SPP Priority Projects Phase II Final Report

MAINTAINED BY
SPP Engineering/Planning

SPP Board Approved
April 27, 2010

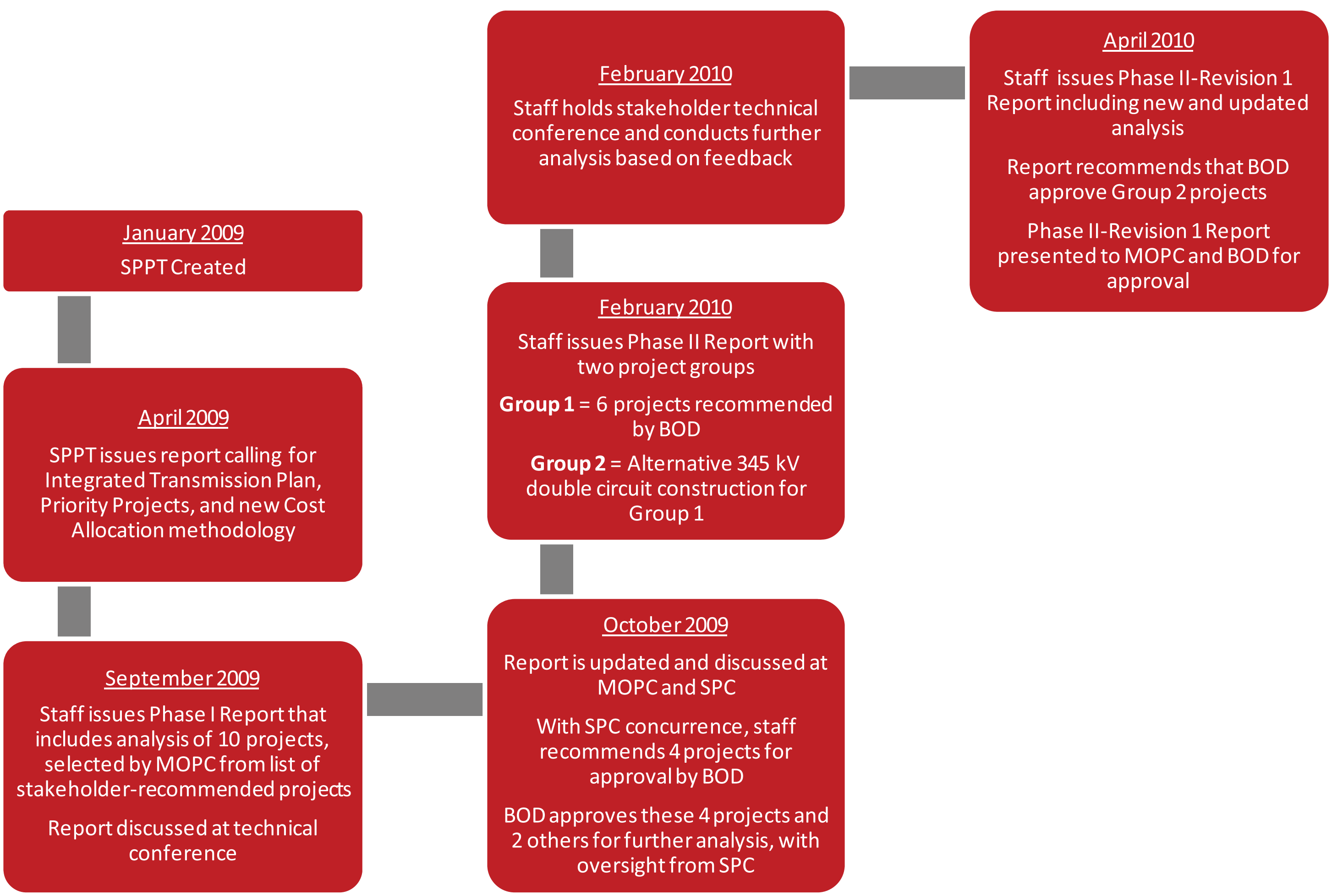
SPP Southwest Power Pool

Table of Contents

Executive Summary

In April 2009, SPP was directed by the SPP Board of Directors to implement the Synergistic Planning Project Team's (SPPT) recommendations for creating a robust, flexible, and cost-effective transmission system for the region, large enough in both scale and geography to meet SPP's future needs. Development of Priority Projects was one major recommendation; the others were to develop an Integrated Transmission Planning process that improves and integrates SPP's existing planning processes, and to implement a new cost allocation methodology.

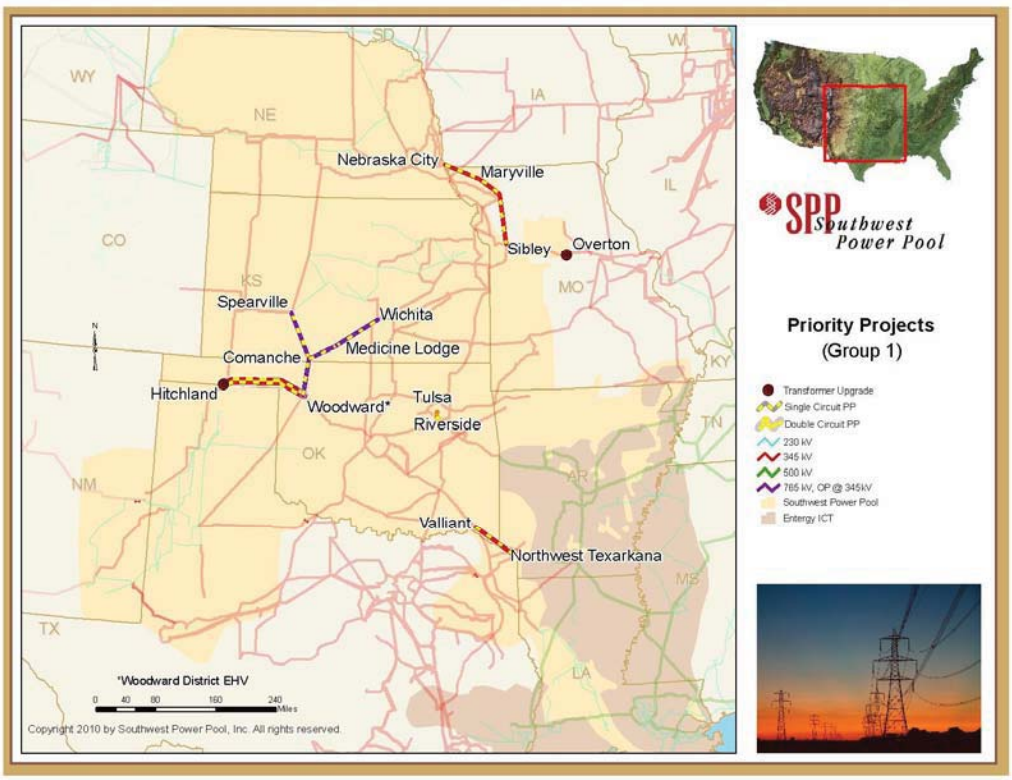
SPP was charged with identifying, evaluating, and recommending Priority Projects that will improve the SPP transmission system and benefit the region, specifically projects that will reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's east and west regions. This report, Priority Projects Report Phase II - Revision 1, is the third in a series of Priority Projects reports that have been completed by SPP staff with input from stakeholders and the Transmission Working Group (TWG), Economic Studies Working Group (ESWG), Cost Allocation Working Group (CAWG), Markets and Operations Policy Committee (MOPC), Strategic Planning Committee (SPC), and Board of Directors (BOD). The following timeline illustrates the iterative development of the reports:



For the Phase I Report, SPP staff and outside consultants performed engineering and economic analyses to assess a number of metrics, including adjusted production costs (APC), system losses, impacts to reliability projects, local and environmental impacts, and deliverability of capacity and energy to load. The Phase I Report included two future scenarios in which either 10% (7 GW) or 20% (14 GW) of the SPP region's energy needs would be served by wind.

This Phase II Report-Revision 1 analysis includes two Priority Project groups with future wind levels of 7 GW and 11 GW.[1] The same projects were studied in both groups; however, in Group 1, Spearville-Comanche-Medicine Lodge-Wichita and Comanche-Woodward District EHV are constructed at 765 kV, while in Group 2 these two lines are constructed at double-circuit 345 kV.

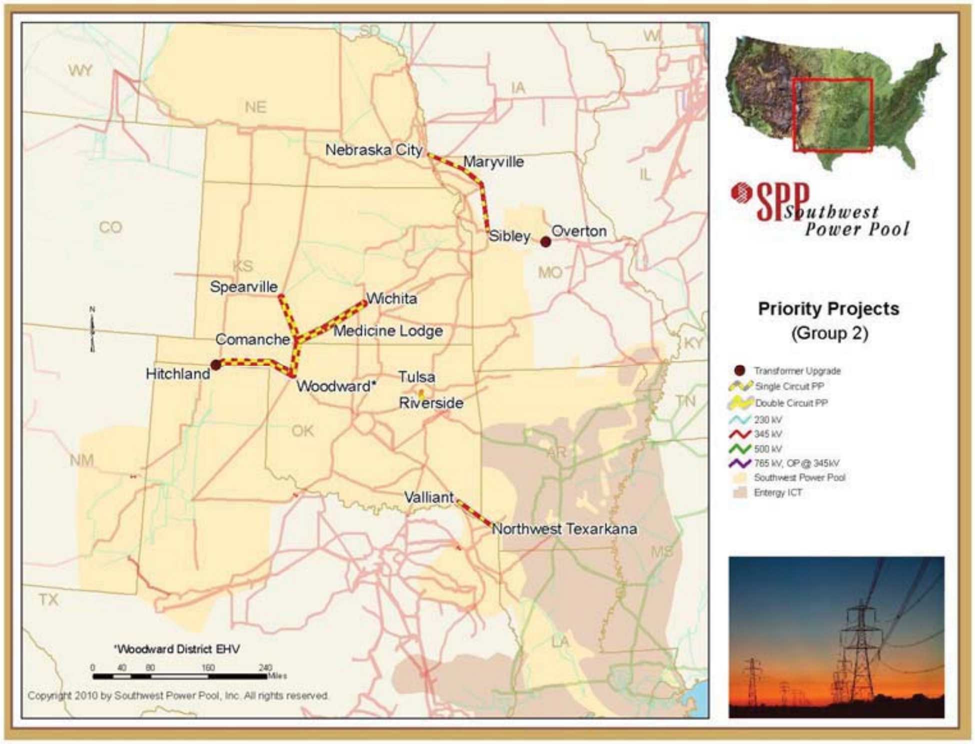
Group 1 has estimated engineering and construction costs of $1.26 billion:



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

[1] The 11 GW wind level was chosen based on a CAWG survey sent to SPP members to determine what levels of renewable resources are needed to meet state mandates or voluntary targets.

Group 2 has estimated costs of $1.11 billion:



1. Spearville – Comanche – Medicine Lodge – Wichita (345 kV double circuit)
2. Comanche – Woodward District EHV (345 kV double circuit)
3. Hitchland – Woodward District EHV (345 kV double circuit)
4. Valiant – NW Texarkana (345 kV)
5. Nebraska City – Maryville – Sibley (345 kV)
6. Riverside – Tulsa Reactor (138 kV)

For Priority Projects Report Phase II - Revision 1, The Brattle Group revised its analysis based on the alternative project groups and wind levels, and KEMA updated its analysis with the most recent SPP economic model outputs. Other additions to this version: inclusion of BOD-approved projects from the 2009 SPP Transmission Expansion Plan, an additional transformer needed at Hitchland to accommodate Priority Projects, changing the Cooper-Maryville-Sibley 345 kV project to terminate at Nebraska City, an updated coal price forecast, the addition of the 11 GW wind analysis, additional constraint identification, and updated load ratio share numbers (see Revision 1 Modifications section).

Revision 1 analysis demonstrates that Group 2 has a greater Benefit to Cost (B/C) ratio: a combined 1.78 quantitative and qualitative B/C for the SPP region. Group 2 has a quantitative B/C ratio of 1.12 and a qualitative B/C of 0.66. Quantitative benefits were determined based on analysis of APC; APC adjustment due to wind revenue; transmission system losses; reduction in gas prices (Attachment 6, KEMA report); and impact on reliability project advancement, deferrals, and additions. Qualitative benefits were based on the economic output (jobs, goods/services, taxes, etc.) from the construction and operation of the projects and the operation of an additional 3.2 GW of wind (Attachment 4, The Brattle Group analysis). [2]

These Priority Projects achieve the strategic goals identified in the April 2009 SPPT report. They will reduce congestion, as demonstrated in the APC analysis and by the levelization of Locational Marginal Prices (LMPs) across the SPP footprint. The average LMP price differential reduces from +/- 35% for the base case to +/- 28% for Group 2. Priority Projects will improve the Aggregate Study process by creating additional transfer capability and allowing additional transmission service requests to be enabled. The addition of 3,000-5,000 MW of wind energy as well as new non-renewable generation will result from these projects. First Contingency Incremental Transfer Capability calculations determined that Priority Projects would increase the ability to transfer power in an eastward direction for two-thirds of the eastward paths by connecting SPP's western and eastern areas (see Attachment 5).

Staff is recommending that the Board of Directors approve Priority Projects Group 2 for construction, based on the projects' compatibility and consistency with the SPPT goals while demonstrating a calculated B/C ratio of 1.78. SPP recognizes these are only a portion of the benefits that will be attained as a result of these projects. Other benefits, which are not measured, include but are not limited to: enabling future SPP energy markets, dispatch savings, reduction in carbon emissions and required operating reserves, storm hardening, meeting future reliability needs, improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, and additional societal economic benefits.

These Priority Projects are incremental to the substantial progress SPP members have already made in expanding transmission for reliability and economic needs. The Report of the Synergistic Planning Project stated, "The SPPT believes that the region should quickly identify, review, and construct, with haste, projects that continue to show up in multiple system evaluations as needed to relieve congestion on existing flowgates and to tie the eastern and western sections of the region together". After 11 months of analysis and review, SPP staff believes the projects in Group 2 clearly meet the goals stated in the SPPT report, and requests the Board of Director's approval in taking the next step in creating regional transmission solutions to address SPP's unique challenges and opportunities.

[2] The Brattle Group studied the benefits of an additional 3.2 GW of wind (combined with SPP's existing 3.8 GW, this comprises the 7 GW scenario). The 0.66 B/C represents a conservative 25% of the $1.6 billion in benefits from the operation of 3.2 GW of wind; benefits from the construction phase were not included in the B/C.

Group 2 Benefits at a Glance

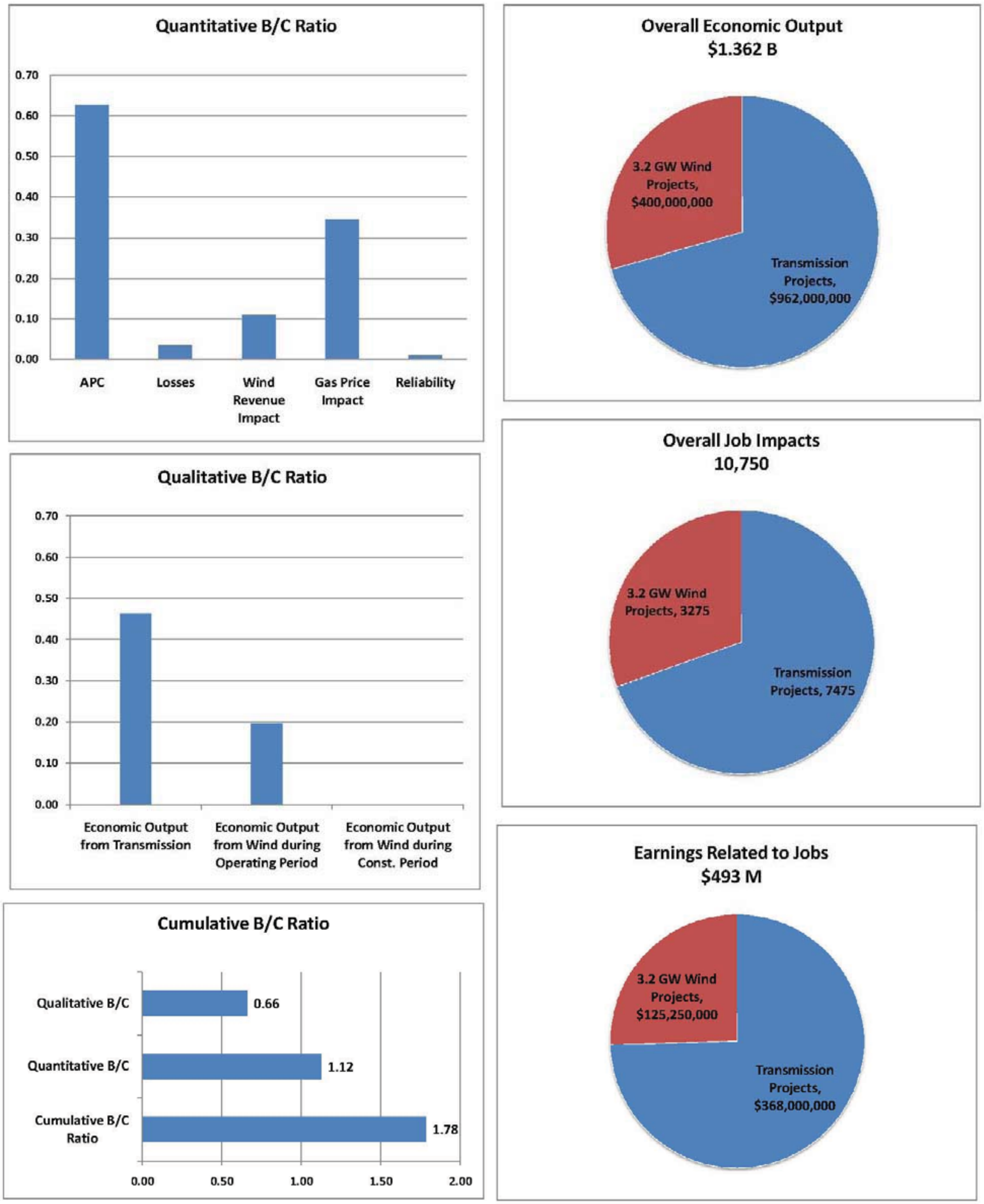


Figure 1

Revision 1 Modifications

SPP released the Priority Projects Phase II draft report on February 2, 2010, and on February 10 facilitated a stakeholder technical conference to discuss the report. Based on feedback received at the conference, SPP made several modifications to the Priority Project analysis. Many of the changes are explained in greater detail throughout this report, but a summary of the major modifications follows:

- **Inclusion of 2009 STEP Projects:** At its January 2010 meeting, the Board of Directors approved a subset of the projects included in Appendix B of the 2009 SPP Transmission Expansion Plan (STEP). SPP modified the Priority Project reliability and economic analysis to include the recently approved 2009 STEP projects; this report now includes all projects that have been issued Notifications to Construct (NTCs).

- **Previously-Identified Reliability Projects:** On January 19, 2010 the TWG endorsed with comment the TWG Reliability Report that analyzed the reliability impact of adding Priority Projects to the transmission system (see Attachments 2 and 3). The report identified an additional 345/230 kV transformer was needed at Hitchland to accommodate Priority Projects. Because this transformer is shown as needed solely due to Priority Projects, the study has been modified to consider it as part of the Priority Projects package (change case project).

- **Nebraska City-Maryville-Sibley 345 kV Project:** At the February 10 technical conference, Nebraska Public Power District (NPPD) presented its analysis of the Cooper South flowgate and potential solutions the organization considered for improving congestion. Based on discussion at the conference and NPPD's analysis and recommendation, SPP modified the termination point of the previously proposed Cooper-Maryville-Sibley 345 kV project to the Nebraska City substation rather than the Cooper substation.

- **Coal Prices:** Discussions with stakeholders identified the need for SPP to better understand the fuel price assumptions being used in the economic modeling. As explained in this report, gas prices are taken from the NYMEX exchange projections. Staff received the coal forecast from the economic modeling software vendor. The forecast used in previous Priority Project analyses indicated coal prices decreasing over time. In preparing Revision 1 analysis, staff asked several member companies what they were using for their own assumptions regarding coal prices and compared these results with the forecast previously used in the study of the Priority Projects. For this Revision 1 analysis, the software vendor provided its most recently updated coal price forecast. This updated forecast showed coal prices increasing over time which is consistent with information provided by stakeholders.

- **11GW Wind Level:** After Priority Project Phase II Report assumptions were finalized and the study began, the Cost Allocation Working Group surveyed SPP members to determine what levels of renewable resources each state was either mandated to meet or were voluntarily targeting by 2030. The results of this survey indicated approximately 11.3 GW of wind would be needed to satisfy these mandates or targets. To give stakeholders as much information as possible, SPP analyzed Priority Projects using approximately 11.3 GW as an additional analysis to the 7 GW study.

- **Additional PAT Analysis:** After performing each study, SPP attempts to improve its study methods. Based on results of previous analysis and discussions with stakeholders, staff performed additional analysis to help identify constraints that should be used in economic modeling. After this additional analysis was completed, the ESWG reviewed the constraints used in the economic modeling. Some additional modifications were made to the constraints based on this review.

- **Updated Load Ratio Share (LRS):** For this report and the calculation of benefit to cost ratios, Priority Projects costs are allocated to each zone based on LRS. LRS numbers used in the previous Priority Project reports were based on numbers used in the Balanced Portfolio analysis approved in 2009. Stakeholders had questions about LRS numbers in previous Priority Project reports since they did not correspond to the LRS numbers used in the recently approved 2009 STEP report. This report uses LRS numbers based on member data received by SPP's Settlements Department as recent as March 2010.

Scope of Priority Projects Phase II, Rev. 1 Analysis

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), 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 used to model 8,760 hours representing a full year of system-wide commitment and dispatch of resources.

- **Time Frame** – The BATTF directed use of a ten-year time frame to analyze Priority Project benefits. Three years throughout the ten-year planning horizon were modeled - 2009, 2014, and 2019 - and benefits for the years in-between were calculated using a linear progression. The total of the ten-year benefit was used to create the Net Present Value (NPV). 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 extrapolated from 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. SPP 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. The coal price forecast was provided by the economic modeling software vendor and was updated for this analysis. Other fossil fuel prices used generic assumptions and publicly-available data.

- **Wind Modeling –** SPP was directed by the SPC to study Priority Projects using 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.

  In addition to the 7 GW study, staff assessed 11.3 GW of wind in the SPP footprint based on results of a Cost Allocation Working Group (CAWG) survey, which assessed the renewables needed to meet state mandates or targets in the SPP region. Data provided in the CAWG survey was reported in MWh. To determine what the necessary wind capacity would be to meet mandates/targets, SPP used a 40% capacity factor for Texas, Oklahoma, New Mexico, Kansas, and Nebraska. For Missouri and Arkansas, a 30% capacity factor was used. In the economic analysis, the wind profiles for wind farms in Missouri and Arkansas will represent this lower capacity factor.

Using the Generation Interconnection (GI) queue as a guide, SPP staff, with the help of the ESWG, recognized the significant amount of GI requests in the relative locations of Spearville and Hitchland. SPP staff worked in conjunction with the ESWG to modify the wind injection placement points. The results are listed below:

Wind Added to Reach 7 GW	
Fairport (MO)	600 MW
Hitchland (OK)	1,077 MW
Hoskins (NE)	196 MW
Gentlemen (NE)	196 MW
Spearville (KS)	605 MW
Woodward (OK)	522 MW

Wind Added to Reach 11.3 GW	
Washington County (AR)	197.5 MW
Fairport (MO)	33 MW
Spearville (KS)	1,500 MW
Knoll (KS)	200 MW
Hoskins (NE)	157 MW
Gentlemen (NE)	157 MW
Potter (TX)	600 MW
Broken Bow (NE)	80 MW
Albion (NE)	120 MW
Roosevelt (NM)	300 MW
Grapevine (TX)	50 MW
Hitchland (OK)	1,025 MW

State	Current Wind	Additional to 7GW	Additional to 11GW	Total Wind
Arkansas	0	0	198	198
Kansas	960	605	1,700	3,265
Louisiana	0	0	0	0
Missouri	0	600	33	633
Nebraska	243	392	514	1,149
New Mexico	204	0	300	504
Oklahoma	1,367	1,599	1,025	3,991
Texas	904	0	650	1,554
Total	3,677	3,196	4,420	11,292

Table 1: Wind Injection Amounts (MW)

Values in the table above do not represent any other renewable resources such as solar, hydroelectric, or biomass which may be used to meet a Renewable Portfolio Standard. Wind allocation and placement are estimates and represent reasonable approximations for the future development of wind resources within SPP as discussed by the ESWG.

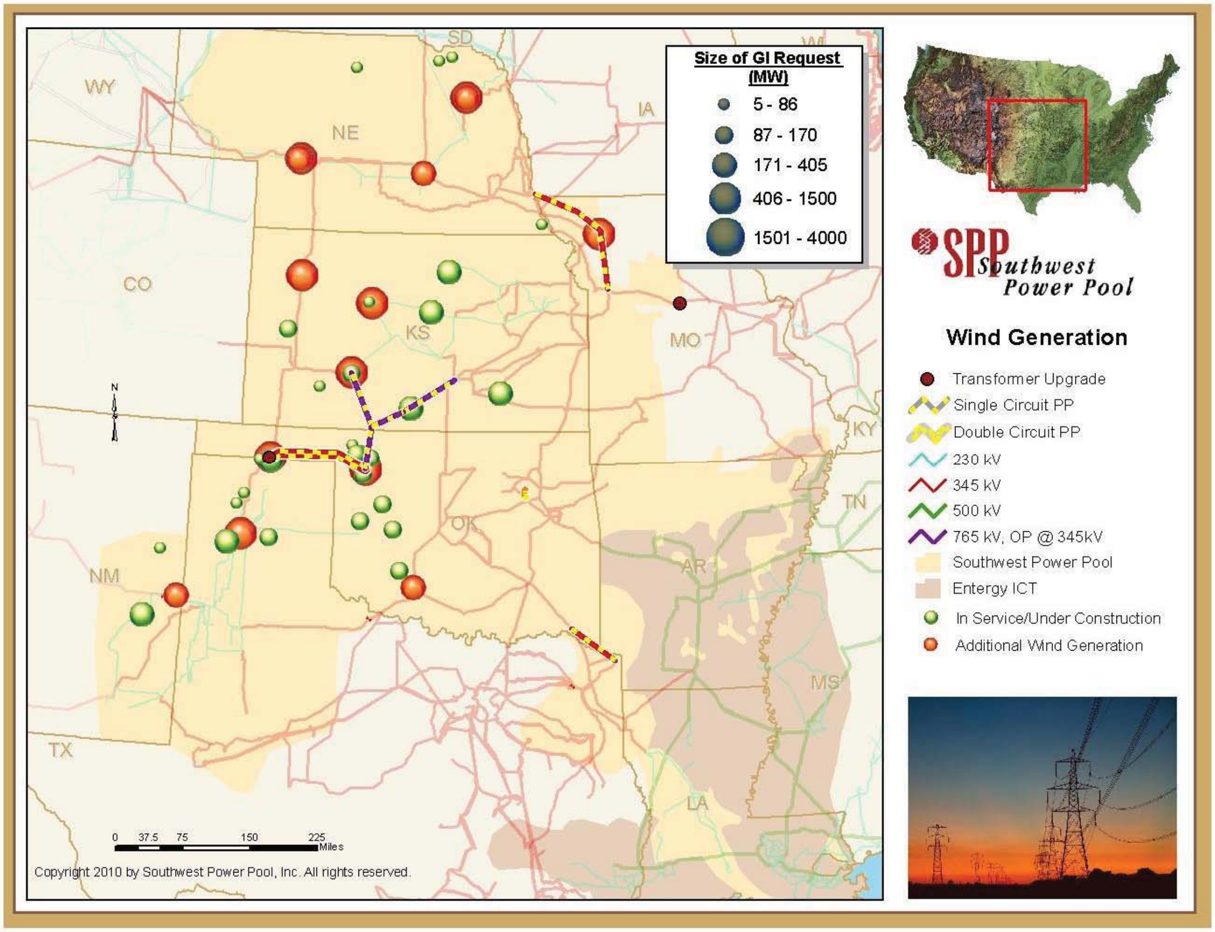


Figure 2: Wind Generation Modeled at 7 GW

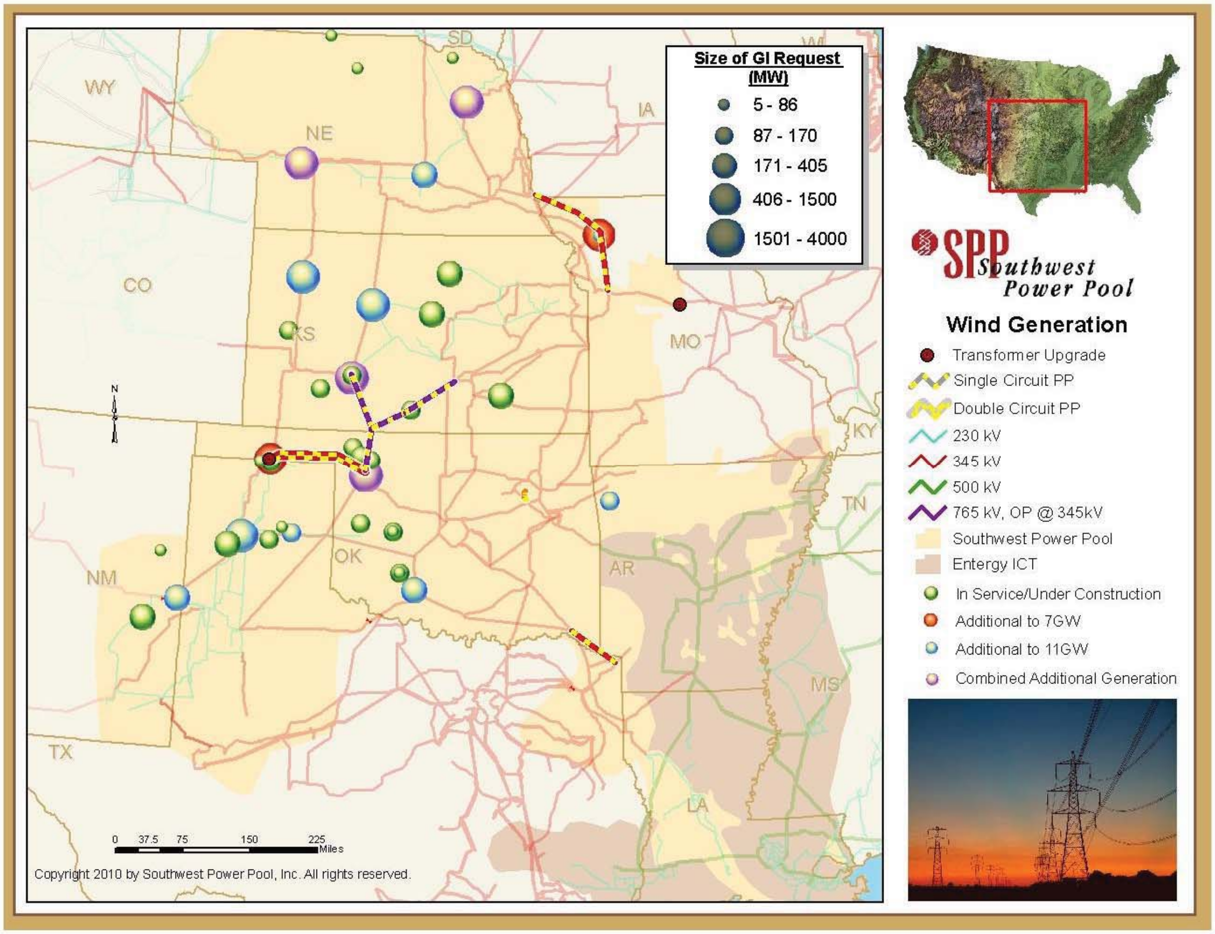


Figure 3: Wind Generation Modeled at 11 GW

- **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. DC ties modeled[3] for the SPP region are located at:

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

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

- **Environmental Costs** – Estimates of emission costs for SO_2 and NO_x were approximated using data from the Chicago Climate Exchange. CO_2 was not explicitly priced in the economic modeling due to the uncertainty of future climate policy. 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's 2009 data collection and review process that was used for 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 –** Hurdle rates are rates that are applied to ensure a minimum price differential is in place before an exchange is made. 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 to reasonably represent transactions that have occurred or will occur in the SPP 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 applied within various studies of the Eastern Interconnection and represent recommended rates as described in the Transmission Network Economic Modeling and Methods document prepared by the Economic Modeling and Methods Task Force 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 resources in the footprint are dispatched economically based on the calculated future prices for each resource. This market structure is very different from 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

Data used in 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 publicly available data. The publicly available data included any generation cost data as well as heat rate information. By using only publicly 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 RTO Tariff 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 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 caused 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 members with an opportunity to review how their changes impacted unit dispatch. 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 stakeholders for approval. All Transmission Owners indicated their approval on the input and output data by Thursday, January 14, 2010.

In Revision 1 stakeholders were given the opportunity to review both the Event File and the Powerflow Branch data. If a stakeholder replied during the timeframe with additional flowgates that SPP should monitor, staff reviewed those suggestions and the flowgates were added to the event file.

Value Metrics

The BATTF developed or approved 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 Marginal Price (LMP), 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 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 APC within SPP. If there are lower LMP prices outside SPP, there will be no transfers from the western portion of SPP. he 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 $LMP_{\text{Gen Weighted}}$
and
Cost of Purchases = MW Import x Zonal $LMP_{\text{Load Weighted}}$

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 LMP 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. 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 could be located further 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

Initially, analysis of carbon benefits was to be conducted; however, the prescribed method of modeling the same level of wind in the base and change cases does not support the previously developed calculations needed for carbon benefit estimates. The ESWG is discussing methods to explicitly model the impacts of carbon for use in the Integrated Transmission Planning process. SPP acknowledges a great deal of additional benefit will be realized by enabling higher amounts of renewable resources to interconnect to SPP's transmission system, thereby reducing the level of carbon being emitted. Not assessing the benefits of reduced carbon emissions provides much more conservative results for the Priority Project analysis.

Reliability Impact

In the Phase I evaluation, 11 potential Priority Projects and three additional Priority Projects groups were evaluated for their impacts on the SPP Transmission Expansion Plan (STEP) Reliability Assessment. Priority Project impacts include net, new needed projects, and STEP projects that could be deferred or advanced. As part of Phase II evaluation, the list of Priority Projects was refined to two groups of projects that are electrically similar, and their impact on the STEP Reliability Assessment and on first tier parties to SPP was evaluated. This Priority Project reliability analysis was conducted in the same manner and with the same methodologies used in the STEP Reliability Assessment.

The Priority Project Reliability Report (Attachment 2) is not intended to justify any Priority Project based on deferred project cost alone; it is only intended to show the effects of Priority Projects on the STEP Reliability Assessment. At this time, in-service dates for 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 a specific Priority Project(s) is in service.

APC Adjustment Due to Wind Revenue Impact

Conventional thermal generation is modeled explicitly based on ownership or designation for each unit. This explicitly modeled generation is then factored into APC calculations through each resource's cost to produce energy as well as determining whether a zone has excess energy each hour (revenues from sales) or lacks sufficient generation to serve its load (costs from purchases).

Traditionally, SPP's APC calculations have not considered the revenues paid to wind resources because they must be modeled as a transaction rather than a conventional generating unit. The wind must be modeled as a transaction so the variability of the wind can be taken into account. Staff does this by profiling the wind based on historical output patterns for each wind resource. Wind generation's impact on *production costs* can be thought of as subtracting the dispatched wind generation from the load that is met from other generation sources. Because of the different modeling method for wind resources, the impact of wind generation on *revenues from sales* and *costs from purchases* was not included in the initial calculation of APC and must be added to obtain a corrected overall measure of these components.

To illustrate this calculation, consider the following simplified example, in which it is assumed that price differences between load and generation assigned to the same zone are zero. A zone's revenues from sales or costs from purchases can then be determined by taking the difference between what loads in a zone pay and what the generation attributed to that zone is paid. For example, if in an hour, a zone has excess generation, it will receive *revenues from sales* in the amount of the number of MWhrs in excess times the gen-weighted LMP for that hour. However, if a zone is deficient in generation for the hour, it will pay *costs from* purchases in the amount of the number of MWhrs deficient times the load-weighted LMP for that hour.

Revenues paid to wind resources were excluded from the initial calculation of *revenues from sales* and *costs of purchases*. For the above scenarios, if wind attributed to the zone is paid $1,000, then to correctly calculate APC, this $1,000 needs to be added to *revenues from sales* or subtracted from *costs for purchases* for that zone in that hour.

What is important in calculating the overall benefit from APC is the difference between APC in the change case compared to the base case. To correctly adjust APC, the Wind Revenue Impacts are calculated by subtracting the base case wind revenues from the change case wind revenues and adding the impacts back to the initial calculation of APC to correct for the initial exclusion of the revenues of these resources. The CAWG developed the methodology used to allocate the wind revenues to each zone. The allocation was calculated using the need of each zone for renewable energy to meet its renewable energy targets as determined from a CAWG survey on renewable energy targets.

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 organizations to engage in the Priority Project stakeholder process through SPP's organizational groups.

Breakeven Analysis

The ESWG met on November 3, 2009 to provide its recommendations to the Strategic Planning Committee regarding Priority Projects. One of the recommendations was for SPP to determine what level of wind would be required to produce a benefit to cost ratio (B/C) of 1 for Priority Projects. Staff agreed this analysis would be performed as time permitted, but the results of this Revision 1 analysis achieved a B/C greater than 1.0.

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 Marginal Price (LMP) 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 LMP market.

LMPs are calculated for both the generation-weighted and load-weighted average hub LMPs 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 LMP. The external sales' revenues are computed as the MW sale level times the generation-weighted sub-region's LMP.

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 LMP 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)

LMP 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. PAT specifically in Priority Projects analysis 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, Rev. 1 Analysis Results

Synergistic Planning Project Team Recommendation Impacts

The Synergistic Planning Project Team (SPPT) recommended that Priority Projects should:

1. Reduce grid congestion
2. Improve the Aggregate Study and Generation Interconnection study queues
3. Integrate SPP's east and west transmission systems

Reduce Congestion

The impact of reducing congestion is primarily captured through APC modeling. Another indicator of reduced congestion is the levelization of Locational Marginal Prices (LMPs) across the footprint. As a robust transmission system is constructed and congestion reduced, the differential between the minimum and maximum LMP is reduced, resulting in lower energy costs to consumers. The difference between the average minimum and maximum LMP price for 7 GW and 11 GW wind levels is depicted in the following charts. The LMP price differential reduces from +/- 35% for the base case to +/- 28% for Group 2. Averages were calculated across the 2009, 2014, and 2019 data points.

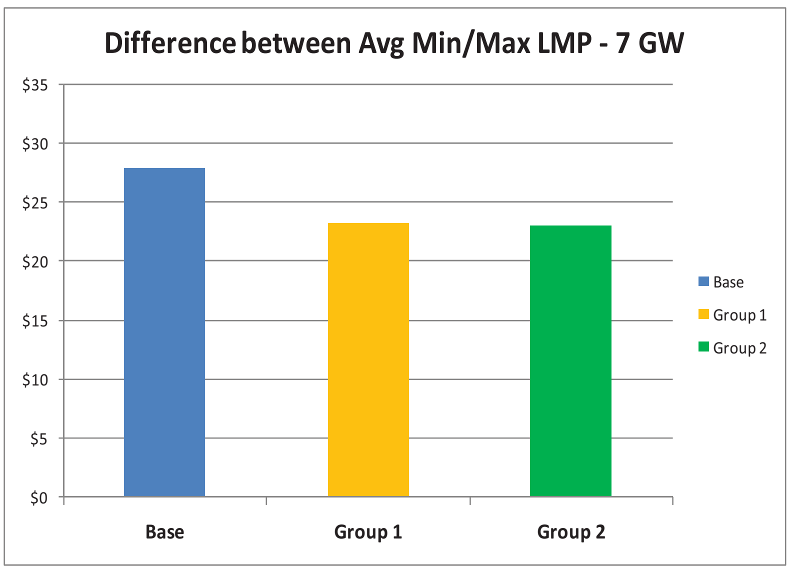


Figure 4: Spread of Avg Min/Max LMPs - 7 GW

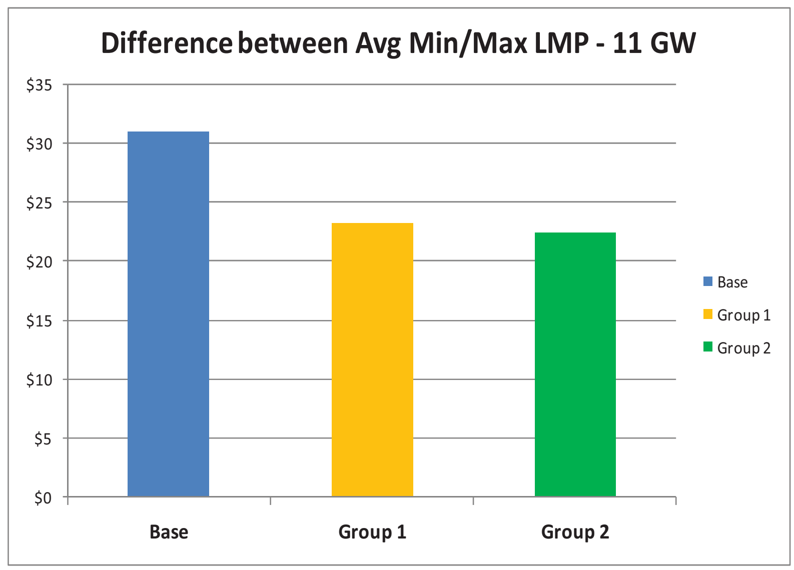


Figure 5: Spread of Avg Min/Max LMPs - 11 GW

Improve Aggregate Study and Generation Interconnection Queues

The SPPT's criteria for Priority Projects included projects that repeatedly appear in the Aggregate Study process as a known and needed upgrade to deliver transmission service for multiple parties. The Priority Projects studied in this report will create additional transfer capability across the SPP footprint. They will also relieve congestion on lower-voltage facilities for local delivery of energy, allowing additional transmission service requests to be enacted. The map below depicts Priority Projects relative to previously identified points of receipt (POR) and points of delivery (POD) taken from Aggregate Studies 2007-AG1, 2007-AG2, and 2006-AG3.

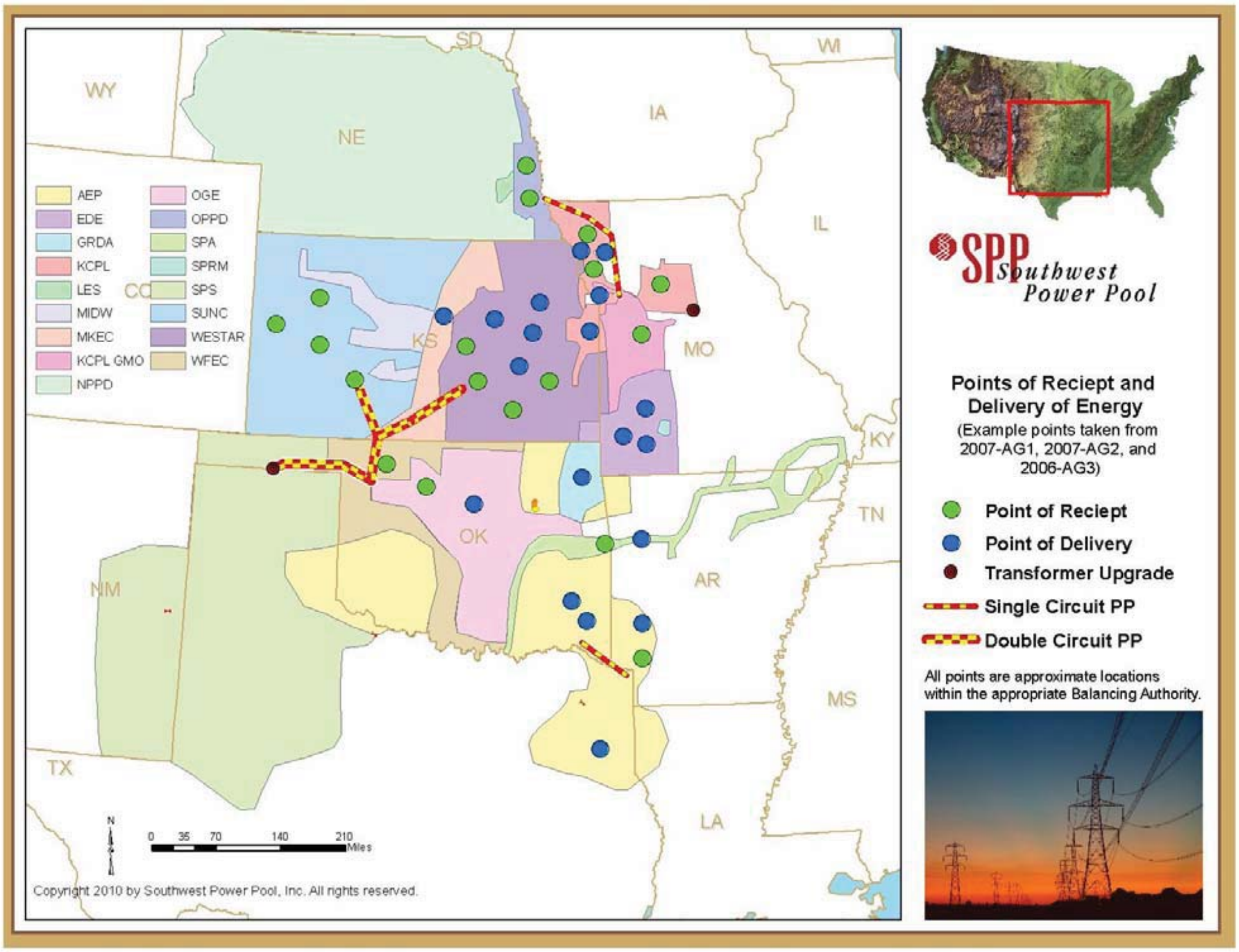


Figure 6

The SPPT stated that Priority Projects should improve the Generation Interconnection (GI) process by enabling the addition of more new generation to the grid. GI study FCS-2008-001 determined the additional transmission needed to interconnect 3,000 – 5,000 MW of additional wind. The transmission identified included a portion of the Priority Projects.

These Priority Projects will also facilitate the addition of other types of generation. Data taken from the GI queue on 2/3/2010 shows that new non-renewable generation is in close proximity to the proposed Priority Projects:

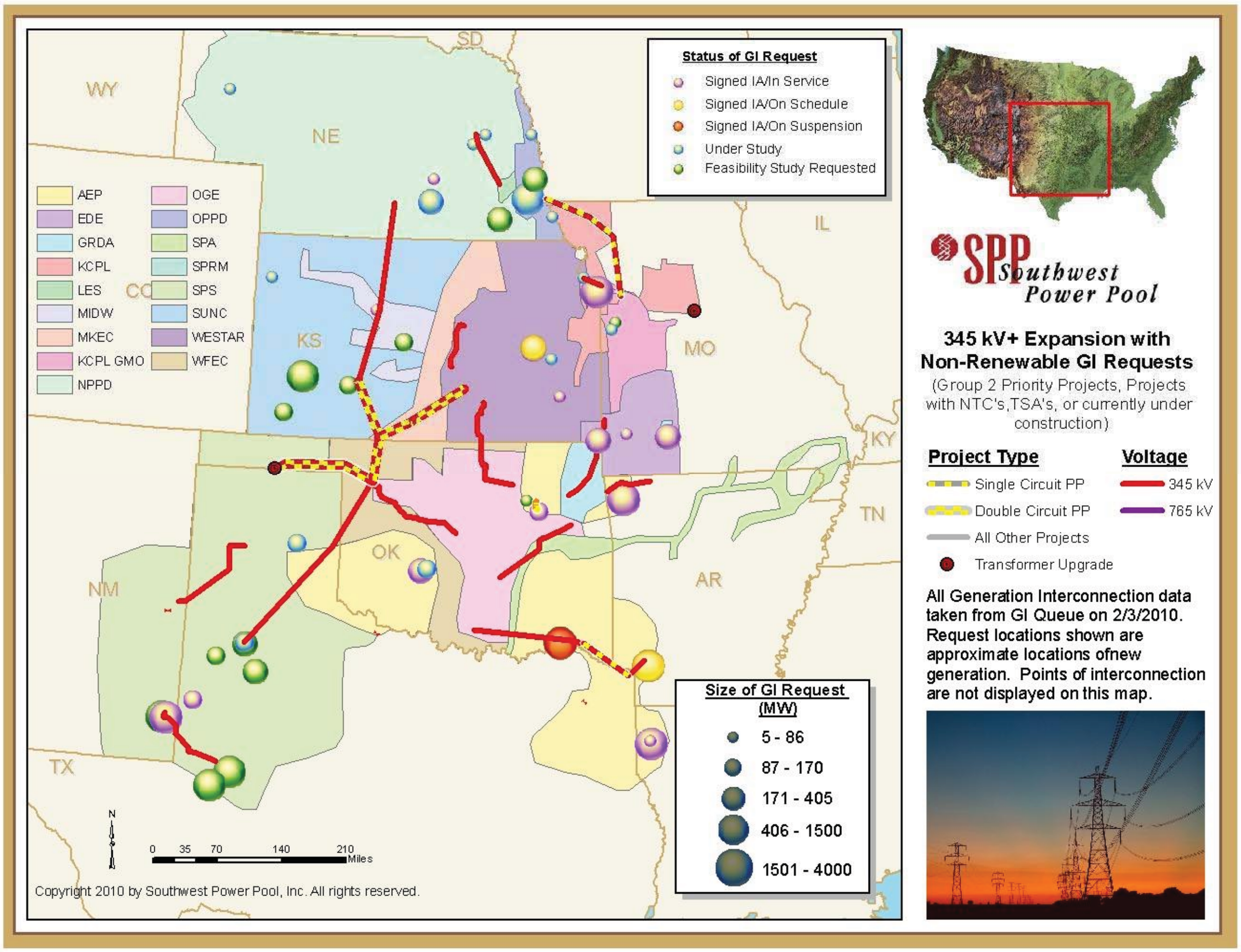


Figure 7: Non-Renewable GI Requests

Loads from multiple major cities within the SPP footprint will be positively impacted by Priority Projects. Improving the transmission system will improve congestion, allowing these cities to be served more efficiently. The figure below depicts Priority Projects and other approved extra high voltage transmission lines in relation to SPP's major load centers:

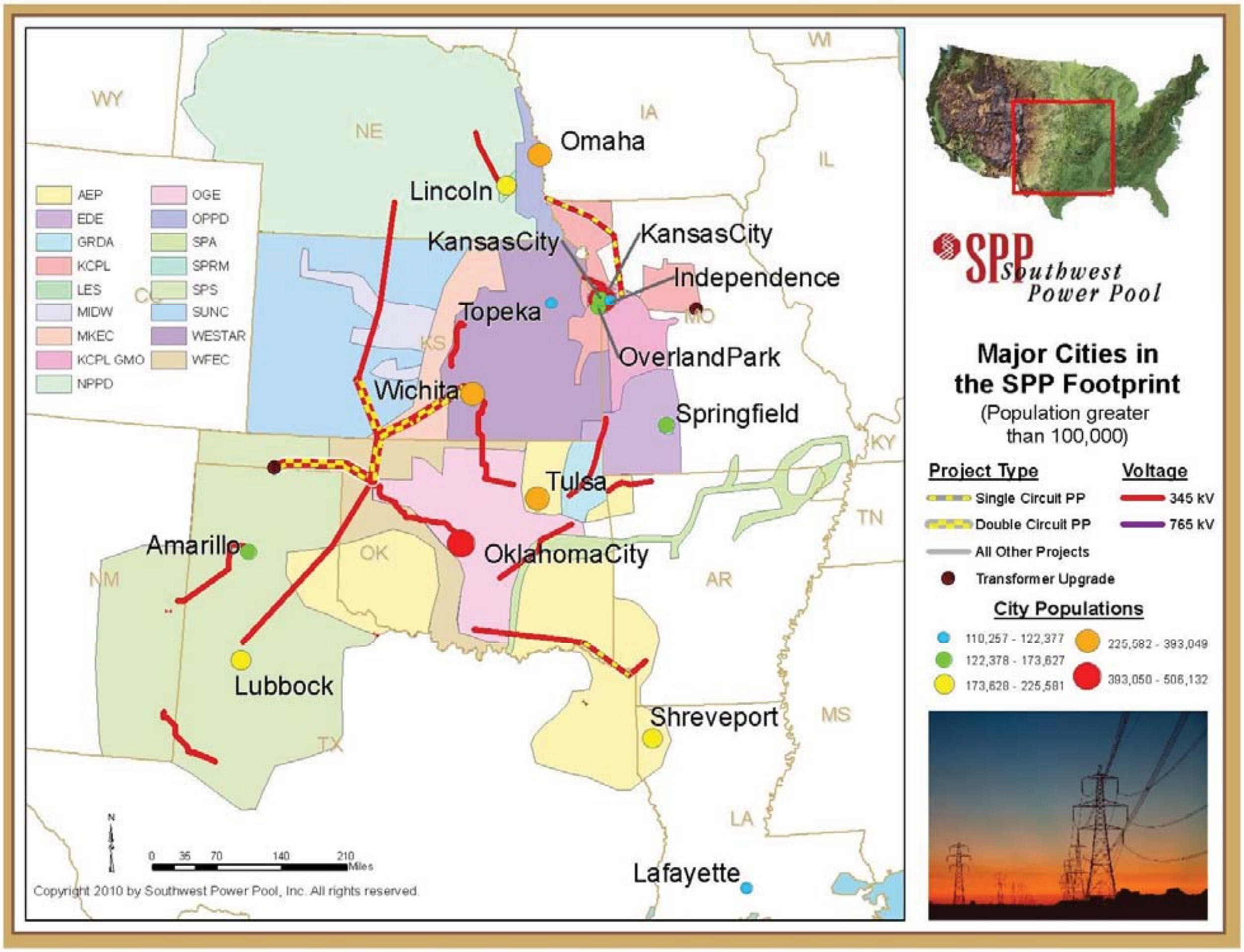


Figure 8: Major Cities in the SPP Footprint

Improve West to East Transfers

Analysis was conducted to measure enhancements to the interface between the SPP footprint's western and eastern regions as a result of Priority Projects. This analysis evaluated the support provided by the projects to power transfers originating in the western part of SPP and terminating in the eastern part. The analysis used a novel approach that geographically divided the SPP footprint into ten sections, then performed First Contingency Incremental Transfer Capability (FCITC) calculations to determine the transfer capability with and without Priority Projects.

The calculations show the Priority Projects increase the ability to transfer power in an eastward direction by connecting the western and eastern areas. This detailed analysis indicates that the greatest rewards will be gained in the future, as more of the underlying limitations are mitigated. The increase in transfer capability correlates exactly with the SPPT's stated goal; that Priority Projects should enhance the interface between SPP's western and eastern transmission systems. See Attachment 5 for this analysis.

Summary of Economic Results

Multi-faceted and detailed analysis was performed using the study assumptions and definitions of the value metrics to derive APC, impact on losses (capacity), reliability (deferral and advancement of STEP projects with Notifications to Construct), gas price impact, and an APC adjustment due to revenues from wind plants.

This report describes the value metric results related to the two project study groups and wind levels. According to the CAWG member survey, the 7 GW wind level is not enough for each member to meet its existing renewable mandates/targets. For this reason, SPP performed supplemental analysis on Priority Projects considering approximately 11.3 GW wind.

The financial analysis is provided in three timeframes including the first ten years, the second ten years, and the last twenty years based on the projects' scope and lifetime.

The impact of transmission expansion on a typical residential customer electric bill is approximately 33.5 cents per kW/month of demand per $1 billion of investment. At the August 26, 2009 CAWG meeting, there was general consensus among regulators, transmission owners, marketers, and wind developers that there is a customer impact of approximately $1/month per $1 billion of transmission investment assuming a residential demand of 3 kW. Additional detail on calculating Priority Projects' impact on customer bills is in Appendix H.

7 GW									
Study Group	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Total Benefit (Years 1-40)	Total Cost (Years 1-40)	Net Benefit (B - C)	B/C
Group 1	$1,309,997,915	$13,318,645	$67,763,548	$209,902,141	$708,295,867	**$2,309,278,116**	**$2,316,856,640**	**($7,578,523)**	**1.00**
Group 2	$1,301,191,318	$20,813,781	$70,570,431	$230,924,482	$718,066,058	**$2,341,566,071**	**$2,082,298,794**	**$259,267,277**	**1.12**

Table 2: Benefits and Costs Summary – 7 GW

11 GW									
Study Group	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Total Benefit (Years 1-40)	Total Cost (Years 1-40)	Net Benefit (B - C)	B/C
Group 1	$1,979,862,546	$13,318,645	$67,763,548	$2,005,193,986	$1,006,676,089	**$5,072,814,813**	**$2,316,856,640**	**$2,755,958,174**	**2.19**
Group 2	$2,053,031,037	$20,813,781	$70,570,431	$2,202,758,931	$1,043,516,243	**$5,390,690,423**	**$2,082,298,794**	**$3,308,391,629**	**2.59**

Table 3: Benefits and Costs Summary – 11 GW

Adjusted Production Cost

The tables below indicate the results of the adjusted production cost (APC) analysis. For each group of projects studied, the APC was calculated between the base and change case for each specific study year. 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	$32,476,000	$81,119,000	$104,576,000
Group 2	$32,681,000	$80,700,000	$103,914,000

Table 4: Regional APC Results – 7 GW

	2009	*2014*	*2019*
Group 1	$69,219,000	$132,958,000	$158,293,000
Group 2	$60,892,000	$141,205,000	$160,502,000

Table 5: Regional APC Results – 11 GW

Impact on Losses – Capacity

Capacity savings and fixed cost benefits were calculated using methods suggested by the Benefit Analysis Techniques Task Force (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. 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. Loss savings were calculated using the same powerflow models as used in the reliability assessment, and do not include additional wind above existing levels. These projected loss savings figures are the same for both the 7 GW and 11 GW study scenarios.

Group 1			
Zone	**2010 - 2019 NPV**	**2020 - 2029 NPV**	**Total**
AEPW	$26,179,331	$466,105	$26,645,436
EMDE	$451,662	$7,521	$459,183
GMO	$343,443	$1,905	$345,348
GRDA	($225,831)	($3,760)	($229,592)
KCPL	$2,151,017	$41,329	$2,192,347
LES	($147,456)	($1,884)	($149,340)
MIDW	$5,315,808	$95,844	$5,411,653
MKEC	$10,553,494	$195,421	$10,748,915
NPPD	$1,577,665	$24,453	$1,602,117
OKGE	($8,569,222)	($141,025)	($8,710,247)
OPPD	$1,162,154	$24,411	$1,186,565
SPRM	$148,480	$1,884	$150,363
SUNC	$301,052	$3,767	$304,820
SWPS	$17,228,076	$283,926	$17,512,002
WEFA	$9,257,033	$154,175	$9,411,209
WRI	$862,125	$20,644	$882,769
Total	**$66,588,831**	**$1,174,716**	**$67,763,548**

Table 6: Impact on Losses - Group 1

Group 2			
Zone	**2010 - 2019 NPV**	**2020 - 2029 NPV**	**Total**
AEPW	$27,993,228	$498,058	$28,491,286
EMDE	$451,662	$7,521	$459,183
GMO	$581,638	$7,535	$589,173
GRDA	($226,855)	($3,760)	($230,615)
KCPL	$2,455,224	$46,966	$2,502,190
LES	($147,456)	($1,884)	($149,340)
MIDW	$5,620,015	$101,481	$5,721,496
MKEC	$10,846,359	$199,188	$11,045,548
NPPD	$1,438,479	$24,439	$1,462,918
OKGE	($7,136,883)	($116,586)	($7,253,469)
OPPD	$1,296,223	$24,425	$1,320,648
SPRM	$148,480	$1,884	$150,363
SUNC	$222,677	$1,891	$224,568
SWPS	$17,377,579	$285,810	$17,663,389
WEFA	$9,932,480	$165,457	$10,097,937
WRI	($1,500,397)	($24,446)	($1,524,843)
Total	**$69,352,453**	**$1,217,978**	**$70,570,431**

Table 7: Impact on Losses - Group 2

Reliability Impact

SPP will work with Ameren as a potentially affected system in accordance with existing agreements to resolve the Overton impacts identified in the reliability assessment. The reliability analysis is summarized in the table below showing revenue requirements associated with advancements, deferments, and overall net impact for the Priority Project study groups. Results are categorized into:

1. Advanced: Projects that would be moved up in the reliability timeline due to the Priority Project
2. New: Projects which are now needed that were not identified in the original 10-year STEP reliability planning horizon, but may have been needed beyond that horizon
3. New third-party: Projects needed on neighboring systems due to the Priority Projects
4. Deferred: Projects which are either deferred beyond the planning horizon or mitigated entirely due to Priority Projects
5. Net Impact – Net cost or benefit of STEP reliability projects related to 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 Nebraska City – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$0M	$4.5M	$0M	$17.8M	$13.3M
Group 2 Hitchland – Woodward District EHV Double 345 kV Spearville – Cmche – Med. Ldg – Wichita Double 345 kV Comanche – Woodward District EHV Double 345 kV Nebraska City – Maryville – Sibley 345 kV Valliant – NW Texarkana 345 kV Riverside Station – Tulsa Power Station 138 kV Reactor	$0M	$16.8M	$0M	$37.6M	$20.8M

Table 8: Reliability Impact Results

APC Adjustment Due to Wind Revenue Impact

Traditionally, SPP's APC calculations have not considered revenues paid to wind resources because they must be modeled as a transaction rather than a conventional generating unit. The wind must be modeled as a transaction so the variability of the wind can be taken into account. SPP does this by profiling wind based on historical output patterns for each wind resource.

Wind generation's impact on *production costs* can be thought of as subtracting the dispatched wind generation from the load that is met from other generation sources. Because of the different modeling method for wind resources, the impact of wind generation on *revenues from sales* and *costs from purchases* was not included in the initial calculation of APC and must be added to obtain a corrected overall measure of these components. A more detailed explanation of this adjustment is provided in the description of value metrics in the Scope of Priority Projects Phase II, Rev. 1 Analysis section of this report.

	2009	*2014*	*2019*
Group 1	$ 15,188,839	$ 10,211,826	$ 19,712,918
Group 2	$ 15,524,748	$ 10,602,407	$ 21,706,821

Table 9: Increased Revenues from Wind – 7 GW

	2009	*2014*	*2019*
Group 1	$ 87,442,443	$ 110,493,011	$ 179,939,488
Group 2	$ 93,394,239	$ 115,558,315	$ 191,136,602

Table 10: Increased Revenues from Wind – 11 GW

The following charts depict the percentage change in MW-hour output between each group of Priority Projects and the base case. The columns displayed are aggregates of the three study years 2009, 2014, and 2019.

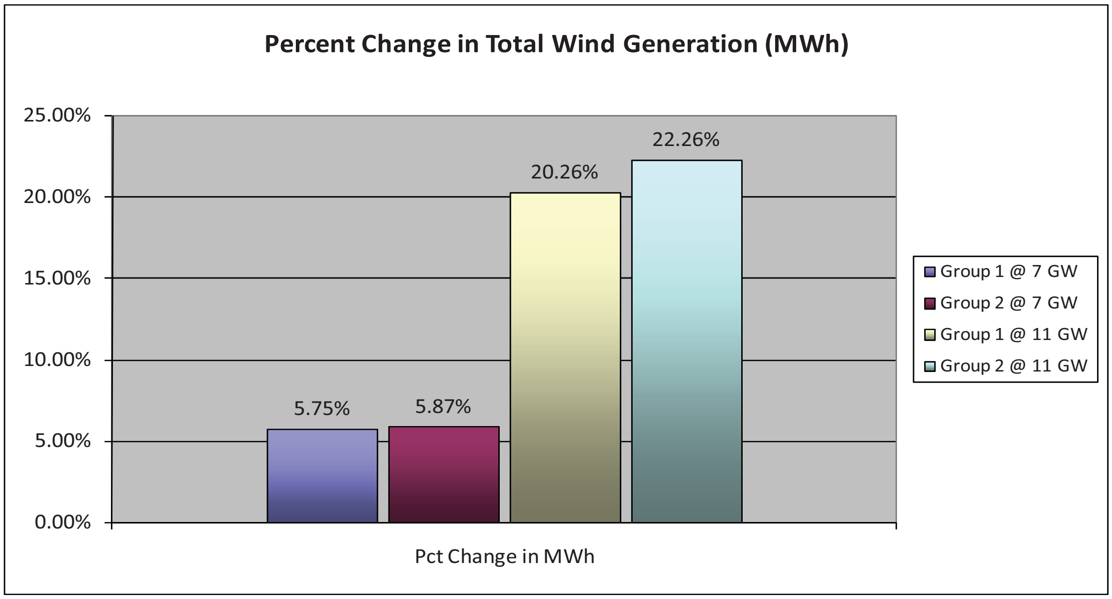


Figure 9: % Change in Total Wind Generation

Related to the above chart above, the following charts show 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 LMP prices, Group 1 allows more wind to be dispatched.

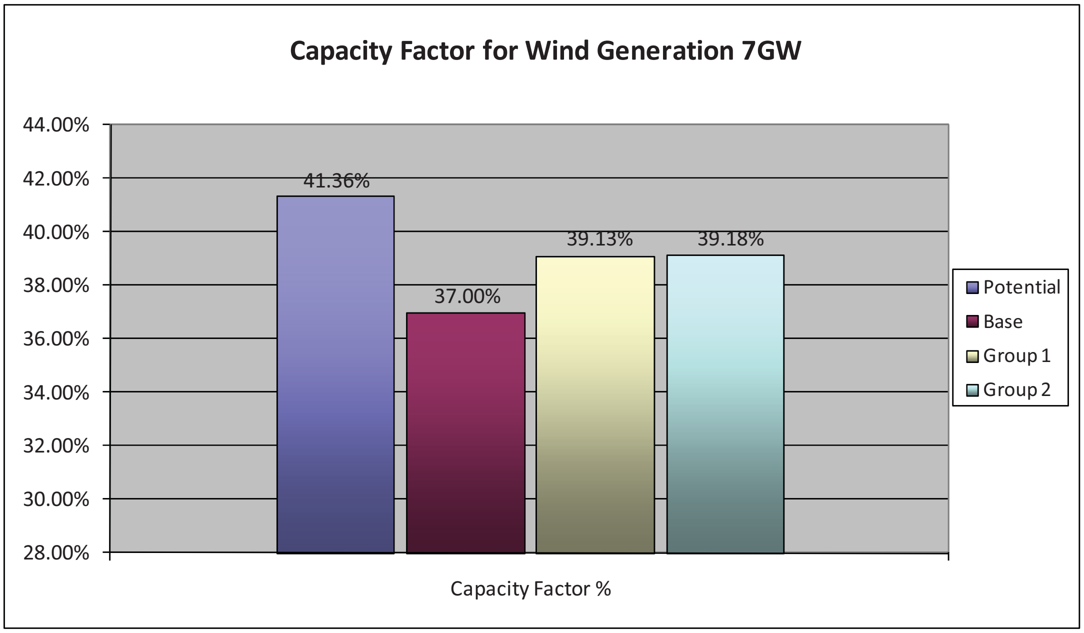


Figure 10: Wind Capacity Factor Changes – 7 GW

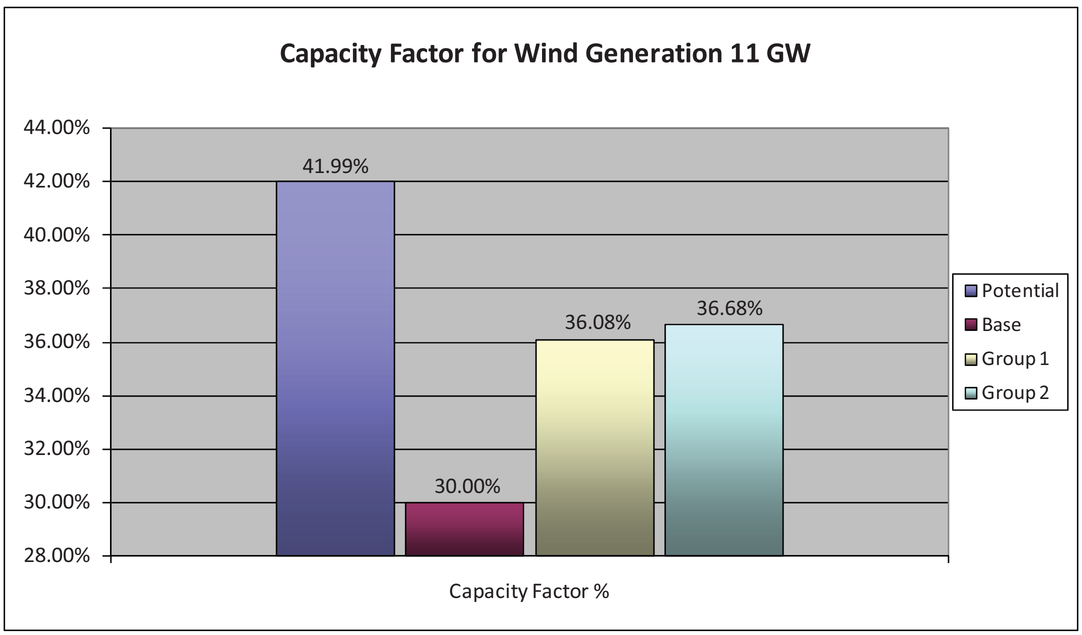


Figure 11: Wind Capacity Factor Changes – 11 GW

The above charts illustrate the change in wind output and wind capacity factor at the regional level. While it is important to see regional impact, the charts do not depict impact on the wind resources located near Priority Projects. The following charts illustrate the MW-hour and capacity factor changes of wind resources near select locations situated near Priority Projects.

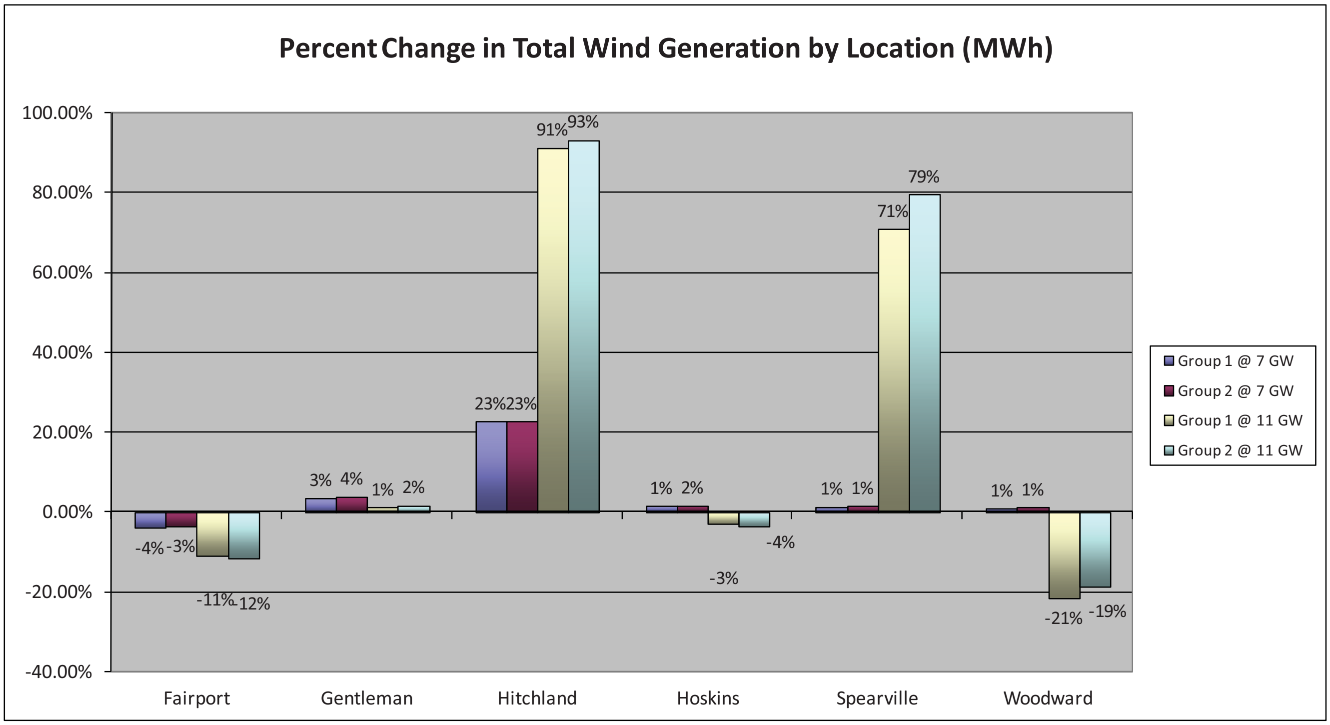


Figure 12: % Change in Wind Generation by Location

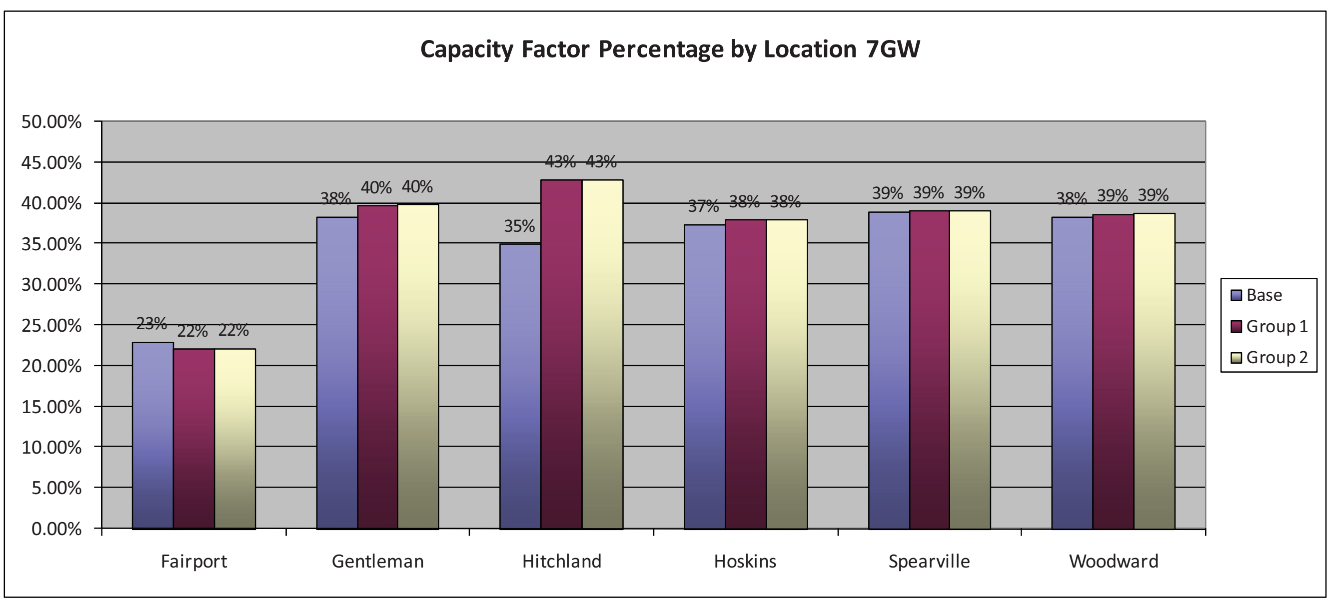


Figure 13: Capacity Factor by Location - 7 GW

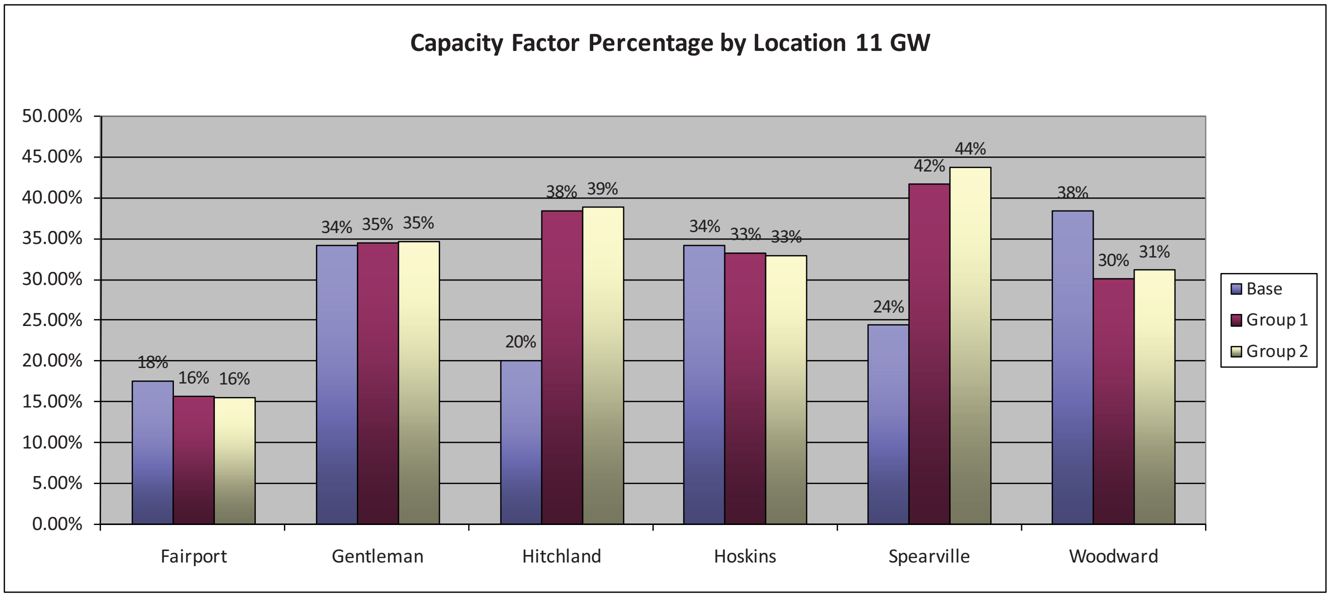


Figure 14: Capacity Factor by Location - 11 GW

Because SPP was asked to model the same level of wind in the base and change case, existing buses in the model were chosen as locations to place the wind. For Missouri, Fairport was the only 345 kV bus on the SPP system in which it was reasonable to place the Missouri wind. However, the proposed 345 kV line Nebraska City – Maryville – Sibley does not have a termination point at Fairport. This modeling nuance likely contributes to the reduced output shown at Fairport.

Priority Project Cost Calculations

The following tables show the Annual Transmission Revenue Requirement (ATRR) by project for Groups 1 and 2. The Engineering and Construction (E&C) cost estimates were provided by the Transmission Owners (TOs). 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 40 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 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
Nebraska City (NPPD) - Maryville (KCPL) - Sibley (KCPL)	345 kV	Nebraska City-NE/MO border towards Maryville (NPPD), Maryville-NE/MO border towards Nebraska City and Maryville - Sibley (KCPL-GMO)	KCPL	15.1%	$301,029,091	$45,455,393
Riverside Station - Tulsa Power Station (Reactor) (AEP)	138 kV	100% AEP	AEP	14.7%	$842,847	$123,730
Hitchland 345/230 kV Xfmr	345/230 kV	100% SPS	SPS	12.1%	8,883,760	$1,074,935
Overton 345/161 kV Xfmr[4]	345/161 kV	100% AMMO	AMMO	13.09%[5]	6,750,000[6]	$883,446

Table 11: Project Cost Calculations – Group 1

4 According to the reliability assessment, loading on the existing transformer increased from 99.8% to 100.6%. This project is not presented for approval as part of the Priority Projects.

5 Estimated by averaging the levelized FCR for SPP members

6 Staff estimate

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)	345 kV DCT	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)	345 kV DCT	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
Nebraska City (NPPD) - Maryville (KCPL) - Sibley (KCPL)	345 kV	Nebraska City-NE/MO border towards Maryville (OPPD), Maryville-NE/MO border towards Nebraska City and Maryville - Sibley (KCPL-GMO)	KCPL	15.1%	$301,029,091	$45,455,393
Riverside Station - Tulsa Power Station (Reactor) (AEP)	138 kV	100% AEP	AEP	14.7%	$842,847	$123,730
Hitchland 345/230 kV Xfmr	345/230 kV	100% SPS	SPS	12.1%	8,883,760	$1,074,935
Overton 345/161 kV Xfmr[7]	345/161 kV	100% AMMO	AMMO	13.09%[8]	6,750,000[9]	$883,446

Table 12: Project Cost Calculations – Group 2

[7] According to the reliability assessment, loading on the existing transformer increased from 99.8% to 100.6%. This project is not presented for approval as part of the Priority Projects.
[8] Estimated by averaging the levelized FCR for SPP members
[9] Staff estimate

KEMA Analysis

The Priority Project economic assessment focuses on APC savings and impact on losses, reliability projects, and the impact from wind revenue. These metrics do not capture the value of transmission as enabling assets that facilitate markets and help maintain 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 discussed many of these metrics and generally agreed that the above 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 Integrated Transmission Plan will result in quantifiable benefits resulting from a robust transmission system.

KEMA Assumptions and Application to Priority Projects

KEMA was contracted to estimate the impact of Priority Projects on overall natural gas consumption and the affect this impact may have on regional gas prices. KEMA assumptions for fuel price impacts in SPP are based on PROMOD results for the Priority Projects with the two wind levels in the base and change cases. SPP was asked to study certain wind levels in the base and change case related to state renewable targets/mandates; the KEMA study assumes similar renewable targets across the country due to federal or state requirements. This assumption means that similar gas usage reductions will also be seen across the country as is measured for the SPP region.

Recent research by the Lawrence Berkeley National Laboratory and the RAND Corporation provide similar results regarding the 0.9 to 1.2 range of inverse supply price elasticity that can be expected for natural gas consumption. RAND found a value of 0.97; KEMA proposed that SPP use 1.2 in the economic analysis associated with gas price impacts of Priority Projects. Additional detail on KEMA's analysis of reduced natural gas prices can be found in Attachment 6.

The PROMOD results with 7 GW of wind in the base and change cases indicate the addition of Priority Projects will reduce natural gas consumption as a boiler fuel by 5.08 – 5.15%, 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	$15.2M	$31.7M	$55.7M
Group 2	$15.4M	$32.1M	$56.4M

Table 13: Expected Savings from Reduced Natural Gas Prices – 7 GW

Results with 11 GW of wind in the base and change cases indicate the addition of Priority Projects will reduce natural gas consumption as a boiler fuel by 7.7 – 8%. The expected savings as a result of this price change are shown in the following table.

	2009	2014	2019
Group 1	$21.7M	$45.2M	$79.1M
Group 2	$22.5M	$46.7M	$81.9M

Table 14: Expected Savings from Reduced Natural Gas Prices – 11 GW

Brattle Group Analysis

In 2009, The Brattle Group estimated the potential economic benefits associated with building a set of transmission projects and expanding the build-out of wind power generation in the SPP region. For this Revision 1 report, SPP asked The Brattle Group to update its report using the most recent wind level assumptions and transmission projects under consideration. The Brattle Group uses the Minnesota IMPLAN model to estimate the potential economic impact of building a set of transmission projects. As a result of constructing the Group 2 set of projects, the Brattle Group estimated the following economic benefits:

- Overall economic output: ~ $962 million
- Overall job impacts: ~ 7,475 full-time equivalent-years
- Additional earnings related to the jobs impact: ~ $368 million
- State and local government tax impacts: ~ $34.4 million

The Brattle Group also used 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 phases. 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 3.2 GW of wind projects would have the following economic benefits:

- Overall economic output during construction: ~ $1.8 billion
- Overall jobs impact during construction: ~ 17,000 full-time equivalent-years
- Additional earnings related to construction jobs impact: ~ $577 million
- Overall economic output during operation: ~ $1.6 billion
- Overall jobs impact during operation: ~ 13,100 full-time equivalent-years
- Additional earnings related to operation jobs impact: ~ $501 million

Staff recommends including all of the $962 million in transmission-related benefits identified by the IMPLAN model in evaluating Priority Projects. To the extent the transmission projects enable the interconnection of the additional wind, some of the benefits related to the continued operation of that additional wind should also be considered while evaluating Priority Projects. Staff recommends a conservative 25% of the $1.6 billion of estimated benefits from wind operation be considered. Because SPP was directed to study the same level of wind capacity in the base and change case, it is not appropriate to consider any of the benefits related to wind construction in directly evaluating Priority Projects.

In addition to the above results, The Brattle Group estimated benefits resulting from constructing 7.6 GW of additional wind above SPP's existing 3.8 GW. The results summarized above do not include any in-region manufacturing of materials needed to build transmission or wind infrastructure. The Brattle Group performed a sensitivity by considering

50% of the transmission and wind-related materials being manufactured within the SPP region. The details of the additional wind and higher in-region manufacturing sensitivity can be found in the complete Brattle Group report in Attachment 4.

Future Considerations and Next Steps

Traditional resource planning tools do not capture the entire value of enabling assets such as extra high voltage transmission. They are limited due to factors such as 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.

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 availability. For instance, extreme cold weather in early 2010 set peak demand for some SPP members and neighboring systems, which traditionally occurs in the summer months. This weather 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 high. 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.

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 for the 20% case an additional 485 miles of 765 kV, 766 miles of 345 kV, 205 miles of 230 kV, and 25 miles of 115 kV lines.

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 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 that over 11 GW of wind is already targeted for the SPP footprint in the next 20 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	MW Target	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 15: State Renewable Targets for SPP Footprint (No Federal RPS)

Conclusion and Recommendations

The Synergistic Planning Project Team report concluded that Priority Projects should improve congestion, improve SPP's current Aggregate Study and Generation Interconnection study processes, and integrate SPP's west and east transmission systems. SPP staff confirms that the benefits provided for Group 2 are consistent with the SPPT's requirements and recommends the following Priority Projects for approval and subsequent 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. Nebraska City – 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 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. The outcome of the ITP analysis should determine if the proposed construction and voltage operation of Priority Projects is consistent with 20-year plan requirements.

Southwest Power Pool

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	$13,979,793	$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	$12,047,793	$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[10]	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		345/230 kV	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		$12,047,793	$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			Includes 2nd Hitchland 345/230 kV Xfmr identified in Reliability Assessment				

10 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	OPPD - KCPL	AEP
	Project	Nebraska City - Maryville - Sibley	Tulsa Power Station Reactor
	Voltage	345 kV	138 kV
Cost	Total Cost	$301,029,091 [11]	$842,847
	Total Material Cost		
	Cost Per Mile	$1,467,857	
	Miles	175	
	Substation Cost	$10,072,689	$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	Breaker and ½ (OPPD), ring (KCPL)	
	Protection Scheme	included	
	Voltage Control		
	Cost	$10,072,689	$448,153
Construction Labor	Amount		
	Cost	$1,508,000 (OPPD)	$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	3%	
	Eng. Design/ Proj. Mang.	$100,000 (OPPD)	Included in Construction Cost
	Total Cost		$110,765
Loadings and Overheads	Type 1	$ 119,473 (P&G)	$143,749
	Type 2	$1,325,276 (General)	
Other Cost Factors and Notes			

[11] 10% contingency for line construction ($23M), OPPD estimates 35% contingency adder ($3.12M), 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 benefits below, the calculated NPV costs for each project grouping was allocated using load ratio share. The "Net Benefit" column is calculated as "Total Benefit" minus "Total Cost" and is indicative of the level of benefits that zone is either short or long relative to a B/C ratio of 1.

Area	7 GW Study Group 1 (765 kv @ 345 kV)								
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Net Benefit (Years 0 - 40)	B/C
AEPW	$521,766,717	$350,396,168	($18,463,348)	$999,807	$26,645,436	$61,308,936	$279,905,338	($171,370,548)	0.67
EMDE	$62,755,212	$30,510,153	$45,639,386	$120,251	($229,592)	($32,999,184)	$17,979,292	($32,245,058)	0.49
GMO	$99,357,682	$74,710,207	$57,431,014	$190,389	$304,820	($5,497,032)	$22,281,017	($24,647,475)	0.75
GRDA	$45,780,155	($55,292,299)	($46,950,723)	$87,724	($8,710,247)	$0	$280,947	($101,072,454)	(1.21)
KCPL	$188,419,476	$124,391,181	$51,084,106	$524,205	$9,411,209	$45,255,389	$18,116,272	($64,028,296)	0.66
LES	$56,153,701	($12,696,176)	($42,206,642)	$107,601	$17,512,002	$8,782,036	$3,108,827	($68,849,876)	(0.23)
MIDW	$17,706,174	($11,578,263)	($26,967,987)	$6,458,029	$5,411,653	$2,022,614	$1,497,428	($29,284,436)	(0.65)
MKEC	$32,480,443	($153,108,860)	($182,648,356)	$1,228,593	$882,769	$14,639,110	$12,789,025	($185,589,303)	(4.71)
NPPD	$151,355,555	$142,511,672	$76,466,709	$290,027	$10,748,915	$50,332,198	$4,673,824	($8,843,883)	0.94
OKGE	$334,260,179	$432,666,250	$376,232,416	$695,996	$345,348	($59,356,915)	$114,749,405	$98,406,072	1.29
OPPD	$119,018,328	$69,890,805	$31,672,275	$228,062	$2,192,347	$33,389,979	$2,408,141	($49,127,523)	0.59
SPRM	$36,030,625	($25,343,109)	($25,860,766)	$69,042	$459,183	($2,203,173)	$2,192,605	($61,373,734)	(0.70)
SUNC	$25,377,319	($70,302,963)	($75,219,440)	$48,628	$150,363	$2,920,711	$1,796,775	($95,680,282)	(2.77)
SWPS	$277,635,784	$1,061,426,112	$895,228,122	$317,399	$1,602,117	($10,479,186)	$174,757,659	$783,790,328	3.82
WEFA	$76,344,246	$169,989,187	$184,741,100	$1,430,892	$1,186,565	($38,426,886)	$21,057,516	$93,644,941	2.23
WRI	$272,415,045	$181,108,052	$9,820,050	$522,000	($149,340)	$140,213,544	$30,701,797	($91,306,993)	0.66
Totals	**$2,316,856,640**	**$2,309,278,116**	**$1,309,997,915**	**$13,318,645**	**$67,763,548**	**$209,902,141**	**$708,295,867**	**($7,578,523)**	**1.00**

Figure 15: Zonal Benefits and Costs – 7 GW Group 1

Area	7 GW Study Group 2 (DCT 345 kV)								
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Net Benefit (Years 0 - 40)	B/C
AEPW	$468,943,217	$346,457,986	($22,591,952)	$1,562,453	$28,491,286	$55,517,451	$283,478,749	($122,485,230)	0.74
EMDE	$56,401,893	$31,094,170	$52,722,617	$285,320	($230,615)	($39,842,207)	$18,159,054	($25,307,724)	0.55
GMO	$89,298,741	$83,051,224	$63,237,068	$297,531	$224,568	($3,238,388)	$22,530,445	($6,247,517)	0.93
GRDA	$41,145,386	($59,907,376)	($53,080,292)	$137,091	($7,253,469)	$0	$289,294	($101,052,762)	(1.46)
KCPL	$169,343,947	$122,074,061	$41,514,135	$727,387	$10,097,937	$51,417,647	$18,316,954	($47,269,886)	0.72
LES	$50,468,717	($13,611,540)	($44,162,448)	$168,155	$17,663,389	$9,573,656	$3,145,708	($64,080,258)	(0.27)
MIDW	$15,913,606	($16,478,987)	($31,877,191)	$6,477,123	$5,721,496	$1,629,544	$1,570,041	($32,392,593)	(1.04)
MKEC	$29,192,133	($175,272,355)	($202,994,721)	$340,031	($1,524,843)	$15,668,857	$13,238,321	($204,464,488)	(6.00)
NPPD	$136,032,366	$141,470,000	$78,550,656	($7,726,971)	$11,045,548	$54,827,306	$4,773,461	$5,437,634	1.04
OKGE	$300,419,782	$454,153,298	$401,503,058	$7,268,516	$589,173	($72,083,006)	$116,875,557	$153,733,516	1.51
OPPD	$106,968,949	$71,558,663	$30,022,810	$356,406	$2,502,190	$36,246,480	$2,430,777	($35,410,286)	0.67
SPRM	$32,382,895	($8,159,430)	($8,760,963)	$107,895	$459,183	($2,186,459)	$2,220,913	($40,542,325)	(0.25)
SUNC	$22,808,127	($71,932,739)	($76,389,809)	$75,993	$150,363	$2,406,868	$1,823,845	($94,740,866)	(3.15)
SWPS	$249,528,024	$1,079,150,211	$885,684,732	$7,484,288	$1,462,918	$8,316,588	$176,201,685	$829,622,187	4.32
WEFA	$68,615,179	$175,295,359	$186,025,261	$2,436,804	$1,320,648	($36,068,675)	$21,581,320	$106,680,180	2.55
WRI	$244,835,830	$182,623,526	$1,788,355	$815,759	($149,340)	$148,738,820	$31,429,933	($62,212,304)	0.75
Totals	**$2,082,298,794**	**$2,341,566,071**	**$1,301,191,318**	**$20,813,781**	**$70,570,431**	**$230,924,482**	**$718,066,058**	**$259,267,277**	**1.12**

Figure 16: Zonal Benefits and Costs - 7 GW Group 2

Area	11 GW Study Group 1 (765 kv @ 345 kV)								
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Net Benefit (Years 0 - 40)	B/C
AEPW	$521,766,717	$865,425,037	($75,464,533)	$999,807	$26,645,436	$502,806,055	$410,438,273	$343,658,320	1.66
EMDE	$62,755,212	$26,761,814	$71,522,347	$120,251	($229,592)	($70,838,728)	$26,187,535	($35,993,398)	0.43
GMO	$99,357,682	$129,539,325	$95,021,077	$190,389	$304,820	$2,229,166	$31,793,874	$30,181,643	1.30
GRDA	$45,780,155	($91,453,261)	($83,223,946)	$87,724	($8,710,247)	$0	$393,208	($137,233,416)	(2.00)
KCPL	$188,419,476	$304,126,283	($36,422,891)	$524,205	$9,411,209	$303,708,811	$26,904,950	$115,706,807	1.61
LES	$56,153,701	($13,139,193)	($41,996,690)	$107,601	$17,512,002	$6,758,077	$4,479,817	($69,292,893)	(0.23)
MIDW	$17,706,174	$72,772,637	($18,353,524)	$6,458,029	$5,411,653	$77,300,976	$1,955,504	$55,066,464	4.11
MKEC	$32,480,443	$56,389,329	($82,706,402)	$1,228,593	$882,769	$117,831,044	$19,153,325	$23,908,885	1.74
NPPD	$151,355,555	$122,282,641	$47,455,125	$290,027	$10,748,915	$57,028,111	$6,760,464	($29,072,914)	0.81
OKGE	$334,260,179	$671,812,937	$420,171,043	$695,996	$345,348	$84,521,087	$166,079,463	$337,552,759	2.01
OPPD	$119,018,328	$48,153,124	$10,880,662	$228,062	$2,192,347	$31,362,275	$3,489,778	($70,865,203)	0.40
SPRM	$36,030,625	($37,338,815)	($40,583,648)	$69,042	$459,183	($551,550)	$3,268,158	($73,369,440)	(1.04)
SUNC	$25,377,319	$66,924,360	($37,211,890)	$48,628	$150,363	$101,572,237	$2,365,022	$41,547,041	2.64
SWPS	$277,635,784	$1,639,885,547	$1,391,373,783	$317,399	$1,602,117	$16,660,158	$229,932,089	$1,362,249,763	5.91
WEFA	$76,344,246	$247,765,212	$244,074,036	$1,430,892	$1,186,565	($28,454,820)	$29,528,539	$171,420,965	3.25
WRI	$272,415,045	$962,907,835	$115,327,997	$522,000	($149,340)	$803,261,088	$43,946,090	$690,492,791	3.53
Totals	**$2,316,856,640**	**$5,072,814,813**	**$1,979,862,546**	**$13,318,645**	**$67,763,548**	**$2,005,193,986**	**$1,006,676,089**	**$2,755,958,174**	**2.19**

Figure 17: Zonal Benefits and Costs - 11 GW Group 1

Area	11 GW Study Group 2 (DCT 345 kV)								
	Total Cost (Years 0 -40)	Total Benefit (Years 0 - 40)	APC	Reliability	Losses	Wind Revenue Impact	Gas Price Impact	Net Benefit (Years 0 - 40)	B/C
AEPW	$468,943,217	$893,945,963	($111,622,742)	$1,562,453	$28,491,286	$549,729,067	$425,785,900	$425,002,746	1.91
EMDE	$56,401,893	$46,402,700	$82,845,213	$285,320	($230,615)	($63,294,000)	$26,796,781	($9,999,193)	0.82
GMO	$89,298,741	$144,173,087	$118,310,273	$297,531	$224,568	($7,159,736)	$32,500,452	$54,874,346	1.61
GRDA	$41,145,386	($105,131,998)	($98,418,805)	$137,091	($7,253,469)	$0	$403,186	($146,277,384)	(2.56)
KCPL	$169,343,947	$277,272,909	($56,403,301)	$727,387	$10,097,937	$295,322,030	$27,528,857	$107,928,962	1.64
LES	$50,468,717	($8,873,542)	($43,774,788)	$168,155	$17,663,389	$12,393,451	$4,676,252	($59,342,259)	(0.18)
MIDW	$15,913,606	$84,366,853	($10,953,963)	$6,477,123	$5,721,496	$81,163,399	$1,958,798	$68,453,247	5.30
MKEC	$29,192,133	$98,194,763	($39,515,925)	$340,031	($1,524,843)	$119,867,590	$19,027,909	$69,002,629	3.36
NPPD	$136,032,366	$125,494,558	$53,003,828	($7,726,971)	$11,045,548	$62,144,128	$7,028,025	($10,537,808)	0.92
OKGE	$300,419,782	$745,247,311	$454,955,793	$7,268,516	$589,173	$109,278,903	$173,154,926	$444,827,529	2.48
OPPD	$106,968,949	$56,309,803	$10,198,076	$356,406	$2,502,190	$39,668,652	$3,584,479	($50,659,146)	0.53
SPRM	$32,382,895	($48,587,478)	($51,477,039)	$107,895	$459,183	($1,068,468)	$3,390,950	($80,970,373)	(1.50)
SUNC	$22,808,127	$68,352,722	($41,060,385)	$75,993	$150,363	$106,718,973	$2,467,777	$45,544,595	3.00
SWPS	$249,528,024	$1,658,598,854	$1,338,518,101	$7,484,288	$1,462,918	$73,476,164	$237,657,382	$1,409,070,830	6.65
WEFA	$68,615,179	$234,887,856	$232,423,531	$2,436,804	$1,320,648	($32,890,211)	$31,597,084	$166,272,678	3.42
WRI	$244,835,830	$1,120,036,062	$216,003,169	$815,759	($149,340)	$857,408,989	$45,957,486	$875,200,232	4.57
Totals	**$2,082,298,794**	**$5,390,690,423**	**$2,053,031,037**	**$20,813,781**	**$70,570,431**	**$2,202,758,931**	**$1,043,516,243**	**$3,308,391,629**	**2.59**

Figure 18: Zonal Benefits and Costs - 11 GW Group 2

Appendix E – Calculation of Zonal Load Ratio Share

The Load Ratio Share (LRS) values in this revision of the Priority Projects analysis were updated to reflect the most up to date information. The figure below shows the monthly 12CP data for 2009 as submitted by stakeholders to the SPP Settlements group in early 2010. The LRS for each zone is calculated by dividing the zonal total load by the sum of all total load.

	January	February	March	April	May	June	July	August	September	October	November	December		Total	LRS
CSWS	7448.00	6990.00	6668.00	6149.00	6995.00	9696.00	9840.44	9474.00	8173.01	6180.00	5794.00	7531.00		90,938.46	22.52%
EDE	1085.99	996.43	936.46	790.72	735.71	1089.33	1008.83	1032.22	815.12	637.77	745.00	1064.00		10,937.57	2.71%
GRDA	675.00	638.00	581.00	547.00	606.00	839.00	808.00	812.00	670.00	564.00	568.00	671.00		7,979.00	1.98%
KCPL	2825.30	2577.60	2419.00	2213.40	2531.90	3654.30	3394.74	3449.30	2583.50	2118.20	2255.40	2816.90		32,839.54	8.13%
LES	799.00	768.00	753.00	714.00	719.00	1061.00	984.00	953.00	845.00	743.00	756.00	692.00		9,787.00	2.42%
MIDW	229.00	210.00	210.00	199.00	234.00	344.00	358.00	342.00	262.00	217.00	232.00	249.00		3,086.00	0.76%
MPS	1586.00	1427.00	1319.00	1166.00	1273.00	1951.00	1720.00	1769.00	1306.00	1080.00	1179.00	1541.00		17,317.00	4.29%
NPPD	2340.46	2047.45	2186.52	1855.74	1915.70	2303.94	2614.88	2624.02	1960.56	1864.77	2174.29	2491.35		26,379.68	6.53%
OKGE	4579.13	4211.53	3986.76	3949.83	4561.84	6310.87	6544.47	6136.71	5441.21	4004.86	3874.58	4656.24		58,258.04	14.43%
OPPD	1627.66	1507.00	1460.79	1502.28	1575.93	2349.12	2096.78	2160.00	1744.38	1452.81	1501.69	1765.21		20,743.64	5.14%
SECI	320.00	311.00	330.00	312.00	375.00	469.00	478.00	465.00	386.00	319.00	317.00	341.00		4,423.00	1.10%
SPRM	498.95	493.47	441.73	410.23	482.95	735.68	655.93	674.31	542.67	409.89	412.35	521.59		6,279.76	1.56%
SPS	3511.00	3431.00	3275.00	3572.00	4264.00	4758.00	5036.00	5005.00	4670.00	3418.00	3488.00	3961.00		48,389.00	11.98%
WFEC	1173.00	1099.00	1029.00	962.00	1009.00	1288.00	1334.00	1282.00	1142.00	818.00	935.00	1235.00		13,306.00	3.30%
WPEK/MKEC	433.00	413.00	398.00	386.00	434.00	622.00	618.00	611.00	471.00	400.00	419.00	456.00		5,661.00	1.40%
WR	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59	3956.59		47,479.08	11.76%
Total														**403,803.77**	

Figure 19: 2009 12CP Data for LRS Calculations

Appendix F – Aggregated Zonal Output Results

At the technical conference held on February 10, 2010 stakeholders requested to see additional detail on actual output results in order to better understand the benefits being presented. Staff also polled the ESWG on data that would help them better interpret the results as well. Stakeholders were particularly interested in how the model was altering the dispatch of thermal generation and how LMP prices were changing as a result of the Priority Projects. Below are a number of charts that illustrate the percent change in PROMOD output data between the respective base and change case by zone related to thermal generation levels and LMP prices.

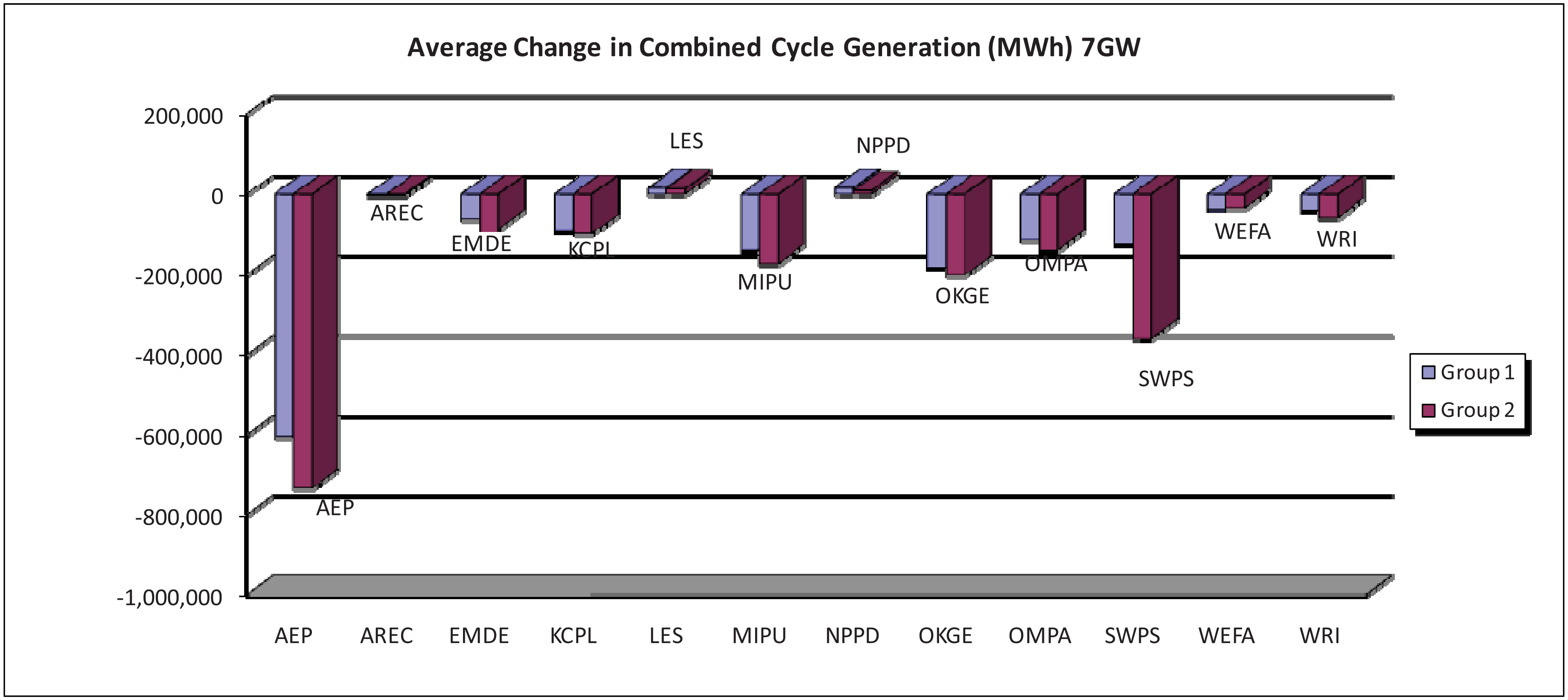


Figure 20: Avg Change in Combined Cycle Generation - 7 GW

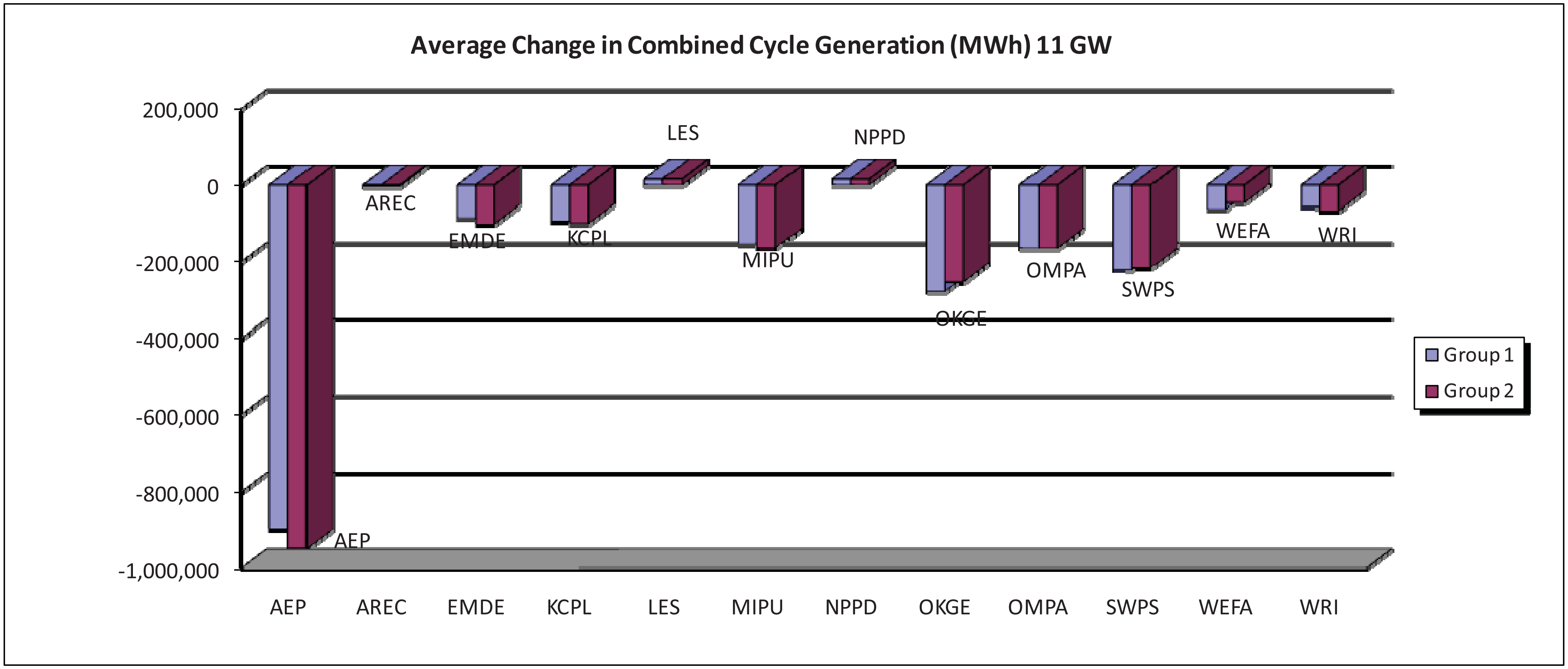


Figure 21: Avg Change in Combined Cycle Generation - 11 GW

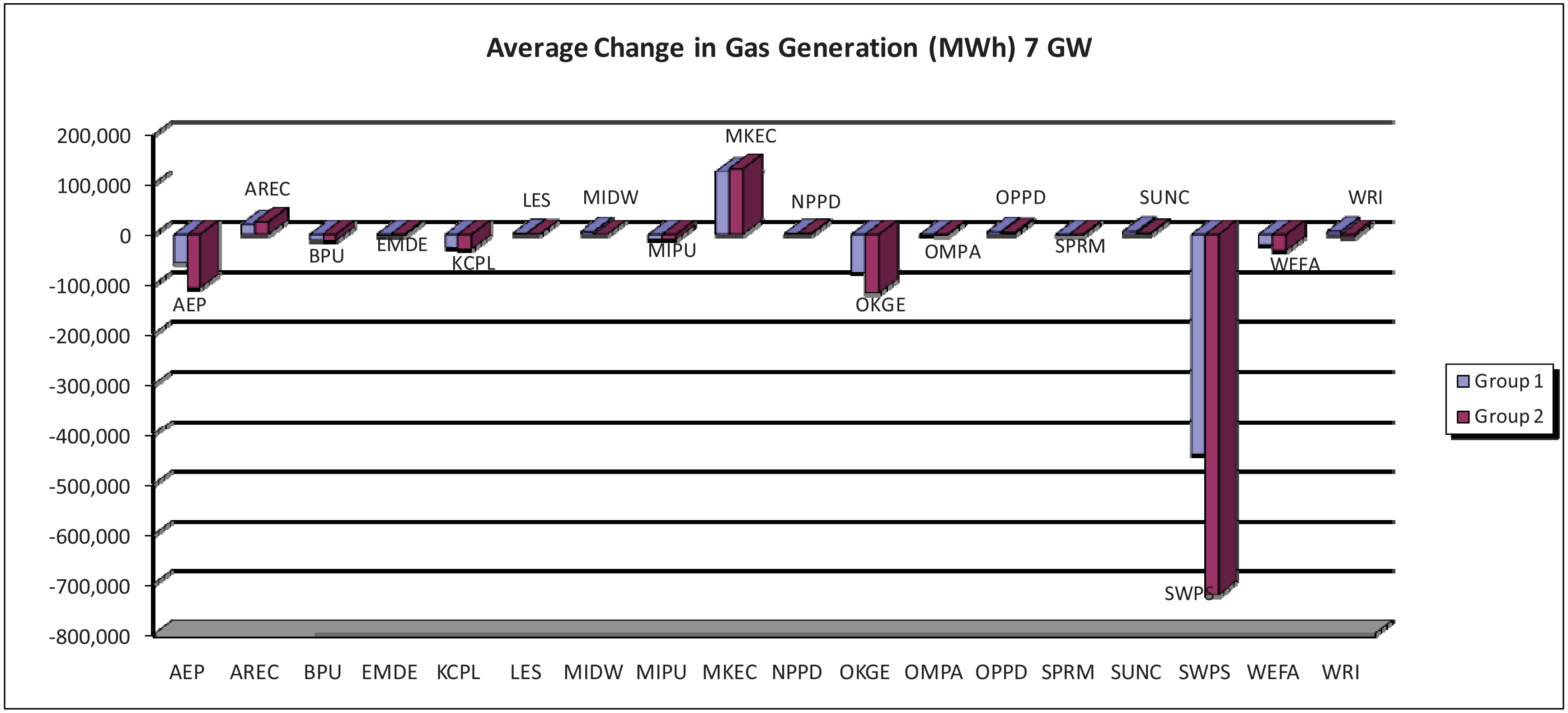


Figure 22: Avg Change in Gas Generation - 7 GW

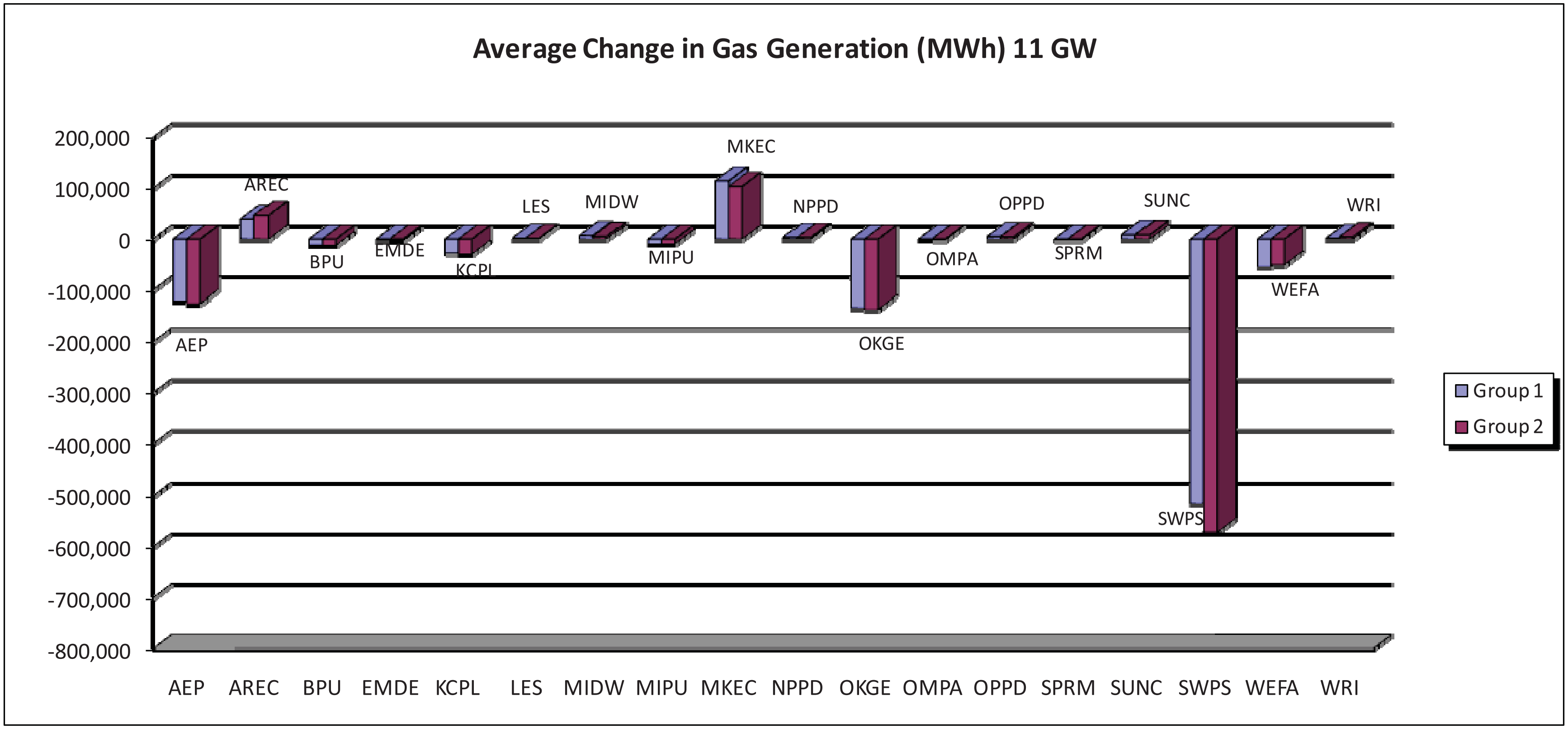


Figure 23: Avg Change in Gas Generation - 11 GW

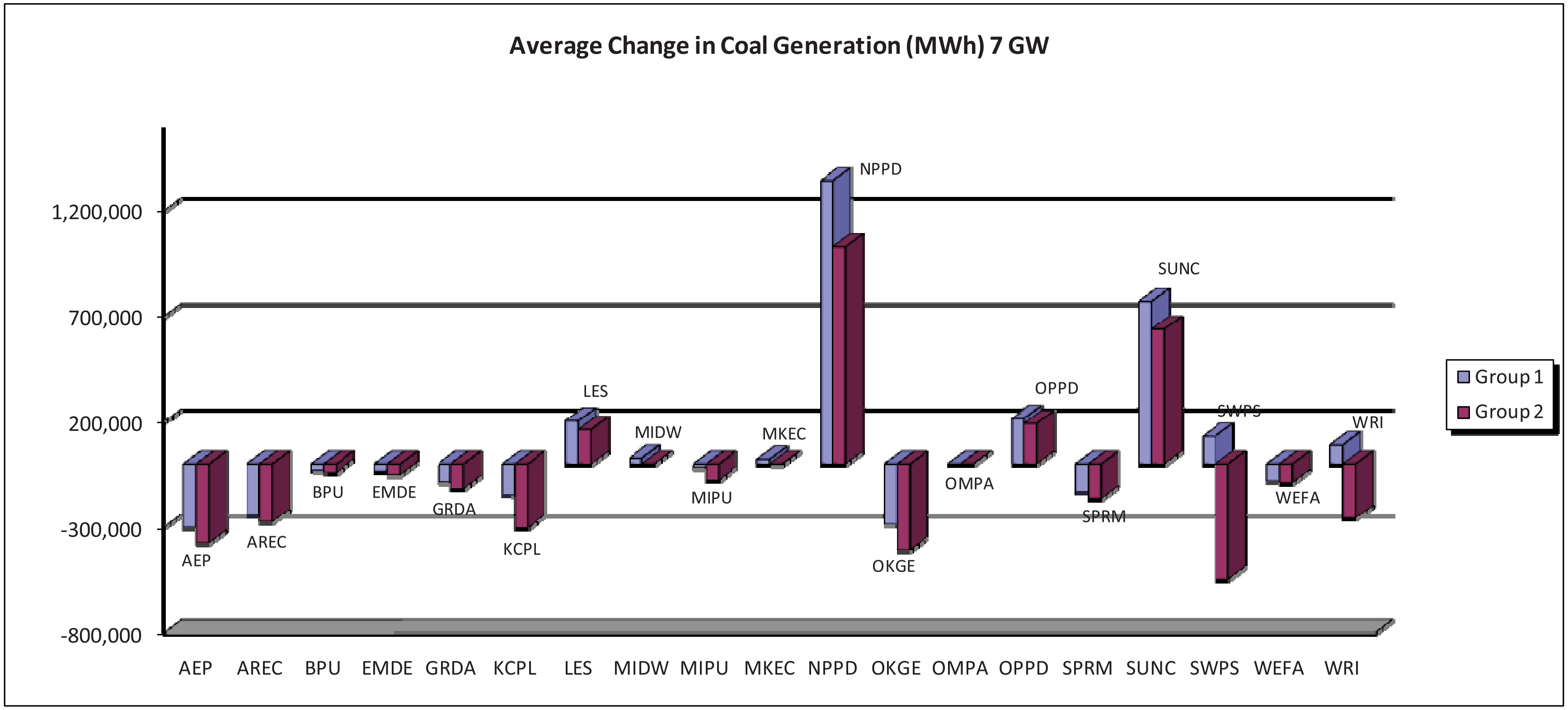


Figure 24: Avg Change in Coal Generation - 7 GW

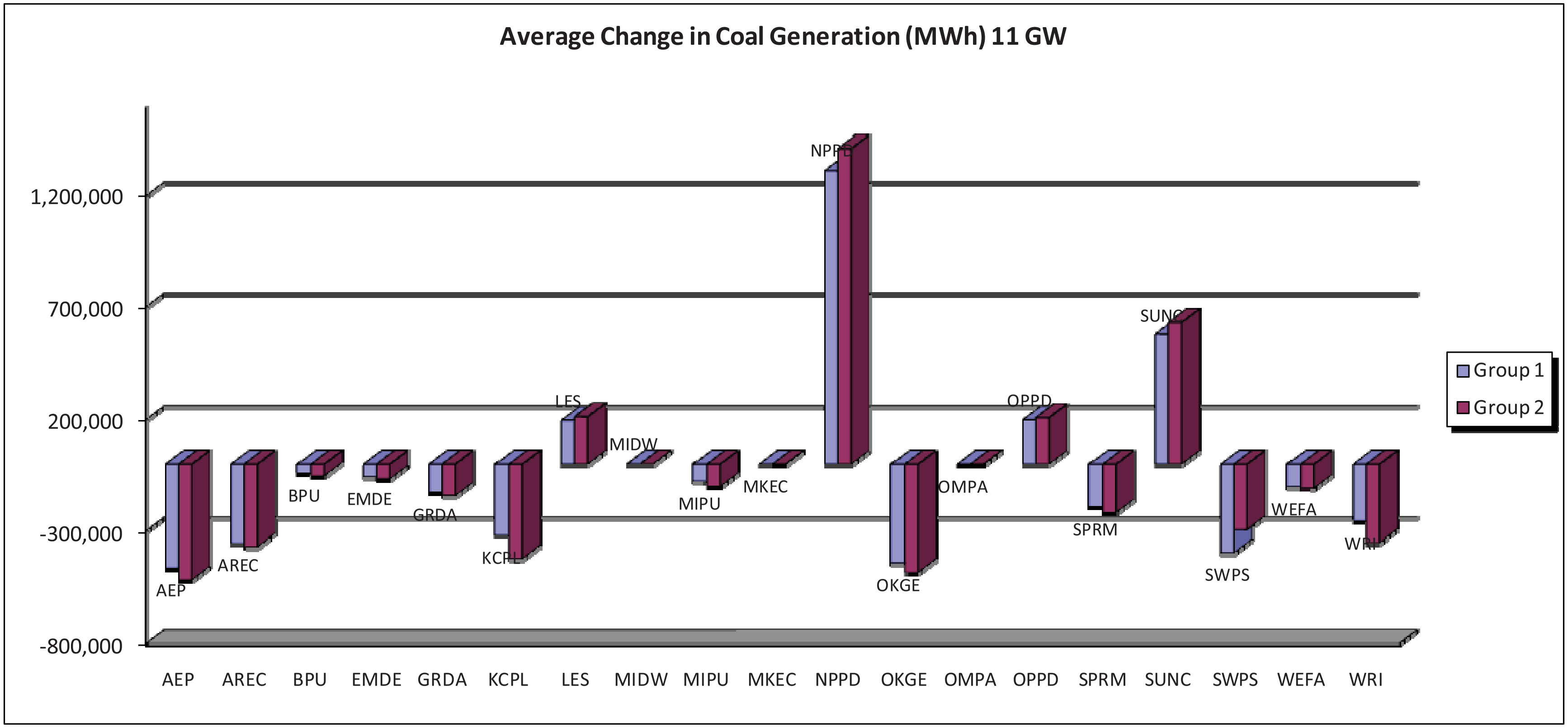


Figure 25: Avg Change in Coal Generation - 11 GW

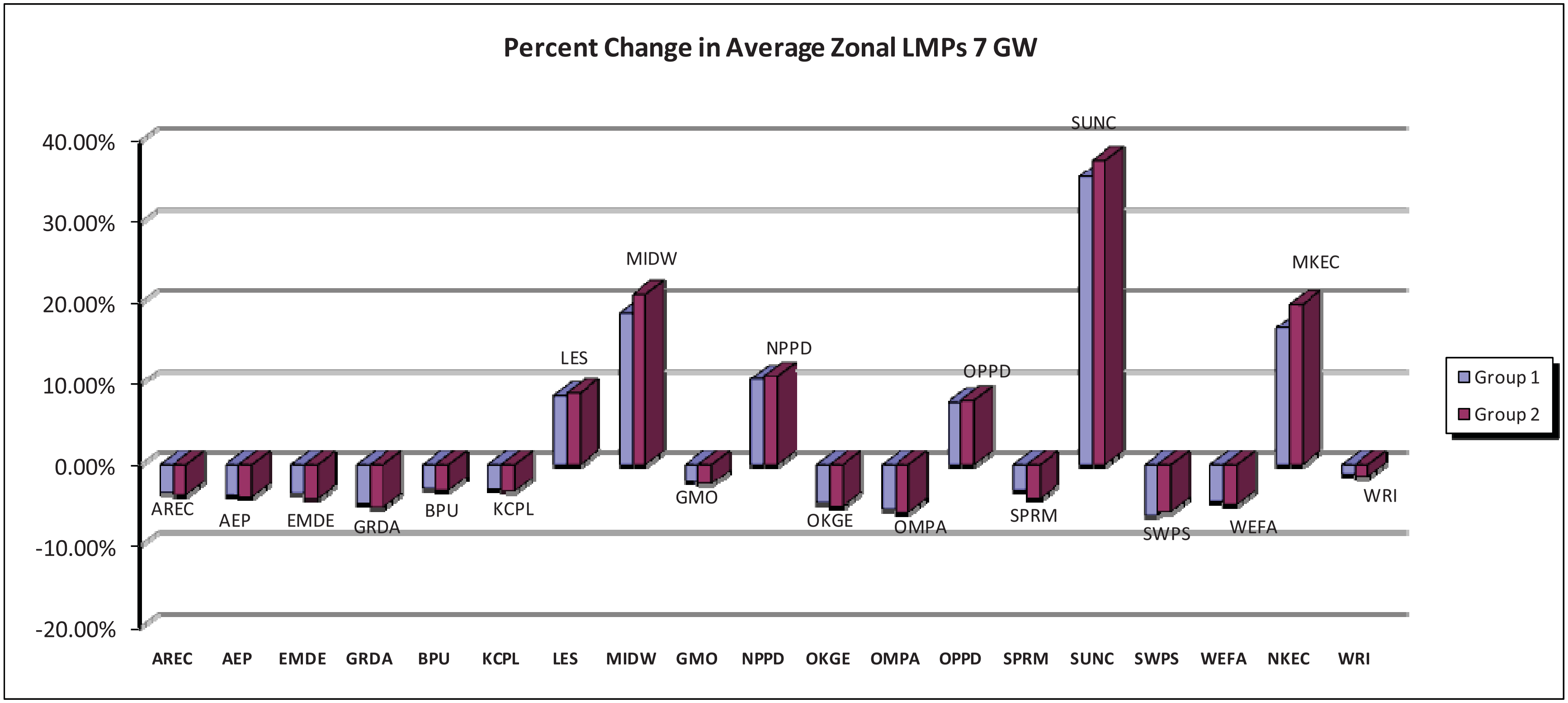


Figure 26: % Change in Avg Zonal LMPs - 7 GW

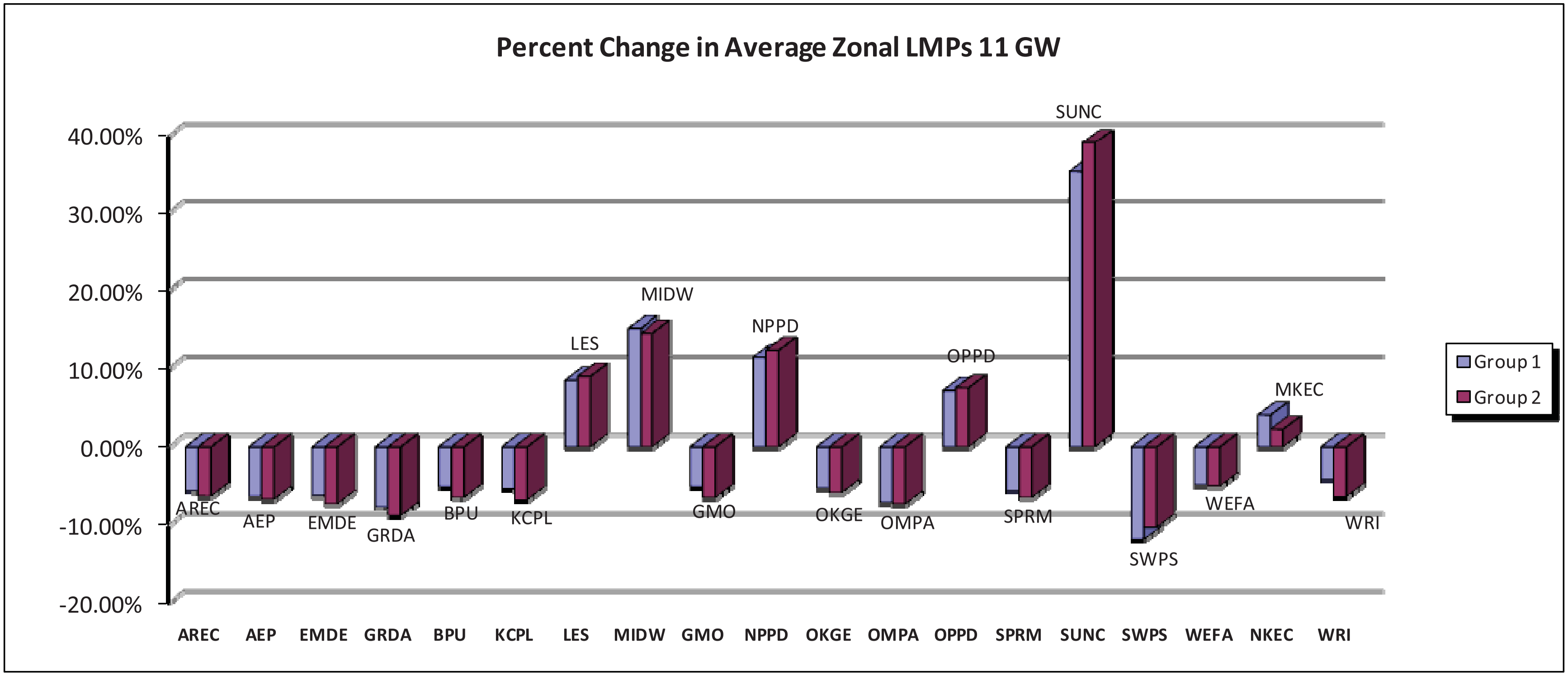


Figure 27: % Change in Avg Zonal LMPs - 11 GW

Appendix G – Wind Revenue Impact Zonal Allocations

The change in wind revenue for all existing designated wind resources was assigned to the zone in which the resource was designated. The CAWG discussed methods for allocating the change in wind revenue for both existing non-designated wind resources and non-designated wind resources added to the model to reach the appropriate 7 GW or 11 GW study level. Consensus was reached by the CAWG on a method presented by Dr. Mike Proctor, consultant for the SPP Regional State Committee. The charts below reflect the allocations of those revenues as developed by Dr. Proctor.

7 GW Wind Benefits						
Group 1 Results						
Sign Convention: Benefits > 0 and Costs < 0						
40 Year Levelized						NPV
Zone	Wind Capacity		DR Wind	Non-DR Wind	Total Wind	Total Wind
	DR	Non-DR	Net Benefit	Net Benefit	Net Benefit	Net Benefit
AEP	421.0	1,114.1	($4,503,884)	$9,645,261	$5,141,377	$61,308,936
EMDE	255.0	64.1	($2,390,281)	($377,036)	($2,767,317)	($32,999,184)
GMO	61.0	265.4	$1,100,274	($1,561,256)	($460,982)	($5,497,032)
GRDA	0.0	0.0	$0	$0	$0	$0
KCPL	125.0	451.6	$4,389,510	($594,386)	$3,795,124	$45,255,389
LES	6.0	52.3	$74,154	$662,309	$736,463	$8,782,036
MIDW	49.2	54.8	($73,763)	$243,380	$169,617	$2,022,614
MKEC	75.0	77.3	$883,919	$343,719	$1,227,638	$14,639,110
NPPD	99.5	234.9	$1,244,883	$2,975,983	$4,220,866	$50,332,198
OKGE	451.0	581.0	($3,992,432)	($985,249)	($4,977,680)	($59,356,915)
OPPD	95.0	146.8	$940,810	$1,859,279	$2,800,089	$33,389,979
SPRM	50.0	18.7	($74,963)	($109,796)	($184,758)	($2,203,173)
SUNC	50.0	72.0	($74,963)	$319,894	$244,931	$2,920,711
SWPS	658.0	294.1	($8,622,061)	$7,743,274	($878,786)	($10,479,186)
WEFA	216.3	44.1	($3,147,652)	($74,833)	($3,222,485)	($38,426,886)
WRI	307.5	558.8	$9,274,879	$2,483,452	$11,758,330	$140,213,544
TOTAL	2,919.5	4,029.9	($4,971,569)	$22,573,996	$17,602,427	$209,902,141
	6,949.4					

Figure 28: Zonal Wind Revenue Allocation - 7 GW Group 1

7 GW Wind Benefits						
Group 2 Results						
Sign Convention: Benefits > 0 and Costs < 0						
40 Year Levelized						NPV
Zone	Wind Capacity		DR Wind	Non-DR Wind	Total Wind	Total Wind
	DR	Non-DR	Net Benefit	Net Benefit	Net Benefit	Net Benefit
AEP	421.0	1,114.1	($4,218,682)	$8,874,385	$4,655,702	$55,517,451
EMDE	255.0	64.1	($2,971,700)	($369,474)	($3,341,174)	($39,842,207)
GMO	61.0	265.4	$1,258,371	($1,529,943)	($271,572)	($3,238,388)
GRDA	0.0	0.0	$0	$0	$0	$0
KCPL	125.0	451.6	$4,993,905	($682,013)	$4,311,892	$51,417,647
LES	6.0	52.3	$80,978	$721,870	$802,848	$9,573,656
MIDW	49.2	54.8	($74,551)	$211,205	$136,654	$1,629,544
MKEC	75.0	77.3	$1,015,714	$298,279	$1,313,993	$15,668,857
NPPD	99.5	234.9	$1,354,215	$3,243,611	$4,597,827	$54,827,306
OKGE	451.0	581.0	($4,461,810)	($1,583,082)	($6,044,893)	($72,083,006)
OPPD	95.0	146.8	$1,013,153	$2,026,482	$3,039,636	$36,246,480
SPRM	50.0	18.7	($75,763)	($107,594)	($183,357)	($2,186,459)
SUNC	50.0	72.0	($75,763)	$277,603	$201,840	$2,406,868
SWPS	658.0	294.1	($7,011,501)	$7,708,931	$697,430	$8,316,588
WEFA	216.3	44.1	($2,904,484)	($120,241)	($3,024,725)	($36,068,675)
WRI	307.5	558.8	$10,318,126	$2,155,136	$12,473,261	$148,738,820
TOTAL	2,919.5	4,029.9	($1,759,792)	$21,125,156	$19,365,364	$230,924,482
	6,949.4					

Figure 29: Zonal Wind Revenue Allocation - 7 GW Group 2

11 GW Wind Benefits						
Group 1 Results						
Sign Convention: Benefits > 0 and Costs < 0						
40 Year Levelized						NPV
Zone	Wind Capacity		DR Wind	Non-DR Wind	Total Wind	Total Wind
	DR	Non-DR	Net Benefit	Net Benefit	Net Benefit	Net Benefit
AEP	421	2,465	($12,380,833)	$54,546,230	$42,165,397	$502,806,055
EMDE	255	95	($5,750,059)	($190,488)	($5,940,547)	($70,838,728)
GMO	61	393	$975,723	($788,785)	$186,938	$2,229,166
GRDA	0	0	$0	$0	$0	$0
KCPL	125	815	$2,607,086	$22,861,984	$25,469,070	$303,708,811
LES	6	111	($391,336)	$958,069	$566,733	$6,758,077
MIDW	49	121	$8,970	$6,473,502	$6,482,472	$77,300,976
MKEC	75	171	$738,982	$9,142,349	$9,881,330	$117,831,044
NPPD	100	498	$477,451	$4,304,935	$4,782,387	$57,028,111
OKGE	451	1,285	($19,793,620)	$26,881,573	$7,087,952	$84,521,087
OPPD	95	311	($59,511)	$2,689,556	$2,630,045	$31,362,275
SPRM	50	28	$9,218	($55,471)	($46,253)	($551,550)
SUNC	50	159	$9,218	$8,508,646	$8,517,864	$101,572,237
SWPS	658	651	($15,821,703)	$17,218,827	$1,397,124	$16,660,158
WEFA	216	98	($4,427,976)	$2,041,750	($2,386,226)	($28,454,820)
WRI	295	1,248	$657,286	$66,704,319	$67,361,605	$803,261,088
TOTAL	2,907	8,449	($53,141,104)	$221,296,996	$168,155,892	$2,005,193,986
	11,356					

Figure 30: Zonal Wind Revenue Allocation - 11 GW Group 1

11 GW Wind Benefits						
Group 2 Results						
Sign Convention: Benefits > 0 and Costs < 0						
40 Year Levelized						NPV
Zone	Wind Capacity		DR Wind	Non-DR Wind	Total Wind	Total Wind
	DR	Non-DR	Net Benefit	Net Benefit	Net Benefit	Net Benefit
AEP	421	2,465	($11,155,560)	$57,255,929	$46,100,368	$549,729,067
EMDE	255	95	($5,038,811)	($269,034)	($5,307,845)	($63,294,000)
GMO	61	393	$513,618	($1,114,035)	($600,417)	($7,159,736)
GRDA	0	0	$0	$0	$0	$0
KCPL	125	815	$958,034	$23,807,719	$24,765,753	$295,322,030
LES	6	111	$39,067	$1,000,250	$1,039,317	$12,393,451
MIDW	49	121	($11,077)	$6,817,453	$6,806,376	$81,163,399
MKEC	75	171	$424,015	$9,628,100	$10,052,115	$119,867,590
NPPD	100	498	$716,950	$4,494,466	$5,211,417	$62,144,128
OKGE	451	1,285	($18,353,927)	$27,518,073	$9,164,146	$109,278,903
OPPD	95	311	$518,652	$2,807,968	$3,326,620	$39,668,652
SPRM	50	28	($11,257)	($78,345)	($89,602)	($1,068,468)
SUNC	50	159	($11,257)	$8,960,727	$8,949,470	$106,718,973
SWPS	658	651	($12,372,249)	$18,533,972	$6,161,723	$73,476,164
WEFA	216	98	($4,848,273)	$2,090,094	($2,758,178)	($32,890,211)
WRI	295	1,248	$1,654,001	$70,248,455	$71,902,456	$857,408,989
TOTAL	2,907	8,449	($46,978,073)	$231,701,793	$184,723,720	$2,202,758,931
	11,356					

Figure 31: Zonal Wind Revenue Allocation - 11 GW Group 2

Appendix H – 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.

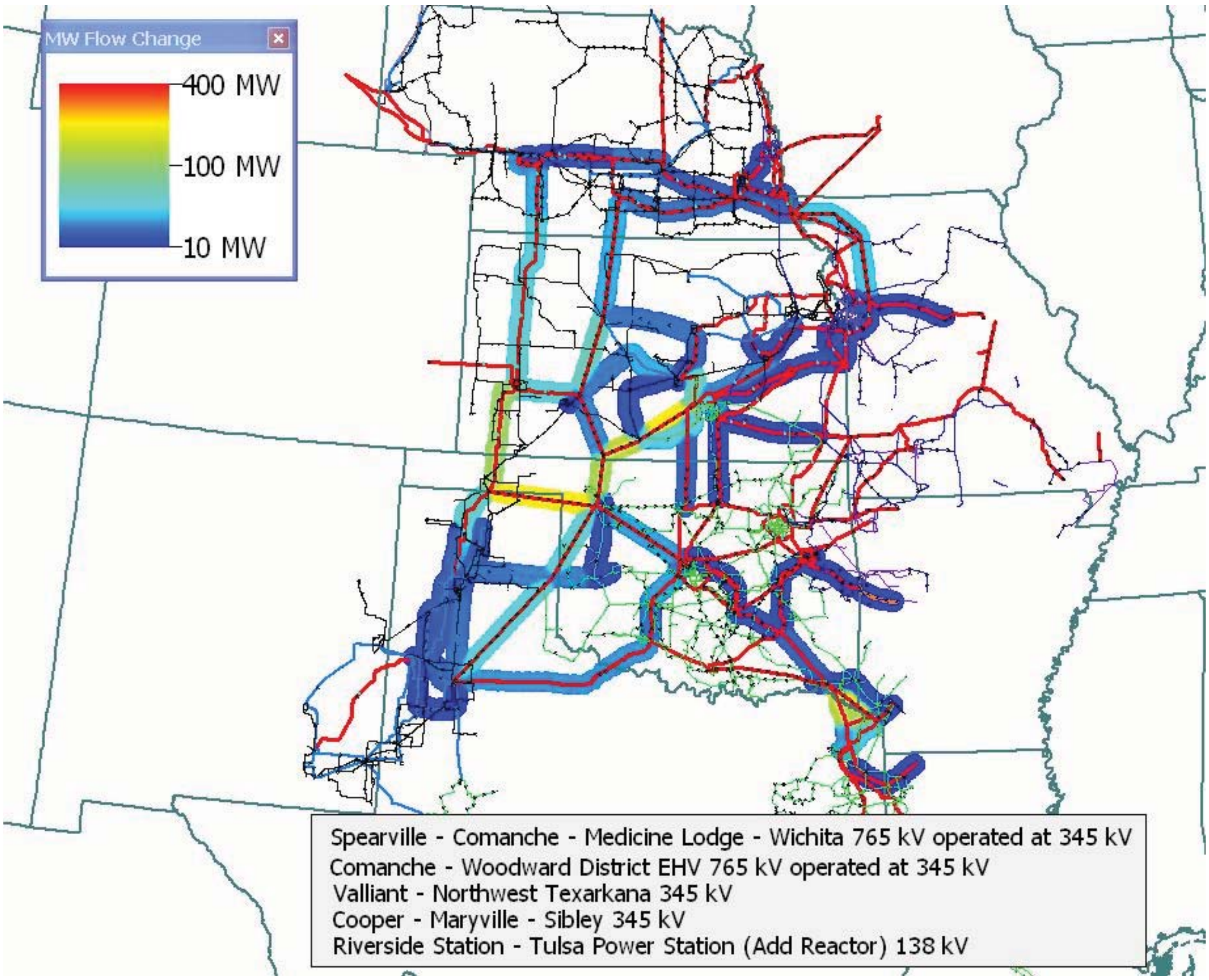


Figure 32: Priority Projects Group 1

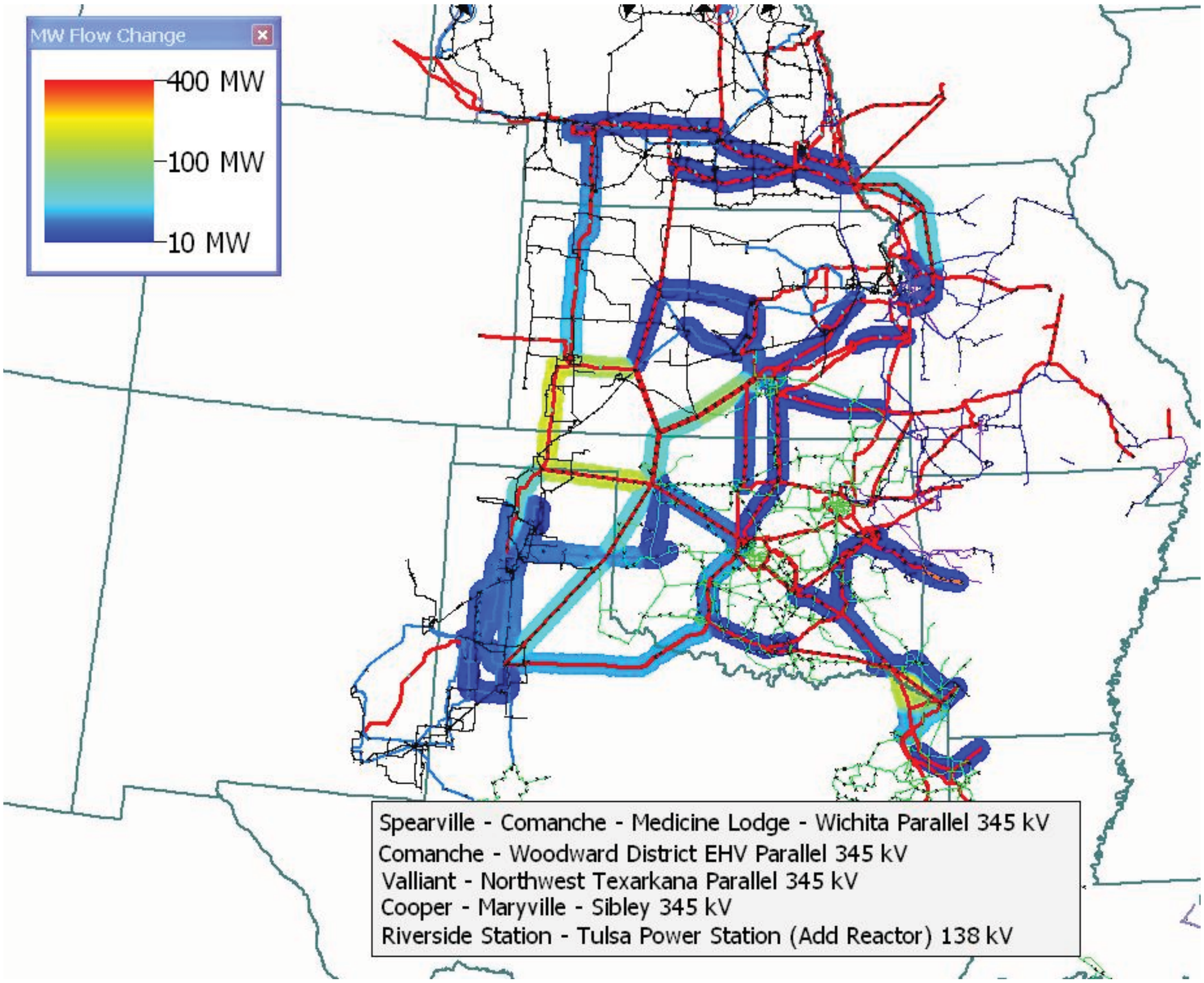


Figure 33: Priority Projects Group 2

Appendix I – 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, 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 J – 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, SPP 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.

Attachments

Click on the links below to see the attachments:

Attachment 1 – BATTF Report

Attachment 2 – TWG Reliability Report

Attachment 3 – TWG Comments to the Priority Project Reliability Report

Attachment 4 – Brattle Group Report

Attachment 5 – Improving the Eastward Transfer Capability

Attachment 6 – KEMA Report