoma	1,009	284	331	1,624	820	231	269	1,319	1,055	307	359	1,721
Woodward - Elk City - LES - Seminole	Oklahoma	3,215	977	1,166	5,358	2,730	830	990	4,549	2,143	637	761	3,542
Northwest Wichita - Wolf Creek	Kansas	1,489	435	666	2,589	1,294	378	579	2,251	885	253	387	1,525
Woodward - Woodring	Oklahoma									559	164	194	918
Valliant - NW Texarkana	Oklahoma									424	124	147	695
Valliant - NW Texarkana	Arkansas									54	14	16	84
Valliant - NW Texarkana	Texas									42	13	20	76
Stateline - Potter- Roosevelt - Tuco	New Mexico									128	40	49	217
Stateline - Potter- Roosevelt - Tuco	Texas									974	315	477	1,766
Cooper - Maryville - Sibley 345kV	Missouri									973	332	494	1,800
Nebraska City - Stranger Creek 345kV	Nebraska									296	87	121	504
Nebraska City - Stranger Creek 345kV	Kansas									683	193	292	1,169
Riverside Station - Tulsa Power Station (Add Reactor)	Oklahoma									3	1	1	5
	Total	8,555	2,514	3,274	14,343	7,063	2,084	2,705	11,852	10,407	3,118	4,201	17,725

Source and Notes: Ressults generated using IMPLAN Professional ®

Table 27: Economic Activity Generated ($ Millions)

PROJECT NAME	STATE	*765*				*765 @ 345*				*Double Circuit 345 (3000 A)*			
		Direct	*Indirect*	*Induced*	*Total*	*Direct*	*Indirect*	*Induced*	*Total*	*Direct*	*Indirect*	*Induced*	*Total*
		$ Millions				*$ Millions*				*$ Millions*			
Hitchland - Woodward	Oklahoma	$150.98	$56.42	$57.49	$264.88	$130.32	$48.70	$49.62	$228.65	$101.53	$38.29	$38.05	$177.87
Spearville - Comanche - Medicine Lodge - Wichita	Kansas	$180.52	$62.91	$73.29	$316.72	$126.88	$44.22	$51.52	$222.62	$152.70	$52.24	$63.46	$268.40
Comanche/Medicine Lodge - Woodward	Kansas	$12.53	$4.37	$5.09	$21.99	$10.18	$3.55	$4.13	$17.86	$13.21	$4.52	$5.49	$23.22
Comanche/Medicine Lodge - Woodward	Oklahoma	$112.78	$44.01	$39.92	$196.71	$91.62	$35.75	$32.43	$159.81	$118.91	$45.67	$43.35	$207.94
Woodward - Elk City - LES - Seminole	Oklahoma	$369.48	$138.08	$140.68	$648.24	$313.70	$117.23	$119.44	$550.37	$245.14	$92.45	$91.87	$429.46
Northwest Wichita - Wolf Creek	Kansas	$191.90	$64.84	$80.97	$337.70	$166.85	$56.37	$70.40	$293.62	$113.19	$38.72	$47.04	$198.94
Woodward - Woodring	Oklahoma									$59.46	$22.39	$22.23	$104.09
Valliant - NW Texarkana	Oklahoma									$45.07	$16.97	$16.85	$78.89
Valliant - NW Texarkana	Arkansas									$5.63	$1.87	$1.78	$9.28
Valliant - NW Texarkana	Texas									$5.63	$2.26	$2.79	$10.69
Stateline - Potter- Roosevelt - Tuco	New Mexico									$14.61	$5.29	$5.57	$25.47
Stateline - Potter- Roosevelt - Tuco	Texas									$131.45	$52.02	$66.61	$250.08
Cooper - Maryville - Sibley 345kV	Missouri									$119.14	$43.55	$59.21	$221.90
Nebraska City - Stranger Creek 345kV	Nebraska									$34.82	$10.54	$13.23	$58.59
Nebraska City - Stranger Creek 345kV	Kansas									$81.24	$27.80	$33.70	$142.73
Riverside Station - Tulsa Power Station (Add Reactor)	Oklahoma									$0.36	$0.14	$0.14	$0.63
	Total	$1,018.19	$370.62	$397.44	$1,786.25	$839.55	$305.82	$327.54	$1,472.92	$1,242.11	$454.73	$511.35	$2,208.19

Source and Notes: Ressults generated using IMPLAN Professional ®. Economic activity is in 2009 dollars.

Table 28: State and Local Government Tax Impact ($ Millions)

Project Name	STATE	*STATE AND LOCAL GOVERNMENT TAX IMPACT ($ Millions)* 765	765 @ 345	Double Circuit 345 (3000 A)
Hitchland - Woodward	Oklahoma	$8.48	$7.32	$5.72
Spearville - Comanche - Medicine Lodge - Wichita	Kansas	$11.33	$7.96	$9.56
Comanche/Medicine Lodge - Woodward	Kansas	$0.79	$0.64	$0.83
Comanche/Medicine Lodge - Woodward	Oklahoma	$6.41	$5.21	$6.73
Woodward - Elk City - LES - Seminole	Oklahoma	$20.74	$17.61	$13.80
Northwest Wichita - Wolf Creek	Kansas	$12.00	$10.43	$7.09
Woodward - Woodring	Oklahoma			$3.34
Valliant - NW Texarkana	Oklahoma			$2.53
Valliant - NW Texarkana	Arkansas			$0.31
Valliant - NW Texarkana	Texas			$0.33
Stateline - Potter- Roosevelt - Tuco	New Mexico			$0.98
Stateline - Potter- Roosevelt - Tuco	Texas			$7.59
Cooper - Maryville - Sibley 345kV	Missouri			$8.09
Nebraska City - Stranger Creek 345kV	Nebraska			$2.02
Nebraska City - Stranger Creek 345kV	Kansas			$5.08
Riverside Station - Tulsa Power Station (Add Reactor)	Oklahoma			$0.02
	Total	$59.75	$49.17	$74.01

Source and Notes: Ressults generated using IMPLAN Professional ®. Economic activity is in 2009 dollars.

Gross employment estimates represent the amount of labor (measured in full-time equivalent jobs, i.e. represents the number of units of 2,080 hours of work created) that would be required in a single year to meet the demand created by the expenditures, and is based on the output/worker relationship in the study area for the particular industry. Whether or not these employment estimates represent net impacts on employment depends on whether or not these resources (people) would be employed elsewhere or not. On the one hand, to the extent that the expenditures use labor that would otherwise be idle, the gross employment effects reported here represent a net increase in employment. On the other hand, to the extent that these labor resources would be employed elsewhere absent the expenditures, the net effects on employment would be smaller than the gross effect reported here. Similarly, the estimates of gross economic impact make no assumptions about how much money would be spent absent these projects or how such money would be spent. The same observation applies to state and local government tax impacts—no assumption was made as to what they would be in the alternative absent these projects.