VOLUME 4.5

TRANSMISSION AND DISTRIBUTION ANALYSIS

THE EMPIRE DISTRICT ELECTRIC COMPANY – A LIBERTY UTILITIES COMPANY (LIBERTY-EMPIRE)

4 CSR 240-22.045

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TRANSMISSION AND DISTRIBUTION ANALYSIS

4 CSR 240-22.045 Transmission and Distribution Analysis

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

SECTION 1 ADEQUACY OF THE TRANSMISSION AND DISTRIBUTION NETWORKS

(1) The electric utility shall describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that—

1.1 Opportunities to Reduce Transmission Power and Energy Losses

(A) Reduce transmission power and energy losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040(3). The utility shall assess the age, condition, and efficiency level of existing transmission and distribution facilities and shall analyze the feasibility and cost-effectiveness of transmission and distribution network loss-reduction measures. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution systems, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options;

Electrical losses in a transmission line are directly dependent on the amount of current flowing on the line as well as the specific characteristics of the line (conductor type, line length, etc.). Liberty-Empire uses a combination of 161-kilovolts (“kV”), 69-kV, and 34.5-kV transmission lines for serving its respective substations. The majority of Liberty-Empire’s 161-kV transmission utilizes H-frame structures with a 795 Aluminum Conductor Steel Reinforced (“ACSR”) type conductor. The associated summer A and B ratings are 290 and 341 Mega Volt Amps (“MVA”), respectively. When a particular line segment studied is found to have become overloaded, Liberty-Empire evaluates the possibility of bundling conductors on the structures. This has the effect of halving the losses and doubling the capacity of the chosen conductor. The resultant summer A and B ratings for 795 ACSR are 579 and 682 MVA, respectively.

In evaluating Liberty-Empire's transmission system losses, approximately 13.5 MW of a total of 31.8 MW is accounted for on the 161-kV system. This is primarily due to the fact that Liberty-Empire's service territory mainly consists of rural loads, which do not necessitate the need to serve dense load pockets with much larger conductor types than 795 ACSR, such as 1192 ACSR used in urban load environments; however, Liberty-Empire's topography necessitates longer distances to be reconductored/bundled once a line segment is identified as a required upgrade. An example of such would be Liberty-Empire's 161-kV line connecting Tipton Ford #292 to Monett #383 Substations. This specific line is approximately 29 miles in length. A general cost comparative analysis of reconductoring the line requiring a rebuild versus bundling the conductor for minimal structural change-outs of the line yields is shown in Table 4.5-1.

Table 4.5-1 – Comparative Costs of Reconductoring versus Conductor Bundling of 161-kV Line

Configuration	R	X	B	Losses in 2015 SP Model (in MW)	Difference (in MW)
795 ACSR	0.0131	0.0856	0.0422	1.07	
2-795 ACSR	0.0065	0.0428	0.0211	1.06	0.01
2-566 ACSR	0.0093	0.0617	0.0585	1.09	0.02
Estimated cost to reconductor/bundle entire circuit:				$18,850,000	
Average cost per kW of loss reduction:				2-795 ACSR	$188,500
				2-556 ACSR	$94,250
Ratio of Avoided Transmission Costs (@ $69.90 / kW):				2-795 ACSR	2,696 : 1
				2-556 ACSR	1,348 : 1

If dual bundled 795 ACSR or dual bundled 556 ACSR were chosen as a loss reduction option, the cost for this specific line is $188,500/kW and $94,250/kW, respectively. As related to the avoided transmission costs, the ratios are 2,696:1 and 1,348:1, respectively. These ratios exhibit the cost-ineffectiveness of transmission loss reduction.

Liberty-Empire's system losses (in MWs) represent approximately 0.02 percent of the losses evident in the projected 2018 summer peak model of the entire Southwest Power Pool ("SPP") footprint. When compared to like-configured systems (i.e. comparable size and topography), Liberty-Empire's system losses are of negligible difference to that of the comparative averages, as shown in Table 4.5-2.

Table 4.5-2 – Liberty-Empire's System Losses

Area	Load (MW)	Losses (MW)	% Loss
523	979	17.45	1.8%
525	1,697	46.62	2.7%
534	1,163	32.42	2.8%
546	758	10.05	1.3%
Liberty-Empire	1,105	25.46	2.3%
Averages	1,140	26.40	2.2%

Additional analysis was done to measure the potential benefits of a case where the entire Liberty-Empire owned/operated 161kV system were to utilize a bundled conductor configuration, thereby reducing the impedance of all 161kV lines by half (doubling conductor equates to halving the impedance). The flows present on the 2018 Summer Peak Model Development Working Group ("MDWG") model set yield the results are as follows, as shown in Table 4.5-3.

Table 4.5-3 – Liberty-Empire's Avoided Transmission Costs

	Original System Losses by Zone (MW)	New System Losses with bundled (MW)	Difference in losses by Zone (MW)	Miles of line rebuilt (mi)	Assumed Cost of rebuild for entire Zone/system (in $ millions @ $700k/mi)	Cost / MW of reduced losses ($ millions/MW)	Avoid Trans. Costs @ $69.90 /kW ($ millions)
Aurora	5.0	5.2	+0.2	173.1	121.2	No benefit	0.00
Baxter	4.6	4.4	-0.2	64.84	45.5	227.5	0.01398
Bolivar	2.1	1.9	-0.2	53.03	37.1	185.5	0.01398
Joplin	7.9	5.9	-2.0	93.5	65.5	32.8	0.13980
Webb City	4.4	3.5	-0.9	86.3	60.4	67.1	0.06291
Neosho	3.2	3.2	0.0	61.01	42.7	No benefit	0.00
Ozark	0.9	0.8	-0.1	6.5	4.5	45.0	0.00699
Branson	1.3	1.0	-0.3	78.3	54.8	182.7	0.02097
Totals	29.5	26.1	-3.4	616.6	431.6	126.9	0.23766

The results show that only one area exhibited a reduction in losses of more than 1 MW (Joplin, at 2 MW). This reduction was at a cost of $65.5 million for a respective avoided transmission cost savings of $139,800. All other areas were below 1 MW of reduced system losses. The findings are a direct result of the positioning of generation on the Liberty-Empire Transmission system. Most generation assets are either within the Joplin area bounds (as defined by the planning model zones) or adjacent to the Joplin zones, and as stated above, the resulting system losses are directly proportional to the current flows. A total of $237,660 of avoided transmission costs would be realized at the expense of $432 million in transmission rebuild costs (a ratio of 1817:1). These results differ from other areas within SPP due to the topography of the Liberty-Empire system. The low density of load coupled with the high cost of longer line builds results in a higher cost per MW of reduced losses. More densely concentrated loads would result in short lines with higher flows during peak conditions, as is evident in a typical Investor Owned Utility ("IOU") topology.

With respect to the distribution level, Liberty-Empire has taken measures to standardize their construction efforts in stocking commonly used conductors within the industry. One example is the evaluation and subsequent restricted use of redundant conductor types. 4/0 ACSR was a commonly used conductor in past installations alongside 336 ACSR. The structural requirements are similar for either conductor type, however; the ampacity of 336 ACSR as compared to 4/0 was 519 and 366 amps, respectively (per Southwire's Overhead Conductor Manual, 2nd Edition). Table 4.5-4 provides a comparison of these conductors.

Table 4.5-4 – Comparison of Conductors of Interest

	Ohm / mi at 75 C	Ampacity (amps)
4/0 ACSR	0.5999	366
336 ACSR	0.3298	519

Standardizing to a 336 ACSR conductor versus the previously used 4/0 ACSR reduces line losses while increasing the capacity of the wires. In doing so, capital projects on the distribution level are delayed, more readily available switching paths are gained, and system flexibility is increased.

1.1.1 Distribution System Overview

Liberty-Empire has a single planning group tasked with transmission and distribution planning efforts. This planning group analyzes data, develops electrical models representative of the Liberty-Empire distribution system, and performs associated power flow studies to assess and prioritize system improvement needs as system dynamics dictate. Liberty-Empire maintains distribution voltages of 25-kV, 12.47-kV, and 4.16-kV three-phase as well as a mixture of open wye (dual-phase) and single-phase feeders. These feeders are composed of an assortment of conductor types and configurations.

The majority of the Liberty-Empire distribution system mirrors that of a rural area co-op. Many of Liberty-Empire's distribution feeders are long in length and have a distributed load profile. The average total distribution feeder exposure length within the Liberty-Empire footprint is approximately 11 miles. This distance encompasses the total circuitry length (i.e. all trunk lines, taps, radials, etc.). The average length of overhead three phase of all Liberty-Empire distribution circuits is 7.21 miles. The highest density loads are located in the Joplin and Branson areas. The rural areas have the most widespread infrastructure components and have the fewest or most limited emergency ties, where minute load manipulation can cause large disturbances to customers' voltage. The limited availability of switching paths is the largest factor in restoration efforts as well as feeder relief. The Liberty-Empire distribution system is configured as a radial fed system under normal operating conditions. Liberty-Empire maintains three auto throw schemes in different parts of the system (Joplin and Branson in Missouri, and Welch, Oklahoma) where alternate switching paths with available capacity are readily available. These type systems have limited applicability due to the typical Liberty-Empire distribution circuit being rural in character.

Expansion of the distribution network occurs in load pockets of expansive development (i.e. subdivision expansion, large industrial customer development on Greenfield sites, etc.). System expansion typically occurs on a smaller scale in magnitude; however, with the addition of these types of incremental load additions, the existing infrastructure is impacted more heavily due to the voltage profile drastically changing from the application of spot load(s) applied to the circuit. Liberty-Empire constantly evaluates possible economic development projects and their associative impacts on the available distribution feeders, power transformers, and existing customer voltage profiles so as to determine what specific large scale upgrades are needed for a specific project of interest.

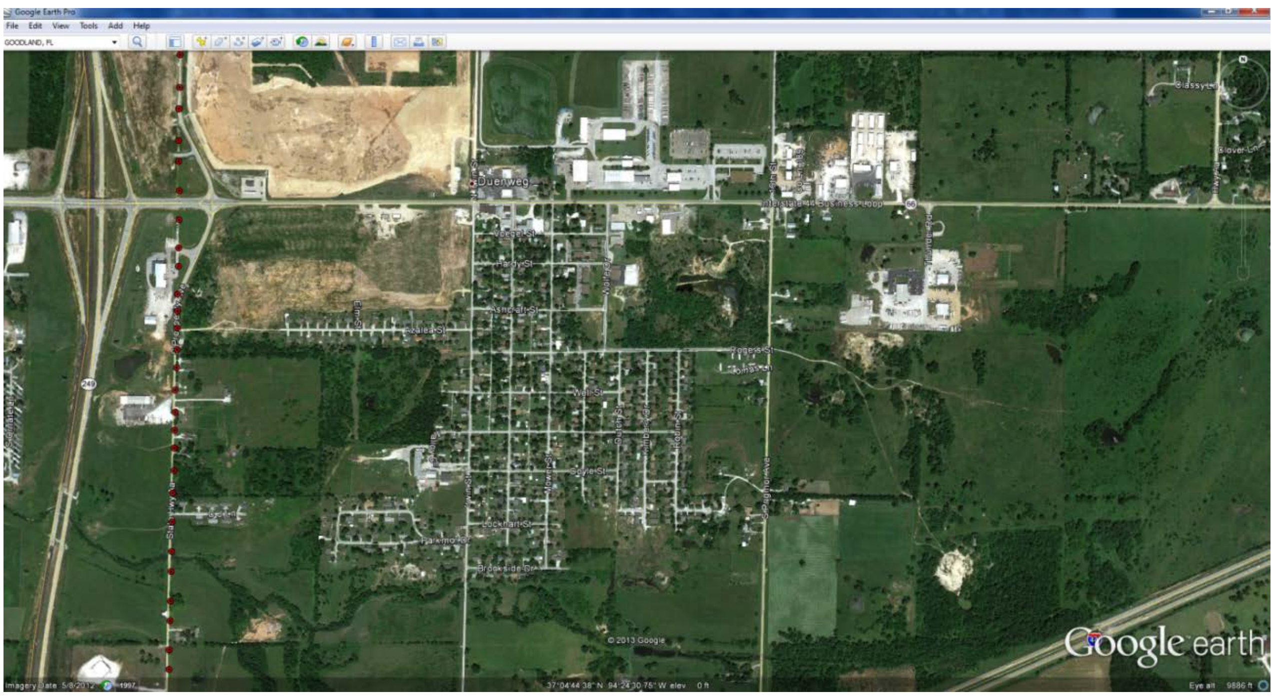
Liberty-Empire's planning department also maintains distribution feeder models. Liberty-Empire has migrated to new distribution evaluation software and is currently integrating the available mapping resources to better model the distribution systems. The new model will allow for detailed evaluations as data becomes available so that as expansion occurs and load reconfigures, projects may be identified and prioritized accordingly.

1.1.2 Annual Scope of Work

Throughout each year, Liberty-Empire's planning department prepares a number of system studies to determine weaknesses or risks and to assess the overall adequacy of their distribution system. The majority of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work encompasses four specific areas, which include capacity, contingency, voltage, and condition. Liberty-Empire uses a variety of tools to conduct these types of evaluations, including software such as Google Earth Pro, CYME International's Power Engineering Solutions, and GTI geospatial analysis and viewing.

Figure 4.5-1 provides a screenshot from Google Earth Pro.

Figure 4.5-1 – Google Earth Pro Screenshot



Liberty-Empire has merged the mapping system topology with Google Earth which allows for detailed mapping of associated feeders to be studied as well as allows for ready review of proximity to alternate switching paths. Allowing for a view of the topography and attempting to head off any construction hindrances has proven effective on past projects. Projects imposed over the Google Earth snapshots allow those with a vested interest in the job to gain further knowledge of the scope of work to be done.

Figure 4.5-2 provides a screenshot from GTI's GTViewer. This software allows engineers to acquire model data for use in distribution analysis software, CYMDIST. GTI's software device characteristics and connectivity drive load-flow models in use by Liberty-Empire's planning department. In the near horizon, Liberty-Empire will attempt to merge all planning software platforms so that real time data and analysis will be available to users. In doing so, real-time models will allow for an exhaustive review should the need arise.

Figure 4.5-2 – GTViewer Screenshot

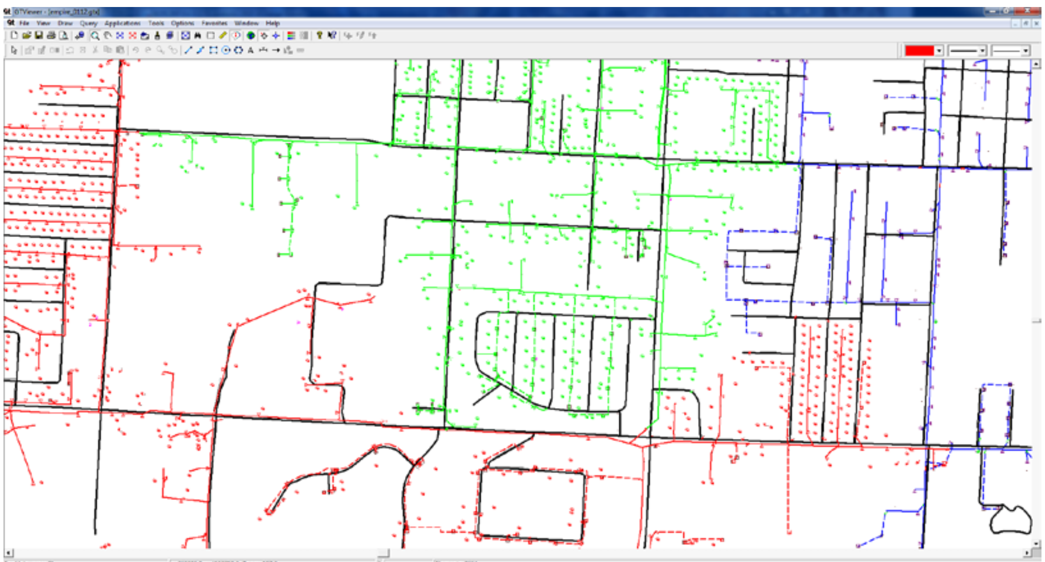
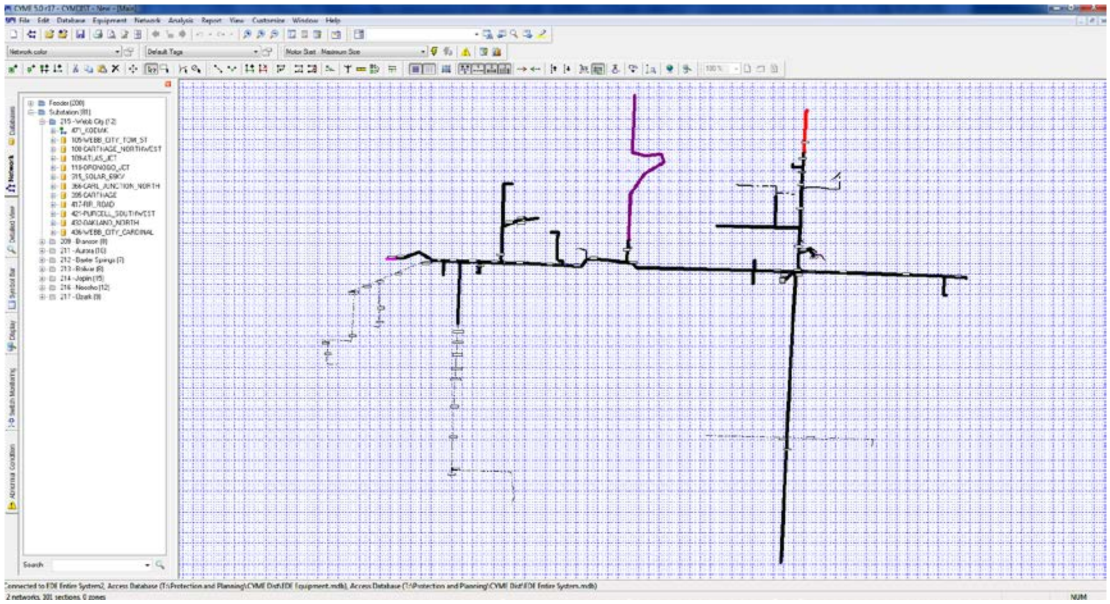


Figure 4.5-3 below provides a screenshot from CYM Distribution System Analysis.

Figure 4.5-3 – CYMDIST Screenshot



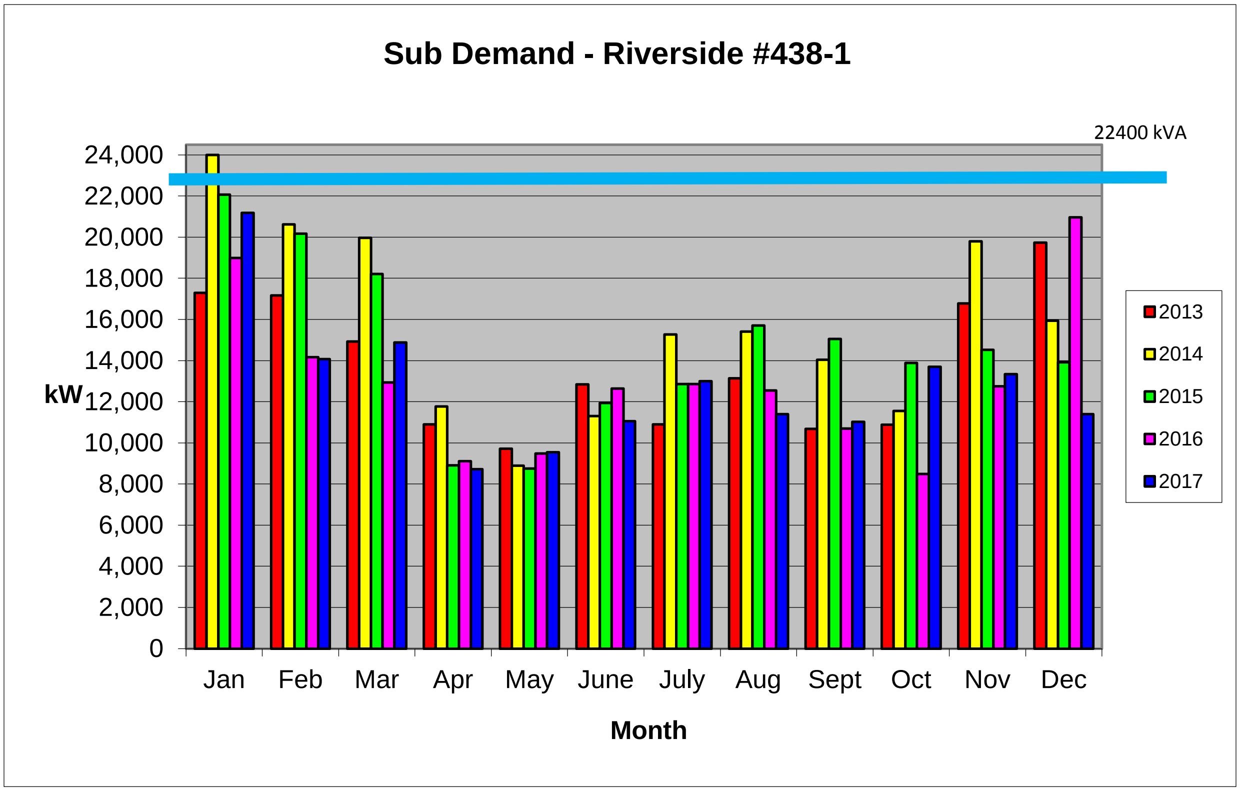
CYMDIST is a multipurpose tool primarily used by engineers to analyze load-flow characteristics of distribution feeders. Liberty-Empire's planning department also provides fault current information to its customers' electrical contractors when performing arc-flash studies, a process which requires the use of CYMDIST.

1.1.2.1 Capacity Planning

Substation transformer and distribution circuit loads are collected annually, with the primary sources being monthly metering data and seasonal station checks. This load data is compiled into a database that can be parsed into different seasons, definite dates, specific months, or years' worth of data for analysis. The data is also compared to the maximum capacity available at the service transformer to determine overloads evident in past scenarios or present system configurations. These types of overloads are higher in priority due to the severity and long lead time mitigations available.

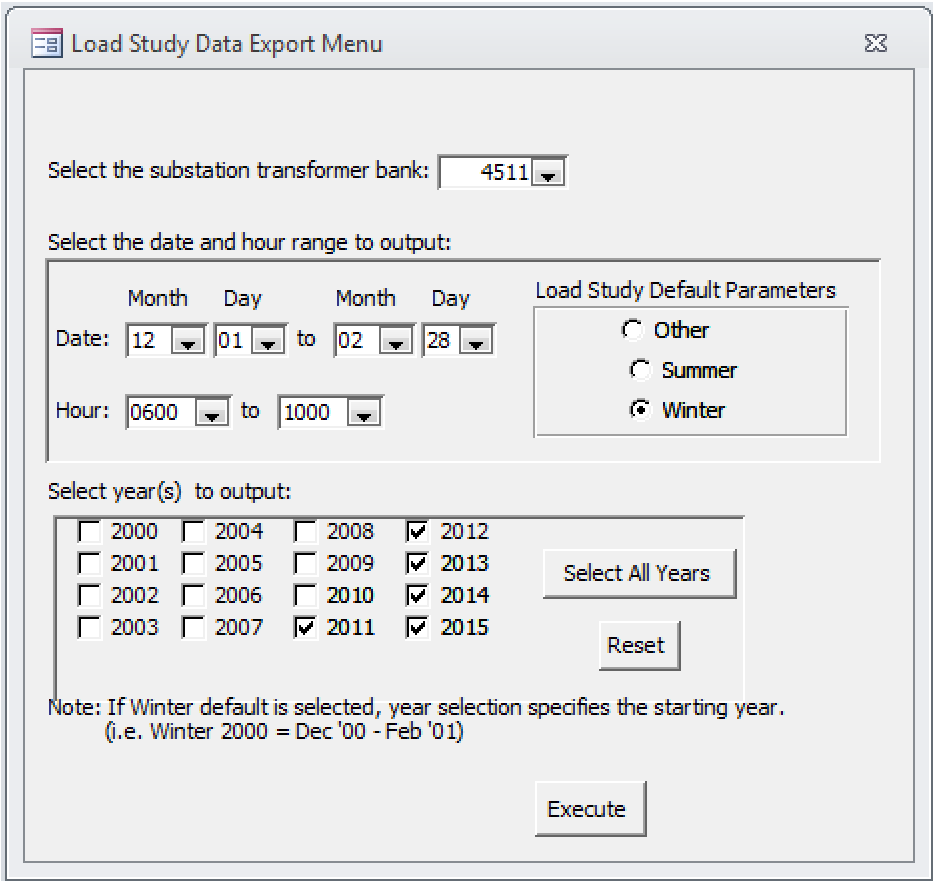
Figure 4.5-4 shows an example of substation trending over multiple years in the multiple seasons.

Figure 4.5-4 - Substation Trending Over Multiple Years during Peak Load Switching



A screenshot of the Microsoft® Access metering database compiled for seasonal, annual, or definite time interval(s) is shown in Figure 4.5-5.

Figure 4.5-5 – Metering Data Compiled For Seasonal, Annual, or Definite Time Interval(s)



1.1.2.2 Contingency Planning

Transmission and distribution system planning includes consideration of contingencies and their impact on the systems as they may change under varying conditions. As the graph above shows, switching arrangements are reflected in our system load database. Inclusion of this type contingency event allows for evaluation in subsequent capital improvement project weighting. Projects are then scoped appropriately to allow for contingency switching events and redundancy of adequate capacity.

1.1.2.2.1 Distribution Contingency Evaluation

From distribution studies performed throughout a given year, Liberty-Empire's planning department determines what switching paths are available during a contingency event. Examples of these types of studies include evaluation of substation transformer loading (as in the graph above) to determine available capacity present on a substation of interest, splitting trunk lines and their effects on voltage profiles on a given feeder, and phase loading imbalance due to the topography changes made during switching adjustments. These studies allow the engineering department to make informed decisions on available transfer capabilities on specific feeders. Once weaknesses are identified and analyzed, the resulting system impacts can be ranked against other results for determining capital budget project priority. Ultimately, this ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost are used to determine whether or not a system improvement is implemented. The Liberty-Empire planning department identifies the weaknesses and provides budgetary estimation and project description in conjunction with Liberty-Empire's Line Design department. It also becomes the responsibility of the planning department to thoroughly communicate the justifications for projects to the vested departments internal to Liberty-Empire.

1.1.2.2.2 Transmission Contingency Evaluation

Liberty-Empire conducts transmission system performance studies as required by the North American Electric Reliability Corporation ("NERC") TPL-001, TPL-002, TPL-003, and TPL-004 standards, soon to be replaced by TPL-001-4. These studies are provided as supplements to the SPP TPL Compliance Report. Studies include evaluations of N-0 (i.e. the base case), N-1 (meeting the N-1 criteria within the Liberty-Empire system footprint), multiple contingencies (Type C), and extreme contingency scenarios (Type D), as defined in Table 1 of the NERC Transmission Planning Standards.

1. Base Case – All Facilities In-Service: The studies are conducted on an annual basis incorporating both near-term and long-term planning periods. The models used in the study process have an initial condition of normal operating procedures in

place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-001 standard.

2. N-1 – Loss of a Single Element:
    a. The studies are conducted on an annual basis incorporating both near-term and long-term planning periods. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-002 standard. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series.
    b. The N-1 contingency analysis was run for each of the seasonal models from the 2011 series cases with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review of all N-1 contingencies within the Liberty-Empire footprint was performed. The rationale used in choosing the contingencies studied included all single elements as defined in SPP Criteria 12 within the Liberty-Empire footprint along with the effects of outaged tie lines with neighboring entities.
3. Multiple Contingencies – Loss of Two or More Elements:
    a. The studies are conducted on an annual basis incorporating both near-term and long-term planning periods. The models used in the study process have an initial condition of normal operating procedures in place, have all

projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series. The multiple contingency analyses were run for each of the seasonal models from the 2011 series case with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review of Type C contingencies within the Liberty-Empire footprint was performed. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-003 standard.

b. The conditions evaluated which conform to Type C contingencies include loss of two or more elements (normal clearing, manual system adjustments between events), bus section faults, double circuit tower lines, and breaker to breaker sectional outages. The resultant thermal and voltage overloads were then evaluated in an effort to mitigate wherever possible with minimal loss of demand and curtailment of firm transfers. In satisfying the requirements of TPL-003, Liberty-Empire does not employ a rating rational on the severity of specific contingency scenarios. Liberty-Empire reviews the aforementioned applicable contingencies as defined in Table 1, Type C. In an effort to encompass the worst case scenario outages, the bus outages were included in the Type C contingencies but are also applicable to Type D contingencies. Bus section outages have been shown to be the most effectual outages on the Liberty-Empire system, due to the number of outaged elements associated with individual simulations. The outages which involve single-line-to-ground or three-phase faults were not evaluated for stability purposes. The rationale for this omission hinged on three factors: no substantial system changes directly relating to stability were made to the Liberty-Empire system, a previous stability study (the 2006 System Facilities Study) showed no Liberty-Empire stability-related issues, and no stability issues were evident in the previous SPP TPL compliance reports.

4. Extreme Event (Multiple Elements) Contingency: The studies are conducted on an annual basis incorporating both near-term and long-term planning periods. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-004 standard. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series. The multiple contingency analyses were run for each of the seasonal models from the 2011 series case with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review using the rationale of all applicable contingencies which conform to Table 1, Type D within the Liberty-Empire footprint was performed. These include loss of a tower line with three or more circuits, all circuits on common right-of-way, substation (one voltage level plus transformer), and the loss of all generating units at a station. The resultant thermal and voltage overloads are then evaluated in an effort to mitigate wherever possible, with minimal loss of demand and curtailment of firm transfers. In satisfying the requirements of TPL-004, Liberty-Empire does not employ a rating rational on the severity of specific contingency scenarios, but rather reviews contingencies applicable to Liberty-Empire as defined in Table 1, Type D. Contingencies that are not applicable to Liberty-Empire's footprint were

not evaluated including Type D contingencies involving special protection systems, load centers, and switching stations.

1.1.2.2.3 Worst Performing Circuit Analysis

To improve the performance of its WPCs, Liberty-Empire adopted a corrective action plan approach that includes the following activities:

1. Liberty-Empire employees perform a "walk-through" of the WPC, collecting engineering data to support the following coordination study and sectionalizing program. Items are noted and corrected as part of the corrective action plan.
2. Upon walk-through completion, a coordination study of the circuit occurs. The coordination study evaluates protective equipment settings and application to ensure each protective device properly operates with other upstream and downstream protective equipment.
3. Additional sectionalizing is then added to the circuit to reduce the number of customers experiencing an outage, in the event that an outage occurs, thus increasing reliability to other customers on the circuit.
4. Faulted circuit indicators are also added to the circuit to reduce restoration time and shorten customer outage duration.
5. In addition to the coordination study and sectionalizing program, any vegetation-related issues identified are scheduled to be cleared for each circuit.

Each of the activities listed above is performed as a process of implementing the WPC remediation. The engineering portion of the process includes the coordination study, and the construction portion follows. Typically, engineering is performed in the year prior to construction.

1.2 Assessment of Interconnecting New Facilities

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;

Liberty-Empire is required to meet the interconnection needs of transmission customers for connection to, and use of, the Liberty-Empire transmission system. The Federal Energy Regulatory Commission ("FERC")-approved transmission tariffs provide procedures for detailed transmission studies and interconnection estimates for connecting to and using Liberty-Empire's transmission system. Liberty-Empire's planning department provides a range of transmission costs for various sites of interest on defined projects and identifies potential transmission limitations with the inclusion of projects of interest. Any Liberty-Empire generation resource addition that would impact transmission level flows is required to proceed through the SPP Generation Interconnection ("GI") process before it can be interconnected to the transmission system. Every resource addition would also have to be included in the SPP Aggregate Facility Study ("AFS") process to obtain firm transmission service for delivery of generation to load. The most recently completed Interconnection Study that directly involved Liberty-Empire petitioning for new transmission service was the SPP Definitive Interconnection System Impact Study ("DISIS") for Generation Interconnection Requests (DISIS-2015-001). Liberty-Empire has two requests: GEN-2017-060 and GEN-2017-082, which are presently being studied within the DISIS-2017-001 groupings. No initial results are available at this time for the 2017-001 study as well as multiple higher-queued studies. The delay of study results is directly related to the excessive amounts of generation requests, particularly wind assets, included in GI Studies (see Table 4.5-5 and Figure 4.5-6 below).

Table 4.5-5 – List of Generation Requests

GI Clusters	MW of Generation	Requires Completion Of	Estimated Date
DISIS-2015-002-6	>5,900 MW	DISIS-2015-002-5	TBD
DISIS-2016-001-3	>7,690 MW	DISIS-2016-001-2	TBD
DISIS-2016-002-1	>12,475 MW	DISIS-2016-002	TBD
DISIS-2017-001	>16,500 MW	DISIS-2016-002-1	2ND QTR 2019
DISIS-2017-002	>31,100 MW	DISIS-2017-001-1	1ST QTR 2020
DISIS-2018-001	>11,300 MW	DISIS-2017-002-1	3RD QTR 2020

Given the extreme magnitude of GI applications and the delay of the involved studies, there is no appreciable way in which to estimate the system impacts and associated estimated costs for the necessary upgrades needed to facilitate the interconnection of the requests submitted by Liberty-Empire.

An example of this process is the addition of Liberty-Empire's Riverton Unit 12 with future expansion to a combined cycle configuration. Once this additional resource had been submitted for study in the GI and AFS processes, the resultant upgrades were identified and evaluated for feasibility and cost-effectiveness. Building on the previous system impact study, the most recent Generation Addition study by way of expanded capacity was the additional capacity realized during the construction of the combined cycle addition to Riverton Unit 12. The initial filing for firm transmission service accounted to an assumed 250 MW of capacity, nine years prior to the actual construction of the recovery unit. Now that actual testing data is available for the generator to be energized, Liberty-Empire was able to gain an additional 35 MW of gross capacity during seasonal operations. Therefore, this additional capacity required a system impact study to ensure deliverability of the additional capacity.

The most recent requests submitted by Liberty-Empire awaiting finalization are GEN-2016-013 and GEN-2016-014, which are included in DISIS-2016-001-2. Each of these requests represented 10 MW increases for individual units at Liberty-Empire's LaRussell Energy Center (Units 3 & 4, respectively). Again, due to the position within the Liberty-Empire transmission system as well as the far Eastern side of the SPP, the impacts were minimal and no appreciable upgrades were needed to incorporate the increase in capacity of the existing units.

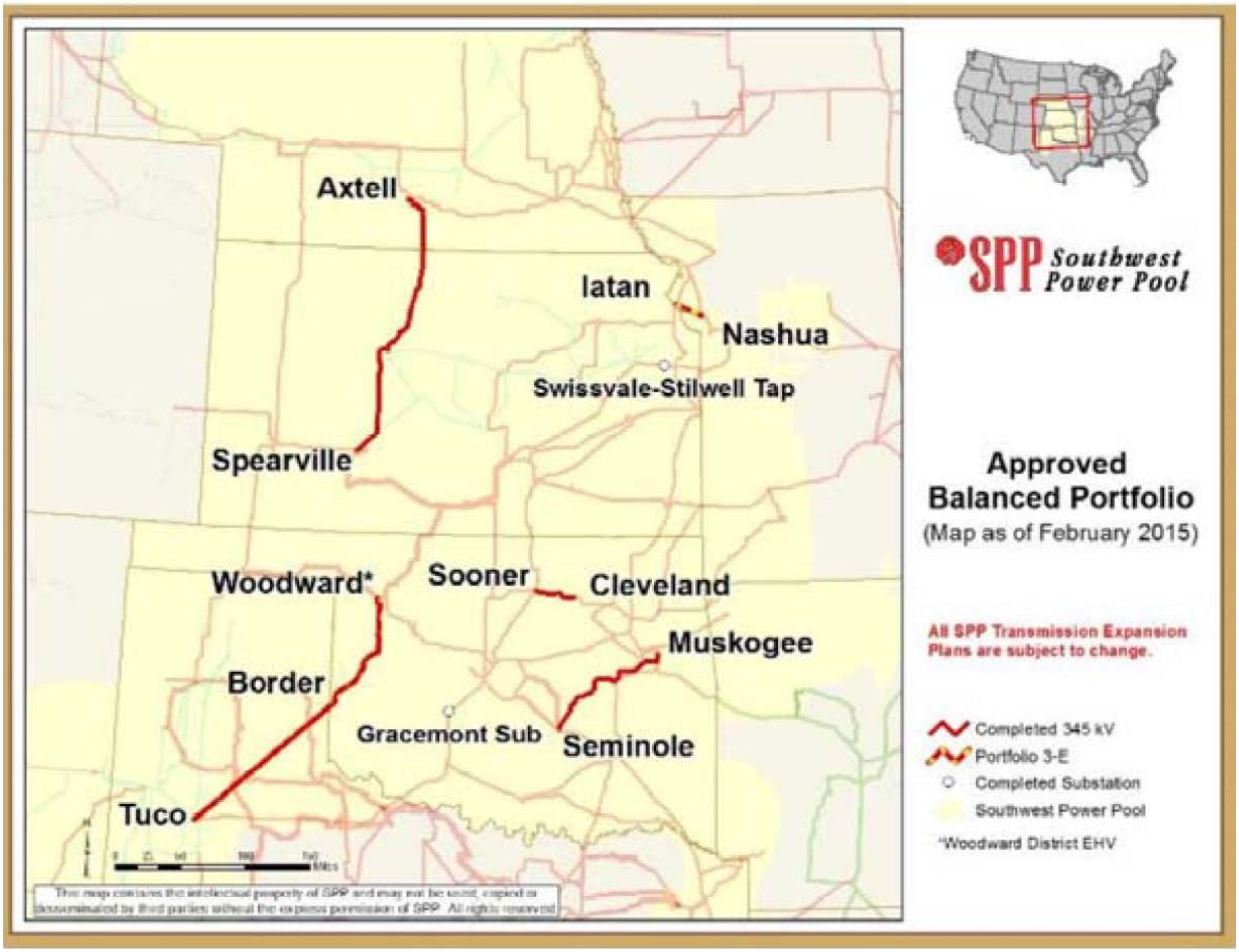
1.3 Assessment of Transmission Upgrades for Power Purchases

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040(3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of preliminary supply-side candidate resource options; and

All Liberty-Empire transmission planning is performed in conjunction with SPP, the Regional Transmission Organization ("RTO") to which Liberty-Empire belongs. Liberty-Empire's affiliation with SPP began during World War II, when SPP was initially formed. FERC empowers RTOs to ensure power supply reliability, transmission infrastructure adequacy, and competitive wholesale electricity prices through the NERC. In turn, SPP oversees enforcement and development of NERC reliability standards within its footprint, which spans across 14 states. Liberty-Empire fully participates in SPP's regional transmission expansion planning processes. Regardless of whether or not Liberty-Empire adds supply resources or contracts for sales, the unique and specific costs of the portfolio of projects determined in the various SPP coordinated studies are allocated throughout SPP. Thus, no costs for Liberty-Empire's allocation of the costs have been included in the analyses of preliminary supply-side resource options in this plan.

The Balanced Portfolio was a SPP strategic initiative to develop economic-based transmission upgrades that benefit the SPP region while allocating costs to utilities in the region. Balanced Portfolio projects have included 345-kV transmission upgrades to obtain potential savings that exceed project costs. Such upgrades are intended to reduce congestion on the SPP transmission system, and thereby reduce generation production costs. Other benefits include increased reliability and lower required reserve margins, deferment of other reliability upgrades, and environmental benefits from more efficient operation of generating assets and increased renewable resource production. SPP's analysis of the Balanced Portfolio concluded that these projects would provide an average benefit of $1.66/month per customer for a corresponding cost of $0.88/month per customer. Seven transmission projects for a total initial estimated engineering and construction cost of approximately $692 million were included in the Balanced Portfolio, as shown in Figure 4.5-6.

Figure 4.5-6 – SPP Approved Balanced Portfolio Transmission Projects[1]



The SPP Balanced Portfolio Report is provided for reference in Appendix 4.5A.

[1] Source: "Intro to SPP" slideshow from the Fast Facts section of SPP's website (http://www.spp.org/Documents/31587/20151001%20Intro%20to%20SPP-October%202015.pdf) as of October 2015, on page 72

The purpose of SPP's Priority Projects plan was to identify, evaluate, and recommend transmission projects that could improve regional production costs, reduce grid congestion, enable large-scale renewable resources (primarily wind), improve the GI and AFS processes, and better integrate SPP's east and west regions. Six transmission projects with an approximate total cost of $1.1 billion were recommended for construction in the Priority Projects process providing a variety of benefits to the region. These Priority Projects will reduce transmission congestion, while improving the AFS process by creating additional transfer capability and increasing the ability to transfer power in an eastward direction to facilitate wind power.

The SPP Priority Projects Phase II Final Report is provided for reference in Appendix 4.5B.

The current study in progress at SPP is the Integrated Transmission Plan ("ITP"). There are three subsets of this particular study: ITP 20-Year ("ITP20"), ITP 10-Year ("ITP10"), and ITP Near-Term ("ITPNT"). Liberty-Empire is an active participant in each of these studies and maintains a voting membership in each of the respective working groups.

The ITP is a three-year study process which assesses SPP's regional transmission needs in the long- and near-term with the intention of creating a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. Along with highway/byway cost allocation methodology, the ITP process, as embodied in SPP Attachment O and approved by FERC in July 2010, promotes transmission investment that will meet reliability, economic, and public policy needs. This report documents analysis of the ITP process which focused on the 20-year horizon with an objective of planning for SPP's long-term regional needs. ITP development was driven by the Synergistic Planning Project Team ("SPPT"), which was created by the SPP Board of Directors to address gaps and conflicts in all of SPP's transmission planning processes including GI and transmission service. ITP's purpose is to develop a holistic, proactive approach to planning that optimizes individual processes and positions SPP to respond to national energy priorities. ITP is based on SPPT's planning principles which emphasize the need to develop a transmission backbone large enough in both scale and geography to provide flexibility for meeting SPP's future needs.

ITP20 looks into the future 20 years as required by Open Access Transmission Tariff ("OATT") Attachment O, Section III. ITP20 is an expansion of the annual SPP Transmission Plan ("STEP"), which is the 10-year transmission expansion plan that began in 2006. SPP has had two previous plans which similarly provide a look into the future that helps form near-term plans. Projects identified in ITP20 provide benefits to the region across multiple futures and create flexibility for SPP to meet future needs. ITP effort has been driven by numerous interactions with stakeholders and with significant support from the Economic Studies Working Group ("ESWG") and Transmission Working Group ("TWG"). Liberty-Empire participates and maintains voting membership in both working groups. ITP20 differs from earlier plans in the level of detail and effort that has gone into its preparation. The SPP 2013 Integrated Transmission Plan 20-Year Assessment Report is provided for reference in Appendix 4.5F.

The second phase of the ITP study process included ITP10 and ITPNT assessments performed under the requirements of OATT Attachment O, Section III. The study process for ITP10 utilized a diverse array of power system and economic analysis tools to evaluate 100-kV and above facility projects that satisfy needs such as:

1. Resolving potential criteria violations
2. Mitigating known or foreseen congestion
3. Improving access to markets
4. Staging transmission expansion
5. Improving interconnections

The recommended portfolio included projects ranging from comprehensive regional solutions to local reliability upgrades that address expected reliability, economic, and policy needs of the studied 10-year horizon. Two distinct futures were considered to account for possible variations in system conditions over the assessment's 10-year horizon. The SPP 2017 Integrated Transmission Plan 10-Year Assessment Report is provided for reference in Appendix 4.5E.

The most recent iteration of the ITPNT was approved by the TWG in December of 2014. ITPNT analyzes SPP's immediate regional transmission needs. ITPNT goals are to preserve grid reliability, in compliance with NERC reliability standards and individual transmission owner planning requirements, and efficiently bridge SPP's 10- and 20-year plans that meet public policy objectives and provide access to more economic energy sources. ITPNT assesses:

1. Near-term regional upgrades required to maintain reliability in accordance with NERC reliability standards and SPP criteria;
2. Near-term zonal upgrades required to maintain reliability in accordance with more stringent individual transmission owner planning criteria; and
3. Coordinated projects with neighboring transmission providers

The SPP 2018 Integrated Transmission Plan Near-Term Assessment Report is provided for reference in Appendix 4.5D.

Liberty-Empire participates with non-SPP members such as Associated Electric Cooperative, Incorporated ("AECI") to examine potential mutually beneficial projects. One recent example is Liberty-Empire's participation in the AECI-SPP Joint Study. The AECI-SPP Joint Study is a recurring study that involves impacted SPP members in the southeastern portion of SPP's footprint, along with neighboring seams companies. The scope of the studies involves identifying forecasted issues on seams parties' footprints and studying proposed projects to acquire mutually beneficial results. This type of study allows for conversation to flow between SPP members and non-members so that interconnections, mitigation techniques, and cost sharing projects can be vetted by both sides of ownership. Collaboration shares the burden and pairs common goals with collective and impactful results. Liberty-Empire not only provides possible projects for study, but also internally studies presented projects. Liberty-Empire does this to determine whether a proposed project could mutually benefit Liberty-Empire and AECI exclusive of other southeastern SPP members' lack of interest or benefit. Liberty-Empire also participates in AECI's Long Range Plan meetings, most recently hosted by Liberty-Empire in October 2015, to assess other proposed tie line projects between Liberty-Empire and AECI.

1.4 Assessment of Transmission or Distribution Improvements with Respect to Cost-Effectiveness of Demand-Side Management or Supply-Side Resources

> *(D) Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the analyses of each resource option.*

1.4.1 Context of Requirement 22.045 (1)(D) and Liberty-Empire's Long-Term Directions

In its 2019 IRP, Liberty-Empire is offering a three-level perspective of its advanced transmission and distribution technology plans in fulfillment of the goals and objectives of the IRP. This three-level perspective is set out below.

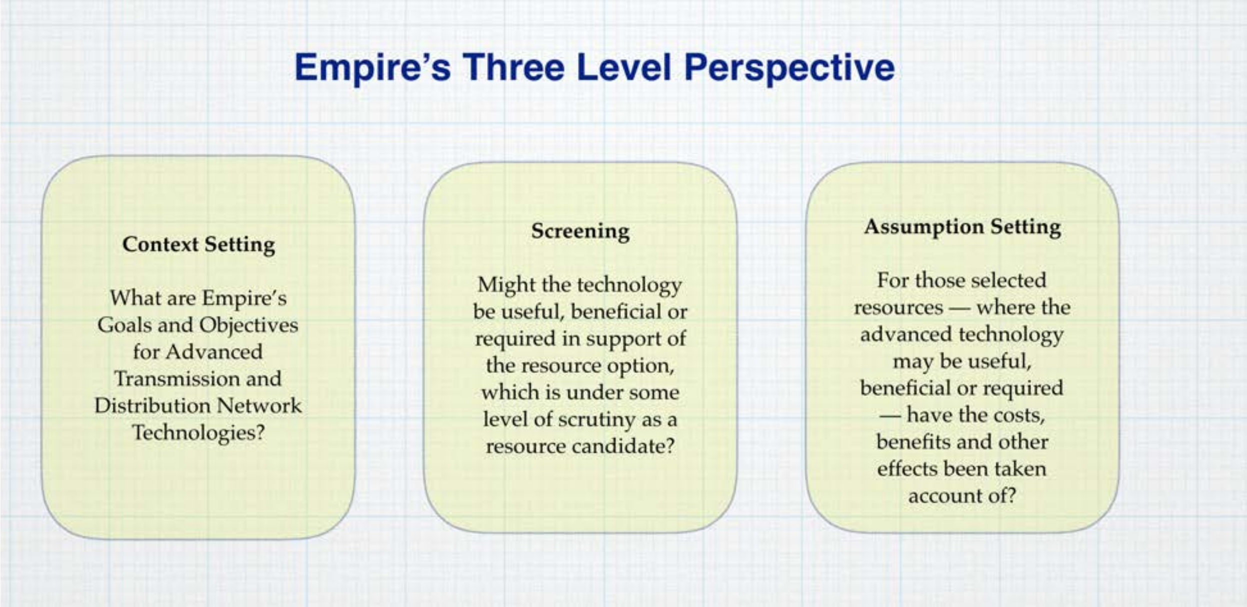
First, and as in its 2016 Triennial IRP, Liberty-Empire continues to pursue implementation of Advanced Transmission and Distribution Network Technologies ("ATDNT") for the purposes of addressing several utility grid operations requirements, including those specifically germane to fulfilling the requirements of Chapter 22 ("IRP Rule"). In Liberty-Empire's view, ATDNT represent the normal but important engineering and business integration of technology that is otherwise needed to sustain grid functions, ensuring that the Liberty-Empire transmission and distribution grid is operating safely, reliably, within standards and requirements, and with an appropriate degree of resilience against a wide range of potential harm. Accordingly, Liberty-Empire is providing in this IRP a description of its long-term directions and aspirations regarding the integration of ATDNT as it serves as an important backdrop to Liberty-Empire's fulfillment of specific IRP compliance requirements in relation to ATDNT. This also includes providing updates to efforts with technologies it has described in its 2016 IRP submittal.

Second, Liberty-Empire has incorporated into its screening of supply- and demand-side resource opportunities a review and determination of whether ATDNT may be useful, beneficial, or required to enable the cost-effective inclusion of the resource into further stages of the IRP resource review and screening process. Liberty-Empire has also identified whether the ATDNT is in place, or whether there are plans for its implementation. In this way, the IRP resource analysis choices in downstream stages and steps (per the step-wise filtering that is conducted of candidate resource options) are not prematurely demoted in their assumed availability to meet load requirements due to the lack of enabling technology on the transmission or distribution networks.

Third, for any further selected Supply and Demand side resources meeting final stages of candidate review, and which require assumptions concerning ATDNT functionality, Liberty-Empire has identified the cost and benefit assumptions that should be considered as part of the resource selection finalization process. For example, if Resource Candidate Option X is included in the IRP as a final candidate, then the costs and benefits of the contributing ATDNT that supports Candidate X should be identified and reflected into the analysis. Liberty-Empire notes, however, that it has not found a specific nexus with ATDNT that falls into this third screening step. It has not found ATDNT assumptions that are dispositive into the consideration of resource candidate options at final stages of resource screening.

This three-level perspective of its advanced transmission and distribution technology plans are depicted in Figure 4.5-7 below.

Figure 4.5-7 – ATDNT Review Stages as Part of the Liberty-Empire IRP



1.4.2 Liberty-Empire's Long-Term Advanced Technology Goals and Objectives

Liberty-Empire is pursuing several areas of ATDNT that will support Liberty-Empire's customers well over time, and that advance capabilities that will: (a) sustain and improve system reliability through such means as recloser and smart fusing operations; (b) improve system resilience through rebuilding core infrastructure such as substations; (c) improve day-to-day operations and customer care functions related to billing and other common customer energy account services; (d) reduce distribution system operational inefficiencies related to metering, billing accuracy, tamper and energy theft; (e) deliver energy efficiencies and power quality enhancements on the distribution system through the pursuit of voltage control capabilities; (f) improve the quality of information Liberty-Empire is able to provide customers about their energy use, therefore empowering customers to be better energy consumers; and (g) support new and expanded customer energy service choices through e.g., metering, rate programs and Liberty-Empire situational awareness of grid performance.

Not all of these improvements will be readily visible to customers, nor are they limited to the installation of physical devices. The ATDNT plans, for example, will lead to more grid self-healing through distribution automation, expanded and improved communication to substations and field devices, and improvements in day-to-day engineering functions due to improved circuit models and maps. Process improvements of these kinds are needed if Liberty-Empire is going to be able to operate and maintain the grid reliably and resiliently, supporting the delivery of the right energy product in the right place and time as demanded by the Liberty-Empire customers over time. In this way, the ATDNT aspirations are best viewed from a systems point of view, involving by necessity field-located hardware, communications, integrated back office systems, and process improvements that apply the new functional capabilities in order to secure benefit achievement.

1.4.3 Principles that Guide Liberty-Empire's Technology Selections

Market Maturity – In defining its long-term ATDNT goals, Liberty-Empire applied several reasonable planning principles. These principles provide actionable guidance to determining what technology makes sense for Liberty-Empire. One such principle pertains to *market maturity*. Liberty-Empire, for example, has evaluated Advanced Metering Infrastructure ("AMI") for several years as this technology system matures. Liberty-Empire believes AMI is now a good choice because of the AMI market maturity, price points, and other risk-oriented factors. In Liberty-Empire's view, it is important to ask itself when it is prudent to embark on implementing advance technologies so as to balance benefit aspirations with organizational capabilities and resources. Benefits will not emerge unless the technology is mature, the systems are well planned, the costs are reasonable, and the resources are in place to implement the system well.

Long-Term Operability – A related principle involves a technology's *long-term operability.* The technology should be well-established – with a vendor support ecosystem in place – so as to provide confidence to Liberty-Empire that it can operate the technology well and safely, can troubleshoot and resolve problems when they arise, and can sustain the system for the long term at a reasonable cost.

Market Policy Design – Liberty-Empire is also aware of implementing technology that supports long-term *market policy design* considerations. The utility community is aware of new demands for attention on energy market performance to ensure that customers are able to meet their energy needs in a way well aligned with their preferences. These preferences are changing as technology changes and demographics affecting energy use consumption patterns change. Today, consumers operate in an “always on” economy and they have new expectations about the cost, quality and performance of their energy providers. Moreover, as these influences relate to the technology Liberty-Empire might deploy, they often involve questions about information: its granularity, quality, cost (to collect, process and dispatch), protection, custody, and ultimately interpretative value for helping customers get a good value for their energy dollars.

Empowering Customers – Another principle involves *empowering customers*. In addition to implementing technologies that increase Liberty-Empire’s control and awareness of system conditions, Liberty-Empire also seeks to deploy technologies that support customers in managing their energy choices (as the customers become more attuned to the range of choices within an expanding energy market). Information gathering and dissemination will help markets function better; advanced network technology – such as AMI – are part of the challenge of unlocking them.

1.4.4 Support through Liberty Utilities

Liberty-Empire reduces its technology risk adoption by leveraging its participation as one of several operating companies within Liberty Utilities. First, Liberty-Empire leverages the learning of its sister companies in the consideration and adoption of new technology. One example is work currently being conducted on an innovative energy storage battery initiative in New Hampshire by its sister company, CalPeco.

1.4.5 Baseline of Activity: Continuity with the Liberty-Empire 2016 IRP

Liberty-Empire places section 22.045 compliance into a context of long-term ATDNT aspirations while also determining any specific nexus of ATDNT to supply and/or demand-side resource choices (involving the identification of associated costs, benefits and other assumptions). Part of this context setting involves explaining its progress on several areas of ATDNT piloting and implementation described in its 2016 IRP (and 2017 update).

In these recent IRPs, Liberty-Empire described the role of advanced technologies on its system, including but not limited to microprocessor relaying, fiber optic relaying and communications, transformer oil dissolved gas monitoring ("DGM"), transformer bushing monitoring, transformer bushing monitoring with partial discharge, transformer fiber optic winding temperature sensors, transformer monitoring, comprehensive transformer health monitoring, fiber optic substation data network, substation data archive, server, and database, 69-kV vacuum circuit breakers. Also discussed were automatic throw-over switching schemes, dynamic voltage control, conservation voltage reduction, energy storage, communications, Liberty-Empire's *Operation Toughen Up* ("OTU"), a feeder automation demonstration, expanded recloser utilization, an advanced fusing study, event analysis activities, and inspection of load profile data.

In the context of the 2019 IRP, many of these efforts form an activity baseline that continues indefinitely, reflects sound engineering practice, comports with current and emerging standards, stays aligned with vendor innovation, applies advanced asset management techniques, stays true to fundamental functional and technology dependencies (such as Supervisory Control and Data Acquisition ("SCADA") communications), and proceeds prudently in recognition of core grid functions (i.e. safety, security, reliability, resiliency, capacity, and contingency). For example, Liberty-Empire expects that it will continue to apply advanced network technology (Optical Ground Wire ("OPGW"), All Dielectric Self-supporting ("ADSS"), microprocessor relaying for protection, automatic throw-over switching schemes on the 69-kV system, use of smart fuses and reclosers), OTU will continue to harden the system, and SCADA communications will continue to enable more grid functions.

1.4.6 The Role of AMI and Operational Performance Improvements

Building on this baseline, and as a next phase of Liberty-Empire's ATDNT efforts, Liberty-Empire intends to improve customer care functions and improve related operational performance through the implementation of an AMI system covering Liberty-Empire's approximately 173,000 residential and commercial electric meter customers.[2] Liberty-Empire intends to continue its detailed implementation planning of its AMI initiative during 2019, followed by the network and meter installation sometime during the 2020-2021 timeframe. This AMI initiative is part of Liberty-Empire's 5-year capital plan and is coordinated with the Liberty Utilities' company-wide rollout of AMI. Liberty-Empire's AMI initiative is designed to occur in specific stages that are tied to integrations to billing, outage management and other essential "back office" systems, which rely in part on advanced metering data. These stages occur over time and in a methodical and prudent step-wise fashion. This AMI Plan is further addressed within Volume 6 and the section addressing Special Contemporary Issues ("SCI") related to AMI.

1.4.7 *Customer First* Initiative

Closely tied to Liberty-Empire's AMI initiative is Liberty Utilities' corporate-wide Customer First initiative. *Customer First* runs parallel to AMI and provides capabilities that over time will enhance Liberty-Empire's customer care functions in conjunction with AMI. *Customer First* is integral to supporting advanced grid functions, operational improvements, and new customer rate programs, among other goals. To cite but one example, *Customer First* includes a meter data management ("MDM") system, to which the AMI system will eventually be integrated, and which is required to support advanced rate design.

Liberty Utilities is also consolidating several systems as part of *Customer First*, including its

[2] Liberty-Empire uses the MV-90 system to gather advanced billing determinants for its largest customers. These are excluded from the AMI implementation at this time. Moreover, Liberty-Empire expects the MV-90 system, which utilizes cellular-based communication means, can be expanded to meet any interim advanced metering needs until such time as the new AMI network is fully installed along with the back-office systems as noted.

Enterprise Resources Planning ("ERP") system, its Geographical Information System ("GIS"), and its Customer Information System ("CIS"). The CIS includes Liberty-Empire's customer billing functions. As AMI is installed at Liberty-Empire during 2020-2021, Liberty-Empire will use a straightforward data and file transfer method to transmit meter reading information into the current Liberty-Empire billing platform; over time, however, the AMI data will be housed in and dispatched from the Liberty company-wide shared MDM system, with further downstream integrations into the anticipated new Liberty Utilities CIS system for billing and other customer care purposes.

1.4.8 Distribution Automation, ADMS, Outage Management, and Voltage Control

A next phase for Liberty-Empire in its ATDNT goals builds on its progress since 2016 in its demonstration and implementation of field automation. Liberty-Empire continues to deploy additional recloser devices and smart fusers on distribution circuits. Some will be enabled with cellular communications immediately, and Liberty-Empire will upgrade all reclosers over time with communications. As communications and control capabilities are upgraded, Liberty-Empire will improve reliability on these circuits and will reduce outage-related repair times. Over time, and in conjunction with advanced software capabilities (described below), Liberty-Empire will be able to further improve the recloser operations, with the control software, to enable them to operate in autonomous, self-healing modes.

As part of this phase to improve the level of distribution automation, the evolution of communications and software permits Liberty-Empire to anticipate (as part of its ATDNT plans) its ability to add more monitoring and automation within both substations and on field capacitors. This will support Liberty-Empire's expansion of its ability to implement conservation voltage reduction ("CVR") capabilities, and other forms of voltage support. CVR, for example, reduces the amount of energy Liberty-Empire must inject into the distribution system, thereby reducing total generation needs. The same voltage monitoring and control capabilities also allow Liberty-Empire to learn more about the variable voltage conditions on distribution circuits, which is useful information as distributed resources connect to the Liberty-Empire grid. This information can help improve circuit models and anticipate Distributed Energy Resource ("DER")-related interconnection requirements.[3]

Long term, distribution automation requires that Liberty-Empire implement an advanced distribution management system ("ADMS"). ADMS is a strategic, Liberty Utilities-wide initiative, and involves the consolidation of many current SCADA control and monitoring functions into a well-integrated common platform. ADMS will consolidate today's GIS and OMS software systems. With the help of the ADMS implementation, Liberty-Empire will improve circuit models and continue its progress towards higher levels of sophisticated grid management capabilities.

The utility industry is moving towards ADMS as a natural progression of needs and technologies. ADMS integrates current or legacy OMS, GIS, asset registry and other systems into a platform that allows for expanded and sophisticated grid monitoring and control functions. Liberty-Empire recognizes that to prepare for a future of increased use of distributed energy – and increased use of more intermittent renewable energy (whether centralized, at large or small scale, or distributed) – it must improve the level of its awareness and control of the transmission and distribution system. It must also improve its ability to forecast performance over time as the state of the system evolves. Creating this "situational awareness" requires improvements to communications, field automation, software control systems, and the integration of systems that today are disparate.

[3] By implementing advanced communicating capacitor bank controllers, voltage monitors, voltage regulators, FCI, and integrated load tap changers ("LTC") at the substation transformers with a communications network and central logic controller, a more uniform and specified voltage profile can be maintained along the entire length of distribution primaries. Additionally, these technologies may better accommodate changes in reactive power demands and enable voltage conservation options. This is commonly referred to as Dynamic Voltage Conservation (DVC). This functionality may be enacted as a demand reduction measure during periods of extremely high load to lessen impacts on distribution system assets and reduce peak power purchases. Similar to DVC, -- and a specific goal of Liberty-Empire – is CVR. CVR consists of the exact same actions and utilizes the same assets to reduce voltage on applied circuits. However, the objective is to safely reduce voltage all the time rather than only during periods of high load. This may reduce immediate impacts to system assets and reduce fuel consumption. However, it will also reduce overall kWh delivered to customers.

With AMI, ADMS, the integrated Customer First systems, expanded communications and additional field devices, Liberty-Empire will be better situated to understand the best energy product for the right location and at the right time, as the grid evolves with an expanding array of energy delivery choices across a wide range of physical and temporal scales. As the power flows on the grid becomes more dynamic, dispersed, and two-way in nature, Liberty-Empire – by way of communications, ADMS, and improved analytical and planning tools – will have the necessary tools, insights and communication reach to manage the grid in a fair, cost-efficient, safe, reliable and resilient manner.

1.4.9 Expanding Communications

Foundational to each of the ATDNT phases described here is the role of expanded, high speed, safe and secure SCADA communications to Liberty-Empire substations and the additional communication paths to field devices located throughout the transmission and distribution service territory. During the next several years, Liberty-Empire plans to expand its fiber optic communication circuits to several transmission and distribution substations. The Company also plans to expand its distribution automation field network communications by leveraging cellular communication channels or its AMI network.[4]

Liberty-Empire plans to expand its fiber optic communications by using a combination of OPGW installations on overhead transmission lines, ADSS cable for lower voltage distribution lines, and separate fiber optic cable lines in other locations. Liberty-Empire also intends to extend asset management-oriented communication within substations. Improving the robustness, safety, reliability, speed, security, and flexibility of the Liberty-Empire SCADA communications system under-girds most of the ATDNT plans.

With robust communication paths to substation, and more cellular communications to field devices (such as reclosers, smart fuses and capacitor banks), Liberty-Empire will not only be able

[4] Liberty-Empire has not yet determined the role of the AMI network to support field network communications in support of distribution automation functions.

to interact with these devices to securely control the flow of power, but will also be able to engage in asset management analyses that contribute to improved awareness of equipment condition and performance. For example, the improvements to communications enables Liberty-Empire to more actively monitor the condition of large transformers to determine their health status, anticipate preventative maintenance needs, and plan for orderly replacement or upgrade as loads change or equipment ages and deteriorates.

In summary, implementing fiber backhaul network, transmission/substation SCADA, distribution SCADA, fixed metering network, and/or distribution field network can help to ensure that the transmission and distribution grid are reliably supported by a secure communication network. A secure network enables all components of the grid to communicate effectively and is protected from cyber-attacks. The network should be robust and support the ability to monitor and control time-sensitive grid operations including frequency and voltage, dispatch generation, analyze and diagnose threats to grid operations, fortify resilience by providing feedback that enables self-healing of disturbances on the grid, and evaluate data from sensors. This support enables the grid to further enhance its overall ability to utilize demand-side resources.

1.4.10 The Role of Energy Storage

Liberty-Empire has not resolved the specific role that energy storage will play in its consideration of ATDNT, but it believes storage will eventually play an important role. Liberty-Empire is also working with its sister company in New Hampshire to learn about the important benefits energy storage may provide (as this company evaluates its residential energy storage pilot program). Liberty-Empire describes storage in the 2019 IRP in terms of its relationship to demand- or supply side resources because of storage's long-term potential to influence resource deliberation and choices.

Electricity can be stored as chemical or mechanical energy and used later by consumers, utilities, or grid operators. In distributed applications, energy storage technologies most likely utilize inverter-based electrical interfaces that can produce real and reactive power. Depending on the capacity and stored energy of these devices, they can provide the following economic, reliability, and environmental benefits for demand-side resources and/or supply-side resources:

- *Optimized Generator Operation* – The ability to respond to changes in load enables grid operators to dispatch a more efficient mix of generation thus helping to optimize dispatch, reduce costs, and associated emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in optimum operating zones. The stored electricity could then be used later, displacing generation requirements during these times. By smoothing out the load curve that the generation fleet must meet, storage permits the power plant operators to achieve an improvement in plant operating efficiencies across their resulting duty cycle. Electricity storage can also decrease generator start-up costs.
- *Reduced Ancillary Services Cost* – Ancillary services, including spinning reserve and frequency regulation, can be provided by electricity storage. If peak demand is reduced, reserve margins would be reduced, thus reducing the required capacity that must be held as spinning reserve.
- *Reduced Congestion Cost* – Wholesale market participants pay for transmission line congestion, and these costs are passed onto the utility's customers. Because DER provides energy closer to the end user, it is possible to lower transmission-level congestion costs, thus reducing customer costs. Electricity storage could participate as a DER to support this benefit.
- *Reduced Electricity Losses* – Electricity losses are innate to electrical systems and increase as circuits become more heavily loaded. By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced, thereby realizing an overall reduction in system losses.
- *Reduced Electricity Costs* – Depending on the customer's electricity rate (or tariff), customers might pay high charges for electricity during certain periods of the day when it is inherently more expensive at the wholesale level (in most markets). If these

customers owned electricity storage they could use the stored electricity to avoid these high charges, thus saving on their electricity bill.

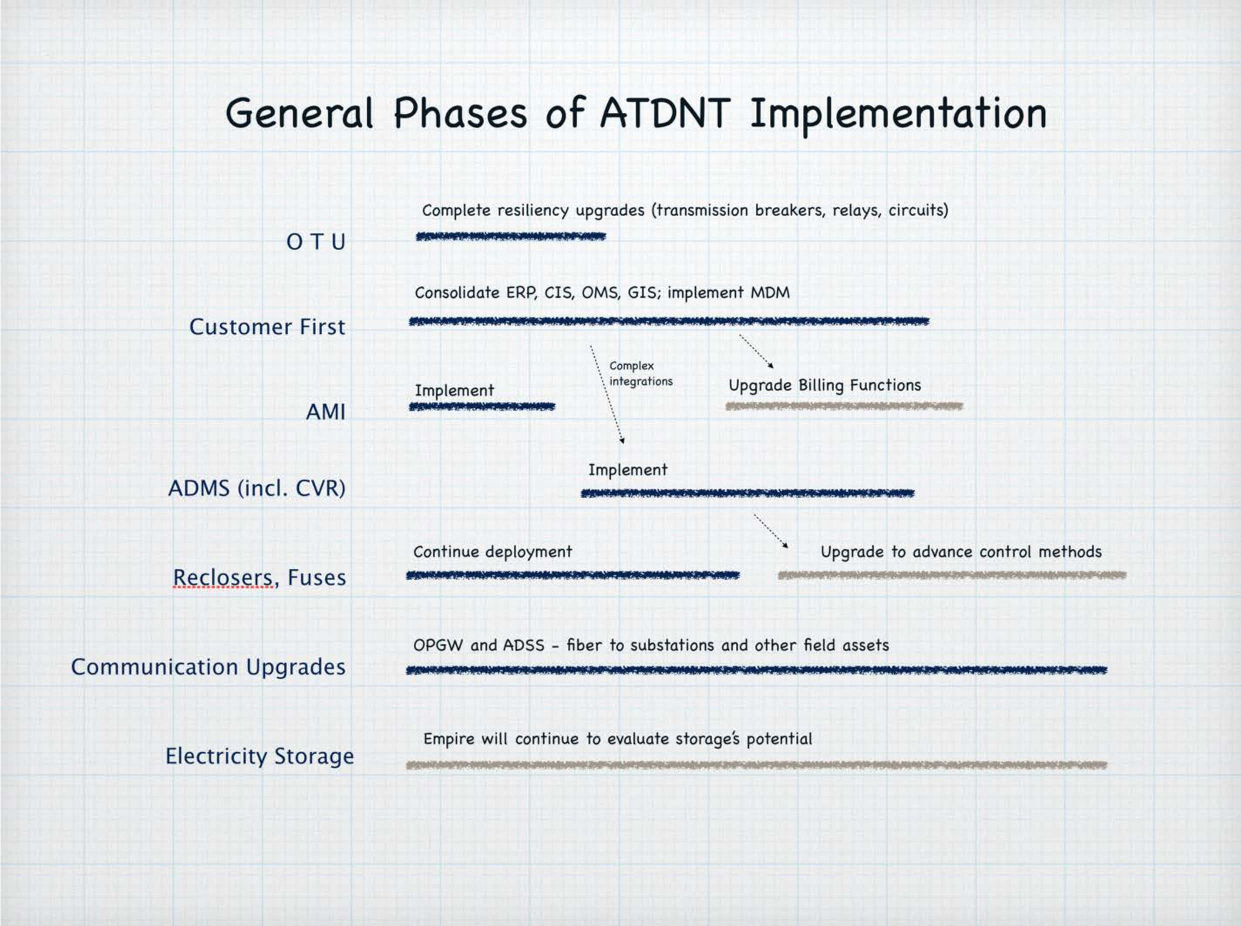
- *Deferred Generation Capacity Investments* – Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
- *Deferred Transmission Capacity Investments* – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- *Deferred Distribution Capacity Investments* – Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required. For example, a distribution substation may have a power transformer that is nearing it total capacity rating under some stressful times of day. Electricity storage could relieve this potential overload condition, thus avoiding the risk of the overload, and the problems that ensue if it does overload.

Liberty-Empire will continue to assess the role storage may play. It is also worth noting that storage – as a unique resource – has potential definitional attributes of a generation source, an electrical load, and an advanced network technology that enables the storage battery to serve in either capacity.

1.4.11 ATDNT's General Relationships and Dependencies

Figure 4.5-8 depicts the general relationships among the elements of Liberty-Empire's ATDNT elements and helps highlight some key dependencies amongst them. Figure 4.5-8 shows the diversity of the activities, their general relationships, and (for many) their assumed persistence and long-term nature. For example, Liberty-Empire will continue to deploy reclosers but once ADMS capabilities are installed it will be able to migrate the recloser operations to more advanced level of control algorithms that provide additional levels of responsiveness and automation (thus further improving reliability). Another example is the on-going and persistent need to upgrade communications.

Figure 4.5-8 – ATDNT Implementation Phases and Dependencies



1.4.12 Status of ATDNT Pursuits as Described in the 2016 IRP

For continuity purposes, it is useful to provide updates on Liberty-Empire's pursuit of various ATDNT as described in its 2016 IRP. Table 4.5-6 provides this update.

Table 4.5-6 – Advanced Network Technology as Described in the 2016 IRP

2016 IRP Plan Element	Pursuit Scope
System Protection and Communications: OPGW and ADSS Cable	Liberty-Empire continues to employ use of ADSS cable and OPGW for system protection and communication needs on transmission circuits. Presently, Liberty-Empire incorporates OPGW in all transmission rebuild efforts. In locations where transmission upgrades have yet to be identified within the capital construction budget, ADSS is employed to further expand the optical network(s).
Microprocessor Relay Controls	Liberty-Empire continues to utilize microprocessor relaying for all new relaying substations (for system protection requirements). These controls provide high levels of reliability as well as diagnostics for root cause analysis. All new line panels are standardized to consist of microprocessor relaying as well as any coupled line terminals. 23 of 24 Transmission Addition projects are driven by the expanded use of microprocessor relays.
Automatic Throw-over switching schemes	Liberty-Empire continues to deploy this scheme on 69 kV transmission circuits to reduce the extent of outages due to the nature and location of 69 kV load taps. 6 Auto Transfer schemes are presently planned within the next 3-4 years.
OTU	"Operation Toughen Up" ("OTU") is progressing and is scheduled to be completed by 2021; however sectionalization and resiliency efforts of the transmission systems will continue in capital project scoping. It has been grounded on the use of advanced transmission and distribution technologies throughout. Furthermore, OTU has made important improvements throughout the Liberty-Empire transmission and distribution system by reinforcing system resiliency and improving reliability. Auto-throw transfer schemes (including new micro-processer controls and switches) have been implemented, breakers replaced, circuits reconductored across all voltage levels. The success of OTU has made the Liberty-Empire system more reliable and resilient, supporting Liberty-Empire's ability to serve load confidently. Moreover, the ATDNT aspirations identified in this IRP are only possible because Liberty-Empire has made the essential OTU investments.

2016 IRP Plan Element	Pursuit Scope
Transformer Monitoring Initiatives: Dissolved Gas (Full Suite)	Liberty-Empire continues to install DGM capabilities on all new large (50 MVA and larger) transformers. Liberty-Empire specifies any large power transformers with the capabilities to incorporate communications and monitoring interfaces for future deployment/utilization as communications and data gathering/repository mature.
Transformer Monitoring Initiatives: Dissolved Gas (Lite Suite)	Liberty-Empire continues to order new transformers with extra sample ports that allow future installation of equipment to monitor hydrogen gas build up. Same as above. Allows for future data gathering and alarming of transformer conditions as communications and data gathering/repository matures.
Transformer Bushing Monitoring	For new 22.4 MVA or larger transformers Liberty-Empire is installing monitoring devices. For 10.5 MVA Liberty-Empire will upgrade the purchase requirement. These will come with a capacitance tap, enabling monitoring. Evaluation ongoing. The inability to alarm in real time limits benefits to be realized. Units have been installed and due to low age of units, results are undeterminable at this time.
Transformer Bushing Monitoring and Partial Discharge Monitoring	This is similar as above, except it additionally includes monitoring equipment and capabilities on neutral bushings. Also, the partial discharge monitor provides a supplement to dissolved gas analysis monitoring. Presently shelved for future consideration. The additional costs paired with inconclusive results from bushing monitoring installs do not justify further implementation.
Transformer Monitor	Liberty-Empire continues to specify new transformers equipped with Schweitzer SEL-2414 monitor. Further deployment of SCADA and alarming for transformer health will allow for the prolonging asset life as well as proactively addressing alarms received in real time.
Fiber Optic Substation Data Network	Schweitzer ICON system, has been installed as pilot during 2016, connecting 20 substations in Joplin area. Presently 5 rings have been deployed. Planned additional rings for upcoming years include the Neosho/AR service area, partial Baxter

2016 IRP Plan Element	Pursuit Scope
	Springs, KS service territory, and the Greenfield to Bolivar areas. Further deployment will be at a higher cost/site due to the additional fiber build out necessary, however hardware and install costs should maintain. This pilot project was completed, and the results are supporting Liberty-Empire's plan for expanded communications.
Substation Data Archive, Server and Database	Liberty-Empire indicated that it would study this in the 2016 IRP. This element is pared to the ICON system pilot. Ongoing and currently in conceptual stage as platforms for ADMS and AMI are solidified and communications are further deployed.
69-kV Vacuum Circuit Breaker	Liberty-Empire recently installed multiple gas-less vacuum breakers and subsequent evaluation points to pausing further deployments. Eleven (11) breakers have been installed at 3 different locations on system. Future installs are planned in 2019 to extinguish stock that has been ordered. Due to the unrealized benefits on the above evaluation, Liberty-Empire does not plan to continue to use 69kV vacuum breakers at this time but will continue to review as new inputs become available.
Feeder Automation System Study	Liberty-Empire deployed radios, remote terminal units ("RTUs"), antennae, advanced micro-processor based reclosers, a SCADA-mate switch, substation breakers, and other control elements to pilot a self-healing schema on a section of 40-mile section of transmission and distribution circuitry. This project has shown to be beneficial to the customers on a particular feeder in question. Although presently a unique install, Liberty-Empire will look to use the Welch feeder automation project as a baseline for future projects which are more conducive to automation and have a higher customer per dollar impact.
Advanced Recloser Controls	Liberty-Empire noted in its 2016 IRP that its Pilot project was completed on the installation of an electronic, single phase recloser with microprocessor controls. This has helped influence Liberty-Empires plan for ATDNT as described throughout this section.
Fusing Pilot Studies	Liberty-Empire has monitored the performance of several smart fuses located on its distribution system. Liberty-Empire has learned more about how the fusing might work on its system, and this knowledge

2016 IRP Plan Element	Pursuit Scope
	has helped influence Liberty-Empires plan for ATDNT as described throughout this section.

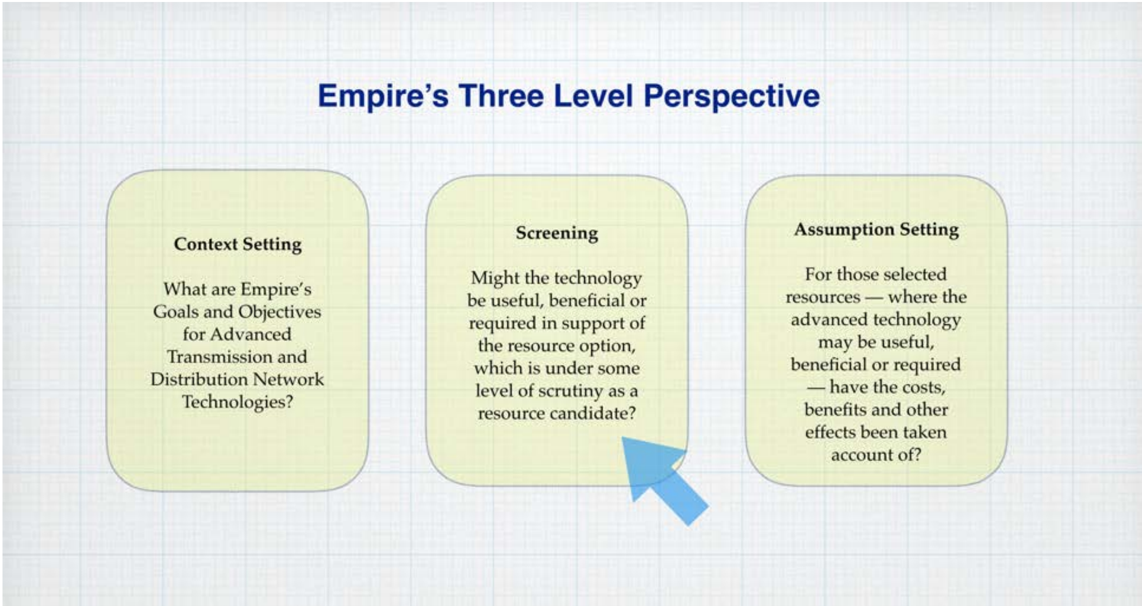
1.4.13 Cost and Capabilities of ATDNT Within Analysis of Resource Options

Per the text emphasis below, 22.045(1)(D) requires that the utility shall provide information regarding the *potential* role of advanced transmission and distribution technologies in influencing demand or supply side resource choices:

> *Sub-requirement (D): Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the analysis of each resource option.*

To address these requirements, Liberty-Empire has performed screening evaluation of its ATDNT. This is represented in Figure 4.5-9 below.

Figure 4.5-9 – Screening Stage of ATDNT



Liberty-Empire interprets that this is a screening step to determine whether there is the potential for its ATDNT plans to influence ("facilitate or expand") resource choices. This screening step is organized below in Table 4.5-7.

It is worth noting that each ATDNT plays a role in supporting essential grid functions, which are nuanced and at times complex. Additionally, these functions relate directly to supporting fundamental grid reliability, resiliency, safety, compliance and other core grid requirements. Grid users need confidence that the supply or demand side resources they intend to provide to the market can serve their intended load. If the grid's reliability is in question, this confidence cannot exist. These core functions, therefore, support *all* supply and demand side resources evaluated as part of the IRP to the extent that they provide the necessary confidence that the resources can participate in the market and serve the load as estimated and forecasted.

In Table 4.5-7, the third column is intended to reinforce that these technologies serve vital grid functions.

Table 4.5-7 – Screening of ATDNT

ATDNT	Description	Supports General, non-specific core grid reliability, resiliency and/or system operation functions?	Expands or Facilitates Supply Side or Demand Side Resource Effects
OTU	Core grid resiliency and reliability improvements (substations, circuits)	Yes	+ Provides resilient platform for interconnection of Supply side resources[5]
Customer First	Consolidation and upgrade of ERP, CIS, GIS, OMS, MDM	Yes	+ Improves capacity to interconnect and manage DER.
AMI	Operational improvements; outage mgmt.; customer care; advanced billing determinants	Yes	+ Facilitates time variant pricing, which could influence nature of dispatchable resources + Enables better informed management of distribution grid, supporting DER interconnection + May support CVR, which in turn lowers total load requirements + Provides customers useful data on energy uses, facilitating more informed choices (which in turn could influence behind the meter substitution or behavior load shifts) + May support measurement of DSM program effects

[5] The specific nature of interconnection requirements is handled through the interconnection process itself whereby wholesale generators must fund the study to determine the nature of power flow effects that may arise by the interconnection of the planned resource. Typically, the developers behind these resources must fund the mitigation of any power flow violations that are caused by the expected dispatch of the resource. Liberty-Empire has not identified any unique interconnection (and mitigation) challenges arising from the evaluation of Supply side resources that, in turn, uniquely and substantially depend on the availability of advanced transmission or distribution network technology.

ATDNT	Description	Supports General, non-specific core grid reliability, resiliency and/or system operation functions?	Expands or Facilitates Supply Side or Demand Side Resource Effects
ADMS	Data analytics, DSM, OMS and DER management functions	Yes	+ Improves capacity to interconnect and manage DER.
CVR	Energy efficiency gains through better management of distribution circuit voltage profiles.	Yes	+ Reduces total load requirements slightly, but long-term performance difficult to forecast. + Under dynamic schema may help shave peak load
DA: Reclosers, Capacitors, Smart Fusing	Improves circuit segmentation, improving outage response and lowering outage impacts; improves voltage quality and improves power factor[6]	Yes	+ May improve distribution system's ability to manage DER impacts + Capacitors may play role in voltage control solution (depending on solution choices) thereby supporting energy efficiency improvements
Expanded Communications	SCADA communications to DA system, AMI system, substations and other field devices	Yes	+ *Enables* advanced grid functions and capabilities + *Essential* to asset management functions (e.g. asset monitoring, health)
Electricity Storage	Battery or other forms of storage located in centralized or distributed locations	Yes	+ May support a variety of market needs (energy, capacity, ancillary)

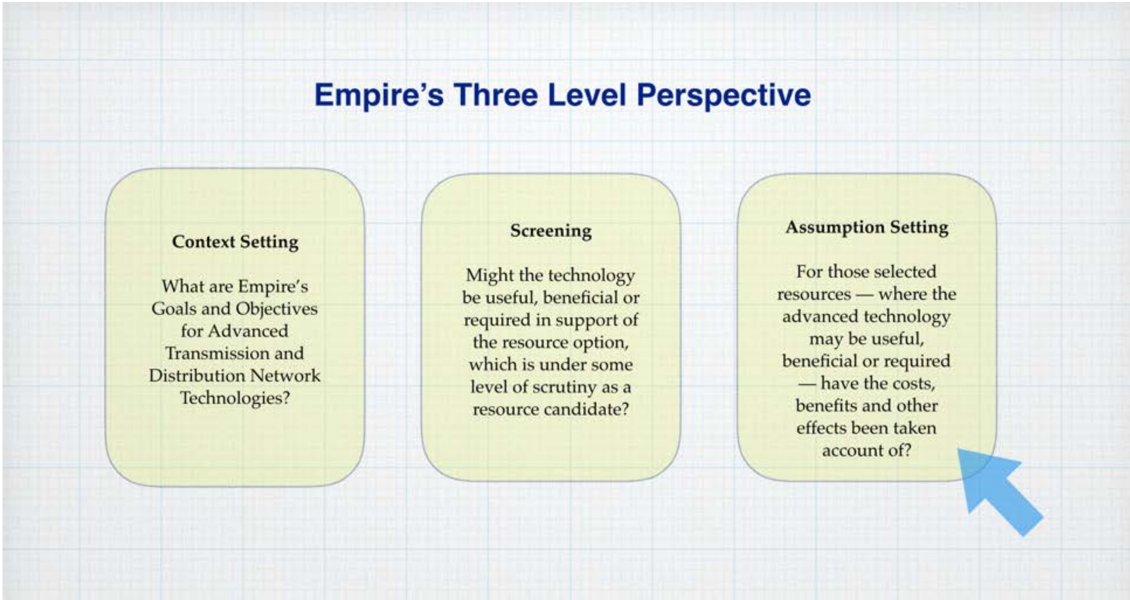
[6] Liberty-Empire has examined and determined needed upgrades for the automation of capacitor bank controls. Previously, simple time and/or temperature controls were installed for capacitor bank control. Upgraded capacitor controls, which include parameters of time, date, temperature, voltage, and VAr (additional option), are installed on all new installations of cap banks. Present controls are replaced on an as-needed basis as original controls fail or become inoperable or faulty. The power factor at the substation is also improved by the automated addition and removal of capacitance when demand necessitates. This immediate response to load profile changes allows the distribution system to be manipulated to optimize voltage profile along a given feeder.

ATDNT	Description	Supports General, non-specific core grid reliability, resiliency and/or system operation functions?	Expands or Facilitates Supply Side or Demand Side Resource Effects
			+ Synergies: improves outcomes of other programs (e.g., electric vehicles (“EV”), solar photovoltaic (“PV”))

1.4.14 Preview of Advanced Technology Analysis: ‘Assumption Setting’

Section 22.045(4)(A)-(E) is focused on the third stage of Liberty-Empire’s screening, namely the careful review of the specific assumptions involving ATDNT that may facilitate or expand the specific supply or demand-side resource choice under final consideration by Liberty-Empire. This “Assumption Setting” stage is depicted in Figure 4.5-10 below. The phrase “Assumption Setting” is used to emphasize the fact that emerging from the stage are assumptions which may need to be *further* analyzed as part of the Supply or Demand side resource evaluation. For example, the ATDNT assumptions may imply a cost or a benefit that should be reflected in the resource evaluation.

Figure 4.5-10 – Assumption Setting Stage of ATDNT



This stage is a logical extension of the ATDNT identified in Figure 4.5-9, the screening stage of ATDNT. The difference is that this final stage is used to evaluate the nature of the specific nexus between Liberty-Empire's final candidate supply and demand-side resources and ATDNT, determining:

- The nature of ATDNT costs and benefits, and their alternatives
- How ATDNT impacts resource costs in relation to a role of enhanced demand side and customer owned generation resources, if any
- Cost-effectiveness (for resulting energy resources) associated with choices between advanced and non-advanced technology use

SECTION 2 AVOIDED TRANSMISSION AND DISTRIBUTION COST

(2) Avoided Transmission and Distribution Cost. The utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

2.1 Avoided Transmission Capacity Cost

The AFS process encompasses the petition of transmission service and the associated impacts on the existing transmission infrastructure or planned projects meeting specified interconnection agreements and/or having been issued a Notice to Construct ("NTC") by SPP during the appropriate study process. All generation requests must be vetted through the AFS process to obtain firm transmission service for delivery of generation to load. In doing so, Liberty-Empire is able to evaluate the impacts either purchasing generation, adding generation onsite, adding generation offsite, or other applicable generation resource impacts upon the SPP transmission system through the multiple iterative processes of the AFS. As the proposed generation resources profiles are updated in the applicable study, Liberty-Empire evaluates the most cost-effective means to address their needed generation resources to meet forecasted load demand. Thus, the AFS study process reveals the transmission component of avoided demand cost.

The AFS study process is dynamic in nature. Locational differences of the requested resources, the available transmission in the immediate area of the resource, and the competing resources requests each affect the resultant cost of any given generation resource request. As competing requests are vetted by their respective companies, requests are withdrawn from the applicable AFS study. This again changes the AFS study portfolio. In the most recent AFS, Liberty-Empire was able to determine its respective avoided transmission, avoided costs by averaging past years' AFS Engineering and Construction ("E&C") costs as compared to the requested MW resources. The total costs were divided by the summation of requested resources to determine an average cost per kilowatt value. The values and the associated studied years are shown in Table 4.5-8.

Table 4.5-8 – Comparison of AFS Results

Study Year	Total E&C Cost(s) Weighted to 2018 $s	MW	2018 $/kW
2008	$87,279,725	3,336	26
2009	$46,437,487	2,777	17
2010	$134,369,426	2,424	55
2011	$793,908,998	3,936	202
2012	$120,083,248	3,581	34
2013	$10,569,377	961	11
2014	$17,522,289	1,556	11
2015	$40,427,777	2,334	17
2016	$16,768,733	963	17
2017	$40,884,552	1,468	28
2018	$527,441,521	2,915	181
Totals	**$1,835,693,133**	**26,251**	69.90

Thus the extrapolated cost per kilowatt for each subsequent year is shown in Table 4.5-9:

Table 4.5-9 – Total Annual AFS Costs as Transmission – Avoided Demand Costs

Year	$/kW-year	Levelized Cost $/kW-year
2019	$71.68	$7.21
2020	$73.47	$7.39
2021	$75.31	$7.57
2022	$77.19	$7.76
2023	$79.12	$7.96
2024	$81.10	$8.15
2025	$83.13	$8.36
2026	$85.20	$8.57
2027	$87.33	$8.78
2028	$89.52	$9.00
2029	$91.76	$9.23
2030	$94.05	$9.46
2031	$96.40	$9.69
2032	$98.81	$9.94
2033	$101.28	$10.18

Year	$/kW-year	Levelized Cost $/kW-year
2034	$103.81	$10.44
2035	$106.41	$10.70
2036	$109.07	$10.97
2037	$111.79	$11.24
2038	$114.59	$11.52

The dynamic nature of the transmission costs is clearly evident. Each year's requests have differing impacts on the transmission service costs.

SECTION 3 ANALYSIS OF TRANSMISSION NETWORK PERTINENT TO A RESOURCE ACQUISITION STRATEGY

(3) Transmission Analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.

3.1 Transmission Assessments

(A) The utility shall provide, and describe and document, its—

3.1.1 Transmission Assessment for Congestion Upgrades

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

Liberty-Empire's participation in SPP was previously addressed in Section 1.3 regarding assessment of transmission upgrades for power purchases. Liberty-Empire also utilizes SPP's ITP process to assess the need for, cost of, and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network along with other SPP members and affiliates.

The SPP ITP process is used to determine transmission requirements for maintaining electric reliability and for providing both near- and long-term economic benefits to SPP members and affiliates. The RTO region includes all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP ITP process identifies transmission expansion projects and prioritizes their schedules in order to maintain a reliable and cost-effective transmission network with improved access to SPP's diverse resources including wind energy. Wind energy development has fluctuated in recent years with variations in federal subsidization, but has dominated new generating capacity additions in SPP for several years.

The SPP ITP process is an iterative, multiple-horizon transmission planning process that has improved transmission planning across the SPP region. By integrating the transmission planning process across member utilities in 14 contiguous states, SPP promotes more rigorous and complete planning throughout a large area that improves the reliability of each utility and SPP as a whole. The result of this integrated planning process is the development of lowest-cost transmission solutions to anticipate and respond to constantly changing loads, environmental and regulatory requirements, and grid anatomy, all while meeting evolving reliability criteria.

The current ITP process includes ITP20, ITP10, ITPNT assessments of transmission requirements to meet load growth and other potential developments. The 2013 ITP20 process examined high-voltage transmission needs at voltages above 300-kV, and included state-by-state requirements for renewable energy over time. ITP20 evaluated potential impacts of a 20-percent federal Renewable Electricity Standard ("RES"), a $36/ton carbon constraint, an additional 10 GW GW of exported wind, investment in Demand Side Management and Smart Grid technology, and a joint SPP/MISO future. ITP20 projected renewable energy generation of 10 GW without a federal RES, and 16.5 GW with a federal RES. The ITP20 Consolidated Portfolio included 436 miles of transmission lines and installation of six 345-kV step-down transformers. Implementation of ITP20 results was estimated in 2013 to have a total cost of $560 million (present value revenue requirement of $845 million), and is expected to provide net benefits of approximately $1.5 billion over the life of the projects. SPP has not performed an ITP20 study since 2013, but monitors the 2013 and 2010 ITP20 approved projects and provides an updated cost estimate in the annual SPP Transmission Expansion Report. Table 4.5-10 below provides the updated cost estimates for the 2010 and 2013 ITP20 projects.

Table 4.5-10 – Cost Estimates for 2010 and 2013 ITP20

Assessment	Updated Cost
2010 ITP20	$ 1,119,587,300
2013 ITP20	$ 514,277,650

A value-based planning approach is used for the ITP10 assessment to analyze the transmission system over a 10-year horizon. In the ITP10 process, economic and reliability analyses develop solutions for issues identified on the system for voltages of 100-kV and above. The 2017 ITP10 process included all statutory/regulatory renewable mandates and goals, per utility in Alignment with SPP's 2015 Utility Public Policy survey. The 2017 ITP10 also considered a future with a decrease in existing base load generation capacity due to the implementation of regional or state level clean power plan solutions. The recommended ITP10 portfolio consisted of projects that provide 93 miles of new transmission infrastructure for potential reliability, economy, and/or policy requirements with an estimated total E&C cost of $201 million in 2017. These projects were predicted to generate net benefits of approximately $1.1 billion over their life under a future that contains 15.7 GW of wind capacity expected to be contracted by SPP members.

The near-term assessment is performed annually and will identify more immediate potential problems using NERC reliability standards, SPP criteria, and local planning criteria. Reliability upgrades at all transmission voltages are developed to address both regional reliability needs and identify necessary reliability upgrades for approval and construction. For the 2018 ITPNT, SPP performed reliability analyses that identified potential bulk power system problems across three scenarios – incremental of the Base Reliability ("BR") case that assumes expected usage of firm long-term transmission service – built across multiple years and seasons to evaluate power flows across the grid and account for various system assumptions. The first scenario assumed the expected usage of long-term firm transmission service usage and Renewable resources are dispatched at each facility's latest five-year average for the SPP coincident summer peak, not to exceed each facility's firm service amount. The second scenario maximized all applicable long-term firm transmission service with its required generation dispatch. The third was a Balancing Authority ("BA") scenario that showed the needs on SPP's transmission system that resulted from

Security Constrained Unit Commitment and Security Constrained Economic Dispatch.

SPP provided results of the BR and the three scenarios to transmission owners and stakeholders to develop solutions. SPP staff identified and presented their recommended solutions for potential reliability violations during planning summits for member and stakeholder review. The result was a list of solutions, necessary at 69-kV and above to ensure near-term reliability in the SPP region, which included 14.1 miles of new and rebuilt/reconductored transmission lines and eight new transformers. E&C cost estimates for the needed reliability projects totaled $47.4 million for upgrades that will receive an NTC. These upgrades solved 74 unique thermal needs and 253 unique voltage needs.

SPP created the Transmission Owner Selection Process ("TOSP") in order to comply with FERC Order 1000. FERC Order 1000 requires the removal of federal right of first refusal ("ROFR") for certain transmission projects under the SPP Tariff. Removal of federal right of first refusal allows non-incumbent utilities to construct approved transmission facilities that meet SPP Tariff criteria, known as Competitive Upgrades. SPP solicits proposals for Competitive Upgrades from Qualified Request for Proposal Participants utilizing the TOSP. Competitive Upgrades are submitted during a 30-day Detailed Project Proposal window and must address a need that was identified by SPP Staff during an ITP study.

Liberty-Empire is very active in the interaction between SPP and its associated members. Liberty-Empire participates by way of multiple working groups and various task forces. Table 4.5-11 provides a list of working groups/committees and task forces in which Liberty-Empire participates.

Table 4.5-11 – Liberty-Empire's SPP Participation

SPP Stakeholder Committee/Task Force (Report to)	Position Type Voting/Monitoring	Name
Members Committee (BOD)	Voting - Liberty-Empire	
Human Resources (BOD)		

SPP Stakeholder Committee/Task Force (Report to)	Position Type Voting/Monitoring	Name
Strategic Planning Committee (BOD)	Monitoring	Wilson/Westfall/Doll
SPC Order 1000 Task Force		
Membership (all members)	Monitoring	Baker
Finance Committee (BOD)		
Governance Committee (BOD)		
Market and Operating Policy Committee (full membership)	Voting - Liberty-Empire	Doll
Transmission Working Group (MOPC)	Voting - Liberty-Empire	Morris
Seams Steering Committee	Voting - VC	Gaines
MDWG, reports to TWG	Voting, Chair - Liberty-Empire	Morris
ESWG reports to MOPC (new)	Monitoring	King/Busse
Business Practices Working Group (MOPC)		
Balancing Authority Operating Committee - ORWG	Monitoring	Pham
Regional Tariff Working Group (MOPC)	Voting - Liberty-Empire	Tarter
Market Working Group (MOPC)	Monitoring	Tupper, Doll
Settlements Users Group	Monitoring	Tackett
Project Cost Working Group	Monitoring	Brown, Bradley
Change Working Group	Monitoring	Parker, Tupper
Supply Adequacy Working Group	Voting - Liberty-Empire	Berkstresser
Operations Reliability Working Group (MOPC)	Voting - Liberty-Empire	Pham
Operations Training Working Group (MOPC)	Monitoring	Pham
Security Working Group	Voting - Liberty-Empire	Eck
System Protection and Control Working Group (MOPC)	Monitoring	Oswald
SPP Regional State Committee	Monitoring	Doll
Cost Allocation Working Group (RSC)	Monitoring	King/Green
Regional Cost Allocation (RCA) review task force	Monitoring	Doll
Credit Practices Working Group		

3.1.2 Transmission Assessment for Advance Technologies

2. Assessment of transmission upgrades to incorporate advanced technologies;

Liberty-Empire incorporates three main advanced technologies in its transmission system: ADSS cable and/or OPGW, microprocessor relaying, and automatic throw-over switching schemes on the 69-kV transmission system(s).

Liberty-Empire currently employs the use of ADSS cable and has previously employed the use of OPGW for most or all of new shield wire installations. This gives not only superior lightning performance, due to the lower resistance of the OPGW compared to conventional galvanized steel strand shield wires, but also provides a high capacity path for internal communications and system protection functions. The standard OPGW options provide either 48 or 144 single-mode fibers per shield wire, whereas ADSS incorporates 144 single-mode fibers allowing for not only presently needed communication paths for protection schemes but also allows for future implementation of further SCADA installation(s) and communication paths for backup/redundant relaying.

Liberty-Empire utilizes microprocessor relaying for all new relaying installations. Substantial gains are found in the implementation of microprocessor relaying with respect to root cause analysis of fault events, as well as in protective coordination of transmission elements. With the use of microprocessor relaying, event recordings are able to be reviewed for possible mis-operation as well as duplication of fault events to determine possible common fault locations. In conjunction with the aforementioned ADSS or OPGW, differential relaying on transmission elements are able to be implemented, which results in a much more robust and increased speed of relay operation.

Liberty-Empire has also implemented automatic throw-over switching schemes on the 69-kV transmission system(s) in attempts to reduce the system average interruption duration index (“SAIDI”) and the system average interruption frequency index (“SAIFI”). Due to their location on the transmission system, load taps on the 69-kV transmission system are dependent on remote relaying operations. When the remote relaying opens a transmission line segment, the load tap is de-energized. A solution is an automated throw-over scheme in which either side of the load tap of transmission is opened during a fault condition and tested to determine the faulted section. Once the faulted section is determined, the alternate section is then restored, thereby restoring power to the load tap. Liberty-Empire incorporates microprocessor relaying in these schemes as well as ADSS cable (when applicable) so as to ensure fast response and robust protection.

In addition to the above technologies evaluated by Liberty-Empire, the following comprises of a list of emerging technologies which Liberty-Empire is currently evaluating for possible future implementation.

Fiber Optic Substation Data Network

Characteristic	Description
Application	Provide a network for substation engineering data
Benefit	A dedicated data network will allow large amounts of engineering data to be collected. Currently the only data connection to the substations is through the EMS system which needs to remain focused on its core function of operations and control. Trying to collect engineering data through the EMS system would have security implications as well as loading down the system with data that is not relevant to its core function

Substation Data Archive, Server, Database

Characteristic	Description
Application	Assumed to be a stand-alone system from that of AMI data repository, a data archive, database, and server hosting the collected substation data would be needed as more data is acquired throughout the system with the increase in deployed technologies across the system. With the collection and analysis of the data gathered, equipment health and real time system impacts can be accumulated for better optics into system conditions. Data processing and analytics can be applied in an effort the make the most appropriate use of capital

Characteristic	Description
Benefit	This is the second component of critical data infrastructure required to allow substation monitoring (the first being the data network itself). When various types of substation monitors begin to be connected, they will quickly create an unusably high number of different databases for all types of information and from different makes and models. A centralized system will make data analysis easier and facilitate analysis which requires data from more than one source

69kV Vacuum Circuit Breaker

Characteristic	Description
Application	A 69-Kv class substation circuit breaker which does not require SF6 as an insulating gas
Benefit	The use of SF6 gas requires careful handling and reporting. Eliminating equipment which requires SF6 gas is a benefit to environmental reporting as well as operations and maintenance. Longer life of asset, lower maintenance costs, reduced gas handling requirements, as well as increased fault current interrupt capabilities.

The above technologies exhibit a focused effort on substation equipment. This focus is of particular priority due to the long lead times of possible equipment failures and the wide-ranging outage impacts to a large number of customers in the event of equipment failures. Liberty-Empire deemed such a focus merited in an attempt to realize the most cost-effective and most reliable solution for our customers. Further investigation as to the utilization of these systems as well as future technologies should yield a more robust electrical network to serve Liberty-Empire's customers.

Although Liberty-Empire has invested in and piloted various advanced technology applications, there is a limit to the accrued benefit customers will actually realize. Spending on emerging technologies can be boundless. Liberty-Empire has attempted and will continue to strike a healthy balance of vetting newly emerging technologies in parallel with time proven implements. The benefits of the piloted projects are presently being weighed against their associated costs to implement/deploy, however benefits of such programs are very difficult to capture. An example of such would be, regardless if a transformer monitor is installed and a failure occurs, the resultant would be an outage to a large number of customers. Alternatively, if the DGM program is implemented system-wide and transformer failures subsided, the metrics to attribute the reduction in outages are very difficult to allocate properly among other initiatives across the company.

Without clarity as to which metrics' weight utilities should focus alongside the high number of unproven technologies, benefits are difficult to quantify. Presently there is a lack of clarity as to what constitutes an advanced technology, definitive standards in which utilities should focus efforts, and no definable cost to benefit ratios deemed as meriting an investment over others. These aspects in concert with sensitivity to impacts upon customer rates give rise to a difficult path utilities must traverse in implementing emerging technologies. Liberty-Empire will continue to vet advanced technologies in an attempt to best balance cost to consumer versus attributable benefits.

3.1.3 Avoided Transmission Cost Estimate

3. Estimate of avoided transmission costs;

Avoided transmission costs are discussed in Section 2. The results of the aforementioned estimation are provided in Table 4.5-8 and Table 4.5-9.

3.1.4 Regional Transmission Upgrade Estimate

4. Estimate of the portion and amount of costs of proposed regional transmission upgrades that would be allocated to the utility, and if such costs may differ due to plans for the construction of facilities by an affiliate of the utility instead of the utility itself, then an estimate, by upgrade, of this cost difference;

The SPP OATT requires that a "Rate Impact Analysis" be performed for each ITP per Attachment O: Transmission Planning Process, Section III: Integrated Transmission Planning Process, Sub-

Section 7):

7) Process to Analyze Transmission Solutions and Alternatives for the Integrated Transmission Planning Assessment":

The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year Assessment, 10-Year Assessment and Near Term Assessment studies:

d) The analysis described above shall take into consideration the following:

"vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis."

The rate impact analysis process required to meet this 2018 ITPNT requirement followed the same approach utilized in previous ITPNT established under the direction of the Regional State Committee in 2010-2011 by the Rate Impact Task Force ("RITF"). The RITF developed a methodology that allocated costs to specific rate classes in each SPP Pricing Zone ("Zone").

The first step in this process is to estimate the zonal cost allocation of the Annual Transmission Revenue Requirement ("ATRR"). This cost allocated ATRR is calculated specifically for the ITPNT upgrades using the ATRR Forecast. The Forecast allocated 2015 ITPNT upgrade costs to the Zones using the Highway/Byway cost allocation method. This method allocates costs to the individual Zones and to the Region based on the voltage level of the upgrade. Transformer costs were allocated based on the low side voltage. Regional ATRRs are summed and allocated to the Zones based on their individual Load Ratio Share percentages.

Table 4.5-12 – Highway Byway Cost Allocation

Highway Byway Cost Allocation		
Voltage	**Regional**	**Zonal**
300-kV and above	100%	0%
100-kV - 299-kV	33%	67%
Below 100-kV	0%	100%

The following inputs and assumptions were required to generate the Forecast:

- Initial investment of each upgrade
    - New 2015 ITPNT upgrade investments modeled were $238 million in 2014 dollars
- Transmission Owner's estimated individual annual carrying charge percentage
- Voltage level of each upgrade
- In-service year of each upgrade
- 2.5 percent annual straight-line rate base depreciation
- 2.5 percent construction price inflation applied to 2018 base year estimates
- Mid-year in-service convention

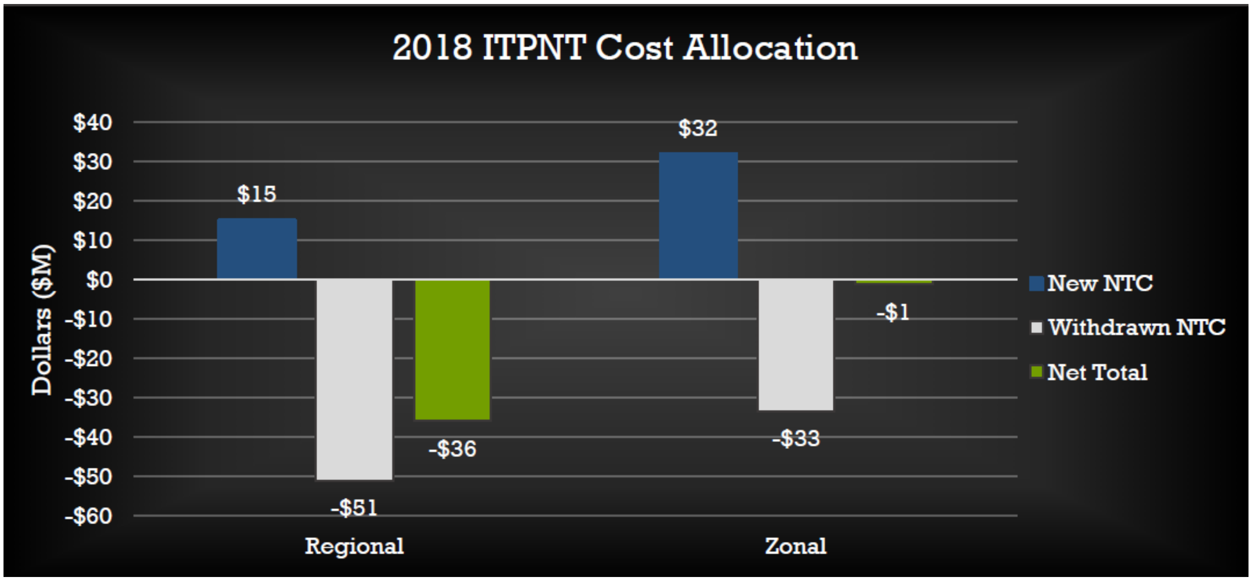
Liberty-Empire presently does not have any projects identified in the ITPNT. The table below shows the dollar amount of new and modified projects of the 2018 ITPNT identified by state.

Table 4.5-13 – 2018 ITPNT Projects by State

State	New NTC
MT	$105,000
MN	-
ND	-
SD	$5,617,000
NE	-
WY	-
IA	-
KS	$6,522,108
MO	$14,235,588
OK	-
AR	$3,409,700
TX	$17,479,495
NM	-
LA	-
Subtotals	**$47,368,891**

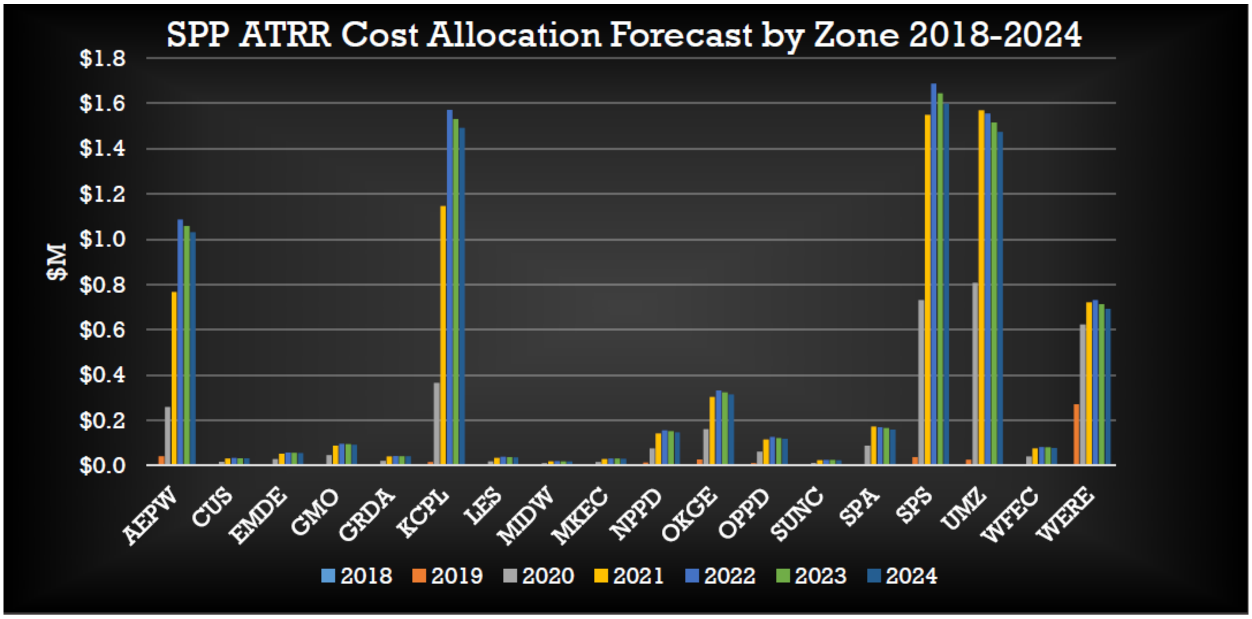
Liberty-Empire will have costs associated with the other members' zonal and regional proposed projects as shown in the following allocation of upgrades with new NTCs between upgrades needed for Regional Reliability and Zonal Reliability. The 2018 ITPNT identified no modified NTC and $84 million of withdrawn NTC. Upgrades classified as Zonal Reliability are required to meet local planning criteria which is more stringent than SPP Criteria.

Figure 4.5-11 – 2015 ITPNT Investment – Regional vs. Zonal



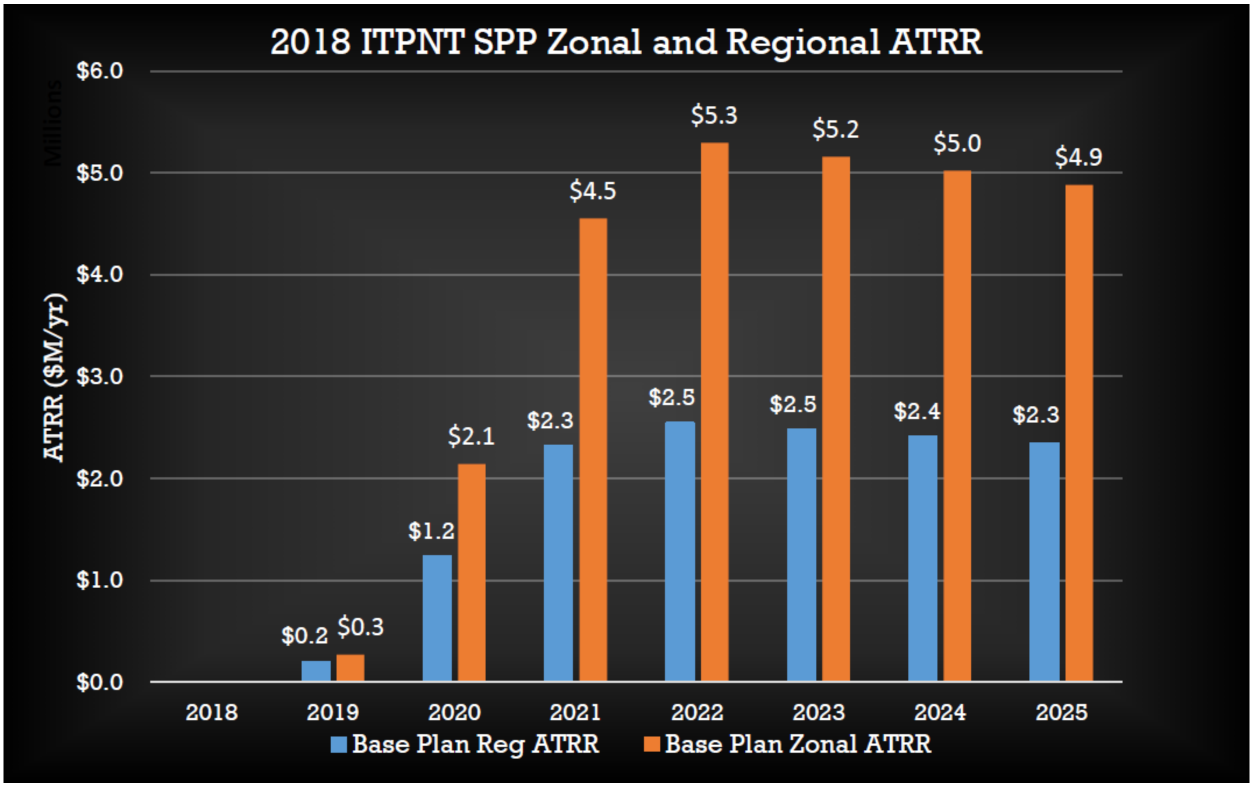
The 2018 ITPNT upgrades were run in the SPP Cost Allocation Forecast. The peak ATRR impact year was shown to be 2022.

Figure 4.5-12 – ATRR Cost Allocation Forecast by Zone of the 2018 ITPNT



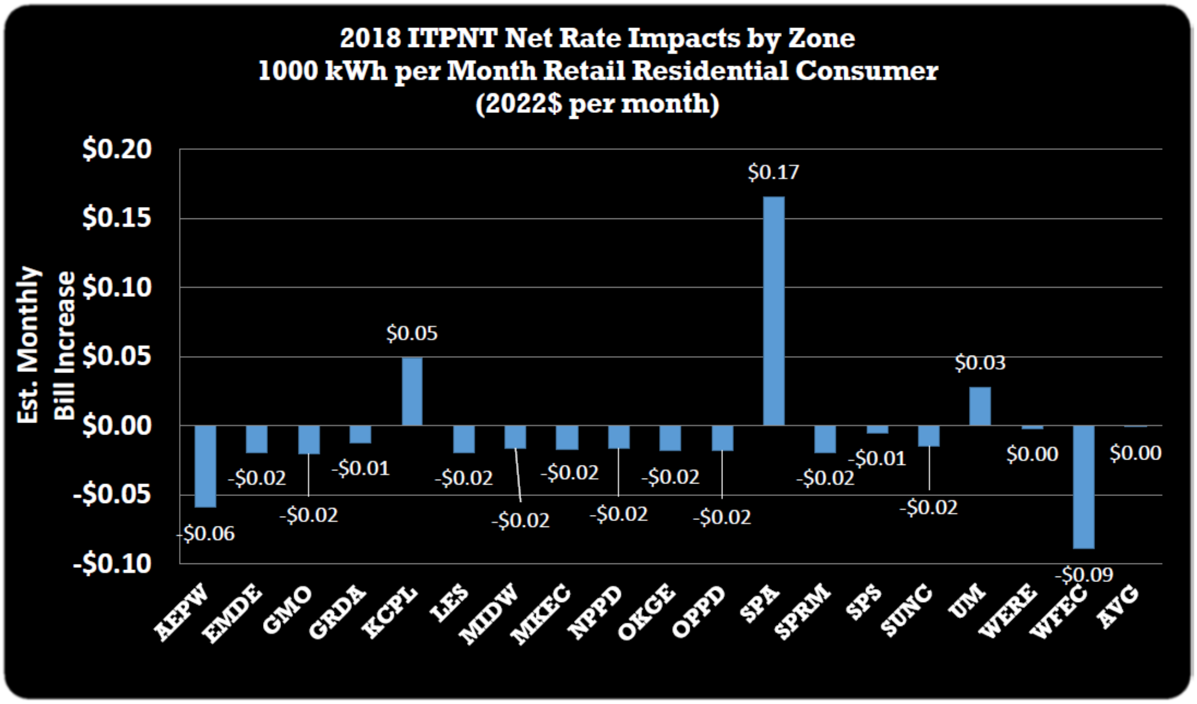
As shown in the following chart, the majority of the 2018 ITPNT projects will be cost allocated to the Pricing Zone hosting the upgrade. A smaller amount will be cost allocated to the SPP region through the regional rate.

Figure 4.5-13 – Zonal and Regional ATRR Allocated in SPP



The peak year ATRR is converted into a monthly impact on a typical 1,000 kWh per month Retail Residential customer. This is done by dividing the ATRR zonal impact by the zonal energy usage as adjusted for typical losses.

Figure 4.5-14 – 2018 ITPNT Monthly Bill Impact by Zone



Zones providing information on more than one state were combined using a weighted average based on sales projections in each state in the peak ATRR year of 2022.

3.1.5 Revenue Credits Estimate

5. Estimate of any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

The revenue credit process for future regional transmission upgrades has not been fully developed by SPP at this time. The Balanced Portfolio cost allocation coupled with newly designed highway/byway cost allocations and previous iterations of base plan funding remain in flux. SPP has forecasted values that were included in the previous sections as to the projected utility-specific ATRR are shown in Figure 4.5-12. Liberty-Empire continues to be in the lowest quartile of the utilities shown, as well as representing less than 1.0 percent of the collective ATRR.

3.1.6 Timing of Needed Resources Estimate

6. Estimate of the timing of needed transmission and distribution resources and any transmission resources being planned by the RTO primarily for economic reasons that may impact the alternative resource plans of the utility.

The SPP Balanced Portfolio of regional transmission projects included no projects in the Liberty-Empire service territory; therefore, there will be no impact on Liberty-Empire alternative resource plans.

3.2 Use of RTO Transmission Expansion Plan

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in subsection (3)(A) if all of the following conditions are satisfied:

See the previous sections for descriptions of Balanced Portfolio studies and ITP studies.

3.2.1 Utility Participation in RTO Transmission Plan

1. The utility actively participates in the development of the RTO transmission plan;

Liberty-Empire actively participates in the development of SPP transmission expansion plans through a number of related activities. Please refer to Table 4.5-11, which lists three dozen SPP stakeholder committee/task force involvements. Several of these groups are directly involved with development of the SPP transmission plan.

Liberty-Empire is a voting member as well as presently serving Chair of the MDWG which reviews and updates the transmission planning models used for regional transmission expansion analysis. Liberty-Empire adds transmission projects into the planning models and provides a substation level load forecast for the seasonal and future years planning models. These models include the generation dispatch Liberty-Empire expects to be required for meeting its native load requirements. The analysis of these models identifies future transmission projects necessary to maintain reliable service and reduce transmission congestion.

Liberty-Empire is also a voting member of the TWG which works on issues of coordinated planning and NERC and SPP compliance with individual transmission owners. The TWG is responsible for the planning criteria for evaluating transmission additions, seasonal available transfer capability ("ATC") calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. The TWG coordinates the calculation of the ATC for commerce maintaining regional reliability, while ensuring study procedures and criteria are updated to meet the regional needs of SPP, in cooperation with governing regulatory entities. The TWG is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. The TWG works closely with the ESWG to develop the scope documents used to direct the analysis and studies performed for the ITP process.

In addition, SPP hosts multiple ITP workshops and Planning Summits each year seeking stakeholder input to the transmission planning process and providing analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and propose transmission projects to reduce congestion and improve reliability. Liberty-Empire reviews transmission projects in its area and proposes alternatives that may provide better benefit or requests restudy of projects that it believes are not required.

3.2.2 Annual Review of RTO Expansion Plans

2. The utility reviews the RTO transmission overall expansion plans each year to assess whether the RTO transmission expansion plans, in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

Liberty-Empire reviews SPP overall expansion plans each year specifically for transmission projects in its area. Liberty-Empire proposes improved alternatives, where applicable, and/or requests restudy for projects that it believes are unmerited. In other instances, Liberty-Empire may suggest solutions to resolve a transmission problem in order to temporarily delay or potentially avoid new transmission construction. Liberty-Empire also submits alternative upgrade projects and their associated NTCs to be withdrawn if the requirements for the project changes or if the project is delayed beyond the scope of the study process, thereby postponing project construction or submitting.

3.2.3 Annual Review of Service Territory Expansion Plan

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO transmission expansion plans pertaining to projects that are partially or fully-driven by economic considerations (i.e., projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

Liberty-Empire reviews SPP transmission expansion plans each year specifically for projects in its area. Some of these are zonal projects that may result in additional obligations to serve or for Liberty-Empire to comply with specific planning and bulk electric reliability criteria. Liberty-Empire participates within the study processes throughout the year by way of the TWG or the Market and Operations Policy Committee ("MOPC"). Planned projects and portfolio of projects are presented to the associated groups for consideration and votes cast accordingly. Liberty-Empire maintains voting membership on both of the above groups.

3.2.4 Documentation and Description of Annual Review of RTO Overall and Utility-Specific Expansion Plans

4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans; and

Liberty-Empire's participation in the SPP planning processes is continuous throughout the year, directly participating on SPP committees, workgroups, various task forces, and projects reviewing transmission plans and providing recommendations. Liberty-Empire reviews SPP overall expansion plans each year specifically for transmission projects in its area. Liberty-Empire proposes improved alternatives, where applicable, and/or requests restudy for projects that it believes are not required. In other instances, Liberty-Empire may suggest solutions to resolve a transmission problem in order to temporarily delay or potentially avoid new transmission construction. Liberty-Empire representatives also participate in the overall approval of SPP transmission expansion plans in the market and operating policy committee (full membership) and the members committee.

Liberty-Empire conducts an annual assessment of its transmission system as required within the reliability standards specified by NERC. The annual assessment includes contingency analysis of the Liberty-Empire owned & operated Bulk Electric System ("BES"), short circuit analysis of in-service/planned additions equipment, as well as a stability analysis prescribed within the NERC standards. These assessments are shared with the adjacent or possibly impacted Transmission Planners and Planning Coordinators. Liberty-Empire specific projects which are either planned and internally funded are included within the assessment as needed or prescribed.

3.2.5 Affiliate Build Transmission Project Discussion

> *5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially or fully-driven by economic considerations, then the utility shall explain why such affiliate-built transmission is in the best interest of the utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate-built transmission is in the interest of the utility's Missouri customers.*

Liberty-Empire does not currently have any affiliate-built transmission at this time.

3.3 RTO Expansion Plan Information

(C) The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

The following SPP regional transmission planning reports are provided as attachments in the appendix to this report.

Appendix 4.5A	SPP Balanced Portfolio Report
Appendix 4.5B	SPP Priority Projects Phase II Final Report
Appendix 4.5C	2018 SPP Transmission Expansion Plan Report (STEP)
Appendix 4.5D	2018 Integrated Transmission Plan Near-Term Assessment Report (ITPNT)
Appendix 4.5E	2017 Integrated Transmission Plan 10-Year Assessment Report (ITP10)
Appendix 4.5F	2013 Integrated Transmission Plan 20-Year Assessment Report (ITP20)

3.4 Transmission Upgrades Report

(D) The utility shall provide a report for consideration in 4 CSR 240-22.040(3) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

3.4.1 Transmission Upgrades Report - Physical Interconnection within RTO

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint;

There are no transmission upgrades identified at present to physically interconnect a generation source within Liberty-Empire's footprint. Liberty-Empire cannot provide a generic list of the transmission upgrades needed to physically interconnect any given generation source within the SPP footprint because each interconnection is unique, and each evaluation is site specific. Each GI request is required to submit to the SPP GI process as defined in the applicable SPP transmission tariff. This process examines the specific location proposed for generator interconnection, its unique technical characteristics, and determines the necessary transmission upgrades necessary for that unique interconnection, as required by SPP. Presently, Liberty-Empire has applied to connect 500 MW of wind generation at two native locations (Asbury, MO & LaRussel, MO) (GEN-2017-060 & GEN-2017-082, respectively; DISIS-2017-001). No results are available as to the cost of these associated interconnection costs due to delay in higher-queued studies (e.g. DISIS-2016-002).

3.4.2 Transmission Upgrades Report - Deliverability Enhancement within RTO

> *2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including requirements for firm transmission service from the point of delivery to the utility's load and requirements for financial transmission rights from a point of delivery within the RTO to the utility's load;*

Requests for firm transmission service are processed through the AFS process in the SPP. Since the AFS is an iterative process, it is not possible to identify a list of the specific transmission upgrades needed to generally deliver energy from a resource in the SPP footprint into Liberty-Empire unless the process for a specific Transmission Service Request has been completed.

The AFS process occurs three times each year when specific Transmission Service Requests and GI requests are modeled collectively across the entire SPP footprint, based on control area to control area transfers. SPP analyzes the transmission system for the service requests including transmission improvements are identified that would enable the service to occur without standard or criteria violations. Costs for the various upgrades deemed necessary to deliver all of the Transmission Service Requests are allocated or socialized to all transmission customers within SPP. Transmission customers may decline the allocated costs and drop out of the study process, after which the analysis is repeated for the reduced set of Transmission Service Requests. This process iteration continues until a final set of Transmission Service Requests is reached for the remaining customers. The remaining transmission customers with service requests in the process agree to the projects needed to deliver the remaining transmission service and share the resulting upgrade cost allocations. These remaining upgrade projects are included in the next cycle of SPP transmission expansion plan process.

3.4.3 Transmission Upgrades Report - Physical Interconnection outside RTO

> *3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;*

Liberty-Empire cannot provide a list of specific transmission upgrades needed to interconnect a generation resource located outside the SPP footprint without performing a project-specific study for SPP GI request for a particular project location.

3.4.4 Transmission Upgrades Report - Deliverability Enhancement outside RTO

> *4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including requirements for firm transmission service to a point of delivery within the RTO footprint and requirements for financial transmission rights to a point of delivery within the RTO footprint;*

A list of the specific transmission upgrades needed to enhance deliverability of capacity and energy from a particular generation resource located outside the SPP footprint cannot be obtained without actually making a SPP GI request and an associated Transmission Service Request at a particular location.

3.4.5 Transmission Upgrades Report - Estimate of Total Cost

5. The estimated total cost of each transmission upgrade; and

Liberty-Empire recently completed a single active NTC on file with SPP (NTC #200448); however, there are no pending NTC's issued and therefore the estimated total cost of pending or upcoming transmission upgrades is $0 (zero). Included in the aforementioned, now complete NTC #200448 were three (3) 69kV line sections which were identified in the Reliability planning processes in the study year 2016 and constructed over the 2017 and 2018 calendar years. The three line sections of interest were in the Republic, MO area and constituted approximately 15 miles of rebuild at a completed cost of $12.4 million in April of 2018. Liberty-Empire continues to participate in the SPP planning process in an effort to continually study the evolution of the regional transmission system.

3.4.6 Transmission Upgrades Report - Cost Estimates

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

Liberty-Empire's estimated fraction of the total cost of transmission upgrades is unknown at this time. Due to the fact that Liberty-Empire has no active NTCs in which direct charges will be applied, the cost for Liberty-Empire-specific projects within the 2018 ITPNT is $0 (zero). 2018 ITPNT zonal cost allocations are displayed in Figure 4.5-12.

SECTION 4 ADVANCED TECHNOLOGY ANALYSIS

(4) Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies.

4.1 Transmission Upgrades for Advanced Transmission Technologies

(A) The utility shall develop, and describe and document, plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in paragraphs (3)(B)1. through (3)(B)3. are satisfied.

As previously discussed in Section 3.1.2, Liberty-Empire incorporates three main advanced technologies in its transmission system: ADSS and/or OPGW, microprocessor relaying, and automatic throw-over switching schemes on the 69-kV transmission system(s). In addition to these technologies evaluated by Liberty-Empire, Section 3.1.2 also provides a list of emerging technologies – transformer oil DGM, transformer bushing monitoring, transformer bushing monitoring with partial discharge, transformer fiber optic winding temperature sensors, transformer monitoring, comprehensive transformer health monitoring, fiber optic substation data network, substation data archive, server, and database, 69-kV vacuum circuit breakers – which Liberty-Empire is currently evaluating for possible future implementation for use on its transmission system.

Liberty-Empire has also endeavored to set out the overarching planning context for its work on ATDNT in Section 1.4. This has been offered to explain to stakeholders the future directions and aspirations of the company in the pursuit of modernizing its transmission and distribution system with advanced technology. The role of AMI, Customer First, Distribution Automation, ADMS implementation, outage management system improvements, voltage control, installation of faulted circuit indicators ("FCI") and reclosers are all discussed (recognizing for purposes here that many of these are distribution system focused versus transmission). Importantly, Liberty-Empire is pursuing these grid capabilities against the *essential* backdrop of expanded, safe and secure communication at both transmission and distribution levels.

Section 1.4 also reviews the very important improvements Liberty-Empire has made – and continues to make – through its OTU program, its feeder automation demonstration, its expanded recloser utilization, and its investigation into advanced fusing. OTU, for example, has delivered important long-term transmission system reliability and resiliency benefits by rebuilding transmission system substations and circuits, and improving system protection, among other improvements. Many of these efforts form an activity baseline that reflects sound engineering practice, comports with current and emerging standards, stays aligned with vendor innovation, applies advanced asset management techniques, stays true to fundamental functional and technology dependencies (such as SCADA communications), and proceeds prudently in recognition of core grid functions (safety, security, reliability, resiliency, capacity, contingency, etc.). In summary, these initiatives demonstrate Liberty-Empire's focus on meeting core grid functions while thoughtfully and prudently implementing advanced technology on the transmission system where practical and feasible.

4.2 Distribution Upgrades for Advanced Distribution Technologies

> *(B) The utility shall develop, and describe and document, plans for distribution network upgrades as necessary to optimize its investment in advanced distribution technologies.*

As explained in Section 1.4, Liberty-Empire is pursuing several important programs that will bring advanced technology capabilities to its distribution system. The role of AMI, *Customer First,* Distribution Automation, ADMS implementation, outage management system improvements, voltage control, installation of FCI and reclosers are all discussed. Essentially, Liberty-Empire is pursuing these grid capabilities against the backdrop of expanded, safe and secure communication at both transmission and distribution levels.

As described above and elsewhere, the OTU program has brought advanced technology-based improvements to system reliability challenges and issues at the distribution level. OTU has involved intensive reviews of issues related to SAIDI and SAIFI across the Liberty-Empire distribution system. A key aspect of OTU and the reliability improvement goals has been the focus on bringing advanced technology solutions to cost-effectively address the reliability challenges. The relation of OTU to Liberty-Empire's distribution network has been (and continues to be) a compilation of distribution circuit sectionalizing evaluations, fuse coordination optimization studies, advanced recloser control upgrades, and measures to increase Liberty-Empire's system hardening. All have advanced technology components. Liberty-Empire will also continue to install OPGW and ADSS cables on the distribution system, improving these conductors and system protection schemas.

In support and furtherance of advanced distribution technologies on Liberty-Empire's system, the company continually evaluates avenues to improve reliability with minimal rate impact in order to better serve its customers. Liberty-Empire strives to strike a balance between vetting, evaluating, and implementing emerging technologies for the benefit of customers.

4.3 Optimization of Investment in Advanced Transmission and Distribution Technologies

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of—

4.3.1 ATDNT Assumptions: Relationship to Resource Options

In Sections 22.045 (4)(A) and (B) Liberty-Empire has described its evaluation of and considerations for the demonstration and use of ATDNT on the Liberty-Empire Transmission and Distribution grid. In Section 22.045 (4)(C) Liberty-Empire narrows the assessment scope so as to focus on transmission and distribution technology assumptions that may have a bearing on supply- or demand-side resource considerations.

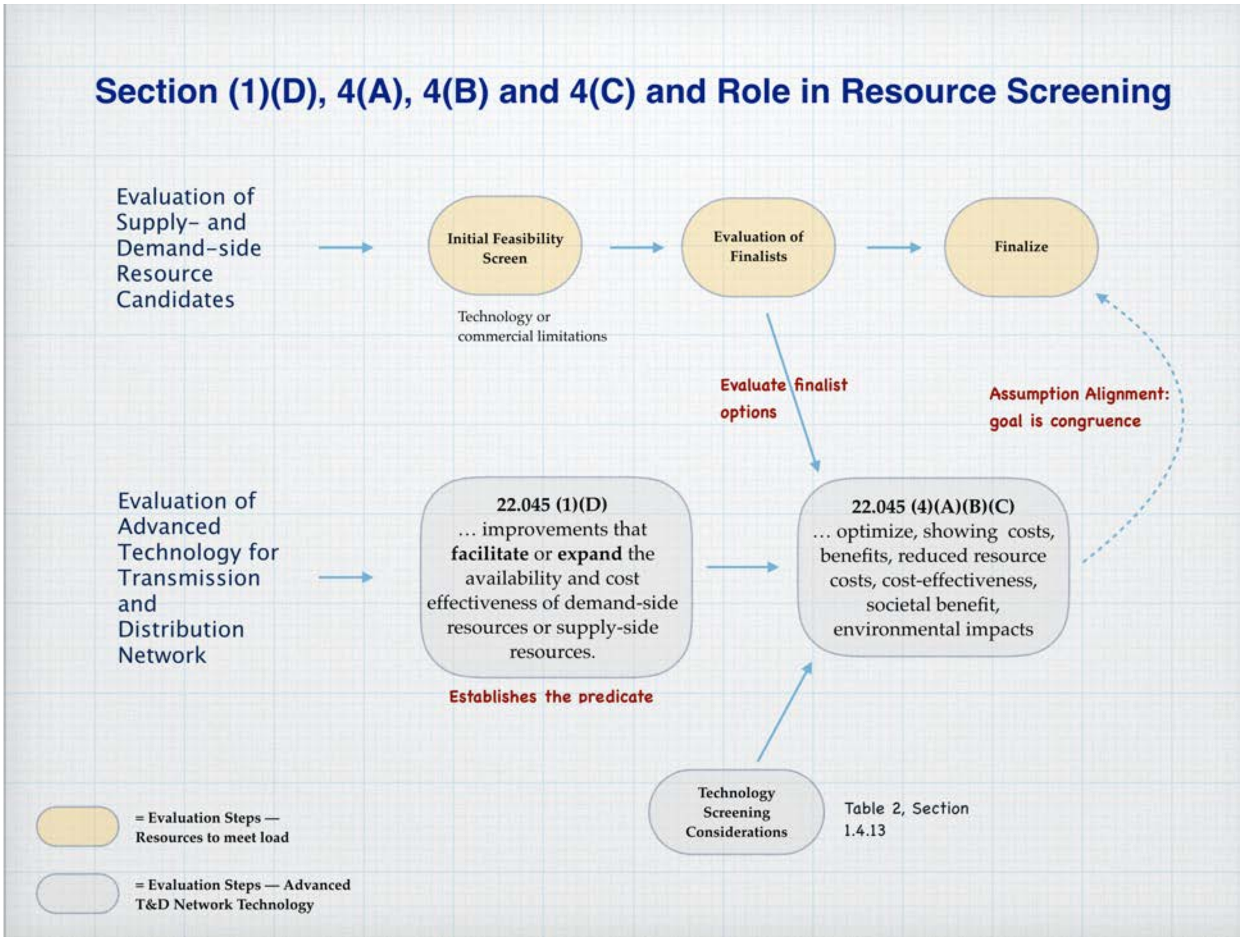
Liberty-Empire sees this stage is a logical extension of the ATDNT identified in Table 2, Screening of ATDNT appearing in Section 1.4.13. The difference is that this stage is used to evaluate the nature of the specific nexus between Liberty-Empire final candidate supply and demand-side resources and ATDNT, determining:

- For those ATDNT having a bearing on supply- or demand-side resource choices:
  - The nature of ATDNT costs and benefits, and their alternatives
  - How ATDNT impacts resource costs in relation to a role of enhanced demand side and customer-owned generation resources, if any
  - Cost-effectiveness (for resulting energy resources) associated with choices between advanced and non-advanced technology use

Figure 4.5-15 depicts Liberty-Empire's view of the relationships between the Resource evaluation and the ATDNT assessment for this final stage of the assessment. For those resource options that pass initial screening (as part of the candidate Supply- or Demand-side resource screening), Liberty-Empire then has checked to determine how they may relate or interact with ATDNT needs or dependencies. If dependencies exist, Liberty-Empire has then described these in relation to the specific 22.045 (4)(C) requirements as set out in this section.

Liberty-Empire believes this is consistent with the requirements of Section 22.045 (1)(D), which calls for the assessment of transmission and distribution improvements "that facilitate or expand the availability or cost-effectiveness of demand-side resources or supply-side resources."

Figure 4.5-15 – Relationships between Resource Screening and ATDNT Evaluation in IRP Rule



4.3.2 Baseline Activities: No Broad Cost/Benefit Findings Possible

Liberty-Empire has described numerous technologies (see Sections 1.4, and 3.1.2) that provide a baseline of activity and investment in promoting the role of ATDNT in the service of sustaining reliability, providing adequate grid resiliency, and safely interconnecting generation to serve load. As a general and broad consideration, Liberty-Empire's cost to benefit analysis on these technologies highlights the rural nature and topography of the Liberty-Empire transmission and distribution systems paired with the location of Liberty-Empire within the SPP footprint, that optimization of investment of advanced transmission and distribution technologies proves to be cost prohibitive of a broad application of specific technologies yet supports the structured inclusion of others. The analysis of various technologies does not point to a specific network technology advancement which could realize a comprehensive benefit to cost ratio greater than one due to the restrictions of cost deployment.

4.3.3 Candidate Supply-side Resource Options

Liberty-Empire identified several supply-side options for inclusion in the detailed resource integration and evaluation process:

- Natural gas-fired simple cycle Aero-derivative CT
- Natural gas-fired combined cycle – 2 x 1 F Class
- Natural gas-fired reciprocating engines*
- New on-shore wind
- Solar PV – single axis tracking with and without lithium ion battery storage*
- Energy storage – lithium ion battery*

* Denotes a resource option evaluated as both a distributed and utility scale energy resource.

To identify potential relationships to ATDNT requirements, Liberty-Empire questioned whether there are any specific challenges of interconnecting these facility types, and whether there is sufficient transmission and distribution system capacity that would limit the output of these resources.

Additionally, there are no transmission upgrades identified at present to physically interconnect a generation source within Liberty-Empire's footprint. In fact, because each interconnection is unique, and each evaluation is site specific, Liberty-Empire cannot provide a generic list of the transmission upgrades needed to physically interconnect any given generation source within the SPP footprint. Moreover, each GI request is required to submit to the SPP GI process as defined in the applicable SPP transmission tariff. This process examines the specific location proposed for generator interconnection, its unique technical characteristics, and determines the necessary transmission upgrades necessary for that unique interconnection, as required by SPP.

Finally, Liberty-Empire has applied to connect 500 MW's of wind generation at two native locations (Asbury, MO & LaRussel, MO) (GEN-2017-060 & GEN-2017-082, respectively; DISIS-2017-001). No results are available as to the cost of these associated interconnection costs due to delay in higher-queued studies (e.g. – DISIS-2016-002).

4.3.4 Candidate Demand-side Resource Options

Liberty-Empire identified several demand-side options for inclusion in the detailed resource integration and evaluation process. Liberty-Empire also evaluated ATDNT opportunities to determine if there is any role within these programs for advanced technology. For the purposes of illustrating the screening process, AMI, DA and voltage control are listed beside each measure, indicating whether some relationship may exist between the measure and the technology.

Table 4.5-14 – ATDNT Evaluations

Sector	Program Measure	AMI	DA	Voltage Control
Res	Residential Lighting	N/A	N/A	N/A
Res	Residential Appliance Recycling	N/A	N/A	N/A
Res	Whole House Efficiency	helpful	N/A	N/A
Res	Residential Behavioral	helpful	N/A	N/A
Res	Low Income Whole House Efficiency	helpful	N/A	N/A
Res	Low Income Behavioral	helpful	N/A	N/A
Res	Low Income Weatherization	helpful	N/A	N/A
Non-Res	C&I Program	helpful	N/A	N/A
Res	Time of Use Rate	required	N/A	N/A
Res	Critical Peak Pricing	required	N/A	N/A
Res	Inclining Block Rates	required	N/A	N/A
Non-Res	Time of Use Rate (Non Res)	required	N/A	N/A
Non-Res	Critical Peak Pricing (Non Res)	required	N/A	N/A
Non-Res	Real Time Pricing	required	N/A	N/A

In the case of AMI, there are some instances where the provision of detailed hourly or sub-hourly measurement information *could* be useful to those designing and implementing the demand side program. However, advanced metering is *not required* for these programs. Secondly, there are other demand-side programs that are listed and which involve some form of time variant pricing. For these programs AMI is required (at least for those meter customers). These programs require the granular, daily, hourly and sub-hourly measurement that AMI will provide. (As described in the SCI items A and E, Liberty-Empire is pursuing AMI and intends to implement it in the 2020-2021 timeframe).

4.3.5 Early Resource Screening (and Disqualification) of certain Demand-side Resource Options

In Table 4.5-7, Liberty-Empire provided a list of advanced technologies that could play a potential role in facilitating the use of certain resource types. For example, distribution automation functionality can support CVR, and this can lower total resource requirements. ADMS, for example, along with improved communications and DA, can help support the distribution grid for the integration and connection of DERs.

Liberty-Empire reviewed its resource screening (i.e., preliminary candidate resources prior to disqualification) to determine if the disqualifying considerations involved the lack of availability of these capabilities. Liberty-Empire confirms that did *not* disqualify resources from further consideration due to assumptions regarding the availability of advanced network technology.

4.3.6 Optimization of Investment - Total Costs and Benefits

1. *Total costs and benefits, including:*

4.3.6.1 Costs of Advanced Grid Investments

A. Costs of the advanced grid investments;

As it relates to Liberty-Empire's baseline consideration of maintain network reliability, Liberty-Empire utilizes a least-cost, high-value, highest-efficacy approach for optimization of investments for advanced grid technologies. Liberty-Empire outages triggered by transmission outages were determined as higher impact events due to the large number of customers affected by a single event. By addressing the transmission system and improving sectionalizing, high impact outage events were able to be remediated by lower cost installations, thereby optimizing Liberty-Empire investments in advanced technologies. If radially fed substations are outaged, the resulting number of customers is far higher than if a single circuit sourced from the substation is outaged. As a result, low cost, high impact to outage indices was determined as the optimized solution. This included a review of the causal relationships for transmission outages, radially fed substations, and resultant outage duration. Related to low aggregated, levelized cost across Liberty-Empire's transmission system(s) and given the ongoing evaluations of various technologies, the optimized investment hinges upon on the application, utilization, and expansion of a communications network by way of the aforementioned fiber optic network project presently in design. Many future technologies will be systematic versus localized management. In constructing a communications platform, devices will be able to gather the needed data, manage said data, and make adjustments to optimize the use and ensure viability of the infrastructure and equipment in place. Liberty-Empire has committed capital in multiple years to further the advancement of a fiber optic network and will continue to evaluate the benefit to cost of such a deployment.

Liberty-Empire has not identified any advanced grid investments which influence at this time any of the supply- or demand-side resource options that were evaluated for inclusion in final screening evaluations. As explained, the interconnection of Supply-side resources is largely unidentified in terms of requirements and locations. However, there are no identified limitations introduced to the candidate resource options due to limits of the transmission or distribution grid capabilities (which *might* be addressable through advanced network technologies).

The exception to this conclusion relates to the implementation of AMI, which is noted as required to support time variant pricing programs. AMI is also potentially helpful in the development of programs that are aimed at assisting utility customers in their energy behavioral choices. There are also some instances where the AMI network can be used as a communication channel for price signals or customer alerts. These later considerations are discretionary ones and depend on program designs and features.

Additionally, the costs of the AMI system have not been included in the analysis of the DSM programs involving time variant solutions. The cost analysis for these programs assume the presence of two-way communicating meters (along with certain back office data management and billing engine capabilities). However, Liberty-Empire believes it will justify the AMI investment (See SCI items A and E) on merits independent of time variant pricing considerations. Liberty-Empire is also pursuing meter data management and billing system upgrades and improvements independently. Therefore, it is reasonable to conclude that there are no incremental costs that need to be considered in the evaluation of the time variant pricing programs specifically as it relates to advanced network technologies.

4.3.6.2 Costs of non-Advanced Grid Investments

B. Costs of the non-advanced grid investments;

Similar to the conclusions above (that there are no advanced grid investments that factor into the supply- or demand- side resource choices), there are no *alternative* costs associated with non-advanced grid investments that influence Liberty-Empire's consideration of the resource choices.

Liberty-Empire additionally notes that by utilizing fusing methodology, Liberty-Empire has optimized distribution grid investments as opposed to expending efforts and resources in attempting to evaluate newly trended technologies and is able to promote a much more robust system for the customers served off the associated feeders to which the recently formatted methodology is applied. Liberty-Empire has developed fusing methodology alongside the use of advanced software modeling of the distribution systems. Fusing is considered non-advanced technology due to the longevity of implementation on the electric system. Liberty-Empire has re-evaluated the methodology used in previous iterations of protective coordination studies and has found improvements could be made in how the distribution system is sectionalized. Evaluation of the fusing methodology entails the use of industry standard fusing and standardization of coordination. Application of the revamped fusing methodology allows for a high efficacy impact on the distribution system sectionalization.

The advancement in fuse technology has allowed for more flexibility and configurability on the coordination on radially fed systems. The previous use of fusing was an improvement over previous guidelines however in evaluating new technologies, Liberty-Empire has been able to provide and increase in service to distribution customers while lessening the cost to the customers. With the associated costs of newly specified fusing mainly residing in the engineering evaluation and specification, install costs are minimal due to the cooperative efforts in the worst performing circuit ("WPC") evaluations. Liberty-Empire foresees no appreciable cost impacts to the customers due to new fuse deployment at this time. If the scope of deployment veers away from WPC cooperation and to total system implementation, the majority of the associated costs for such an initiative would be encompassed within the labor costs of install. This would be site deterministic and could not be estimated on a system wide basis.

4.3.6.3 Reduced Resource Costs through Demand Response and Demand Generation

> C. *Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and*

Liberty-Empire has evaluated demand response measures and included several as candidate demand-side resources. See Volume 5. These resources include the need for time variant pricing. Accordingly, they require the availability of detailed participant billing determinants at the hourly or sub-hourly level of granularity. (Some programs also require customers to receive timely price signals and alerts). Liberty-Empire will need to provide this data by way of some type of two-way AMI. However, Liberty-Empire has established plans to implement AMI in the 2020-2021 timeframe and will separately cost-justify this investment. Liberty-Empire's analysis is not constrained or altered in any way by today's lack of AMI capabilities.

Additionally, Liberty-Empire has not identified any customer-owned generation resource options that factor into the screening and final selection of resource options. Nor are these customer-owned generation resource options constrained within the resource modelling or evaluation by assumptions regarding the availability of advanced distribution network technologies that may be useful for their integration and monitoring to the extent they participate in serving load. As described elsewhere, Liberty-Empire's long-term plan to implement AMI, DA, and voltage controls – among other advanced distribution system grid functions – will assist Liberty-Empire in integrating customer owned resources as they emerge over time.

4.3.6.4 Reduced Supply-side Production Costs

D. Reduced supply-side production costs;

Liberty-Empire interprets this requirement in the context of the analysis of total costs and benefits of applying ATDNT for purposes of supporting supply- or demand-side resources. As explained in this section, Liberty-Empire has not identified any candidate resource options – except for time variant pricing programs – that require the availability of advanced network technology.

As noted earlier, Liberty-Empire does aspire to implement a CVR schema to lower total system energy use by flattening voltage profiles. While useful to pursue, Liberty-Empire does not have knowledge at this time about the extent of any energy efficiency savings that the CVR program will generate, and so has not adjusted the supply forecast for assumptions about CVR implementation.

4.3.7 Cost-Effectiveness of Advanced Technologies

2. Cost effectiveness, including:

4.3.7.1 Incremental Costs of Energy Resources (With and Without Advanced Technology)

A. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

Liberty-Empire has not identified specific advanced technologies – except AMI as noted in relation to certain forms of time variant pricing – that influence the final candidates Liberty-Empire considered for its Supply- and Demand-side resource selection. Moreover, it did not disqualify any resource due to the lack of availability of an advanced network technology. To the extent that certain resources were not selected for further review in the final resource analysis stages these factors were unrelated to the question of the availability of advanced network technology.

Therefore, Liberty-Empire is not able to define a difference in the resource costs of a delivery system based on advanced grid technologies versus non-advanced grid technologies.

4.3.7.2 Incremental Benefits Advanced Grid Technologies vs. Non-Advanced Grid Technologies

B. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and

Liberty-Empire has not identified specific advanced technologies – except AMI as noted in relation to certain forms of time variant pricing – that influence the final candidates Liberty-Empire considered for its Supply- and Demand-side resource selection. Moreover, Liberty-Empire did not disqualify any resource due to the lack of availability of an advanced network technology. To the extent that certain resources were not selected for further review in the final resource analysis stages these factors were unrelated to the question of the availability of advanced network technology.

Therefore, Liberty-Empire is not able to define a difference in the resource costs of a delivery system based on advanced grid technologies versus non-advanced grid technologies.
Liberty-Empire has identified several long-term and aspiration areas of investment in relation to advanced network technologies. It believes that these investments will help it accommodate new energy products and services as these new energy choices, technologies and markets mature. As they do, Liberty-Empire will be in a stronger position to interconnect and interact with these resources, ensuring that they can participate in fair, equitable, efficient and safe ways.

4.3.7.3 Optimization of Investment - Non-Monetary Factors

C. Additional non-monetary factors considered by the utility;

As documented in Section 1.4, Liberty-Empire considers many factors when approaching its use of new technology. For example, Section 1.4.2 describes Liberty-Empire's long-term goals and objectives for its use of advanced grid technologies. Section 1.4.3 describes principles that guide its planning and investment. Section 1.4.4 describes the leverage Liberty-Empire receives by collaboration with its Liberty Utility parent organization and other Liberty Utility-owned operating companies.

4.3.8 Optimization of Investment - Societal Benefit

3. Societal benefit, including:

Liberty-Empire has not identified specific requirements for ATDNT that influences currently considered Supply- or Demand-side resource choices. It has not identified societal benefits associated with ATDNT that would influence the resource analysis.

As documented in Section 1.4, Liberty-Empire has established long term goals and objectives for the use of ATDNT that includes addressing emerging customer requirements related to how customers are changing their participation in the electric energy market. Liberty-Empire is prudently looking over the horizon to determine the capabilities it will need to be able to support its customers as they consider new forms of energy services and products. Its aspirations related to AMI, DA, CVR, ADMS and expanded communications – to name several initiative areas – will support Liberty-Empire's ability to usher in the needed change to the distribution system in support of new market services whether provided by Liberty-Empire directly or by others.

4.3.8.1 Societal Benefit - Consumer Choice

A. More consumer power choices;

Liberty-Empire has not identified specific requirements for ATDNT that influences currently considered Supply- or Demand-side resource choices.

Accommodating more consumer power choices is very much part of Liberty-Empire's vision. As documented in Section 1.4, Liberty-Empire has established long term goals and objectives for the use of ATDNT that includes addressing emerging customer requirements related to how customers are changing their participation in the electric energy market. Liberty-Empire is prudently looking over the horizon to determine the capabilities it will need to be able to support its customers as they consider new forms of energy services and products. Its aspirations related to AMI, DA, CVR, ADMS and expanded communications – to name several initiative areas – will support Liberty-Empire's ability to usher in the needed change to the distribution system in support of new market services whether provided by Liberty-Empire directly or by others.

AMI has particular relevance to Liberty-Empire and its customers. As explained in response to SCI #A and #E, Liberty-Empire is pursuing the deployment of AMI in the 2020-2021 timeframe (with planning underway now in conjunction with Liberty Utilities' corporate wide effort to install supporting back office systems such as Meter Data Management, or MDM). AMI unlocks Liberty-Empire's ability to offer the cost-effective means to provide its customers with new rate programs, which in turn support emerging energy technologies and services. With the two-way AMI-provisioned metering data, customers will become increasing empowered to make independent choices concerning their energy service provision.

4.3.8.2 Societal Benefit - Existing Resource Improvement

B. Improved utilization of existing resources;

Liberty-Empire has not identified specific requirements for ATDNT that influences currently considered Supply- or Demand-side resource choices. It has not identified benefits associated with ATDNT – and utilization of existing resource considerations -- that would influence the resource analysis.

As documented in Section 1.4, Liberty-Empire has established long term goals and objectives for the use of ATDNT that include addressing the operational efficiency of how the grid operates. Such capabilities as sectionalizing (to improve reliability) and CVR (to lower energy use) will have a direct relationship on improving the utilization of the current distribution grid assets. These investments will help Liberty-Empire get more from its existing resources and will: improve reliability, reduce energy losses, improve power quality, and increase load serving capacity.

4.3.8.3 Societal Benefit - Price Signal Cost Reduction

C. Opportunity to reduce cost in response to price signals;

Liberty-Empire's Demand-side resource plan includes price signals to affect energy use behaviors. AMI is an essential part of these programs.

4.3.8.4 Societal Benefit

D. Opportunity to reduce environmental impact in response to environmental signals;

Liberty-Empire's AMI technology will support time variant pricing. These programs can increase total resource efficiency including environmental resources. AMI can also assist the utility in lower energy losses (such as theft and tamper). CVR, by flattening voltage profiles, can assist Liberty-Empire in lowering distribution system losses, thus conserving energy. Over-time the grid control functionality envisioned by Liberty-Empire with the implementation of AMI, DA, and other systems will permit the increased use of storage technology, which can influence the total operating efficiencies of wholesale generation resources.

4.3.9 Optimization of Investment - Other Utility-Identified Factors

4. Any other factors identified by the utility; and

No other factors were identified by Liberty-Empire.

4.3.10 Optimization of Investment - Other Non-Utility Identified Factors

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240-22.080(5).

No other factors were identified by Liberty-Empire.

4.4 Non-Advanced Transmission and Distribution Inclusion

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing, the utility shall—

4.4.1 Non-Advanced Transmission and Distribution Required Analysis

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. The utility may rely on a generic analysis as long as it verifies its applicability; and

4.4.1.1 Transmission

In Sections 1.4, 3.1.2, 4.1, and 4.2, Liberty-Empire has documented the cost ineffectiveness of the use of several non-advanced technologies in the attempt to optimize investment. The analysis points to an optimum investment relating to infrastructure platforms from which multiple future initiatives may be built upon and utilize for further gains to be realized. Liberty-Empire's analysis exhibits the stranding of capital, both immediate and future, with the installation of non-advanced technologies.

In summary, Liberty-Empire is not proposing installation of any new non-advanced transmission grid technologies or programs in this triennial IRP compliance filing. Liberty-Empire's evaluation points to more merit on installing advanced technologies on the transmissions systems.

4.4.1.2 Distribution

4.4.1.2.1 Capacitor Control Upgrades

Liberty-Empire has examined and determined needed upgrades for the automation of capacitor bank controls. Previously, simple time and/or temperature controls were installed for capacitor bank control. Upgraded capacitor controls, which include parameters of time, date, temperature, voltage, and VAr (additional option), are installed on all new installations of cap banks. Present controls are replaced on an as-needed basis as original controls fail or become inoperable or faulty. The power factor at the substation is also improved by the automated addition and removal of capacitance when demand necessitates. This immediate response to load profile changes allows the distribution system to be manipulated to optimize voltage profile along a given feeder.

4.4.1.2.2 Regulator Controls Upgrades

In reviewing possible candidates for the installation of regulators on a distribution feeder, the Liberty-Empire planning department makes use of advanced regulator controls in an effort to optimize the voltage profile alongside the use/installation of capacitor banks with advanced controls. Liberty-Empire's regulator controls have multiple functionalities and parameters that can be tailored to the feeder specifications. Liberty-Empire evaluates feeders' voltage profiles and programs as such to attain the most effectual response from the regulator. Liberty-Empire does not simply raise/buck voltage as a response to demand but also implements the proper bandwidths, timer delays so as not to over-wear contacts within the regulators, and the associated compensative settings (impedance and reactance) for the needed end-of-line response. In utilizing regulator controls to this level, Liberty-Empire gains multiple benefits (i.e., MW demand reduction from voltage control, substation voltage regulation/flexibility, load tap changer flexibility and manipulative bandwidth, VAr flexibility allowing reflection onto the transmission system, etc.) from not only the regulator itself but also the Liberty-Empire distribution system as a whole.

4.4.1.2.3 Relaying Upgrading

In an effort to modernize Liberty-Empire's distribution and transmission systems, all proposed, merited capital projects are reviewed during Liberty-Empire's construction budget process to identify gains that could be realized with the inclusion of advanced relaying. When presented with a project, Liberty-Empire's planning and protection department alongside the substation construction department reviews the scope of work and attempts to identify upgrades needed which would most benefit the customers served off the identified feeders and/or substations. One example would be the auto transformer failure at Liberty-Empire's Powersite No. 312 in the spring of 2012. Liberty-Empire's planning and protection department along with the substation construction department were able to identify electromechanical relaying that had limited availability of replacement components, no way of recording event data, non-redundant protection, inadequate overlapping zones of protection, and additional exposure to high value equipment which could drastically affect the SAIDI and SAIFI for the area transmission systems.

Due to the extent of the work to replace an auto transformer, the relaying was deemed as a prime candidate for upgrade. The job was engineered to not only bring the relaying up to adequate Liberty-Empire protective specifications, but also to allow for future betterment of the protection scheme at the substation of interest. Liberty-Empire saw a need and attempted to gain coaction while undertaking a common site task by expanding the original project scope so as to better the reliability for its customers. The gains to be realized once the project has been completed include adequate fault recording for root cause analysis in future events, overlapping zones of protection for the newly positioned auto transformer, and reduction of exposure to out of zone events as related to the auto transformer.

An example on the distribution level is the inclusion of microprocessor relaying in all new feeder breakers. Liberty-Empire also replaces electromechanical relaying with microprocessor relays as breakers fail or interrupting capabilities are surpassed. Alongside replacement of breakers, each new substations that Liberty-Empire constructs will be equipped with multiple microprocessor relays so as to better coordinate with downstream protective devices, expand fault data recording, aid in root cause analysis, expansion of load data profiling, allow for over lapping zones of protection, enable bus differential relaying for additional protection capabilities, etc. By making use of microprocessor relaying, much more additional information can be readily reviewed after an event has occurred to adjust, evolve, and streamline the protective schemes to eliminate prolonged customer outages.

4.4.1.2.4 Utilization of Regulator Controls

Liberty-Empire utilizes advanced controls in the voltage regulation of its distribution system. These controls are microprocessor driven and allow for acute adjustments to be made on a given feeder. Voltage regulation lessens the infrastructure to be installed due to the ability to raise or lower the voltage profile along a feeder experiencing high or lightened loads. By way of raising the voltage, the current demand is lowered on a given section of primary conductor. Lowering the current to within allowable ampacity ratings, said section of conductor would not require a reconductor, rather offset the cost of construction. Although voltage regulation is not a new concept to the power industry, the combined use of voltage regulation alongside capacitor controls and load tap changers can offset construction costs if these controls are operated in conjunction with each respective controller's effects on the given feeder. Liberty-Empire conducts such a review if a voltage issue is presented. Liberty-Empire reviews the lowest cost, highest efficacy solution for a given distribution system by using the aforementioned distribution modeling software (CYMDIST), microprocessor controls, and evaluation of the entire feeder as a system.

Liberty-Empire is not proposing installation of any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing, but rather a continuation of present efforts in the development and optimization of fusing schema. Liberty-Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Liberty-Empire is to include such non-advanced technologies in future IRP filings.

4.4.2 Non-Advanced Transmission and Distribution Analysis Documentation

2. Describe and document the analysis.

4.4.2.1 Transmission

In Sections 1.4, 3.1.2, 4.1, and 4.2 Liberty-Empire has documented the cost ineffectiveness of the use of non-advanced technologies in the attempt to optimize investment. The above analysis points to an optimum investment relating to infrastructure platforms from which multiple future initiatives may be built upon and utilize for further gains to be realized. Liberty-Empire's analysis exhibits the stranding of capital, both immediate and future, with the installation of non-advanced technologies. Liberty-Empire is not proposing installation of any new non-advanced transmission grid technologies or programs in this triennial IRP compliance filing. Liberty-

Empire's evaluation points to more merit on installing advanced technologies on the transmissions systems.

4.4.2.2 Distribution

Liberty-Empire is not proposing installation of any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing, but rather a continuation of present efforts in the development and optimization of fusing schema. Liberty-Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Liberty-Empire is to include such non-advanced technologies in future IRP filings.

4.5 Advanced Transmission and Distribution Required Cost - Benefit Analysis

> *(E) The utility shall develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:*

In section 1.4, 3.1.2, 4.1, and 4.2, Liberty-Empire has described a diverse set of technology evaluations, demonstrations, implementations and current uses that collectively document and demonstrate Liberty-Empire's prudent and reasonable approach to the incorporation of advanced grid technologies. In Section 1.4 Liberty-Empire also provides an overview as to its long-term aspirations and investment plans to adopt advanced grid technologies to achieve reliability, operational efficiencies, energy reductions (via CVR), and to accommodate the future demands and challenges associated with distributed energy resources.
Liberty-Empire has provided in its response to SCI items A and E its detailed plans as best can be explained today about its AMI initiative (and that Liberty-Empire expects to implement AMI in the 2020-2021 timeframe).

An important backdrop to these considerations in Liberty-Empire's view is the fact that -- at both the Transmission and Distribution system planning levels, -- Liberty-Empire's ability to provide the needed reliability, security, safety, and resiliency to the grid in turn allows wholesale generators to participate effectively in serving Liberty-Empire load consistent with the requirements of interconnection procedures and rules. This applies whether interconnecting at the transmission level or at major points on the distribution system.

As a reflection of its commitment to pursue advanced technology, Liberty-Empire has invested in and piloted various advanced technology applications. At the same time there is a limit to the accrued benefit customers will actually realize that must also be taken into account. Spending on emerging technologies can be boundless. Accordingly, Liberty-Empire has attempted and will continue to strike a healthy balance of vetting newly emerging technologies in parallel with time proven implements. The benefits of the piloted projects are presently being weighed against their associated costs to implement/deploy. However, benefits of such programs are difficult to capture. An example of such would be, regardless if a transformer monitor is installed and a failure occurs, the result would be an outage to a large number of customers. Alternatively, if the DGM program is implemented system-wide, and transformer failures subsided, the metrics to attribute the reduction in outages are difficult to allocate properly among other initiatives across the company. Benefits most certainly accrue but are difficult to assign narrowly.

The above examples help illustrate that -- without clarity as to how utilities should weigh and allocation benefit (and trade off benefits for investment dollars) – the pursuit of unproven advanced technologies can be both difficult to quantify and can add undue operational and implementation risk. (It should be stressed that transmission and distribution planning involve long-lived assets, so choices to invest are made with long term perspectives. Liberty-Empire will continue to vet advanced technologies in an attempt to best balance cost to consumer versus attributable benefits. Additionally, Liberty-Empire has developed the associated costs in the advanced technologies reviewed and has spoken accordingly to each technology's specific cost and justification. Benefits, however, are still under development as metrics, specific outcomes, and other related factors are assessed. Additionally, benefits associated with outages, -- such as quality of life due to reduced number of outages, societal benefits, and lost productivity associated with outages, etc., -- are difficult to capture and often involve invoking evaluation methods such as Value of Lost Load ("VOLL"). Regardless, Liberty-Empire will continue to attempt to capture benefits in subsequent analyses to pair with the gathered costs for implementation.

4.5.1 Advanced Grid Technologies Utility's Efforts Description

1. A description of the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

In section 1.4, 3.1.2, 4.1, and 4.2, Liberty-Empire's use of advanced technologies on the transmission and distribution system includes, but is not limited to, microprocessor relaying, fiber optic relaying and communications, transformer oil DGM, transformer bushing monitoring, transformer bushing monitoring with partial discharge, transformer fiber optic winding temperature sensors, transformer monitoring, comprehensive transformer health monitoring, fiber optic substation data network, substation data archive, server, and database, 69-kV vacuum circuit breakers. Liberty-Empire has also described its aspirations for the application of advanced technology as it relates to AMI, DA, ADMS, CVR, greater levels of circuit segmentation, and many back-office systems integrations and capability improvements (that relate to future capabilities to support DER).

For many of the technologies described in section 1.4, 3.1.2, 4.1, and 4.2, initial results are positive and appear to serve Liberty-Empire well; in fact Liberty-Empire has incorporated some of these elements in recent projects and has gathered meaningful operational information.[7] As a result of these efforts, Liberty-Empire has been able to attain a more robust transmission and

[7] The Welch FAS has served as a pilot project in which subsequent installations may be able to be based. It is too early to determine whether this application can be used in alternate locations due to the complexity of not only the installation but also due to dynamic loading characteristics of various alternate feeders. Liberty-Empire will continue to vet this system as time of in-service increases and will review alternate locations for inclusion. The complex relaying and communications required for such a project has shown to be restrictive in implementation.

distribution system due to the expanded protective advantages realized by the inherent benefits of (e.g.) microprocessor relaying and fiber optic communications.

In summary, Liberty-Empire not only makes every effort to incorporate advanced technologies in presently budgeted projects but also actively reviews present relay configurations to determine where merited upgrades would benefit the customers served by the associated transmission and/or distribution line sections.

4.5.2 Distribution Advanced Grid Technologies Impact Description

2. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

The implementation of *distribution* advanced grid technologies did not influence the selection of resource acquisition strategy. The screening approach applied by Liberty-Empire is described in Section 4.3. As explained in Section (4)(C) and (4)(D), Liberty-Empire took into account AMI capabilities in its review and consideration of demand side measures. Additionally, it does not see any specific demand side technologies that warranty the application or use of more or greater levels of distribution automation (DA) in an accelerated time scale. This includes increased levels of segmentation, more smart fusing, greater levels of grid monitoring and control (provided by way of ADMS implementation and improvements to GIS, OMS and circuit models), and any acceleration of expanded and improved levels of field communications (that are required to support DA functions). Finally, while useful to evaluate and consider, Liberty-Empire does not estimate that the application of CVR will affect forecasted load needs during the planning period.

The aforementioned implementations – and the diverse set of specifically aspirational and long-term investment areas such as DA – are intended to be used as a possible springboard for future deployment and are viewed as foundational in possible future development. Additionally, and in the specific case of AMI, Liberty-Empire is submitting its descriptions of AMI costs, benefits and plan attributes in its response to SCI items A and E.

Liberty-Empire anticipates subsequent cost benefit analyses could possibly determine several advanced grid technologies to be cost-effective. As described in section 1.4, Liberty-Empire is working in close coordination and conjunction with Liberty Utilities to establish a platform of capabilities involving e.g., AMI, DA, ADMS and other capabilities that Liberty-Empire and Liberty Utilities believe are very important for the future cost-effective, safe and compliance operation of the distribution grid.

Over time, and at a minimum, Liberty-Empire will better understand the extent of implementation of these programs, determining Liberty-Empire's specific requirements in relation to load and customer needs, and when said advanced technologies may become cost-effective. In summary, advanced grid technologies on resource acquisition have been shown to be of minimal impact. However, Liberty-Empire will continue to evaluate the possible influence these technologies may have within subsequent future filings.

4.5.3 Transmission Advanced Grid Technologies Impact Description

3. A description of the impact of the implementation of transmission advanced grid technologies on the selection of a resource acquisition strategy.

Notwithstanding the central and critical role of Liberty-Empire's application of technology to support the fundamental reliability and resiliency of the transmission system, thereby facilitating the interconnection of wholesale generators to the grid to serve intended market functions, the implementation of *transmission* advanced grid technologies did not influence the selection of resource acquisition strategy. The screening approach applied by Liberty-Empire is described in Section 4.3.

Similar to the statements to item 4.6.2., above, the aforementioned implementations – including the long-term aspiration elements of Liberty-Empire's approach to ATDNT – are intended to be used as a possible springboard for future deployment and are viewed as foundational in possible future development. Liberty-Empire anticipates that subsequent cost benefit analyses could possibly determine several advanced grid technologies to be cost-effective. At a minimum, Liberty-Empire will better understand the extent of implementation at which said advanced technologies become cost-effective.

SECTION 5 UTILITY AFFILIATION

(5). The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation requirements in sections (1) through (4) also apply to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility.

Liberty-Empire collaborates with SPP members and non-members in the annual RTO-hosted model building summits, planning summits, and various cooperative joint study meetings. Liberty-Empire actively participates on multiple committees, working groups, and task forces. Liberty-Empire participates in the development of and annually reviews the various RTO reports. Liberty-Empire annually confirms tie line ratings with interconnected utilities in an effort to maintain communication and congruency during the associated model building process.

SECTION 6 FUTURE TRANSMISSION PROJECTS

(6) The electric utility shall identify and describe any transmission projects under consideration by an RTO for the electric utility's service territory.

No economically viable Liberty-Empire transmission projects are merited at this time for review by the RTO. Liberty-Empire has previously submitted high-value projects for consideration as mitigation to various overloads and voltage issues around the Southwest Missouri areas. Due to muted load growth over the past years, paired with the position within the SPP footprint, subsequent evaluations by the RTO and Liberty-Empire have not exhibited the need for any future transmission projects at this time. Liberty-Empire has and will continually attempt to identify transmission projects that will have positive impacts for their customers.

SPP Balanced Portfolio Report

MAINTAINED BY
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Southwest Power Pool

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Executive Summary

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

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

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

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

- Total E&C Costs: $692M

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

Portfolio 3E "Adjusted" provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58.

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

Million of Dollars

Portfolio 3-E "Adjusted"	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

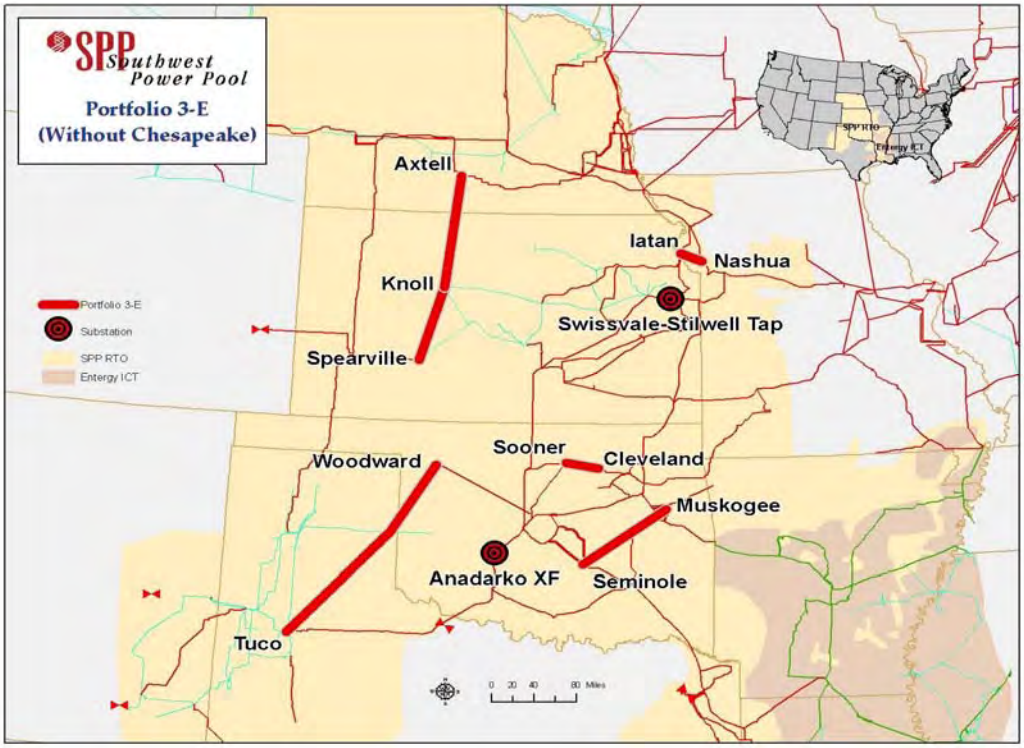
Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

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

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

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

Portfolio 3-E "Adjusted"



Introduction

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

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

Economic Benefits: Adjusted Production Cost

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

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

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases

Where:

Revenues from Sales = Export x Zonal $LMP_{\text{Gen Weighted}}$

and

Cost of Purchases = Import x Zonal $LMP_{\text{Load Weighted}}$

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

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

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

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

[‡] SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages

generators within a context of a modeled transmission system and load delivery points. The commitment and dispatch of the generators is constrained by the software to ensure that no overloads will occur on any monitored transmission element, typically referred to as the NERC book of flowgates, but can include additional congestion points of interest. The software produces a security constrained economic dispatch and unit commitment.

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

Balanced Portfolio Development

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

Table: CAWG Timeline for Balanced Portfolio Development

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

<u>August-November, 2007</u>: Screening of Candidate Upgrades for Portfolios

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

<u>February-April, 2008</u>: Initial Four Portfolios

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

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

[§] Note: Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note in the original analysis was the inclusion of Holcomb 2, Red Rock, Hugo 2 as well as 4,600 MW of generic wind capacity which affected the calculated benefits of certain projects.

2. Portfolio 2 was a subset of Portfolio 1 where projects with similar benefits were narrowed to remove upgrades that would not provide additional benefits.

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

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

These four portfolios, along with their B/C screening ratios, are shown in the following exhibits.

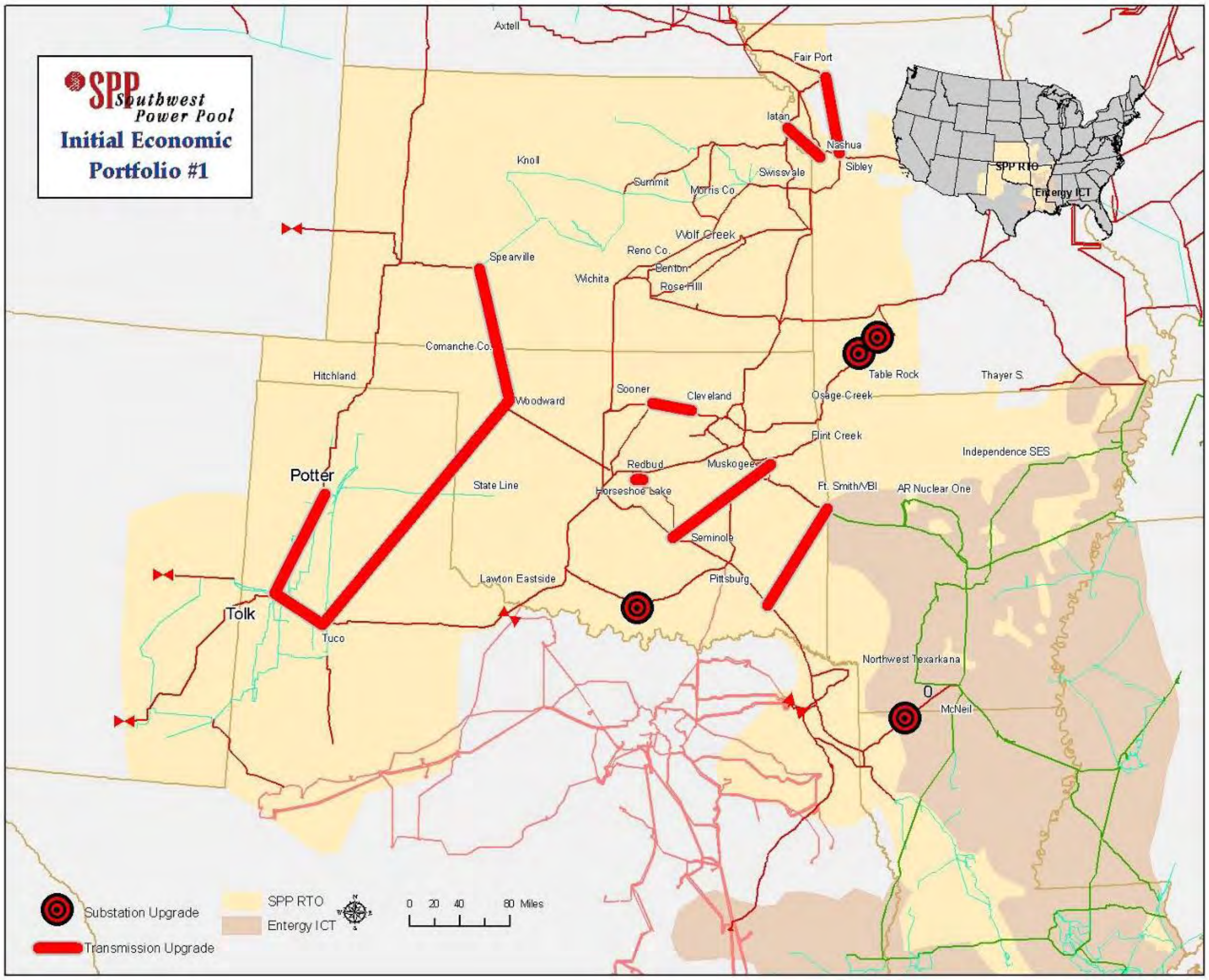
Screening of Proposed Economic Upgrades

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

(NOTE: "Tolk – Potter" project is a subset of the "Tuco – Tolk – Potter" project.)

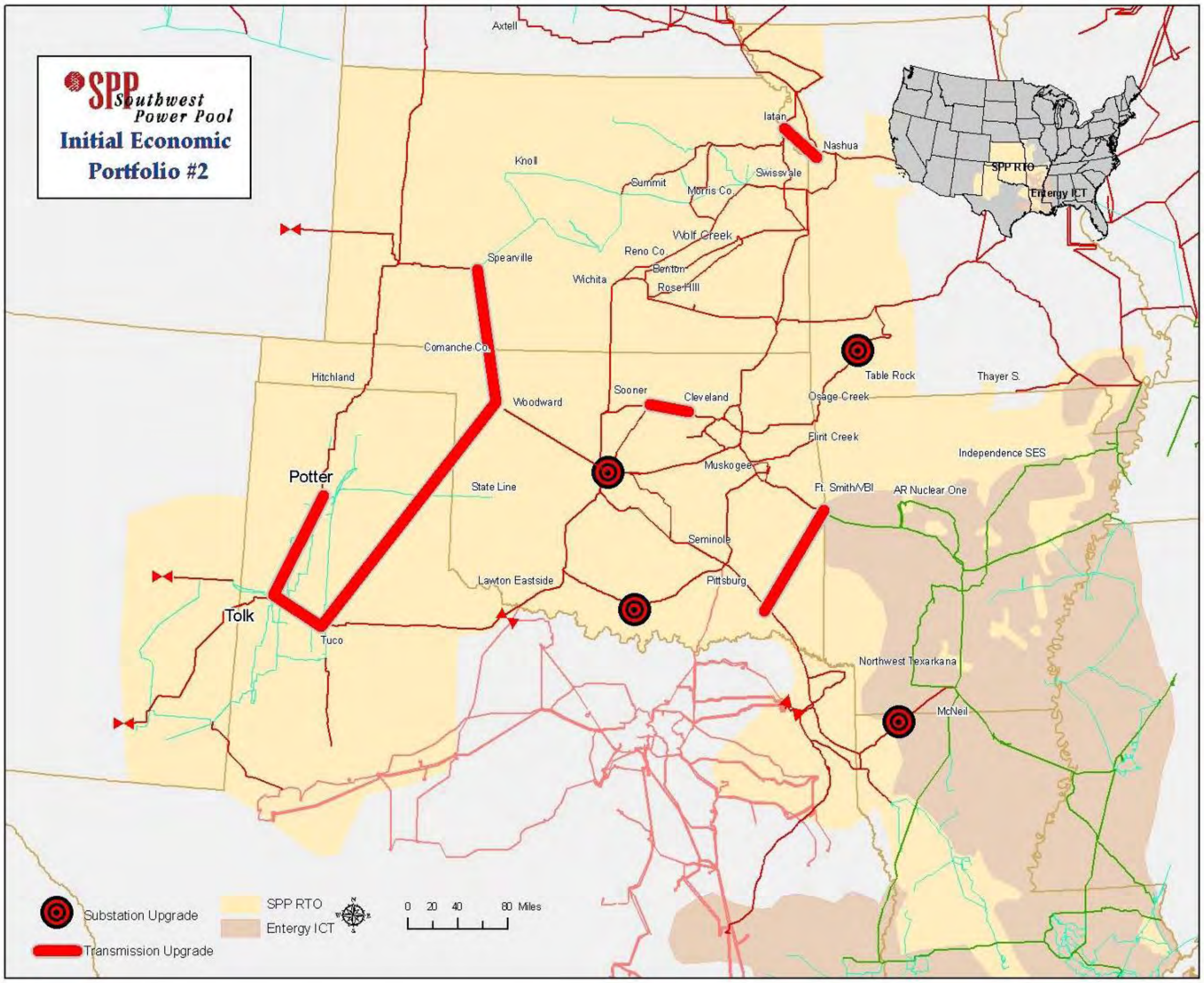
The Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note was the inclusion of Holcomb 2, Red Rock, and Hugo 2 as well as 4,600 MW of generic wind capacity, each of which affected the calculated benefits of certain projects.

Portfolio 1

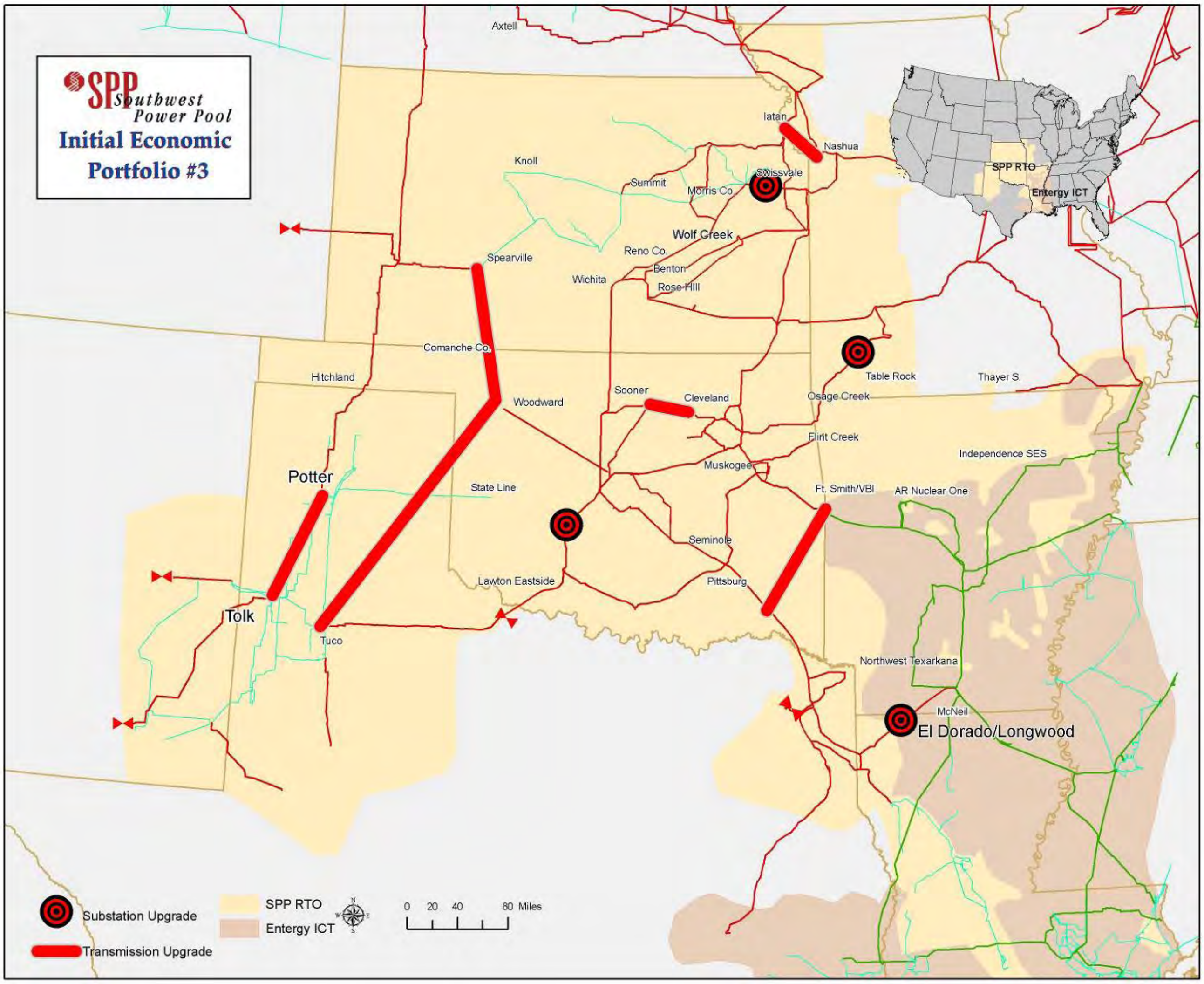


Because Portfolio 2 eliminated duplicative upgrades from Portfolio 1, Portfolio 1 was not carried forward as a possible Balanced Portfolio candidate.

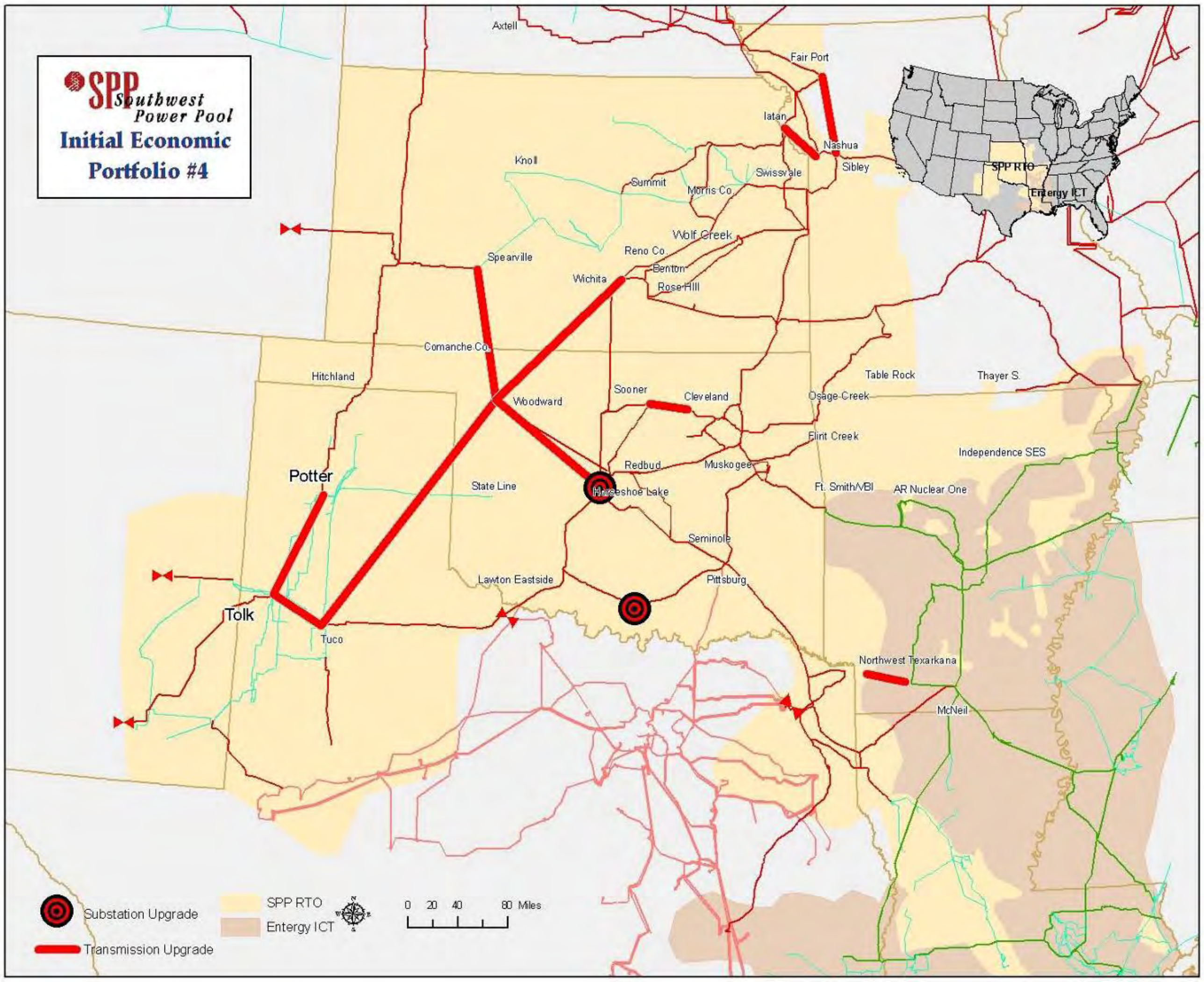
Portfolio 2


SPP Southwest Power Pool
Initial Economic Portfolio #2
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Reno Co
Benton
Rose Hill
Spearville
Wichita
SPP RTO
Entergy ICT
Comanche Co.
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Potter
Muskogee
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
Substation Upgrade
Transmission Upgrade
SPP RTO
Entergy ICT
0 20 40 80 Miles

Portfolio 3


Southwest Power Pool
Initial Economic Portfolio #3
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Reno Co.
Spearville
Benton
Wichita
Rose Hill
Comanche Co.
Table Rock
Thayer S.
Hitchland
Sooner
Cleveland
Osage Creek
Woodward
Flint Creek
Independence SES
Potter
Muskogee
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
El Dorado/Longwood
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

Portfolio 4

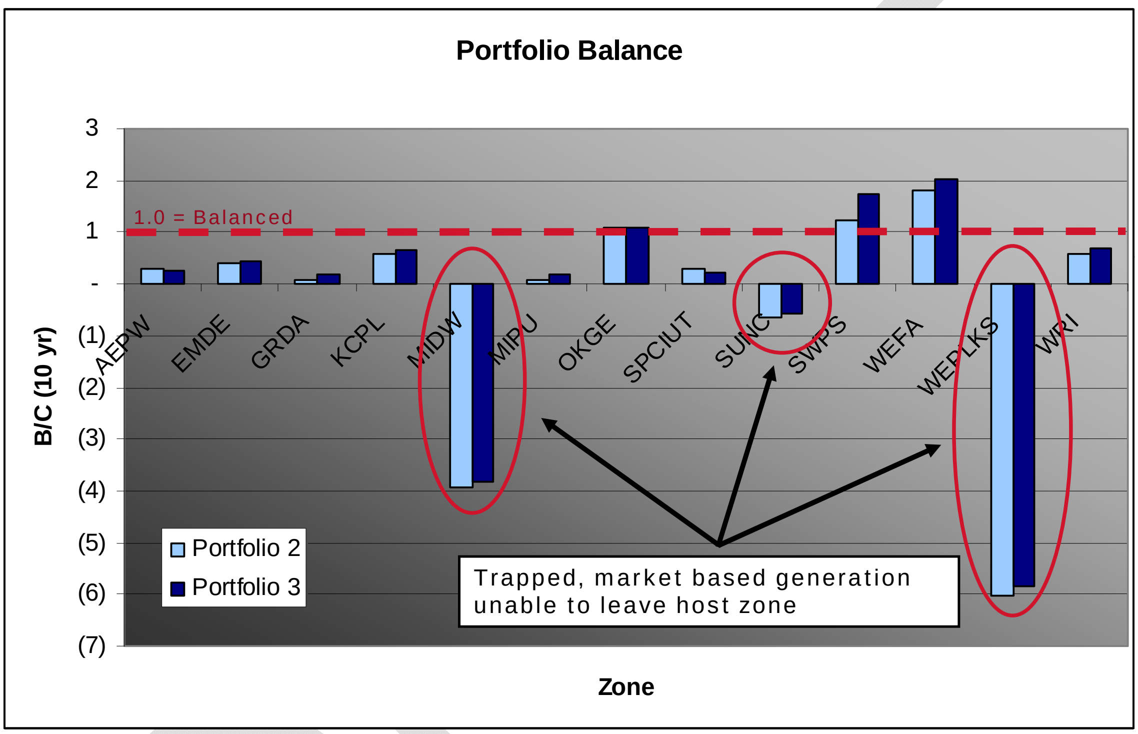


Southwest Power Pool
Initial Economic Portfolio #4
Axtell
Fair Port
Iatan
Nashua
Sibley
Knoll
Summit
Swissvale
Morris Co
Wolf Creek
Reno Co
Spearville
Benton
Wichita
Rose Hill
SPP RTO
Entergy ICT
Comanche Co
Hitchland
Table Rock
Thayer S.
Sooner
Cleveland
Osage Creek
Woodward
Flint Creek
Independence SES
Redbud
Muskogee
Potter
State Line
Horseshoe Lake
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

May 2008: Trapped Generation

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

Trapped Generation in Economic Models



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

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

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

[**] This coincides with the amount of wind in the SPP footprint at the end of 2008, as well as the transmission upgrades required to delivery wind with firm service.

shown are changes in adjusted production costs. Therefore, a red parenthetical represents lower adjusted production costs after an upgrade takes place, and it is the estimate of overall benefit.

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

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_June08	($50,482,000)	($41,409,000)	($9,073,000)	$ 371	0.92
Economic Portfolio - P3_June08	($53,325,000)	($42,060,000)	($11,266,000)	$ 347	1.04
Economic Portfolio - P4_June08	($48,429,000)	($38,581,000)	($9,848,000)	$ 608	0.54

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

Impact of Spearville – Knoll – Axtell

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_SKA_June08	($90,215,000)	($71,327,000)	($18,889,000)	$ 539	1.13
Economic Portfolio - P3_SKA_June08	($92,307,000)	($72,235,000)	($20,072,000)	$ 515	1.22
Economic Portfolio - P4_SKA_June08	($84,031,000)	($64,709,000)	($19,322,000)	$ 776	0.73

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

<u>July 2008</u>: Update Designated Resources

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

Impact of Updates on Portfolios 2 and 3

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C	SPP B/C
Portfolio 2 - July 08	($38,291,000)	($28,825,000)	($9,466,000)	$ 371	0.70	0.53
Portfolio 3 - July 08	($42,033,000)	($32,281,000)	($9,751,000)	$ 347	0.82	0.63

<u>August 2008</u>: Firm Wind Sensitivities

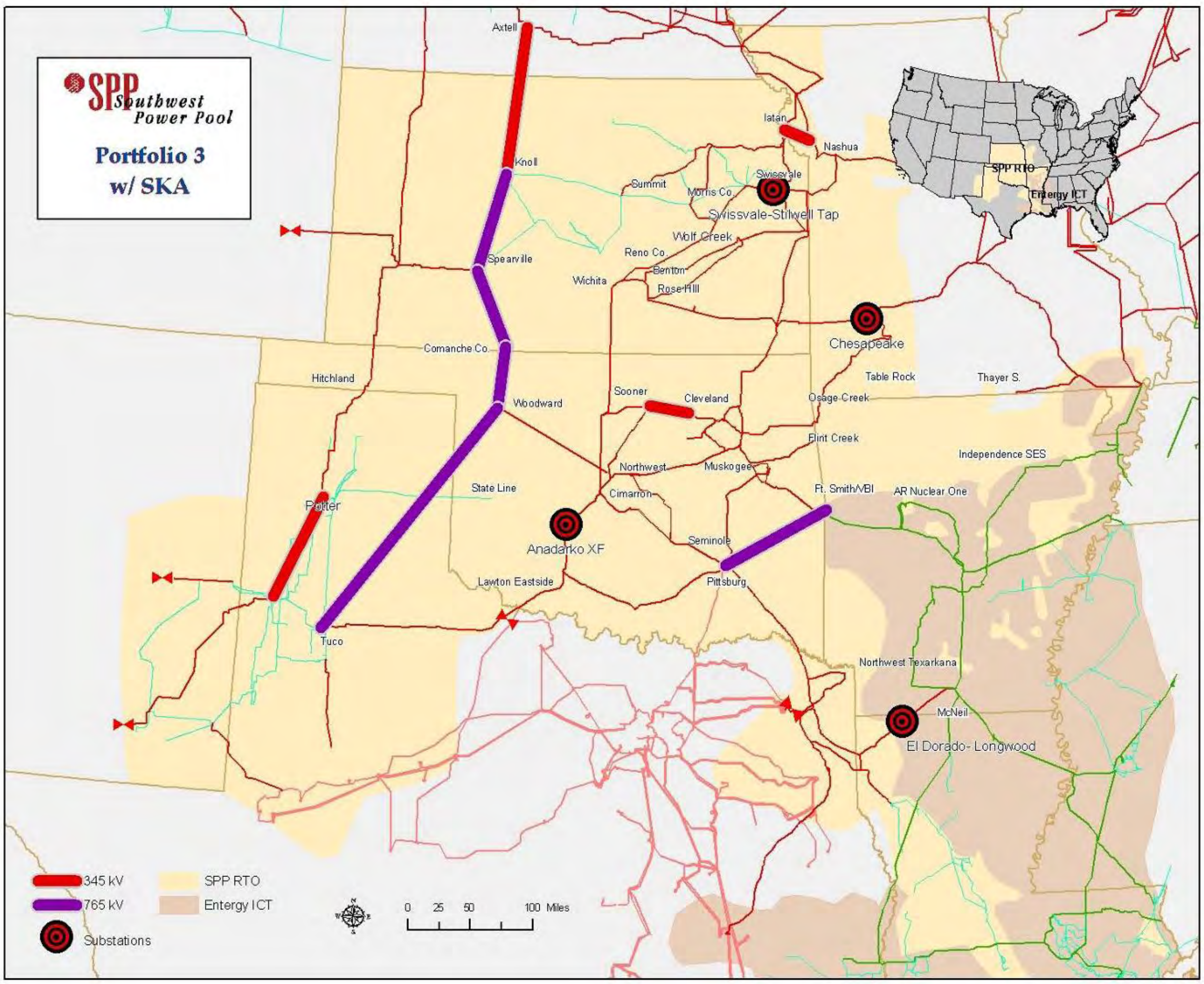
Additional wind sensitivities were conducted for Portfolios 2 and 3 to determine the impact that the amount of wind assumed in the model would have on the benefits. Benefits were estimated for 700 MW of firm wind in the base case and an additional 1,900 MW of market-based wind in the change case. The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

<u>September 2008</u>: Introduction of Portfolio Variations 3-A and 3-B

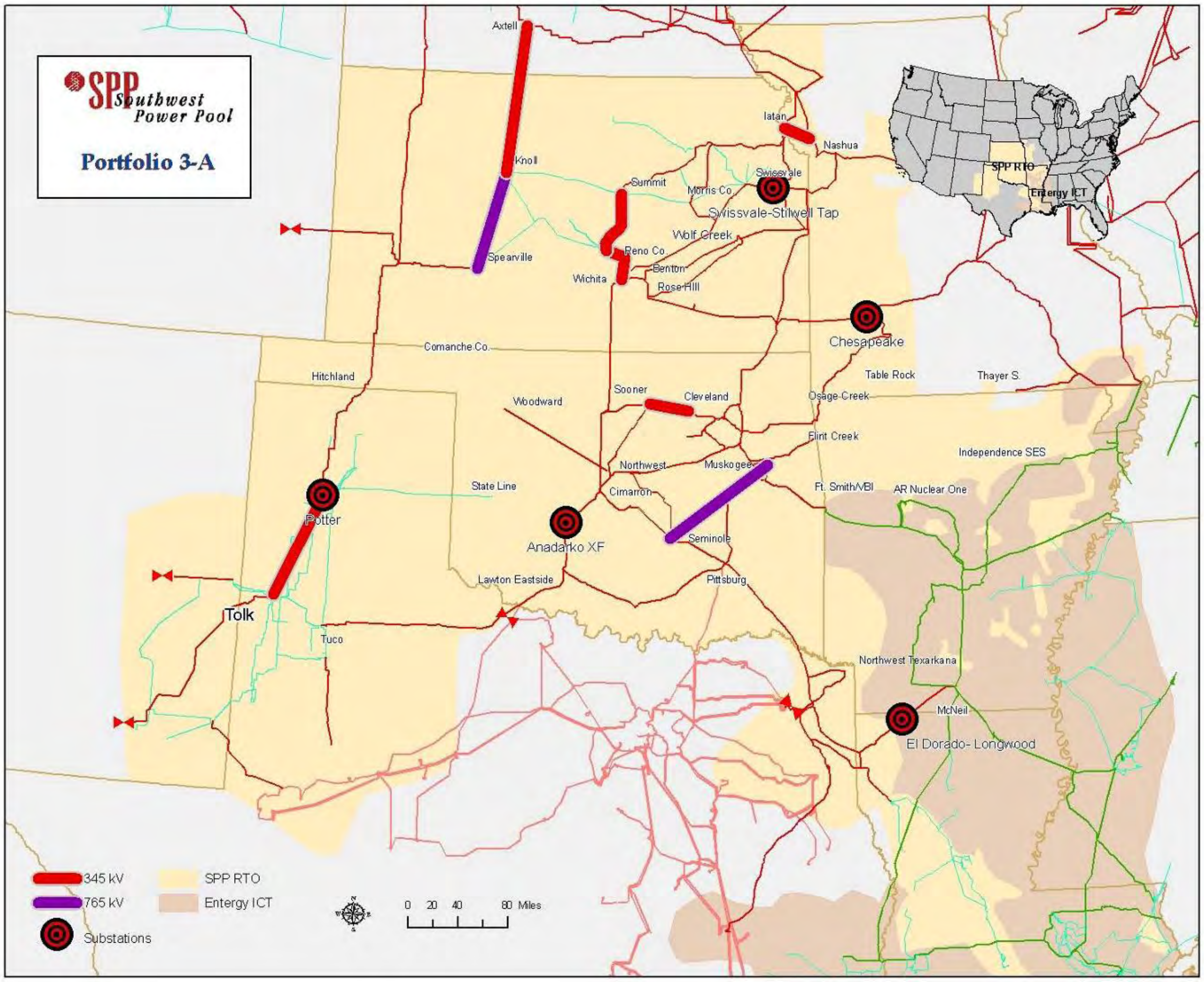
SPP staff developed two modified portfolios based on Portfolio 3. Adjustments to Portfolio 3 included an upgrade of the Wichita – Reno Co - Summit line and carried through the addition of Spearville-Knoll-Axtell. From this modification of Portfolio 3 two variations were developed and labeled 3-A and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

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

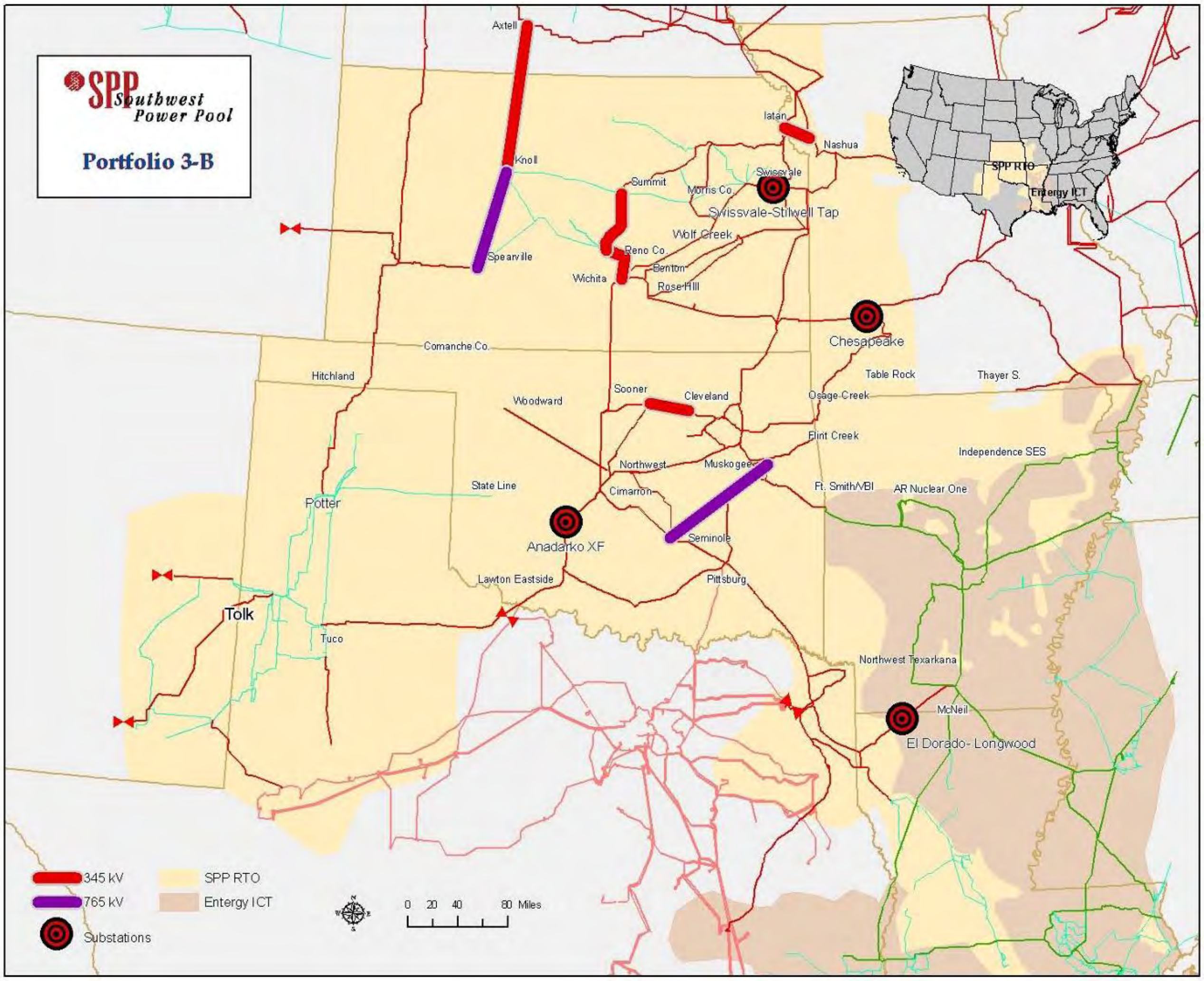
Portfolio 3, with Spearville – Knoll – Axtell (SKA)



Portfolio 3-A with Wichita - Reno Co - Summit



Portfolio 3-B with Wichita – Reno Co - Summit



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

Initial Results for Portfolios 3-A and 3-B

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

<u>October 2008</u>: Portfolio 3 (High Wind) and 3-A (Current Wind)

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

High Wind (7 GW) for Portfolio 3

Scenario	SPP 10 Yr Benefit	Cost ($M)	B/C
Portfolio 3 - 345 kV	$ 1,920,593,438	829	2.32
Portfolio 3 - 765 kV*	$ 1,920,593,438	1,213	1.58

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

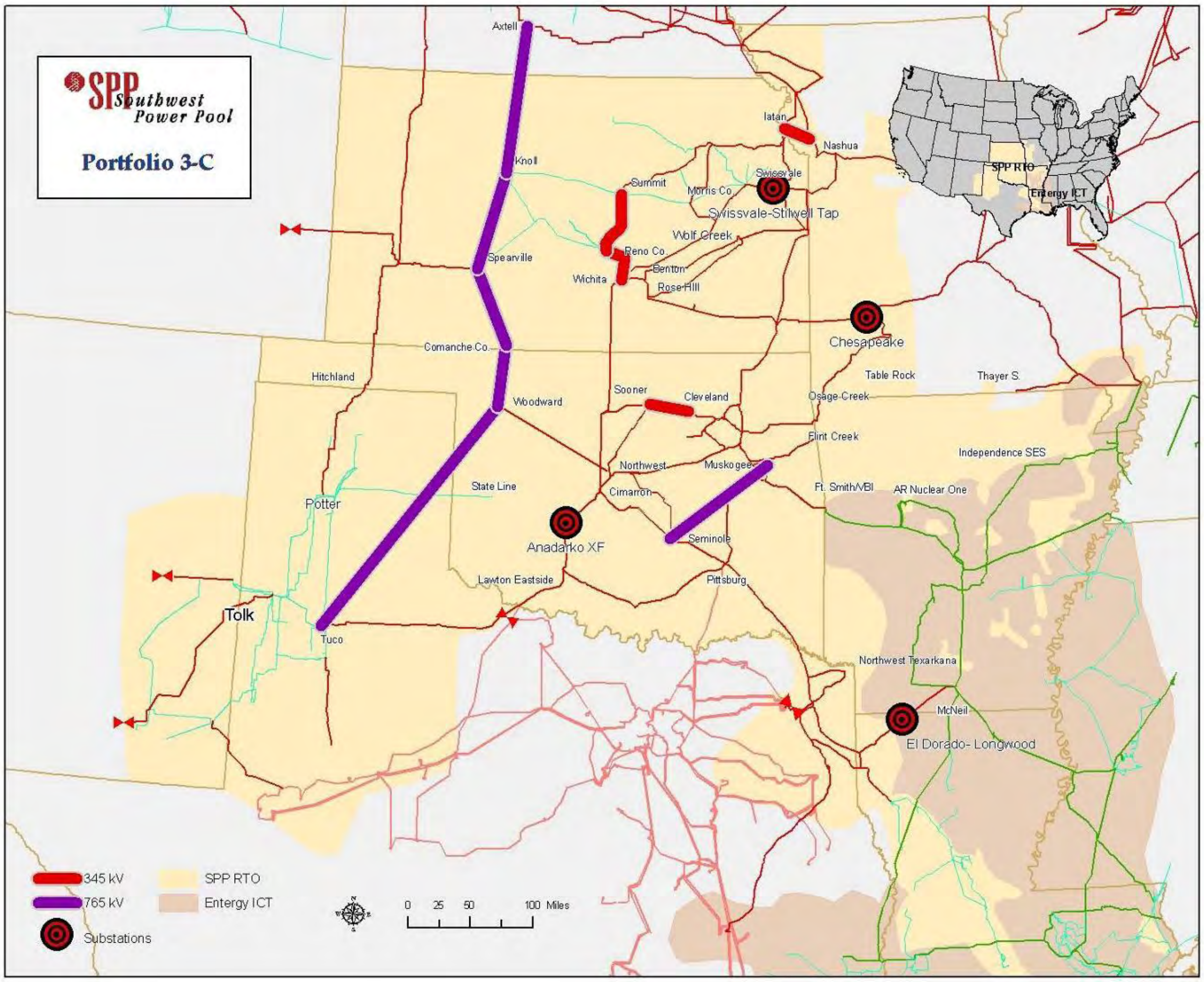
Carbon Tax Sensitivity Results for Portfolio 3-A at Current Wind (2.6 GW)

Project	Total Adjusted Production Cost	SPP NON-OATT	SPP OATT	TIER1	Cost	SPP B/C
Portfolio - P3A - Base	($119,180,000)	($2,454,920)	($111,931,080)	($4,794,000)	$ 597	1.27
Portfolio - P3A - $15 Carbon Tax	($60,140,000)	($4,000)	($52,699,000)	($5,543,000)	$ 597	0.60
Portfolio - P3A - $40 Carbon Tax	($17,992,000)	($317,000)	($16,926,000)	($1,630,000)	$ 597	0.19

December 2008: Portfolio 3-C (Modify Portfolio 3)

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

Portfolio 3-C



It should be noted that by this time SPP staff had resolved a problem with its application of the PROMOD that had resulted in dispatching wind on a small number of days, resulting in what appeared to be a significant "trapped generation" problem. With the resolution of that issue, wind was now being dispatched from specified injection points at $0.05/MWh. Note that this was an offer price for the wind injection into the market since using an offer price of $0/MWh which caused problems in the modeling. The final clearing price of wind is at the marginal zonal market price for each hour, which is significantly higher than the offer price; i.e. wind in the actual production cost models is priced at the marginal zonal market price.

SPP staff used Portfolio 3-C to perform an analysis of an integration plan for the EHV Overlay. For this effort, scenarios were conducted at 3,300 MW of wind injection in 2012, 7,000 MW of wind injection in 2017, and 13,500 MW of wind injection in 2023, with 765 kV transmission being added to the analysis to accommodate the higher wind levels assumed for wind. The following table shows the B/C ratio that would apply had the results of year 2012 been distributed uniformly over a ten-year period and compared to the ten-year cost. In addition, the results are shown using ten years of Annual Transmission Revenue Requirements (ATRR) for the EHV projects contained in the study periods 2012, 2017 and 2023.

Portfolio 3-C + EHV Build Out		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C (P3-C)	0.74	0.66
10 yr vs E&C (P3-C+West EHV)	0.79	0.72
10 yr vs E&C (P-3C+West & Central EHV)	2.43	1.45
10 yr vs ATRR	**0.71**	**0.49**
Annual B/C (final year)	1.99	1.19

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

Portfolio 3-A		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C	1.46	1.30
10 yr vs ATRR	**1.19**	**1.06**
Annual B/C (final year)	1.46	1.29

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

P3-A and 3-C impact on STEP reliability assessment

Project	New Violations	Solved Violations	Net
Portfolio 3-A	$4,385,000	$4,004,900	**-$380,100**
Portfolio 3-C	$4,585,000	$35,265,250	**$30,680,250**

<u>January 2009</u>: Further Analysis of Portfolios 3-A and 3-C With Nebraska

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

Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

#	Zone	Benefits	Costs	Transfer Allocation	Transfer Out	Transfer Net	Net Benefit	B/C	Original B/C
1	AEPW	$20,880,672	$24,939,597	$14,640,350	-$18,699,275	-$4,058,925	$0	1.00	0.84
2	EMDE	$5,828,820	$2,923,755	$1,716,339	$0	$1,716,339	$1,188,726	1.26	1.99
3	GRDA	$1,797,527	$2,170,293	$1,274,032	-$1,646,798	-$372,766	$0	1.00	0.83
4	KCPL	$8,337,354	$8,571,771	$5,031,907	-$5,266,324	-$234,417	$0	1.00	0.97
5	MIDW	$1,590,879	$798,241	$468,593	$0	$468,593	$324,045	1.26	1.99
6	MIPU	$1,598,074	$4,491,010	$2,636,368	-$5,529,303	-$2,892,935	$0	1.00	0.36
7	MKEC	$5,294,897	$1,243,893	$730,206	$0	$730,206	$3,320,798	2.68	4.26
8	OKGE	$44,982,968	$15,731,003	$9,234,607	$0	$9,234,607	$20,017,358	1.80	2.86
9	SPRM	-$29,773	$1,719,556	$1,009,435	-$2,758,764	-$1,749,329	$0	1.00	-0.02
10	SUNC	$389,069	$1,185,151	$695,722	-$1,491,804	-$796,082	$0	1.00	0.33
11	SWPS	$43,102,775	$12,809,661	$7,519,685	$0	$7,519,685	$22,773,429	2.12	3.36
12	WEFA	$11,792,345	$3,508,023	$2,059,323	$0	$2,059,323	$6,224,999	2.12	3.36
13	WRI	$23,072,688	$12,818,241	$7,524,722	$0	$7,524,722	$2,729,725	1.13	1.80
14	NPPD	-$608,956	$8,896,109	$5,222,303	-$14,727,368	-$9,505,065	$0	1.00	-0.07
15	OPPD	-$472,047	$6,896,029	$4,048,192	-$11,416,267	-$7,368,075	$0	1.00	-0.07
16	LES	-$145,808	$2,130,072	$1,250,421	-$3,526,301	-$2,275,880	$0	1.00	-0.07
Total		$167,411,485	$110,832,404	$65,062,205	-$65,062,205	$0	$56,579,080	1.51	1.51

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

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

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

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

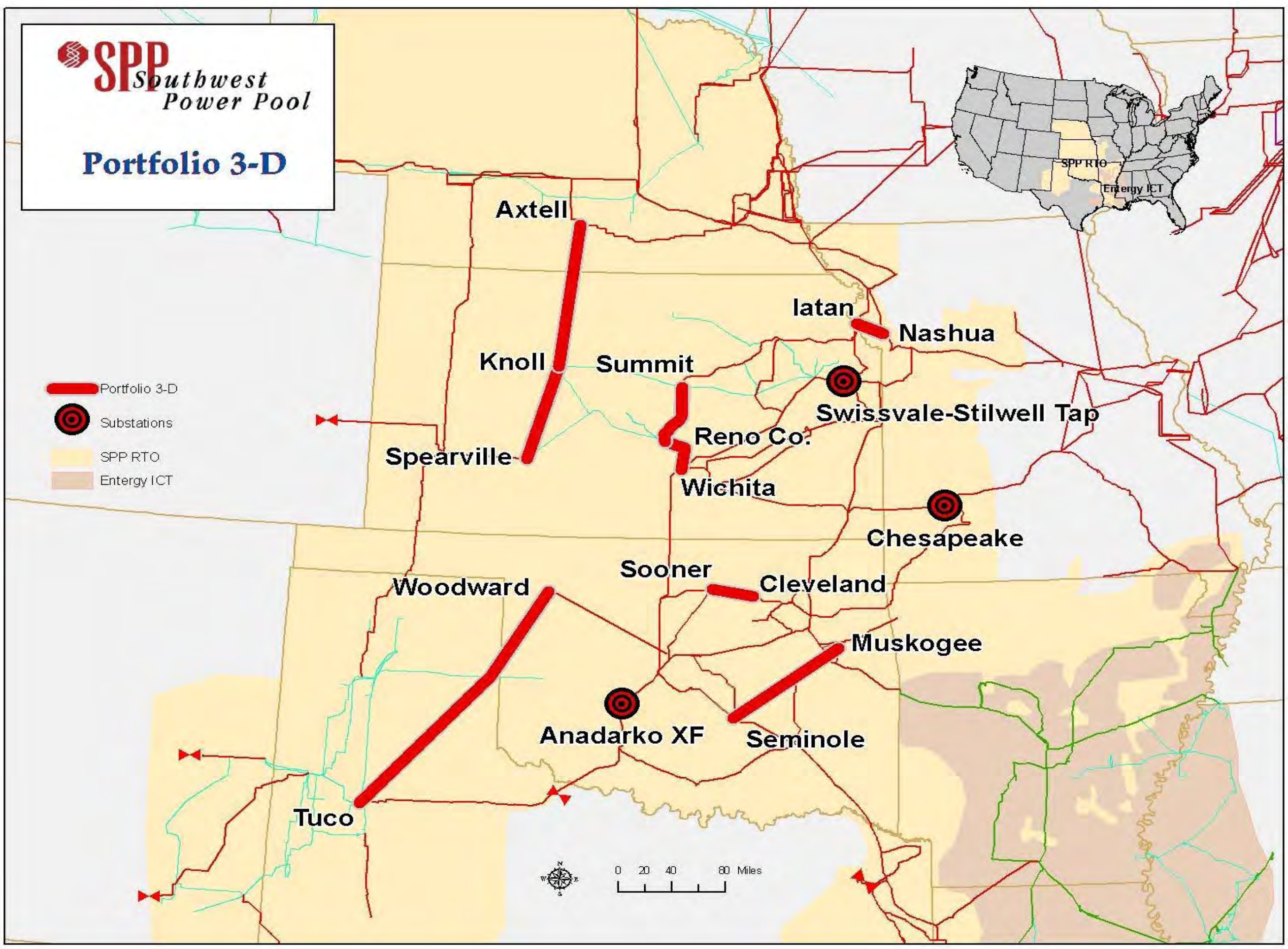
CAWG Response

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

SPP Staff Action Plan

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

Portfolio 3-D



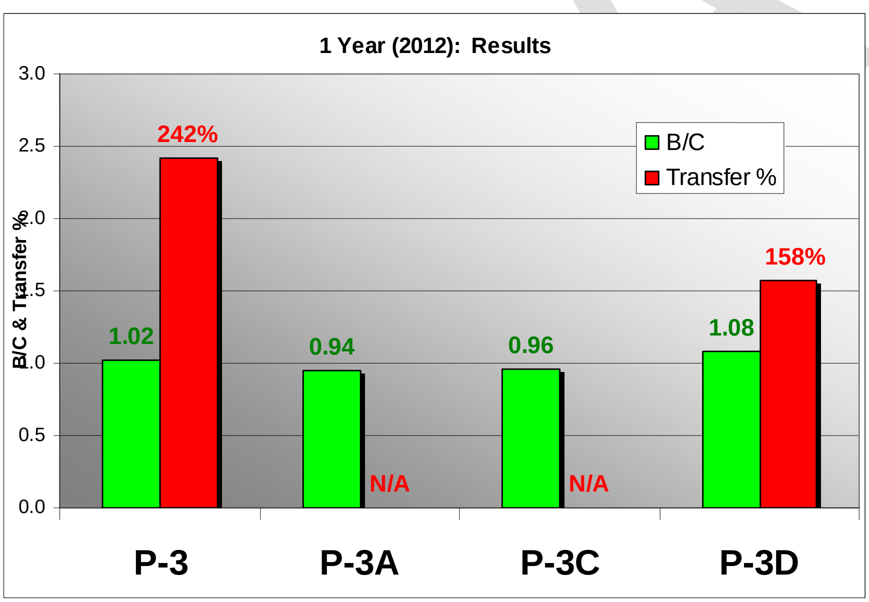
March 2009: Final Balanced Portfolio Analysis

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

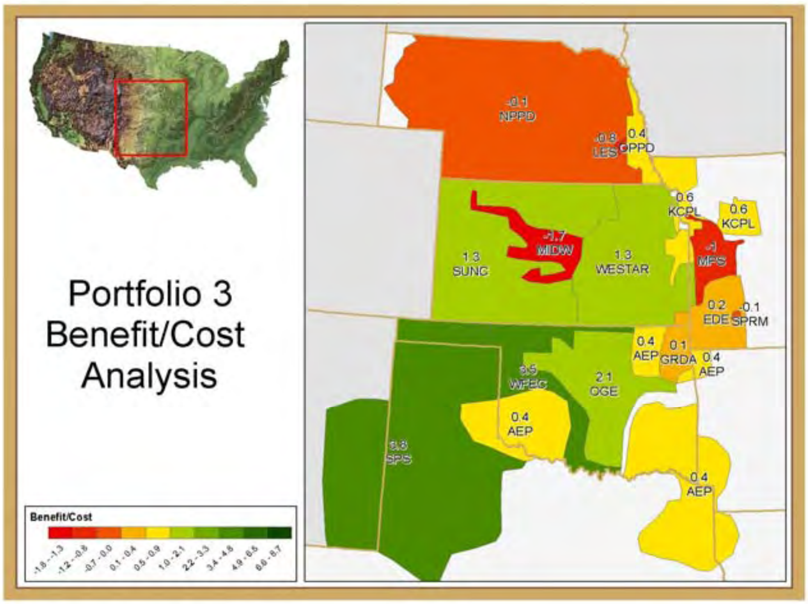
During the March 2009 CAWG meeting, the results from the analysis described above were presented. SPP staff started with a screening analysis on Portfolios 3, 3-A, 3-C, and 3-D. This analysis was conducted on the 2012 model and taken as an annual benefit to cost basis. The results are shown in the following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

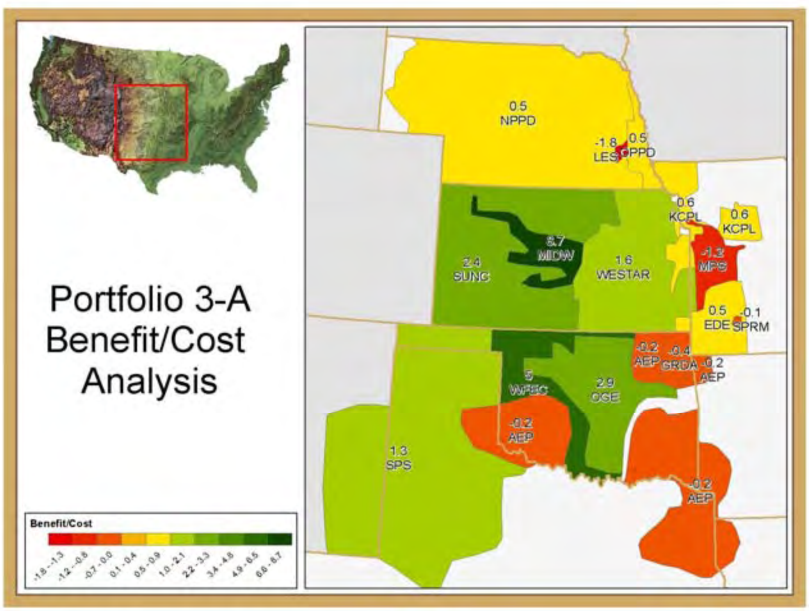
1 Year (2012) Screening Results

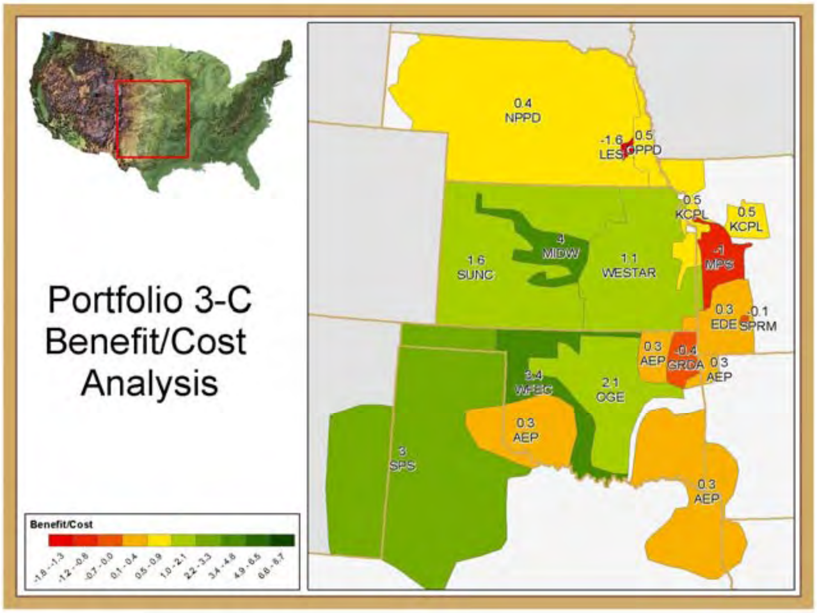
Project	Total APC Benefit ($M)	SPP OATT Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3	$124	$122	$2.6	$ 120	**1.02**	**242%**
P-3A	$117	$114	$2.7	$ 121	**0.94**	**n/a**
P-3C	$159	$159	($0.4)	$ 166	**0.96**	**n/a**
P-3D	**$148**	**$149**	**($1.3)**	***$ 139***	**1.08**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

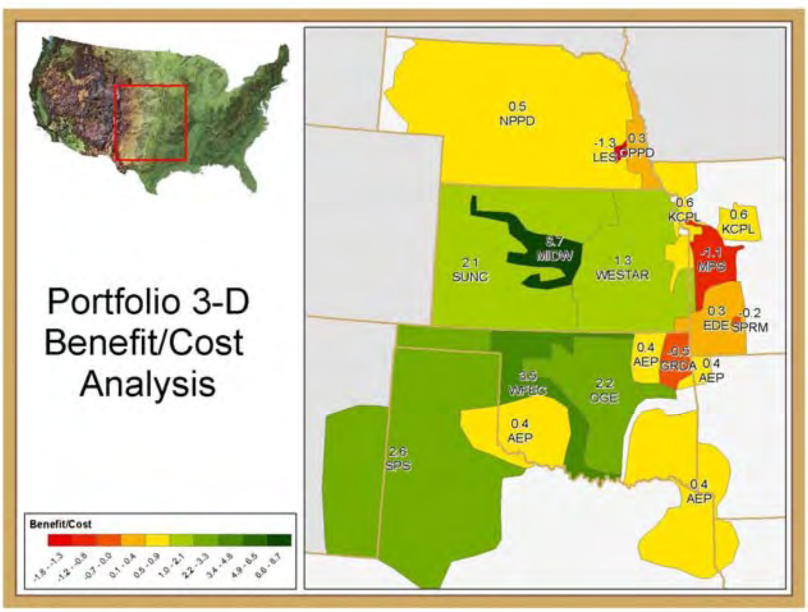


The Benefit to Cost ratio per zone is shown for the respective portfolios in the following pictures. The B/Cs shown here are before transfers have been conducted to balance the respective portfolios.









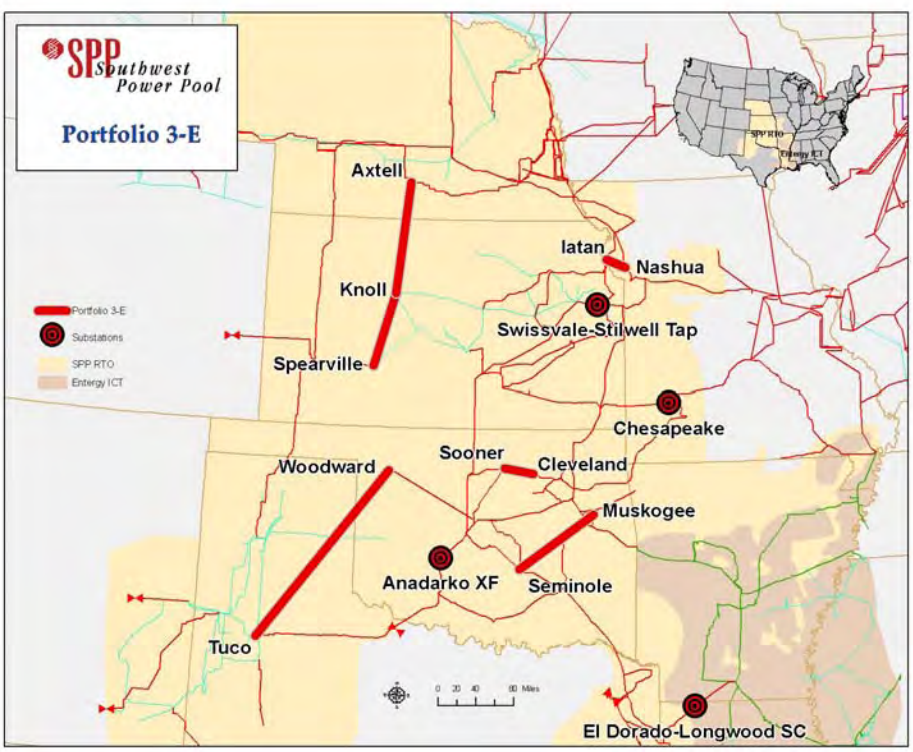
Portfolio 3-D had the highest B/C ratio of the four portfolios screened and was selected for further development. In this analysis, each of the individual projects in the Portfolio was removed to determine the impact of the project on the portfolio as a whole. These results are shown in the following table. The table is divided into total Adjusted Production Cost (APC) benefit, benefit for SPP Open Access Transmission Tariff (OATT) members as well as benefits to areas outside the region, shown here as Tier 1 benefits. The transfer percentage (%) shown is the percentage of the total portfolio cost in dollars that must be transferred, following tariff provisions, to balance the respective portfolios shown below. Ideally, the goal is a lower transfer percentage is desirable with a higher B/C.

Portfolio 3-D Refinement Analysis

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

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

Portfolio 3-E



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

Portfolio 3-D: 10 Year Benefit vs. Costs

				Million of Dollars			
Portfolio 3-D			**Total Benefit**	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Incremental Cost**	**Cost (E&C)**
2012			$ 149.0		$ 138.55		826.4
2017			$ 208.5	$ 11.904	$ 138.55	$ -	**Annual**
2022			$ 260.3	$ 10.364	$ 138.55	$ -	138.5
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 149	$ 149	$ 139	$ 139	**1.08**
2013	2	0.93	$ 161	$ 149	$ 139	$ 128	1.16
2014	3	0.86	$ 173	$ 148	$ 139	$ 119	1.25
2015	4	0.79	$ 185	$ 147	$ 139	$ 110	1.33
2016	5	0.74	$ 197	$ 145	$ 139	$ 102	1.42
2017	6	0.68	$ 209	$ 142	$ 139	$ 94	**1.50**
2018	7	0.63	$ 219	$ 138	$ 139	$ 87	1.58
2019	8	0.58	$ 229	$ 134	$ 139	$ 81	1.65
2020	9	0.54	$ 240	$ 129	$ 139	$ 75	1.73
2021	10	0.50	$ 250	$ 125	$ 139	$ 69	1.80
2022	11	0.46	$ 260	$ 121	$ 139	$ 64	**1.88**
Ten Year Totals	Yrs 1-10	7.25	$ 2,010	$ 1,405	$ 1,385	$ 1,004	**1.40**
Per Year Levelized				**$ 194**		**$ 139**	**1.40**

Portfolio 3-DE: 10 Year Benefit vs. Costs

				Million of Dollars			
Portfolio 3-E			**Total Benefit**	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Incremental Cost**	**Cost (E&C)**
2012			$ 132.3		$ 106.63		657.4
2017			$ 181.2	$ 9.786	$ 106.63	$ -	**Annual**
2022			$ 229.5	$ 9.652	$ 106.63	$ -	106.6
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 107	$ 107	**1.24**
2013	2	0.93	$ 144	$ 133	$ 107	$ 99	1.35
2014	3	0.86	$ 156	$ 134	$ 107	$ 91	1.46
2015	4	0.79	$ 168	$ 133	$ 107	$ 85	1.58
2016	5	0.74	$ 180	$ 132	$ 107	$ 78	1.69
2017	6	0.68	$ 181	$ 123	$ 107	$ 73	**1.70**
2018	7	0.63	$ 192	$ 121	$ 107	$ 67	1.80
2019	8	0.58	$ 202	$ 118	$ 107	$ 62	1.89
2020	9	0.54	$ 212	$ 115	$ 107	$ 58	1.99
2021	10	0.50	$ 223	$ 111	$ 107	$ 53	2.09
2022	11	0.46	$ 229	$ 106	$ 107	$ 49	**2.15**
Ten Year Totals	Yrs 1-10	7.25	$ 1,790	$ 1,253	$ 1,066	$ 773	**1.62**
Per Year Levelized				**$ 173**		**$ 107**	**1.62**

A reliability impact analysis was conducted on the portfolio projects to determine the impact of the Balanced Portfolio on the STEP reliability analysis as well as on Tier 1 entities, third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2008 STEP 10 year reliability analysis. The analysis was conducted for the entire collection of portfolio projects considered for the March CAWG meeting. The results are broken into (1) advanced projects, those projects that would be moved up in the reliability timeline due to the Balanced Portfolio; (2) new projects, projects which are now needed that were not identified in the original 10 year reliability planning horizon, but may have been needed beyond that horizon; (3) third party impacts or projects needed on neighboring systems due to the Balanced Portfolio; and (4) deferred projects, projects which are either deferred beyond the planning horizon or mitigated entirely due to the portfolio. A summary of these results is shown in the table below.

Reliability Impact (E&C Dollars)

Portfolio	Advanced Projects	New Projects	3rd Party Impacts	Deferred Projects	Net Benefit
P-3	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3A	$ 1.0	$ 3.4	$ 10.2	$ 27.7	$ 13.1
P-3C	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3D	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7
P-3E	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7

<u>April 2009</u>: Balanced Portfolio Summit

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

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

<u>April 2009</u>: CAWG Conference Call

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

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

Portfolio 3-E No Chesapeake: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches			Million of Dollars				
			Total Benefit	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Incremental Cost**	**Cost (E&C)**
2012			$ 132.3		$ 93.73		691.9
2017			$ 181.2	$ 9.79	$ 93.73	$ -	**Annual**
2022			$ 229.5	$ 9.65	$ 93.73	$ -	93.7
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 94	$ 94	**1.41**
2013	2	0.93	$ 145	$ 134	$ 94	$ 87	1.55
2014	3	0.86	$ 158	$ 135	$ 94	$ 80	1.68
2015	4	0.79	$ 171	$ 136	$ 94	$ 74	1.82
2016	5	0.74	$ 184	$ 135	$ 94	$ 69	1.96
2017	6	0.68	$ 181	$ 123	$ 94	$ 64	**1.93**
2018	7	0.63	$ 191	$ 120	$ 94	$ 59	2.04
2019	8	0.58	$ 201	$ 117	$ 94	$ 55	2.14
2020	9	0.54	$ 210	$ 114	$ 94	$ 51	2.24
2021	10	0.50	$ 220	$ 110	$ 94	$ 47	2.35
2022	11	0.46	$ 229	$ 106	$ 94	$ 43	**2.45**
Ten Year Totals	Yrs 1-10	7.25	$ 1,792	$ 1,257	$ 937	$ 679	**1.85**
Per Year Levelized				**$ 173**		**$ 94**	**1.85**

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

Attachment H Transfer Adjustments - Portfolio 3E no Ches - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.8	$21.1	$0.0	$7.2	$7.2	$2.5	1.1
2	EMDE	($0.4)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.8	$1.8	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.3	$7.2	($1.4)	$2.5	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.6)	$3.8	($6.7)	$1.3	($5.4)	$0.0	1.0
7	MKEC	$11.7	$1.1	$0.0	$0.4	$0.4	$10.2	8.3
8	OKGE	$26.5	$13.3	$0.0	$4.6	$4.6	$8.6	1.5
9	SPRM	($0.2)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.2	$1.0	$0.0	$0.3	$0.3	$1.9	2.4
11	SWPS	$56.0	$10.8	$0.0	$3.7	$3.7	$41.5	3.9
12	WEFA	$7.9	$3.0	$0.0	$1.0	$1.0	$3.9	2.0
13	WRI	$14.2	$10.8	($0.4)	$3.7	$3.4	$0.0	1.0
14	NPPD	$5.5	$7.5	($4.6)	$2.6	($2.0)	$0.0	1.0
15	OPPD	$2.2	$5.8	($5.7)	$2.0	($3.7)	$0.0	1.0
16	LES	($3.5)	$1.8	($5.9)	$0.6	($5.3)	$0.0	1.0
Total		$174	$94	-$32	$32	$0	$80	1.9

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

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

Portfolio 3-E No Ches, With RS

Million of Dollars

	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012	$ 178.0		$ 105.56		789.0
2017	$ 242.1	$ 12.816	$ 105.56	$ -	Annual
2022	$ 290.4	$ 9.658	$ 105.56	$ -	105.6

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 178	$ 178	$ 106	$ 106	1.69
2013	2	0.93	$ 191	$ 177	$ 106	$ 98	1.81
2014	3	0.86	$ 204	$ 175	$ 106	$ 90	1.93
2015	4	0.79	$ 216	$ 172	$ 106	$ 84	2.05
2016	5	0.74	$ 229	$ 169	$ 106	$ 78	2.17
2017	6	0.68	$ 242	$ 165	$ 106	$ 72	2.29
2018	7	0.63	$ 252	$ 159	$ 106	$ 67	2.38
2019	8	0.58	$ 261	$ 153	$ 106	$ 62	2.48
2020	9	0.54	$ 271	$ 146	$ 106	$ 57	2.57
2021	10	0.50	$ 281	$ 140	$ 106	$ 53	2.66
2022	11	0.46	$ 290	$ 135	$ 106	$ 49	2.75
Ten Year Totals	Yrs 1-10	7.25	$ 2,325	$ 1,632	$ 1,056	$ 765	2.13
Per Year Levelized				**$ 225**		**$ 106**	2.13

The transfer analysis for portfolio 3-E without Chesapeake but including with Reno Co. - Summit is shown in the following table. The analysis concluded that $62M of transfers were required to balanced this portfolio

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

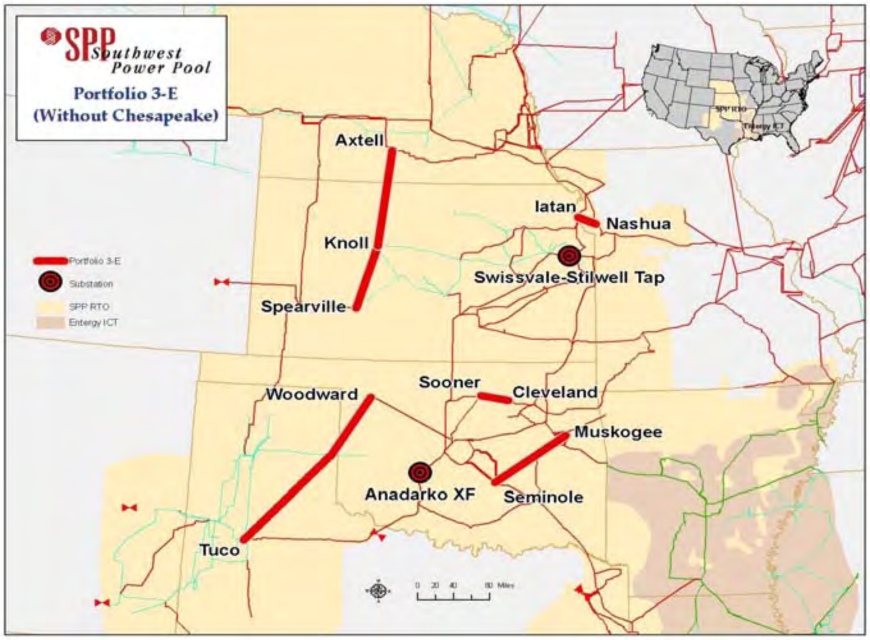
#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$25.8	$23.7	($11.8)	$13.9	$2.1	$0.0	1.0
2	EMDE	($0.1)	$2.8	($4.5)	$1.6	($2.9)	$0.0	1.0
3	GRDA	$0.1	$2.1	($3.2)	$1.2	($1.9)	$0.0	1.0
4	KCPL	$8.7	$8.2	($4.2)	$4.8	$0.5	$0.0	1.0
5	MIDW	$12.8	$0.8	$0.0	$0.4	$0.4	$11.6	10.7
6	MIPU	($5.6)	$4.3	($12.4)	$2.5	($9.9)	$0.0	1.0
7	MKEC	$11.3	$1.2	$0.0	$0.7	$0.7	$9.4	6.0
8	OKGE	$36.8	$15.0	$0.0	$8.8	$8.8	$13.0	1.5
9	SPRM	($0.3)	$1.6	($2.9)	$1.0	($1.9)	$0.0	1.0
10	SUNC	$3.6	$1.1	$0.0	$0.7	$0.7	$1.8	2.0
11	SWPS	$55.9	$12.2	$0.0	$7.1	$7.1	$36.6	2.9
12	WEFA	$11.8	$3.3	$0.0	$2.0	$2.0	$6.5	2.2
13	WRI	$59.9	$12.2	$0.0	$7.1	$7.1	$40.6	3.1
14	NPPD	$5.4	$8.5	($8.0)	$5.0	($3.0)	$0.0	1.0
15	OPPD	$2.7	$6.6	($7.7)	$3.8	($3.8)	$0.0	1.0
16	LES	($3.9)	$2.0	($7.1)	$1.2	($5.9)	$0.0	1.0
Total		$225	$106	-$62	$62	$0	$120	2.1

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

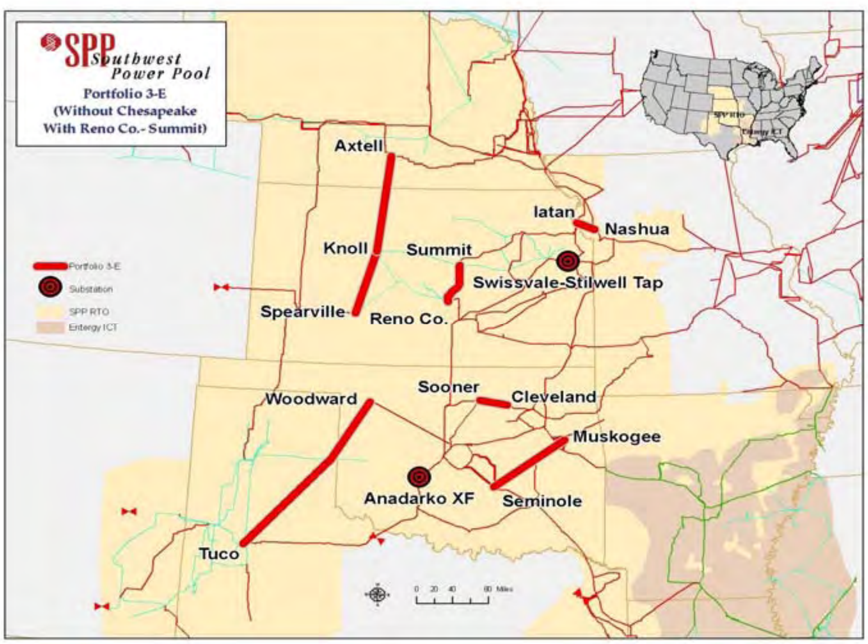
Total ATRR for Proposed Balanced Portfolios

	BP 3E	3E no Ches	BP 3E no Ches w RS
Zone	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR
AEPW	$ 175,484,688	$ 177,104,393	$ 174,641,806
SPRM	$ 8,934,262	$ 8,659,884	$ 8,524,079
EMDE	$ 14,660,746	$ 14,007,997	$ 14,294,209
GRDA	$ 25,891,875	$ 26,032,862	$ 25,312,950
KCPL	$ 43,661,239	$ 44,709,872	$ 45,060,781
OKGE	$ 118,952,010	$ 116,849,771	$ 122,735,245
MIDW	$ 5,277,346	$ 5,170,672	$ 5,469,320
MIPU	$ 19,618,726	$ 19,420,118	$ 15,471,824
SWPA	$ 9,431,500	$ 9,431,500	$ 9,431,500
SWPS	$ 104,700,870	$ 102,989,030	$ 107,781,536
SUNC	$ 16,092,722	$ 15,934,343	$ 16,377,746
WEFA	$ 25,545,806	$ 25,077,005	$ 26,389,469
WRI	$ 128,845,823	$ 129,135,340	$ 134,286,149
MKEC	$ 7,723,354	$ 7,557,124	$ 8,022,505
LES	$ 8,877,057	$ 8,718,252	$ 8,313,564
NPPD	$ 53,140,390	$ 53,181,895	$ 53,125,563
OPPD	$ 38,645,990	$ 38,661,265	$ 39,227,136
	$ 805,484,404	**$ 802,641,325**	**$ 814,465,382**

Portfolio 3-E "Adjusted"



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



Recommendation

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

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

- Total E&C Costs: $692M

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

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

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

Existing Zonal ATRR	Base Plan		New Base Plan NTCs		P-3E Costs
	1/3	**2/3**	**1/3**	**2/3**	Annual
$688M	$7M	$14M	$33M	$66M	$106 M
Total: $808M					13%
Avg. Cost Per Customer Per Month: $7.58					**88 ¢**

P-3E "Adjusted" Benefit = $1.66

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

Balanced Portfolio Stakeholder Process
The SPP Regional State Committee (**RSC**) requested the Cost Allocation Working Group (CAWG) to consider alternative cost allocations for economic upgrades.

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

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

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

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

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

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

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

Appendix

Final Benefit to Cost Results for the Balanced Portfolio

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

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

Portfolio 3-E "Adjusted"	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
			Million of Dollars		
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	1.87

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

2012 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$21,285,000	($14,003,000)	$31,439,000	($24,155,000)
EMDE	$2,990,000	($2,096,000)	$207,000	$687,000
GRDA	$72,000	$159,000	$982,000	($751,000)
KCPL	$4,273,000	($637,000)	$9,994,000	($6,358,000)
LES	$1,297,000	$1,226,000	$0	$2,523,000
MIDW	($350,000)	($8,783,000)	$0	($9,133,000)
MIPU	$6,027,000	($3,968,000)	($5,000)	$2,064,000
MKEC	($7,563,000)	($2,015,000)	($925,000)	($8,653,000)
NPPD	$6,519,000	($28,000)	$11,726,000	($5,235,000)
OKGE	($85,787,000)	$52,737,000	($9,386,000)	($23,664,000)
OPPD	$2,165,000	$160,000	$4,247,000	($1,922,000)
SPRM	$734,000	($42,000)	$668,000	$24,000
SUNC	($5,206,000)	($2,096,000)	($5,171,000)	($2,131,000)
SWPS	($70,516,000)	$31,769,000	($519,000)	($38,228,000)
WEFA	($13,163,000)	$4,105,000	($375,000)	($8,682,000)
WRI	($5,257,000)	($359,000)	$2,131,000	($7,747,000)

2017 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$55,943,000	($17,738,000)	$71,548,000	($33,344,000)
EMDE	$3,525,000	($3,272,000)	$100,000	$153,000
GRDA	($28,000)	$163,000	$889,000	($754,000)
KCPL	$6,229,000	($3,576,000)	$11,897,000	($9,244,000)
LES	$2,019,000	$1,970,000	$0	$3,989,000
MIDW	($764,000)	($14,046,000)	$0	($14,810,000)
MIPU	$5,483,000	($3,915,000)	$79,000	$1,489,000
MKEC	($10,893,000)	($2,667,000)	($793,000)	($12,767,000)
NPPD	$5,842,000	($779,000)	$10,741,000	($5,678,000)
OKGE	($129,794,000)	$88,180,000	($14,032,000)	($27,582,472)
OPPD	$3,030,000	$276,000	$5,663,000	($2,357,000)
SPRM	$603,000	($60,000)	$251,000	$292,000
SUNC	($7,575,000)	($2,386,000)	($6,776,000)	($3,185,000)
SWPS	($80,497,000)	$18,914,000	($924,000)	($60,659,000)
WEFA	($22,863,000)	$14,785,000	($468,000)	($7,610,000)
WRI	($14,392,000)	($1,073,000)	$1,674,000	($17,139,000)

2022 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$67,322,000	($22,618,000)	$83,884,000	($39,181,000)
EMDE	$4,703,000	($4,421,000)	$91,000	$191,000
GRDA	($480,000)	$123,000	$1,003,000	($1,360,000)
KCPL	$6,624,000	($2,828,000)	$14,974,000	($11,178,000)
LES	$2,249,000	$2,150,000	$0	$4,399,000
MIDW	($736,000)	($14,659,000)	$0	($15,395,000)
MIPU	$2,680,000	($1,044,000)	($19,000)	$1,655,000
MKEC	($14,429,000)	($1,525,000)	($287,000)	($15,667,000)
NPPD	$6,488,000	($1,250,000)	$10,748,000	($5,510,000)
OKGE	($138,499,000)	$85,998,000	($22,388,000)	($30,113,000)
OPPD	$3,787,000	$378,000	$6,258,000	($2,093,000)
SPRM	$637,000	($317,000)	$301,000	$19,000
SUNC	($7,360,000)	($2,495,000)	($3,923,000)	($5,932,000)
SWPS	($89,381,000)	$2,205,000	($1,184,000)	($85,992,000)
WEFA	($20,837,000)	$13,197,000	($575,000)	($7,065,000)
WRI	($11,595,000)	($6,705,000)	$2,730,000	($21,030,000)

The following table demonstrates the benefits, costs and transfers on an annualized basis after the resulting reliability impacts, both the advancement and deferral, are accounted for. The net B/C impact of the reliability projects was an approximate marginal increase of .01 of the total Portfolio.

Portfolio 3-E "Adjusted" Annualized Benefits, Costs and Transfers, including Reliability Impacts

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

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		$176	$95	-$31	$31	$0	$81	1.86

The spreadsheet which was used to calculate the transfers in the above table can be found on the Balanced Portfolio section of the SPP Website.[††]

[††] http://www.spp.org/section.asp?pageID=120

The table shown below demonstrates the MW-mi impact of the deferred reliability projects. This impact is used to determine who receives the benefit for the deferral of each reliability project from the portfolio.

Portfolio 3-E – Reliability Impact MW-mi analysis

	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	CLEARWATER-GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	EL RENO- EL RENO SW 69KV CKT 1 - Upgrade	LONGVIEW-WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps
Date	**2015**	**2015**	**2016**	**2017**	**2018**
AEPW		1.6%			
EMDE					
GRDA					
KCPL					
MIDW	46.7%	16.2%			
MIPU					100.0%
MKEC	19.4%	36.0%			
OKGE	1.3%	5.3%		24.7%	
SPRM					
SUNC	9.9%	10.9%			
SWPS		4.4%			
WEFA				75.3%	
WRI	22.6%	22.1%	100.0%		
NPPD		3.6%			
OPPD					
LES					
	100.0%	100.0%	100.0%	100.0%	100.0%

Reliability Results

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

Portfolio 3e without Chesapeake

Costs of STEP Projects Solved by Portfolio 3e, with STEP date

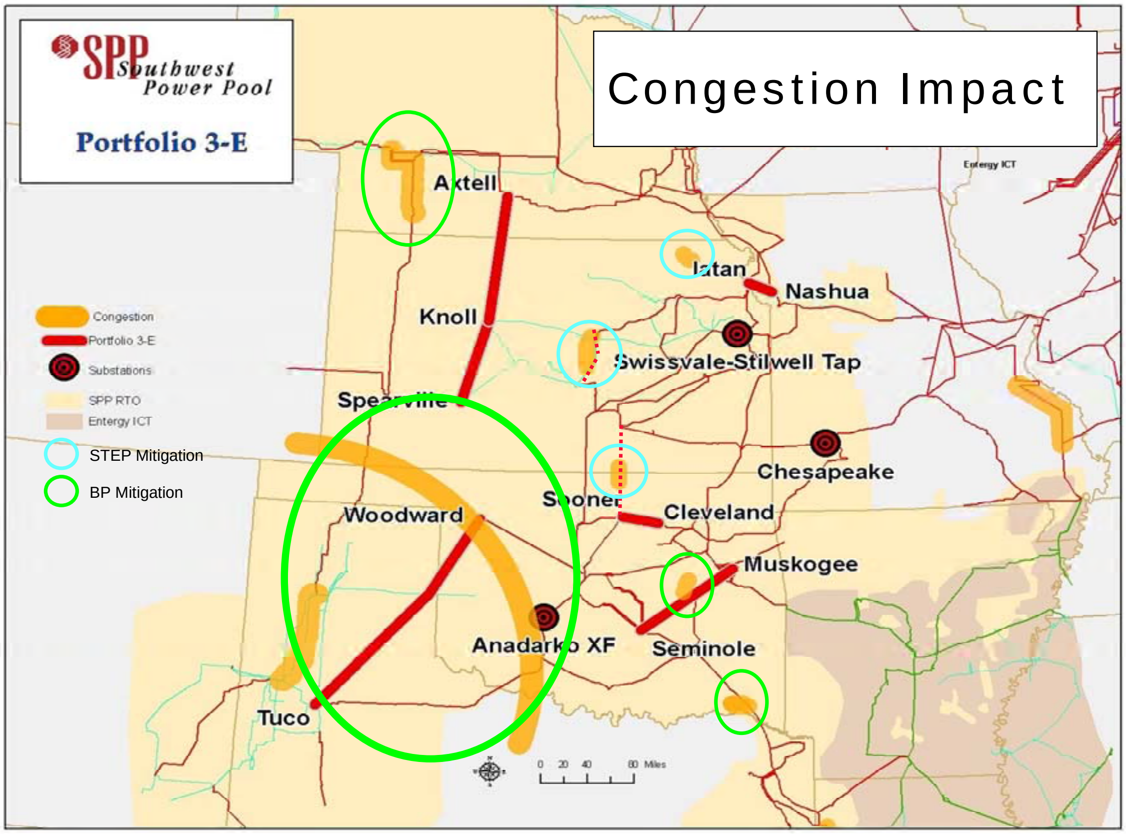
Issue Type	Project Name	Area	STEP Date	Deferred costs to TO: STEP projects solved by BP
Overload	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	WERE	16SP	$3,324,375
Overload	EL RENO - EL RENO SW 69KV CKT 1 - Upgrade	WFEC	17SP	$1,950,000
Overload	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	WERE	15SP	$12,487,500
Overload	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	MIDW	15SP	$7,965,000
Overload	LONGVIEW - WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps	MIPU	18SP	$50,000
Voltages	None			
			Totals	**$25,776,875**

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

Description	Project Name	Area	Date of Needed Mitigation	SPP New Issues, Cost	Third Party Issues: Cost
Overloads-SPP	EARLSBORO - FIXICO 69KV CKT 1 - Increase limits (trap, CT ratio)	OKGE	13SP	$150,000	
Overloads-SPP	MED LODGE-PRATT, ST.JOHN-GREATBENDTAP 115 KV LINE REBUILD	MKEC	18SP	$15,840,000	
Overloads-Third Party	PLATTE CITY 161/69KV TRANSFORMER CKT 1 - Replace AECI XFMR	MIPU-AECI	13WP		$7,500,000
Voltages	None				
			Totals	**$15,990,000**	**$7,500,000**
			Grand Total	**$23,490,000**	
			Net: Solved Minus SPP New	**$9,786,875**	
			Net: Solved Minus Total New	**$2,286,875**	

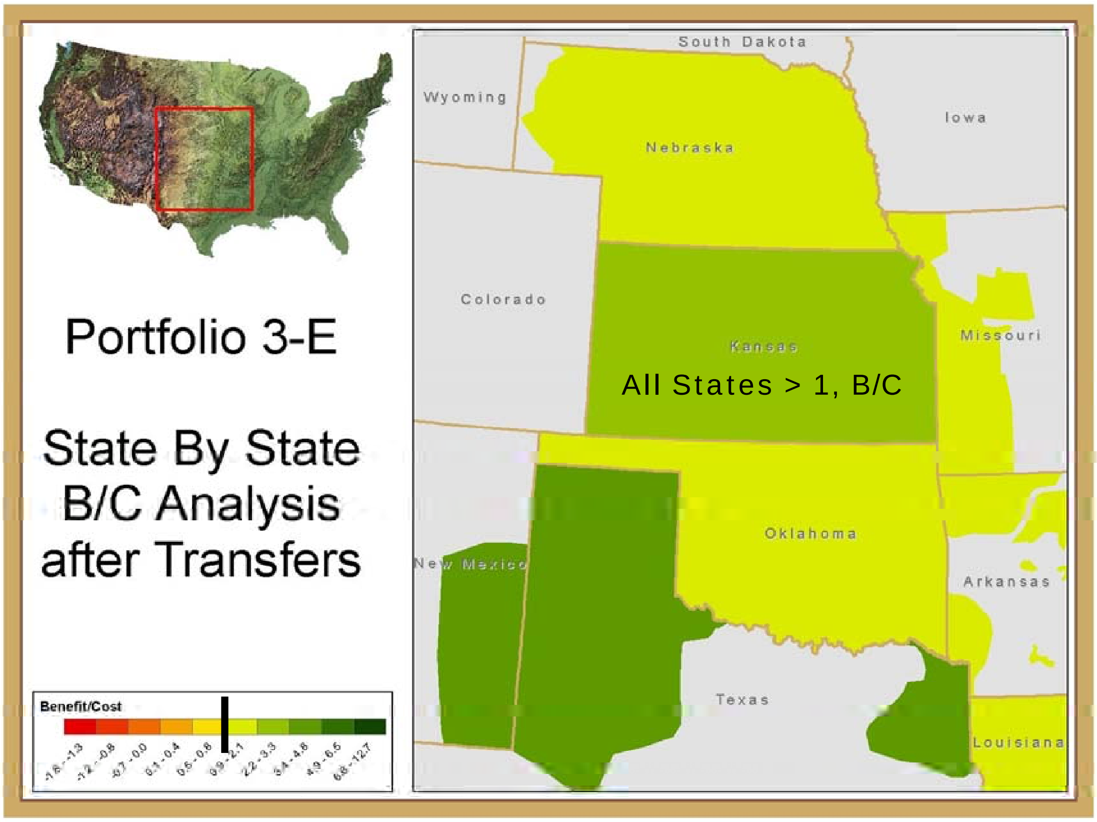
It should be noted that the third party impact of Platte City 161/69 kV transformer was coordinated with Associated Electric Cooperative, Inc. (AECI) staff. AECI staff did not see the same issue in their analysis.

Congestion Impact



The graphic shown above represents the top flowgates in the SPP EIS Market as they exist today. Congestion here is shown as an orange highlight. Portfolio projects, shown on the map as bold red highlight lines, relieve or mitigate much of the congestion that exists today. The congestion relief provided by the portfolio is shown as a green circle. Projects in the 10-year STEP plan that provide additional congestion relief are shown in light blue.

B/C by State



The diagram above demonstrates the B/C ratio of the Balanced Portfolio divided by state boundaries. While it should be noted that the portfolio of projects provides broad, regional benefits to all SPP members, this diagram is a good representation of the balance aspect of the portfolio broken into the respective state boundaries. This picture represents the balance of the portfolio after transfers have taken place in order to balance all zones. As can be seen from the diagram, all states have a B/C ratio greater than 1

SPP Balanced Portfolio Report

	Zone	OKGE	OKGE	OKGE	SPS	KCPL	NPPD	ITC	KCPL	OKGE
	Project	Sooner - Cleveland	Seminole - Muskogee	Tuco - Woodward	Tuco - Woodward	Iatan - Nashua	Knoll - Axtell	Spearville - Knoll - Axtell	Swissvale - Stilwell Tap	Andadarko Sub
	Projected In-Service Date	12/31/2012	12/31/2013	5/19/2014	5/19/2014	6/1/2015	6/1/2013	6/1/2013	6/1/2012	12/31/2011
Cost	Total Cost	$33,530,000	$129,000,000	$79,000,000	$148,727,500	$54,444,000	$71,377,015	$165,180,000	$2,00,000	$8,000,000
	Cost Per Mile	$900,000	$1,250,000	$900,000	$688,750	$1,214,800	$1,416,667	$846,000		$666,666
	Miles	36	100	72	178	30	45	170		3
	Substation Cost	$1,130,000	$4,000,000	$15,000,000	$26,130,000	$18,000,000	$6,827,000	$16,800,000		
	Fixed Charge Rates	15.1%	15.1%	15.1%	12.1%	15.1%	13.5%	12.0%	15.1%	15.1%
Conductor	Size	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1192.5, 38/19 Grackle TW	2 Conductor Bundle 477 T2 Hawk	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	138 kV line
	Design	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit		
	Electrical Capacity	2578 Amps 1540 MVA at 345kV	3000 Amps 1800 MVA at 345kV	2578 Amps 1540 MVA at 345kV	2468 Amps Normal	4,100A	2,324 amps per bundle	3,000 amps		
	Other	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire					
Structure	Type	H-frame	Single Pole	H-frame	H-frame	H-frame	Single Pole	H-frame		
	Materials	Steel	Steel	Steel	Steel	Steel	Steel	Steel		
	Base	Direct buried w/ aggregate backfill	Steel base plate reinforced concrete	Direct buried w/ aggregate backfill	Direct buried with aggregate or natural backfill	Direct Embed	Poured concrete anchor bolt	Direct embed concrete piers		
	NESC Assumption	Heavy	Heavy	Heavy	Heavy	Heavy	Heavy, 1.5 inch ice load			
	Dead Ends	Unknown	Unknown	Unknown	Unknown @ $65,000 each	16 @ $50,000 each	20 @ $140,000 each	60 @ $50,000 each	2 to 3 Deadends	
	Under build	No	No	No	No	No	No	No		
Substations	Transformers	Breakers and Relays	Two 345/138kV	345/138kV 50 MVAR reactor bank	345/230kV 560 MVA	600 MVA	None	345/230kV 200 MVA		345/138 kV
	Breaker Scheme	Ring-bus	Ring-bus, replace 2 2,000 A breakers	Ring-bus	345kV Ring	Ring-bus	Ring-bus	Ring-bus	2 breakers, breaker disconnects, line panels	
	Protection Scheme	included in sub cost	included in sub cost	included in sub cost	$1,000,000	$400,000	$156,000	$220,000		included in sub cost
	Voltage Control			+\- 50 MVAR						
	Cost (millions)	$1	$4	$15	$26	$18	$4	$14		
Construction Labor	Amount	1/3 of line construction	1/3 of line construction	1/3 of line construction						
	Cost (millions)	$14	$52	$27	$18	$7	$17	$49		
Eng Design, Project Management, Permitting	ROW	150ft @$5,500 an acre	200ft @$5,500 an acre	150ft @ $5,500 an acre	150ft	160ft	200ft	150ft		
	ROW Condition	rural, pasture	rural, pasture, hill, rock, high tree clearing cost	rural, pasture	Farmland and Pasture	50% Urban 50% Rural	rural farmland rainwater basin	rural, agri, pasture, range land	No ROW acquisition required	
	Permitting/Certifications	RR and Highway	RR and Highway	RR and Highway	Texas CCN, Highway, storm water, RR, County roads	Yes	NE Power Review Board, NPSC, RR, Airport, etc	Included		
	Escalation Rate	2.5% per year	2.5% per year	2.5% per year		2.5% per year	3% per year	0% for 2 years		
	Eng. Design / Proj. Mang.				Included	$349,000	$8,798,000	$13,770,000		
	Total Cost (millions)	cost included	cost included	cost included	$15	$26	$18	$24		
Loadings and Overheads	Type 1	Included in total cost	Included in total cost	Included in total cost	Included in total cost	$123,000	Included in total cost	20% of line and substation work, $26.7 million		
Other Cost Factors and Notes			$25,000/ mile cost included for tree clearing		Included in substation cost is $6.52 mil for mid-point reactor station	Large portion involves developed urban areas	Environmentally sensitive areas, possible double-circuit for 10 miles	$4.56 mil addition contingency added		

Study Assumptions

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

Environmental Costs - Carbon sensitivities have been conducted, but were not included in the portfolio selection process. A price of $15 and $40 per metric ton was used in these sensitivities. No sensitivity analysis was conducted for higher SO_2 or NO_X prices. SO_2 and NO_X were priced at $466.50 and $1742.16 per ton respectively.

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

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

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

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

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

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

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

Flowgate Assumptions – The NERC Book of Flowgates was used as the source for flowgates used in the analysis.

DC Tie Profiles - Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

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

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

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

Operating Reserves – SPP's current reserve sharing program (as of 2008) was used in the simulation for operating reserves.

Waivers

SPP Southwest Power Pool

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Requested Waivers

Southwest Power Pool

Waivers

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

Southwest Power Pool

Westar - Meridian Way

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

Westar - Meridian Way

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

Westar – Flat Ridge Wind

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

Southwest Power Pool

Westar – Flat Ridge Wind

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

Southwest Power Pool

Coffeyville Amended Waiver

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

Southwest Power Pool

Coffeyville Amended Waiver

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

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Southwest Power Pool

Waiver Approval

- **Westar – Meridian Way**
  - **SPP Staff recommended a waiver of Attachment J language for a BPF cap of $17,280,000 less the direct assignment of upgrades as allocated in final study.**
  - **The CAWG recommended the MOPC approve the WR waiver for such amount to Base Plan fund the project. The MOPC approved the request at their June 12, 2009 meeting**
- **Westar – Flat Ridge**
  - **SPP Staff recommends a waiver of Attachment J language for a BPF cap of $18,000,000 less the direct assignment of upgrades as allocated in final study.**
  - **The CAWG recommended the MOPC approve the WR waiver for such amount to Base Plan fund the project. The MOPC approved the request at their June 12, 2009 meeting.**

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Waiver Approval

- **Coffeyville Amended Waiver**
  - **Coffeyville estimates completion of steps should coincide with a vote at the July 2009 SPP Board of Directors meeting.**
  - **SPP recommended approval of the amended waiver request to fully fund the project including the CMLP-owned direct assignment upgrades at such time that the city owned facilities are brought under the OATT.**
  - **Coffeyville estimates the completion of these tasks should coincide with a vote at the July 2009 SPP Board of Directors meeting.**
  - **The MOPC approved the request at their June 12, 2009 meeting.**

SPP Southwest Power Pool

Les Dillahunty
Executive Vice President, Engineering and Regulatory Policy
501-614-3215
questions@spp.org

Southwest Power Pool, Inc.
SOUTHWEST POWER POOL STAFF
Report to the Markets and Operations Policy Committee
on
Attachment J Waiver Requests
June 12, 2009

Organizational Roster

The following members represent the Southwest Power Pool:

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

Background

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

SPP recently received the following waiver requests:

1. On March 25, SPP received a request for waiver under Attachment J of the SPP Tariff for costs in excess of the Safe Harbor Cost Limit for Base Plan funding from American Electric Power Service Corporation (AEPSC) for a new Designated Resource for 15 MW from the Sleeping Bear wind farm. AEPSC is seeking a waiver for this cost above the Base Plan funding limit so that all of the allocated expenses associated with AEPSC's request is eligible for Base Plan funding. SPP's 120 day deadline under Attachment J is July 23, 2009.

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

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

4. On March 27, SPP received a request for waiver under Attachment J of the SPP Tariff for costs in excess of the Safe Harbor Cost Limit for Base Plan funding from Westar Energy (WR) for a new Designated Resource for 100 MW from the Flat Ridge wind farm. WR seeks approval of this waiver request base on the New Attachment J criteria for wind farms. WR acknowledges that this may expose them to direct assigned transmission costs when changing costs allocation methodologies from the

previously filed method to the recently approved RSC methodology. SPP's 120 day deadline under Attachment J is July 25, 2009.

Analysis:

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

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

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

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

Recommendation

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

Westar Energy.

March 27, 2009

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

Subject: Request for Waiver for OASIS Request #1346837

Dear John:

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

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

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

Section 12.1.5.3 (g) of the SPP Criteria specifies that the actual accredited capacity for a wind farm will be based on the hourly net power output values that can be expected more than 85% of the time occurring during the top 10% of Westar Energy's monthly peak load. Westar Energy believes the resulting accredited capacity value for our wind farm will be less than the 10% default value used as a placeholder for determining the initial wind farm funding allocation. Once the actual accreditation value is known for this wind farm, we anticipate the base plan funding allocation will be significantly less than the amount of the projected E&C cost.

818 S Kansas Ave / PO Box 889 / Topeka, Kansas 66601-0889
Office Telephone: (785) 575-8078

Based on the information known today, Westar Energy acknowledges that this waiver request may expose us to direct assigned transmission cost when changing costs allocation methodologies from the previously filed method to the recently approved RSC methodology. However, we prefer the new RSC cost allocation methodology for wind resources. Also this will also provide Westar Energy, assuming our waiver for Transmission Request #1346842 is approved, similar treatment for all three wind farms for which we are the off-taker.

Sincerely,

John P. Olsen
Executive Director,
Bulk Power Marketing

SPP Southwest Power Pool

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SPP Southwest Power Pool

Waiver Request
Westar Energy
Meridian Way Wind

April 2009

Summary of Waiver Request

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

Waiver Request Discussion

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

Attachment J changes to Base Plan funding for Wind Farms

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

Attachment J changes to Base Plan funding for Wind Farms

- If upgrade associated with Wind Generation located in same zone as Customer's POD
  - 33% Regional 67% Zonal
- If upgrade associated with Wind Generation located in different zone than Customer's POD
  - 67% Regional 33% Direct assigned to customer

Southwest Power Pool

Attachment J changes to Base Plan funding for Wind Farms

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

SPP.ORG 7

Southwest Power Pool

Attachment J changes to Base Plan funding for Wind Farms

- **If upgrade associated with Wind Generation located in different zone than Customer's POD**
  - **67% Regional equates to $291,008 RR**
  - **33% Direct Assigned equates to $145,504 RR or $55,185 E & C**

SPP.ORG 8

Southwest Power Pool

Base Plan funding allocation

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

Southwest Power Pool

SPP Conclusions and Waiver Recommendation

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

John Mills
Manager – Tariff Studies
501-614-3356
jmills@spp.org

Westar Energy®

March 27, 2009

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

Subject: Request for Waiver for OASIS Request #1346842

Dear John:

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

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

Based on the latest results of the SPP study AG3-2007-AFS-7, this transmission service request has an allocated Engineering and Construction (E&C) cost of $17,417,601. The current cost allocation method would provide a potential base plan funding allocation of $1.800.000 based on a 10% nameplate capacity allocation times the safe harbor cost limit, exposing us to a direct assigned cost of $15,617,601. Our understanding of the recently approved RSC methodology would reduce the direct assigned cost to $5,679,345 put $379,396 in the Westar Energy zonal rate and the remainder uplifted to the footprint.

Sincerely,

John P. Olsen
Executive Director,
Bulk Power Marketing

818 S Kansas Ave / PO Box 889 / Topeka, Kansas 66601-0889
Office Telephone: (785) 575-8078

Southwest Power Pool

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Southwest Power Pool

Waiver Request
Westar Energy
Flat Ridge Wind

April 2009

Southwest Power Pool

Summary of Waiver Request

- **Westar reservation 1346842 studied in 2007-AG3**
- **Westar requesting 100 MW from Flat Ridge Wind farm**
- **Base Plan Funding (BPF) potential calculated in AFS-7: 10 MW x $180,000/MW = $1,800,000 based on 10% nameplate net dependable capacity**
- **E & C upgrade allocation in AFS-6 study posting is $17,417,601.**
- **E & C upgrade allocation in AFS-7 study posting is $17,158,681.**
- **March 27, 2009 Letter – Westar requests waiver following posting of AFS-6 based on new Attachment J language**
- **Recommendation to SPP Board of Directors within 120 days per the tariff required not later than July 25, 2009.**
- **SPP staff recommended MOPC acknowledge unusual circumstances per Attachment J III. 2**
- **Next SPP Board of Directors meeting for action is July 28, 2009**

SPP.org 3

Southwest Power Pool

Waiver Request Discussion

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

SPP.org 4

SOUTHWEST POWER POOL

Attachment J changes to Base Plan funding for Wind Farms

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

SPP.ORG 5

SOUTHWEST POWER POOL

Attachment J changes to Base Plan funding for Wind Farms

- If upgrade associated with Wind Generation located in same zone as Customer's POD
  - 33% Regional 67% Zonal
- If upgrade associated with Wind Generation located in different zone than Customer's POD
  - 67% Regional 33% Direct assigned to customer

SPP.ORG 6

Southwest Power Pool

Attachment J changes to Base Plan funding for Wind Farms

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

Southwest Power Pool

Attachment J changes to Base Plan funding for Wind Farms

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

Southwest Power Pool

Base Plan funding allocation

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

Southwest Power Pool

SPP Conclusions and Waiver Recommendation

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

SPP Southwest Power Pool

John Mills
Manager – Tariff Studies
501-614-3356
jmills@spp.org

CITY OF Coffeyville KANSAS

7th & WALNUT • P.O. BOX 1629 • (620) 252-6100
COFFEYVILLE, KANSAS 67337-0949

May 15, 2009

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

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

Dear John,

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

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

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

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KANSAS

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COFFEYVILLE, KANSAS 67337-0949

into the SPP facilities studies and allow them to be included in engineering and construction costs for the base plan funding calculations.

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

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

Sincerely,

Bernard A. Cevera

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

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

SPP Southwest Power Pool

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SPP Southwest Power Pool

Amended Waiver Request – City of Coffeyville, Kansas

June 2009

Summary of Amended Waiver Request

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

Summary of Amended Waiver Request

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

Amended Waiver Request Discussion

- **Attachment J, Section III.C.2.ii - Allows all or part of excess above the Safe Harbor Cost Limit to be classified as Base Plan Upgrade Costs, taking into account the extent to which commitment to the new or changed DR exceeds the five-year commitment**
- **These facilities for which a waiver is being sought are not presently under the SPP OATT**
- **The city is taking the necessary steps to become a transmission owning member of the Southwest Power Pool and to release its transmission facilities under the SPP Open Access Transmission Tariff and file a formula rate.**
- **Coffeyville estimates the completion of these tasks should coincide with a vote at the July 2009 SPP Board of directors meeting.**

SPP Amended Waiver Recommendation

- **SPP recommends approval of the amended waiver request to fully fund the project including the CMLP-owned direct assignment upgrades at such time that the city owned facilities are brought under the OATT.**
  - **Based on the commitment in excess of five years (29 years)**
  - **Based on all assigned facilities being SPP jurisdictional**

SPP Southwest Power Pool

John Mills
Manager – Tariff Studies
501-614-3356
jmills@spp.org

Southwest Power Pool, Inc.

2009, 3RD QUARTER

PROJECT TRACKING REPORT

Southwest Power Pool

Southwest Power Pool, Inc.

2009 3RD QUARTER PROJECT TRACKING REPORT

July 2009

PROJECT TRACKING, Current SPP Process:

SPP actively monitors and supports the progress of transmission expansion projects, emphasizing the importance of maintaining accountability for areas such as grid regional reliability standards, firm transmission commitments and tariff cost recovery.

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

Results:

Project Summary:

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

3rd Quarter 2009 Project Tracking Summary		
Upgrade Type	Number of Upgrades	Cost Estimate
Regional Reliability	264	$1,178,086,228
Regional Reliability - Non OATT	12	$70,825,000
Zonal Reliability	9	$13,472,843
Transmission Service	55	$427,168,763
Generation Interconnect	12	$92,727,000
Balanced Portfolio	18	$700,168,500
Other Sponsored Upgrades	81	$747,888,095
TOTALS	451	$3,230,336,429

Figure 1: 2009 3rd Quarter Project Summary

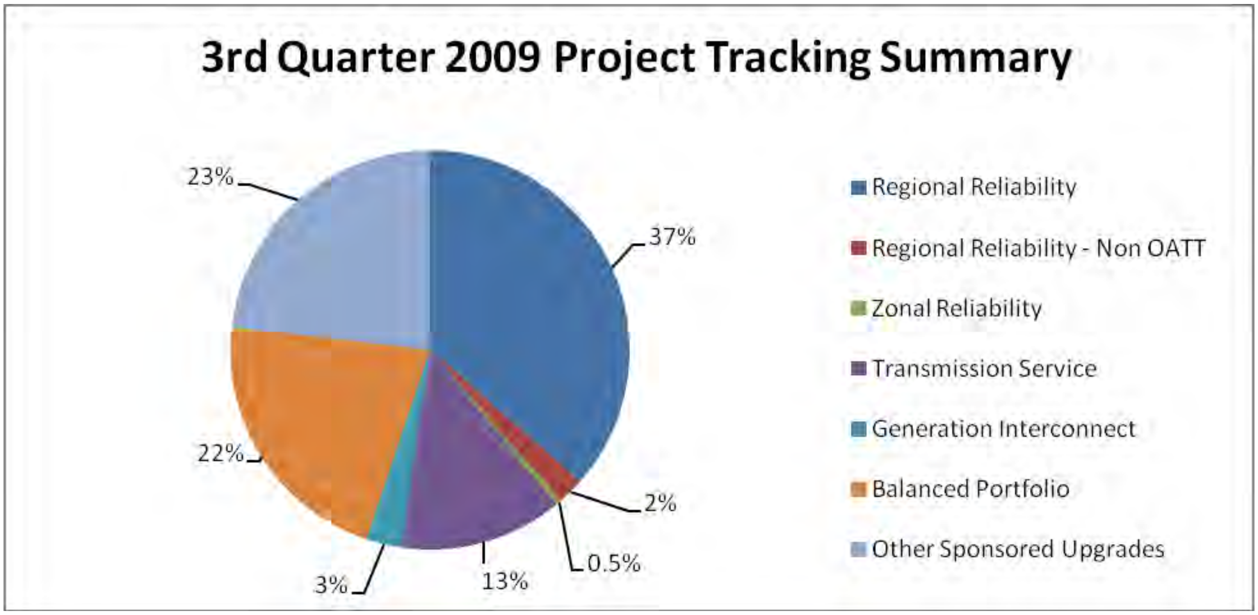


Figure 2: Breakdown of Project Categories on Cost Basis

Regional Reliability Project Summary:

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

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

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

This category contains projects identified as needed to support new Transmission Service (TSR) and Generation Interconnection (GI) service agreements. There are sixty-seven TSR/GI upgrades with an E&C cost of $520 million.

There were seven upgrades with latest estimates at $12 million completed in this category during the second quarter of 2009. There are fifty-five upgrades estimated at $490 million on schedule. Transmission owners have provided mitigation plan for two projects valued at $5.5 million. No upgrade has been delayed beyond the RTO determined need date without having an interim mitigation plan.

3rd Quarter 2009 Project Tracking Status

Top number is number of upgrades in category

Bottom number is estimated cost of upgrades in category

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

Figure 2: Project Status

Conclusions:

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

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

SPP 3rd Quarter 2009 Project Tracking List - Branch_Xfr

Blue	Complete.
Green	On Schedule 4 Year Horizon.
Green	On Schedule beyond 4 Year Horizon.
Yellow	Behind schedule, interim mitigation provided or project may change but time permits the implementation of project.
Yellow	Behind schedule, require re-evaluation due to anticipated load forecast changes.
Red	Delayed beyond the RTO Determined need date and no mitigation plan provided
$ / months	Project lead time and cost estimated by SPP staff

Project types "sponsored" and "regional reliability - non OATT" do not receive NTCs and are not filed at FERC but are being tracked because they are expected to be built in the near term

NTC_ID	PID	UID	Area	Project Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Letter of Notification to Construct Issue Date	Current Cost Estimate	Final Cost	Project Lead Time	Project Status	Project Status Comments
			Year 2008										
19984	104	10128	515	Line - Springfield - Brookline 161 kV	transmission service	06/01/08	06/01/08		$300,000				Prior to BPF tariff
19999	115	10145	520	Line - Northwest Texarkana - Alumax Tap	regional reliability	03/04/08	06/01/07	02/01/07	$2,160,000				
19957	114	10144	520	Line - Northwest Texarkana-Bann T - Bann 138kV	transmission service	03/26/08	06/01/08	01/02/07	$25,000				
19957	116	10146	520	Line - Alumax Tap - Bann	transmission service	03/26/08	06/01/09	01/02/07	$1,180,000				86% BPF
20000	110	10137	520	XFR - Pryor Junction 138/69 kV	regional reliability	04/25/08	06/01/08	02/13/08	$1,829,100				
19997	120	10150	520	Line - Linwood to McWillie Street Rebuild	regional reliability	04/30/08	06/01/08	03/09/06	$1,100,000				
19999	109	10133	520	Multi - Fayetteville 69 kV conversion	regional reliability	05/08/08	06/01/08	02/02/07	$21,000,000				
19999	109	10134	520		regional reliability	05/08/08	06/01/08	02/02/07					
19999	109	10135	520		regional reliability	05/08/08	06/01/08	02/02/07					
19999	109	10136	520		regional reliability	05/08/08	06/01/08	02/02/07					
19998	117	10147	520	Line - Chamber Springs - Tontitown 345 kV	regional reliability	05/15/08	06/01/07	02/14/07	$14,405,000				
20000	107	10132	520	Line - E Rogers - Avoca 161 kV	regional reliability	05/20/08	06/01/08	02/13/08	$720,000				Switchable Series Reactor
19958	119	10149	520	Line - Cache - Snyder 138kV	transmission service	05/21/08	06/01/08	10/11/06	$85,000				Only 86.3% of costs BPF as rest covered by PTP base rate
20000	106	10130	520	Line - Snyder - Altus Junction 138 kV	regional reliability	05/21/08	06/01/13	02/13/08	$16,760,000				
20000	227	10291	520	Line - Breaker Daingerfield - Jenkins REC 69 kV	regional reliability	12/12/08	06/01/09	02/13/08	$250,000		12 months		
20001	121	10151	523	Line - 412 Sub - Kansas Tap 161 kV	regional reliability	06/08/08	06/01/10	02/13/08	$2,971,180				
20002	131	10165	524	Line - Canadian - Cedar Lane 138 kV	regional reliability	06/01/08	06/01/08	02/13/08	$12,637	$31,127			
20002	124	10157	524	Line - Fort Smith - Colony 161 kV	regional reliability	11/01/08	06/01/09	02/13/08	$133,000	$86,875			Replace 1200A terminal Equipment at Ft. Smith & Colony
19995-1	127	10160	524	Line - Westmoore - Pennsylvania 138 kV	zonal reliability	12/30/08	10/01/07	03/07/07	$250,000	$170,751			
19985	72	10090	525	Line - Elmore - Wallville 69 kV	regional reliability	03/31/08	06/01/12	02/02/07	$1,488,000		16 months		Project Under Construction, will be completed early 2008
19951	141	10180	525	XFR - Ft Supply 70 MVA	transmission service	06/01/08	06/01/08	01/02/07	$2,000,000		18- months		48% BPF
20003	244	10312	525	XFR - Paoli 138 kV/69 kV Transformer	regional reliability	06/01/08	06/01/09	02/13/08	$1,500,000		12 months		
20003	312	10404	525	Line - Alva - Cherokee SW 69 kV	regional reliability	06/01/08	06/01/10	02/13/08	$150,000		6 months		
19985	134	10168	525	Multi - Erick - Morewood SW conversion	regional reliability	10/01/08	06/01/08	02/02/07	$12,000,000		12 months		Complete
19985	134	10169	525	Multi - Erick - Morewood SW conversion	regional reliability	10/01/08	06/01/08	02/02/07			12 months		Complete
19985	134	10170	525	Multi - Erick - Morewood SW conversion	regional reliability	10/01/08	06/01/08	02/02/07			12 months		Complete
19985	134	10171	525	Multi - Erick - Morewood SW conversion	regional reliability	10/01/08	06/01/08	02/02/07			12 months		Complete
19985	134	10172	525	Multi - Erick - Morewood SW conversion	regional reliability	10/01/08	06/01/08	02/02/07			12 months		Complete
20003	139	10177	525	Multi - Kingfisher 69 kV	regional reliability	11/01/08	06/01/08	02/13/08	$4,050,000		10 months		Complete
20003	139	10178	525	Multi - Kingfisher 69 kV	regional reliability	11/01/08	06/01/08	02/13/08	$3,540,000		10 months		Complete
19987	76	10096	526	XFR - Terry Co 115/69 kV	regional reliability	11/01/07	06/01/07	02/02/07	$2,375,000	$2,145,926			Both transformer upgrades are complete and in-service
19987	76	10097	526		regional reliability	10/24/08	06/01/07	02/02/07			18 months		Both transformer upgrades are complete and in-service
19986	84	10107	536	Line - Hesston - Golden Plain - Gatz 69 kV Rebuild	regional reliability	08/04/08	06/01/07	02/02/07	$1,617,177	$1,553,395			Mitigation not required if Project completed before 08 Summer Peak. LOA received by Westar 2 February 2007 with required date 1 June 2007. Project Delayed due to ice storm.
19986	84	10108	536	Line - Hesston - Golden Plain - Gatz 69 kV Rebuild	regional reliability	08/04/08	06/01/07	02/02/07					
20006	167	10216	536	Line - Gill Energy Center East - Gill Energy Center Jct 69 kV Rebuild	regional reliability	12/20/08	06/01/08	02/13/08	$1,589,322	$1,987,109	18 months		

19986	174	10223	536	Line - Murry Gill Energy Center - MacArthur 69 kV	regional reliability	06/01/08	06/01/08	02/02/07	$150,000		8 months		
20006	175	10224	536	Line - McDowell Creek - Fort Junction 115 kV	regional reliability	12/15/08	10/01/08	02/13/08	$6,350,667	$6,409,525	10 months		
20006	175	10225	536	Line - McDowell Creek - Fort Junction 115 kV	regional reliability	12/15/08	10/01/08	02/13/08			10 months		
19986	176	10226	536	Line - Dearing - Coffeyville 69 kV Rebuild	regional reliability	12/08/08	06/01/08	02/02/07	$1,226,705	$778,658	7 months		
19986	176	10227	536	Line - Coffeyville - CRA 69 kV Rebuild	regional reliability	12/08/08	06/01/08	02/02/07			7 months		
19986	181	10230	536	XFR - County Line 115/69 kV Replacement	regional reliability	10/30/08	06/01/07	02/02/07	$2,860,000		14 months		
19986	185	10234	536	Multi - Hutchinson 115 kV conversion	zonal reliability	12/01/08	12/31/08	02/02/07	$6,711,881		20 months		Completed per Westar sub regional presentation October 2008
19966	253	10333	536	Line - Jarbalo - 166th Street 115 kV	transmission service	09/18/08	06/01/09	05/29/07	$7,943,430	$3,339,680	18 months		
19965	253	10334	536	Line- 166th - Jaggard Junction 115 kV Rebuild	transmission service	08/31/09	06/01/09	05/29/07	$2,373,030		18 months		5639248; Interim mitigation is implementation of Transmission Operating Directive 800
19965	253	10335	536	Line - Jaggard Junction - Pentagon 115 kV Rebuild	transmission service	12/15/09	06/01/09	05/29/07	$3,168,637		18 months		Interim mitigation is implementation of Transmission Operating Directive 800
20009	197	10252	541	XFR - West Gardner 345/161 kV	regional reliability	06/01/08	06/01/08	02/13/08	$5,000,000	$4,574,216	6 months		Complete
20009	198	10253	541	Line - Antioch - Oxford 161 kV	regional reliability	12/31/08	06/01/08	02/13/08	$2,500,000				Project complete; costs not finalized
20010	207	10263	544	Line - Sub 145 - Joplin West 7th - Sub 341 - Joplin NorthWest 69 kV	regional reliability	06/01/08	06/01/08	02/13/08	$780,000		12 months		
19992	208	10264	544	Line - SUB 167 - RIVERTON - SUB 406 - RIVERTON SOUTH 1	regional reliability	06/01/08	06/01/08	02/02/07	$20,000		6 months		
	605	10774	640	Multi - North Platt 230/115 kV Transformers	regional reliability	04/01/07	06/01/09		$5,801,175				
	605	10775	640	Multi - North Platt 230/115 kV Transformers	regional reliability	06/01/10	06/01/09						Mitigation Plan involves local area re-dispatch to relieve post contingent overloads. GGS generation is reduced while generation at N.Platte, Jeffrey, Johnson and Canaday is increased.
	606	10776	640	Multi - ETR Project	regional reliability	06/01/08	06/01/10		$170,330,000				
	606	10777	640	Multi - ETR Project	regional reliability	01/01/10	06/01/10						
20007	164	10213	534	Line - WEPL Cimarron Plant - North Cimarron 115 kV	regional reliability	10/01/09	06/01/08	02/13/08	$1,350,000				Construction is in progress. Mitigation is to request SPS to adjust the Texas Co Phase Shifter, and adjust generation on the Holcomb and Fort Dodge Plants.
			Year 2009										
	101	10125	515	XFR - Eufaula 161/138 kV	regional reliability - non OATT	10/01/10	04/01/09		$3,000,000				
20012	112	10139	520	Line - Sayre - Erick	regional reliability	02/06/09	06/01/09	07/28/08	$10,400,000		24 months		
20016	30151	50159	520	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	transmission service	04/30/09	06/01/09	01/16/09	$125,000		15 months		Completed 04/30/009
20000	217	10276	520	Line - Tap N. Huntington - Waldron 69 kV	regional reliability	10/20/09	06/01/08	02/13/08	$776,000		15 months		Mitigation Plan: North Huntington - Midland Relief Procedure
20000	218	10277	520	Line - Huntington - N Huntington 69 kV	regional reliability	10/20/09	06/01/09	02/13/08	$20,000		9 months		Need for this project is dependant upon completion of N. Huntington - Waldron (PID 217). This project is still on schedule for completion before N. Huntington - Waldron.
20000	219	10278	520	Line - Excelsior - Excelsior Tap 161 kV	regional reliability	06/30/09	06/01/09	02/13/08	$4,000,000		24 months		Reeves Road station will be built under the existing North Huntington - Bonanza 161kV line. This project will replace the Excelsior Tap project.
19954	220	10279	520	Line - Riverside Station - Explorer Glenpool 138 kV Ckt 1	transmission service	03/23/09	06/01/09	07/21/06	$1,000,000		24 months		3.3% BPF. Remainder of RR paid by PTP base rate
20000	221	10280	520	Line - Hope - Fulton 115 kV	regional reliability	03/31/09	06/01/09	02/13/08	$100,000		15 months		Completed on 03/31/09
20027	222	10281	520	Line - Bonanza - Bonanza Tap 161 kV	regional reliability	11/30/09	06/01/10	01/27/09	$594,000		15 months		
19956	224	10283	520	XFR - Southwest Shreveport Transformer Ckt 1 345/161 kV	transmission service	04/03/09	06/01/10	06/27/07	$6,873,000		30 months		Completed on 04/03/09
19956	224	10284	520	XFR - Southwest Shreveport Transformer Ckt 2 345/161 kV	transmission service	04/03/09	06/01/10	06/27/07			30 months		Completed on 04/03/09
20000	225	10286	520	Line - North Magazine - Magazine REC - Danville 161 kV	regional reliability	06/17/09	06/01/09	02/13/08	$13,705,000		24 months		
20000	225	10289	520	Line - North Magazine - Magazine REC - Danville 161 kV	regional reliability	06/17/09	06/01/09	02/13/08	$6,090,000		24 months		
20000	113	10745	520	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	regional reliability	06/01/09	06/01/12	02/13/08	$2,580,000		24 months		Could not locate NTC. Perhaps SPP added UIDs to capture new branches created due to new busses added to branch that had a previous NTC ??? SPP please confirm. SPP Coments: These projects didn't get an NTC but the project was modified and agreed to by SPP and AEP in the 2008 STEP process.
20000	113	10746	520	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	regional reliability	06/01/09	06/01/12	02/13/08	$4,460,000		24 months		Could not locate NTC. Perhaps SPP added UIDs to capture new branches created due to new busses added to branch that had a previous NTC ??? SPP please confirm. SPP Coments: These projects didn't get an NTC but the project was modified and agreed to by SPP and AEP in the 2008 STEP process.
20000	229	10292	520	Multi - Flint Creek - E Centerton 161 kV	regional reliability	05/19/09	06/01/11	02/13/08	$14,200,000		24 months		Completed on 05/19/09
20000	229	10293	520	Multi - Flint Creek - E Centerton 161 kV	regional reliability	05/19/09	06/01/13	02/13/08			24 months		Completed on 05/19/09
20000	229	10294	520	Multi - Flint Creek - E Centerton 161 kV	regional reliability	06/01/10	06/01/13	02/13/08			24 months		
20000	230	10295	520	Line - Broken Bow - Craig Junction 138 kV	regional reliability	05/08/09	06/01/08	02/13/08	$6,602,000		18 months		
20005	177	10728	520	Line - Atoka 138 kV Three Breaker Ring Bus & Relay Work at Tupelo	regional reliability	11/30/09	06/01/12	02/20/08	$2,887,800		12 months		Add to pick up AEP breaker work
20005	177	10729	520	Line - Atoka 138 kV Three Breaker Ring Bus & Relay Work at Tupelo	regional reliability	11/30/09	06/01/12	02/20/08	$442,800		12 months		Added to pick up AEP relay work
	695	10911	520	Line- Canadian Pump Station line tap	sponsored	03/20/09			$1,616,000		10 months		Completed 03/20/09
	695	10912	520	Line- Canadian Pump Station line tap	sponsored	03/20/09					10 months		Completed 03/20/09
			520	Line - Bransdall Pump Station Tap	sponsored	12/31/09			$4,450,000		15 months		New Planned Project by AEP Too late to put in 2008 STEP
			520	Line - Bransdall Pump Station Tap	sponsored	12/31/09					15 months		New Planned Project by AEP Too late to put in 2008 STEP

20028	233	10298	523	XFR - Claremore 161/69 kV autos 1 and 2	regional reliability	06/01/09	06/01/09	01/27/09	$7,200,000		24 months		It has been identified that the CBs in this station need to converted from oil to gas to meet enviormental requirements. 11 CBs will need to be replaced.
19996	52	10070	524	Line - Stillwater - McElroy 138 kV	regional reliability	02/27/09	05/31/08	02/01/07	$1,758,527	$2,067,530	18 months		COMPLETE
20029	583	10749	524	Multi VBI-Adabell 161 kV	regional reliability	03/31/12	06/01/12	01/27/09	$200,000		12 months		Project delayed - NTC date will be honored
19960	234	10299	524	Line - Explorer Glenpool - Beeline 138 kV Ckt 1	transmission service	06/01/09	06/01/09	07/21/06	$200,000	$310,000			3.3% BPF. Remainder of RR paid by PTP base rate - COMPLETE
20002	236	10301	524	Line - Alva - Knobhill 69 kV	regional reliability	06/01/09	06/01/09	02/13/08	$35,000	$26,000	6 months		COMPLETE
19960	237	10302	524	Line - Explorer Glenpool - Riverside Station138 kV Ckt 1	transmission service	06/01/09	06/01/09	07/21/06	$400,000	$660,000			3.3% BPF. Remainder of RR paid by PTP base rate - COMPLETE
20029	584	10751	524	Line-Cleo Corner-Cleo Jct 69 kV	regional reliability	12/01/09	12/01/09	01/27/09	$250,000		6 months		
	126	10159	524	Line - Maud - Seminole 138kV	sponsored	05/01/09			$326,346	$240,000			An SPP Flowgate. Project will be complete 5/1/2009. COMPLETE
	67	10085	524	Line - Igo - Razorback 69 kV	sponsored	06/30/09			$5,939,246				COMPLETE as of 6/25/09 All charges have not yet been credited to project.
	123	10153	524	Multi - Earlywine	sponsored	06/01/09			$12,900,000	$9,500,000			TO Zonal/local upgrade. Not for SPP reliability. COMPLETE
	123	10154	524	Multi - Earlywine	sponsored	06/01/09							TO Zonal/local upgrade. Not for SPP reliability. COMPLETE
	123	10155	524	Multi - Earlywine	sponsored	06/01/09							TO Zonal/local upgrade. Not for SPP reliability. COMPLETE
	123	10156	524	Multi - Earlywine	sponsored	06/01/09							TO Zonal/local upgrade. Not for SPP reliability. COMPLETE
	582	10747	524	Multi - Arcadia Tap	sponsored	06/01/11			$1,200,000				Project delayed due to lower load growth
	582	10748	524	Multi - Arcadia Tap	sponsored	06/01/11							Project delayed due to lower load growth
	56	10074	524	Line - Chitwood - Garber 138 kV	sponsored	12/31/09			$5,920,226				Presently under construction.
	304	10731	524	Multi - Johnson County Project	sponsored	06/01/11			$32,975,000				Multi-upgrade project for new arc furnance near Arbuckle (on upgrade in device tab - Cap bank at Madill)
	304	10732	524	Multi - Johnson County Project	sponsored	06/01/11							
	304	10733	524	Multi - Johnson County Project	sponsored	06/01/11							
	304	10734	524	Multi - Johnson County Project	sponsored	06/01/11							
	304	10735	524	Multi - Johnson County Project	sponsored	06/01/11							
	304	10736	524	Multi - Johnson County Project	sponsored	12/01/10							
	304	10737	524	Multi - Johnson County Project	sponsored	06/01/10							
20030	585	10752	525	Line-Buffalo-FT Supply CKT 1	regional reliability	04/01/09	04/01/09	01/27/09	$150,000		8 months		
20003	142	10181	525	Line - Little Axe - Noble 69 kV	regional reliability	06/01/09	04/01/09	02/13/08	$2,640,000		16 months		
20003	132	10166	525	Line - Anadarko - Cyril 69 kV	regional reliability	06/01/09	04/01/09	02/13/08	$3,120,000		16 months		
19985	140	10179	525	Line - ACME - W Norman 69 kV	regional reliability	06/01/10	06/01/08	02/02/07	$912,000		8 months		Mitigation Plan under review by SPP. Defered in latest SPP Transmission Expansion Plan.
20003	138	10176	525	Line - OGE Woodword - WFEC Woodword 69 kV	regional reliability	06/01/09	04/01/09	02/13/08	$1,050,000		10 months		Mitigation: Temporary Op Guide provided.
20003	238	10303	525	Line - Atoka - WFEC Tupelo - Lane 138 kV	regional reliability	06/01/09	06/01/12	02/13/08	$8,265,000		12 months		AEP's station cost is $1.665M. WFEC's construction cost is $6.6M. An interconnection agreement has been executed between WFEC and AEP.
20003	238	10304	525	Line - Atoka - WFEC Tupelo - Lane 138 kV	regional reliability	06/01/09	06/01/12	02/13/08			12 months		
20030	586	10753	525	Line-Burlington-Cherokee SW 69 kV CT	regional reliability	04/01/09	04/01/09	01/27/09	$150,000		8 months		
20003	240	10306	525	Line - Cyril to Medicine Park Jct 69 kV	regional reliability	06/01/09	06/01/09	02/13/08	$750,000		16 months		
20003	241	10307	525	Line - Anadarko - Georgia Tap 138 kV	regional reliability	06/01/10	06/01/09	02/13/08	$1,124,000		12 months		Mitigation: Temporary Op Guide provided.
20003	242	10308	525	Line - Elmore - Paoli 69 kV	regional reliability	06/01/10	06/01/09	02/13/08	$3,240,000		12 months		Mitigation: Temporary Op Guide provided.
20003	243	10309	525	Multi - OU SW - Goldsby - Canadian SW 138 kV	regional reliability	06/01/10	06/01/09	02/13/08	$2,753,800		16 months		Mitigation: Temporary Op Guide provided.
20003	243	10310	525	Multi - OU SW - Goldsby - Canadian SW 138 kV	regional reliability	06/01/10	06/01/09	02/13/08	$2,250,000		16 months		Mitigation: Temporary Op Guide provided.
20003	243	10311	525	Multi - OU SW - Goldsby - Canadian SW 138 kV	regional reliability	06/01/10	06/01/09	02/13/08	$5,000,000		16 months		Mitigation: Temporary Op Guide provided.
20003	403	10525	525	XFR - Comanche 138/69 kV Transformer	regional reliability	06/01/09	06/01/12	02/13/08	$210,000		24 months		
20030	587	10754	525	Line - IODINE - MOORELAND 138KV CKT 1	regional reliability	04/01/09	04/01/09	01/27/09	$150,000		8 months		
20030	588	10755	525	Line - MOORELAND - MOREWOOD SW 138KV CKT 1	regional reliability	04/01/09	04/01/09	01/27/09	$150,000		6 months		Update 10/9/08: Moorlend to Moorewood CT good for 600A, 143MVA
20003	356	10466	525	Line - Medicine Park Jct - Fletcher 69 kV	regional reliability	06/01/09	06/01/11	02/13/08	$1,230,000		16 months		
20003	361	10471	525	Line - Fletcher - Marlow Jct 69 kV	regional reliability	06/01/11	06/01/11	02/13/08	$2,000,000		16 months		
20030	589	10756	525	Line-Grandfield-Hollister 69 kV	regional reliability	06/01/09	06/01/09	01/27/09	$150,000		8 months		
20004	159	10206	526	Line - Plant X Station - Tolk Station West 230 kV	regional reliability	12/31/09	04/01/09	02/13/08	$56,000		6 months		Only mititigation would depend on manual switching so this project needs to be done instead.
20004	246	10314	526	Multi - Nichols - Whitaker Sub 115kV; Nichols - Cherry 115 kV	regional reliability	12/31/09	06/01/09	02/13/08	$5,000		6 months		SPP STEP study results indicate this terminal upgrade is needed before the 2017 summer peak without any overload occurences in any of the models before then.
20004	246	10315	526	Multi - Nichols - Whitaker Sub 115kV; Nichols - Cherry 115 kV	regional reliability	12/31/09	06/01/09	02/13/08			6 months		SPP STEP study results indicate this terminal upgrade is needed before the 2017 summer peak without any overload occurences in any of the models before then.
19987	162	10210	526	XFR - Lubbock East 115/69 kV	regional reliability	11/20/09	06/01/07	02/02/07	$1,300,000		18 months		Mitigation Plan verified by SPP staff. Transformer delivery from manufacturer has been later than expected. Cannot take the necessary outages until fall/winter 2009.
19987	162	10211	526	XFR - Lubbock East 115/69 kV	regional reliability	12/18/09	06/01/07	02/02/07	$1,300,000		18 months		Cannot take necessary outages until fall/winter 2009

20031	590	10757	526	Line - Ocotillo sub conversion 115 kV	regional reliability	06/01/11	06/01/09	01/27/09	$1,222,843		24 months		kV transformer for the outage of the parallel transformer, start the Carlsbad GT. Shed load to mitigate overload while Carlsbad generation brought on line, if necessary.
20004	249	10320	526	Multi - Seven Rivers - Pecos - Potash 230 kV	regional reliability	06/12/09	06/01/09	02/13/08	$15,891,640		30 months		Project in-service as of 6/12/2009
20004	249	10321	526	Multi - Seven Rivers - Pecos - Potash 230 kV	regional reliability	06/12/09	06/01/09	02/13/08			30 months		Project in-service as of 6/12/2009
20004	249	10322	526	Multi - Seven Rivers - Pecos - Potash 230 kV	regional reliability	06/12/09	06/01/09	02/13/08			30 months		Project in-service as of 6/12/2009
19987	250	10323	526	XFR - Cochran 115/69 kV	regional reliability	12/31/09	06/01/08	02/02/07	$2,750,000		18months		Mitigation Plan verified by SPP staff. Outage restrictions until winter 2009
19987	250	10324	526		regional reliability	12/31/09	06/01/08	02/02/07			18 months		
20004	146	10185	526	Multi - Seminole - Hobbs Project 230 kV	regional reliability	04/01/11	06/01/08	02/13/08	$8,762,733		36 months		Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012.
20004	146	10187	526	Multi - Seminole - Hobbs Project 230 kV	regional reliability	07/03/09	06/01/08	02/13/08	$7,715,262		24 months		Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. First 230/115 kV - 150 MVA is in place and expected to be in-serviced by 7/3/2009.
20004	146	10188	526	Multi - Seminole - Hobbs Project 230 kV	regional reliability	12/31/09	06/01/08	02/13/08			24 months		Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. Second 230/115 kV - 150 MVA is expected to be in-service by 12/31/2009.
20004	146	10189	526	Multi - Seminole - Hobbs Project 230 kV	regional reliability	08/14/09	06/01/08	02/13/08	$3,891,288		24 months		Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. Gaines to Seminole 115 kV.
20004	146	10190	526	Multi - Seminole - Hobbs Project 230 kV	regional reliability	07/17/09	06/01/08	02/13/08			24 months		Project is not behind schedule: Loads have been swapped as part of the interim mitigation. This delays the need for the project until 6/1/2012. Hess to Seminole 115 kV
20004	146	10186	526	Multi - Seminole - Hobbs Project 230 kV	regional reliability	06/01/15	06/01/08	02/13/08	$8,920,699		48 months		230 kv from Hobbs to Seminole is currently in suspension due to the lack of need. Customer load has been greatly lowered, reducing need for line. Project will be accelerated, if load projections show need.
20031	252	10332	526	XFR - Yoakum County Interchange 230/115 kV	regional reliability	11/20/09	06/01/09	01/27/09	$802,084		24 months		The project was modified to only add a 2nd 230/115 kV transformer to avoid future overloads. Completion is by 12/01/2009. Interim SPS mitigation was verified by SPP staff.
20004	155	10199	526	XFR - Nichols 230/115 kV	regional reliability	10/01/09	06/01/11	02/13/08	$6,000,000		24 months		First transformer is replaced and in-service. The second transformer will not be replaced and in-service until Fall.
19987	157	10202	526	XFR - Hale Co 115/69 kV	regional reliability	12/04/09	06/01/07	02/02/07	$2,900,000		18 months		Mitigation Plan verified by SPP staff. Per project tracking info in this project list, these projects should be complete by 3/13/09.
19987	157	10203	526		regional reliability	12/31/09	06/01/07	02/02/07			18 months		
	591	10758	526	Line Roz3 - Amerada Hess Co2 115 kV	sponsored	08/03/09							
	592	10759	526	Line - Roz3 - Seminole 115 kV	sponsored	08/03/09							
	593	10760	526	Line - Denver City - seminole 115 kV	sponsored	08/03/09							
	594	10761	526	Line - Seminole - Doss Interchange 115 kV	sponsored	08/03/09							
	595	10762	527	Line - Ompvet - Ompark - 4 138 kV	sponsored	07/15/09			$1,946,000				delayed due to lack of TELCO service
	596	10763	527	Line - Ompvet - OmAltus - 4 138 kV	sponsored	06/05/09			$1,094,000				Complete
	597	10764	527	Line - Altus Junction Ompark - 4 138 kV	sponsored	06/26/09			$1,174,552				delayed due to lack of TELCO service
	598	10765	527	Line-Tamarack Tap-OmAltus-4 138 kV	sponsored	07/31/09			$586,250				delayed due to lack of TELCO service
20007	166	10215	534	Line - Holcomb - Plymell 115 kV	regional reliability	12/31/09	06/01/08	02/13/08	$3,650,000		18 months		Review of the Line design is in progress, and matarial procurement is in progress. Mitigation is to reduce generation in area 534 and increase in area 539 as needed to relive overload.
20014	367	10480	534	Line - Plymell - Pioneer Tap 115 kV	regional reliability	12/31/09	06/01/09	09/18/08	$3,200,000		24 months		Review of the Line design is in progress, and matarial procurement is in progress. Mitigation is to reduce generation in area 534 and increase in area 539 as needed to relive overload.
	165	10214	534	Line - Phillipsburg - Rhoades 115 kV Ckt 1	sponsored	12/31/09			$10,500,000				Construction is in progress.
20006	265	10348	536	XFR - Stranger Creek 345/115 #2 Addition	regional reliability	09/01/09	06/01/09	02/13/08	$8,300,000		24 months		Transformer will be in service prior to summer peak load conditions.
20033	266	10349	536	Line - Circle - HEC GT 115 kV Rebuild	regional reliability	06/01/11	06/01/11	01/27/09	$710,000		18 months		Interim mitigation is redipatch of HEC GT units.
19986	180	10229	536	Line - Stranger Creek - Thornton Street 115 kV Addition	regional reliability	12/01/09	06/01/07	02/02/07	$9,675,000		12 months		Interim mitigation is implementation of Transmission Operating Directive 1216; Project delay is due to routing difficulties at Stranger Creek substation taking into account the addition of the 2nd 345-115 kV transformer in 2009; Current line cost estimate is $2,875,000
20006	179	10228	536	Line - Summit - NE Saline 115 kV	regional reliability	12/01/09	06/01/09	02/13/08	$6,819,380		18 months		Project is modified: Rebuild Summit-Northview 115 kV , in-service date 6/1/2009,$ 6,819,380 Build Summit-Southgate 115 kV; Remove Northview-Southgate 115 kV; Work will be performed when extensive crews are completing Reno County-Summit 345 kV work; Cost for substation work is $1.2 million.
20006	323	10419	536	Line - West McPherson - Wheatland 115 kV	regional reliability	03/01/09	06/01/10	02/13/08	$3,949,405		12 months		Terminal upgrades at Wheatland complete
20006	260	10343	536	Line - Reno - Circle 115 kV Ckt 1	regional reliability	03/01/09	06/01/09	02/13/08	$4,056,582		18 months		Rebuild will be done as part of Wichita - Reno County 345 kV; Reviewing the connections of the Reno County - Circle 115 kV lines
20006	170	10219	536	Line - Fort Junction - Anzio 115 kV	regional reliability	06/01/10	06/01/08	02/13/08	$3,639,327		6 months		Increase generation at McPherson and Hutchinson to relieve overloading Transmisson Operating Directive 1217

	262	10345	536	Line - Reno County-Summit 345 kV ckt 1	sponsored	06/01/10			$100,618,016		24 months		Project costs include rebuilding of 115 kV and 230 kV underlying system on same ROW
	262	10346	536	XFR - Reno County 345/115 kV #2	sponsored	10/01/09					24 months		
20034	650	10854	540	Multi - South Harper 161 kV cut-in to Stilwell-Archie Junction 161 kV line	regional reliability	06/01/11	06/01/09	01/27/09	$2,259,673		18 months		mitigation plan is to reduce South Harper generation to eliminate contingent overloads
20034	601	10768	540	Multi - Grandview East - Sampson - Longview 161kV lines	regional reliability	06/01/10	06/01/09	01/27/09	$50,000		6 months		Grandview East wavetraps upgrades completed; mitigation plan is to increase Greenwood generation to eliminate contingent overloads
20034	602	10771	540	Line - Glenare - Liberty 69 kV	regional reliability	10/01/09	06/01/09	01/27/09	$80,000		6 months		Only mitigation to eliminate criteria violation is to shed load. Plan to complete the project by the required in-service-date. No mitigation plan is needed by then.
	195	10249	540	Line - Pope Lane to Smithville 161kV	sponsored	01/01/09			$4,550,000		12~18 months		Complete; costs not finalized
	275	10359	540	Multi - 161kV Tap of Platte City to Stranger Creek	generation interconnect	12/31/09			$7,127,000		12~18 months		Project under construction
	275	10360	540	Multi - 161kV Tap of Platte City to Stranger Creek	generation interconnect	12/31/09					12~18 months		Project under construction
19967	280	10364	541	Line - College - Craig 161 kV	transmission service	11/01/09	06/01/11	05/31/07	$1,193,400		24 months		Actually originally assigned to EDE Iatan TSR needed 6/1/16 but displaced to 6/1/11 for 2 SPSM PTP request resold to KCPL not BPF; reconductor complete, terminal equipment upgrades delayed till fall
	199	10254	541	Multi - Lackman Sub	sponsored	05/29/09			$138,200		6 months		Major construction work is complete; waiting on phone line for SCADA
	199	10255	541	Multi - Lackman Sub	sponsored	05/29/09							Major construction work is complete; waiting on phone line for SCADA
	200	10256	541	Line - Terrace - Westside 161 kV	sponsored	09/30/10			$4,352,600		10 months		Project delayed by easement issues; estimate 4th quarter 2010 completion
	201	10257	541	Line - Crosstown - Midtown 161 kV	sponsored	03/30/10			$4,750,000				Project delayed by easement issues; estimate 1st quarter 2010 completion
	279	10363	541	Line - Craig - Lenexa 161 kV	sponsored	06/01/10			$192,000		6 months		
20036	440	10571	544	Line - Diamond Jct - Sarcoxie SW 69 kV	regional reliability		06/01/09	01/27/09	$2,274,000		18 months		Line segment uprated (New Summer Rate A/B: 32/41 MVA) due to special case study on limiting element in question. New need date identified as Summer 2013.
19992	209	10265	544	Multi - Riverdale - Ozarks 161 kV Ckt 1	regional reliability	12/01/09	06/01/10	02/02/07	$14,057,000		30 months		Project completion delayed due to construction delays. New in-service date of 12/1/2009.
19992	209	10266	544		regional reliability	12/01/09	06/01/10	02/02/07					
19992	209	10267	544		regional reliability	12/01/09	06/01/10	02/02/07					
19992	209	10268	544		regional reliability	12/01/09	06/01/10	02/02/07					
20010	282	10366	544	Line - Sub 389-Joplin Southwest - Sub 422-Joplin 24th & Connecticut 161 kV	regional reliability	06/01/09	06/01/09	02/13/08	$5,000		6 months		
	603	10772	640	Line - NPPD / WERE - Steele City - Kansas Border 115 kV	regional reliability	06/01/10	06/01/09		$2,200,000		48 months		Coordinated with WERE on Knob Hill - State Line
	604	10773	640	Grand Island 345/230 kV Transformer	regional reliability	07/01/09	07/01/09		$6,950,971				JH - Need date changed to come in line with previous Nebraska planning.
	607	10778	640	Bloomfield Wind Generation Interconnection, Delivery & Facilities	regional reliability	03/01/09	03/01/09		$5,500,000				Complete - In-Service
	608	10779	645	Build New 161 kV Substation Sub 1305	regional reliability	05/22/09	12/01/09		$21,600,000				Change Project Name to "Build New 161 KV Substation Sub 1305"
	608	10919	645	Line - Sub 1251 - Sub 1305 161 kV	regional reliability	05/22/09	12/01/09						
	608	10920	645	Line - Sub 1298 - Sub 1305 161 kV	regional reliability	05/22/09	12/01/09						
	608	10921	645	Line - Sub 1251 - Sub 1298 161 kV	regional reliability	05/22/09	12/01/09						
	608	10922	645	Line - Sub 1226 - Sub 1298 161 kV	regional reliability	05/22/09	12/01/09						
			645	Line - Rebuild Sub 1209 - Sub 1252 161 kV	sponsored	12/31/09			$4,500,000				The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.
			Year 2010										
	283	10367	330	Multi - Blackberry - Chouteau - GRDA 1	regional reliability - non OATT	06/01/10			$57,000,000				
	283	10368	330	Multi - Blackberry - Chouteau - GRDA 1	regional reliability - non OATT	02/01/11							
	283	10369	330	Multi - Blackberry - Chouteau - GRDA 1	regional reliability - non OATT	02/01/11							
	283	10916	330	Multi - Blackberry - Chouteau - GRDA 1	regional reliability - non OATT	02/01/11							
	283	10781	330	Multi - Blackberry - Chouteau - GRDA 1	regional reliability - non OATT	02/01/11							Chouteau 2 Sub estimated completion date is 04/01/10
	610	10782	330	Line - Camp Clark - Lamar 161 kV	regional reliability - non OATT	06/01/10							
	611	10783	330	XFR - Lamar 69/161 kV	regional reliability - non OATT	06/01/10							
20016	507	10652	520	ARSENAL HILL - FORT HUMBUG 138KV CKT 1	transmission service	06/01/10	06/01/10	01/16/09	$5,428,300		18 months		Full BPF Displacement filing needed at FERC
20016	30149	50157	520	DYESS - TONTITOWN 161KV CKT 1	transmission service	06/01/10	06/01/10	01/16/09	$276,000		15 months		Full BPF
20016	30147	50155	520	ARSENAL HILL (ARSHILL2) 138/69/14.5KV TRANSFORMER CKT 2	transmission service	06/01/10	06/01/10	01/16/09	$3,005,700		18 months		Full BFP
20016	30146	50154	520	ARSENAL HILL (ARSHILL1) 138/69/12.47KV TRANSFORMER CKT 1	transmission service	06/01/10	06/01/10	01/16/09	$3,005,700		18 months		Full BFP

20016	30145	50153	520	ARSENAL HILL - WATERWORKS 69KV CKT 1	transmission service	05/19/09	06/01/10	01/16/09	$3,898,800		18 months		Full BFP
20016	30144	50152	520	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1	transmission service	05/06/09	06/01/10	01/16/09	$100,000		12 months		Full BPF Displacement filing needed at FERC. Completed
20016	30153	50161	520	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	transmission service	06/01/10	06/01/10	01/16/09	$200,000				
20000	113	10140	520	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	regional reliability	06/01/10	06/01/12	02/13/08	$9,480,000		24 months		
20000	113	10786	520	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	regional reliability	06/01/10	06/01/12	02/13/08	$13,380,000		24 months		
20000	113	10143	520	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	regional reliability	05/09/08	06/01/12	02/13/08	$3,000,000		24 months		
20000	113	10141	520	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	regional reliability	06/01/10	06/01/12	02/13/08	$19,482,000		24 months		
19959	289	10375	520	Line - Clinton City Wave Trap	transmission service	06/01/10	06/01/10	10/17/06	$122,000		9 months		
20016	291	10377	520	Line - Bann - Lonestar Ordinance Tap 69 kV	transmission service	06/01/10	06/01/12	01/16/09	$25,000		6 months		
20000	294	10380	520	Line - North Mineola - Mineola 69 kV	regional reliability	06/01/10	06/01/10	02/13/08	$350,000		15 months		
19953	295	10381	520	Line - Coffeyville Tap - Dearing - 138 kV	transmission service	06/01/10	06/01/10	06/26/07	$1,008,000		24 months		Displacement need to make filing for displacement $
20000	297	10383	520	Line - Quitman - Westwood 69 kV	regional reliability	06/01/10	06/01/10	02/13/08	$3,827,000		24 months		
20016	296	10382	520	Line - Dyess - Elm Springs REC 161 kV CKT 1 #2	transmission service	06/01/10	06/01/10	01/16/09	$6,252,000		24 months		Switch replacement, not a reconductor, is needed in 2008.
20027	613	10784	520	Line - Diana-Lone Star South 138 kV	regional reliability	12/01/10	12/01/10	01/27/09	$100,000		12 months		
20027	449	10581	520	Line - Carthage - Rock Hill 69 kV	regional reliability	06/01/10	06/01/10	01/27/09	$50,000		9 months		
20027	480	10617	520	Line - Snyder - Snyder 138kV	regional reliability	12/31/10	06/01/09	01/27/09	$800,000		24 months		WFEC to supply mitigation plan
20027	292	10378	520	Line - Greggton - Lake Lamond 69 kV	regional reliability	06/01/10	06/01/11	01/27/09	$1,496,000		24 months		
	231	10296	520	Line - Turk - SE Texarkana - 138 kV	generation interconnect	12/31/10			$25,590,000		48 months		
	232	10297	520	Line - Turk - Sugar Hill 138 kV	generation interconnect	12/31/10			$18,427,000		48 months		
	216	10275	520	Line - Ben Wheeler - Barton's Chapel (Rayburn) 138 kV Ckt 1	regional reliability - non OATT	06/01/10					18 months		Rayburn Country Project.
20021	299	10385	523	Multi-Kansas Tap - Siloam City 161KV	regional reliability	06/01/10	06/01/12	01/16/09	$4,212,500		24 months		
20021	299	10386	523	Multi-Kansas Tap - Siloam City 161KV	regional reliability	06/01/10	06/01/12	01/16/09	$1,700,000		24 months		
20001	300	10387	523	Line - Kerr - 412 Sub 161 kV Rebuild	regional reliability	06/01/10	06/01/10	02/13/08	$950,000		24 months		
20001	301	10388	523	XFR - Sallisaw 161/69 kV Auto #2	regional reliability	06/01/10	06/01/08	02/13/08	$3,000,000		24 months		
	302	10389	523	Line - Slioam Springs Tap - Siloam City	sponsored	06/01/10			$3,210,200		24 months		
20029	615	10792	524	Multi: Dover-Twin Lake-Crescent-Cottonwood conversion 138 kV	regional reliability	06/01/11	06/01/10	01/27/09	$1,074,000		18 months		conversion until WFEC is complete with their line. MITIGATION: Transfer all OG&E's Turkey Creek load to OG&E's Hennessey 138-12.5 kV Substation. This eliminates the need to address the voltage drop for the loss of the WFEC Dover
20029	615	10793	524	Multi: Dover-Twin Lake-Crescent-Cottonwood conversion 138 kV	regional reliability	06/01/11	06/01/10	01/27/09	$4,330,250		18 months		conversion until WFEC is complete with their line. MITIGATION: Transfer all OG&E's Turkey Creek load to OG&E's Hennessey 138-12.5 kV Substation. This eliminates the need to address the voltage drop for the loss of the WFEC Dover
	614	10787	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10							
	614	10915	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10							
	614	10788	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10							
	614	10789	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10			$218,000,000				
	614	10790	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10							
	614	10791	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10							
	614	10913	524	Multi- Northwest-Woodward 345 kV	sponsored	03/30/10							
	310	10391	524	Line - Fitzhugh - Helberg 161 kV	sponsored	06/01/10			$1,416,000				
	310	10392	524	Line - Great Lakes Carbon - Altus 161 kV	sponsored	12/31/10			$543,000				
	310	10393	524	Line - Altus - Fitzhugh 161 kV	sponsored	12/31/10			$660,000				
	310	10394	524	Line - Igo - Noark 161 kV	sponsored	12/31/10			$2,994,000				
	310	10395	524	Line - Little Spadra - Igo 161 kV	sponsored	06/01/10			$2,112,000				
	310	10396	524	Line - Noark - Great Lakes Carbon 161 kV	sponsored	12/31/10			$522,000				
	309	10397	524	Line - Park Lane - Ahloso Tap 69 kV	sponsored	06/01/10			$50,000				
	310	10398	524	Line - Razorback - Igo 161 kV	sponsored	06/01/10			$2,973,000				
	310	10399	524	Line - Razorback - Short Mountain 161 kV	sponsored	06/01/10			$500,000				
	310	10400	524	Line - Short Mountain - Branch 161 kV	sponsored	06/01/10			$3,231,000				
20030	239	10305	525	Line - WFEC Snyder - AEP Snyder	regional reliability	12/31/10	06/01/09	01/27/09	$3,373,000		16 months		Mitigation: Temporary Op Guide provided.
20003	136	10174	525	Line - Meeker - Hammett 138 kV	regional reliability	06/01/10	06/01/08	02/13/08	$6,674,000		10 months		Mitigation: Temporary Op Guide provided.

20003	137	10175	525	Line - Wakita - Hazelton 69 kV	regional reliability	06/01/10	04/01/09	02/13/08	$5,378,750		10 months		Mitigation: Temporary Op Guide provided.
20003	311	10401	525	Multi - Franklin SW - Acme - Norman - OU SW Conversion 138 kV	regional reliability	06/01/10	06/01/10	02/13/08	$2,065,000		12 months		
20003	311	10402	525	Multi - Franklin SW - Acme - Norman - OU SW Conversion 138 kV	regional reliability	06/01/10	06/01/10	02/13/08	$1,601,000		12 months		
20003	311	10403	525	Multi - Franklin SW - Acme - Norman - OU SW Conversion 138 kV	regional reliability	06/01/10	06/01/10	02/13/08	$1,577,000		12 months		
20030	616	10794	525	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	regional reliability	06/01/10	06/01/10	01/27/09	$5,765,600		24 months		
20030	616	10795	525	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	regional reliability	06/01/10	06/01/10	01/27/09	$5,315,700		24 months		
20030	616	10796	525	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	regional reliability	06/01/10	06/01/10	01/27/09	$3,164,000		24 months		
20030	616	10797	525	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	regional reliability	06/01/10	06/01/10	01/27/09	$3,937,500		24 months		
20030	617	10798	525	Line - Carter Jct-Lake Creek 69 kV	regional reliability	06/01/10	06/01/10	01/27/09	$150,000		8 months		
20030	135	10799	525	Multi: Lindsay - Lindsay SW and Bradley-Rush Springs lines	regional reliability	06/01/10	06/01/10	01/27/09	$1,248,750		24 months		
20030	135	10173	525	Multi - Lindsay - Lindsay SW and Bradley-Rush Springs	regional reliability	06/01/10	06/01/10	01/27/09	$2,328,750		24 months		Deferred in 2007 Expansion Plan. Cancelled by BOD in July 2008. Determined as needed in 2008 Expansion Plan.
20031	144	10183	526	Line - Curry County - North Clovis Conversion	regional reliability	06/01/10	06/01/10	01/27/09	$200,000		24 months		Approved in 2008 budget. Replacement for upgrade of Curry autos. Requires changeout of 69 kV dist transformer to 115 kV. No mitigation needed if built by 6/1/10.
20004	248	10317	526		regional reliability	06/01/10	06/01/09	02/13/08			30 months		The earliest that any portion of the Wheeler County Interchange project can be in-service will be 6/1/2010. NTC should be modified to show the tap of the 230 kV line.
20004	248	10318	526	Multi - Wheeler County Project - Tap 230 kV line - Two new XFs - new 115 kV line	regional reliability	06/01/10	06/01/09	02/13/08	$10,585,000		30 months		The earliest that any portion of the Wheeler County Interchange project can be in-service will be 6/1/2010. NTC should be modified to show the tap of the 230 kV line.
20004	248	10319	526		regional reliability	06/01/10	06/01/09	02/13/08			30 months		The earliest that any portion of the Wheeler County Interchange project can be in-service will be 6/1/2010. NTC should be modified to show the tap of the 230 kV line.
20031	156	10326	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	12/31/10	06/01/10	01/27/09	$16,094,371		48 months		Same as provided last year with load shed being the greatest measure of mitigating low voltages and overloads for the worst contingencies. Hitchland to Moore County 230 kv Transmission Project.
20004	156	10327	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/10	04/01/09	02/13/08	$12,577,500		24 months		This large project is underway and portions of this project will be complete after the Summer of 2009. Add 345/230 kV - 560 MVA transformer at Hitchland.
20004	156	10328	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/10	06/01/09	02/13/08	$15,848,000		48 months		This large project is underway and portions of this project will be complete after the Summer of 2009. 115 kV from Hitchland to Sherman Tap.
20004	156	10329	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/10	06/01/09	02/13/08	$10,771,825		48 months		The correction idev made this line from Sherman to Dallam instead of Sherman to Dalhart. This large project is underway and portions of this project will be complete after the Summer of 2009. Dallam to Sherman 115 kv project.
20004	156	10330	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/11	06/01/09	02/13/08	$10,766,250		48 months		This large project is underway and portions of this project will be complete after the Summer of 2009. Hitchland to Ochiltree 230 kV project.
20004	156	10331	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/11	06/01/09	02/13/08	$5,846,295		24 months		This large project is underway and portions of this project will be complete after the Summer of 2009. Ochiltree Sub 230/115 kV transformer.
20004	156	10200	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/10	06/01/08	02/13/08	$5,132,829		24 months		This large project is underway and portions of this project will be complete after the Summer of 2009. Hitchland to Texas Co. 115 kV cutin.
20004	156	10201	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	regional reliability	06/01/10	06/01/09	02/13/08	$31,915,701		24 months		This large project is underway and portions of this project will be complete after the Summer of 2009.
20004	156	10325	526	Multi - Hitchland - Texas Co. 230 kV and 115 kV	sponsored	06/01/11		02/13/08	$11,922,643				This large project is underway and portions of this project will be complete after the Summer of 2009. Hitchland to Pringle 230 kV transmission project.
20031	554	10704	526	Multi: Dallam - Channing - Tascosa - Northwest Lines	regional reliability	12/31/10	06/01/09	01/27/09			30 months		no backup for the 69 kV service at Channing and Tacsosa. Any contingency on this radial line will remove load from the system. Therefore, no mitigations
20031	554	10705	526	Multi - Dallam - Channing - Tascosa - Northwest lines	regional reliability	12/31/10	06/01/09	01/27/09	$27,452,677		30 months		there is no backup for the 69 kV service at Channing and Tacsosa. Any contingency on this radial line will remove load from the system. Therefore, no mitigations. Tascosa to NW sub 115 kV project.
20031	554	10706	526	Multi - Dallam - Channing - Tascosa - Northwest lines	regional reliability	12/31/10	06/01/09	01/27/09			30 months		there is no backup for the 69 kV service at Channing and Tacsosa. Any contingency on this radial line will remove load from the sytem. Therefore, no mitigations
	315	10407	526	Line - Roosevelt County Interchange 115 kV - Curry County Interchange 115 kV	regional reliability	06/01/10	06/01/15		$200,000		6 months		Will need additional study
19989	316	10409	531	Multi - Knoll -Hays -Vine	regional reliability	06/01/10	06/01/08	02/02/07	$536,000		18 months		Project removed from 2009 STEP, NTC to be withdrawn
20033	622	10810	536	Line - Richland - Rose Hill Junction 69 kV	regional reliability	06/01/13	06/01/10	01/27/09	$2,815,000		18 months		Currently re-evaluating this project in light of Timber Jct. 138-69 kV project and TransCanada
20019	578	10739	536	Line - Knob Hill - Steele City 115 kV	regional reliability	06/01/10	06/01/09	11/17/08	$14,747,550		48 months		FLOWGATE 5328 Mitigation is putting the Clifton Unit (539655) on and increasing the output as needed to relieve the line loading. Substation cost 12 $1.0 million.
20006	321	10417	536	Line - Oaklawn - Oliver 69 kV	regional reliability	06/01/10	06/01/10	02/13/08	$1,292,500		12 months		
19964	318	10412	536	Line - Coffeyville - Dearing 138 kV	transmission service	06/01/10	06/01/10	06/27/07	$2,819,000		18 months		Cost is WERE portion only
20033	493	10638	536	Multi - Jarbalo - Stranger Creek - NW Leavenworth	regional reliability	06/01/11	06/01/10	01/27/09	$8,050,000		15 months		Transmission Operating Directive 1216 modified to open Jarbalo-NW Leavenworth
20033	493	10639	536	Multi - Jarbalo - Stranger Creek - NW Leavenworth	regional reliability	06/01/11	06/01/10	01/27/09			15 months		Transmission Operating Directive 1216 modified to open Jarbalo-NW Leavenworth
20006	330	10426	536	Multi - Fort Scott - Marmaton/Lichtfield 161kV	regional reliability		06/01/10	02/13/08	$5,000,000		18 months		Mitigation is power factor correction on 69 kV system between Marmton and Litchfield
20006	330	10427	536	Multi - Fort Scott - Marmaton/Lichtfield 161kV	regional reliability		06/01/10	02/13/08	$2,400,000		18 months		Mitigation is power factor correction on 69 kV system between Marmton and Litchfield
20033	495	10640	536	Line - Lawrence Hill - Mockingbird 115 kV	regional reliability		06/01/10	01/27/09	$2,377,448		18 months		Re-evaluating scope of project as part of a comprehensive assessment of the Lawrence load area.
20033	618	10806	536	Multi - NW Manhattan	regional reliability	12/01/11	06/01/10	01/27/09	$17,437,500		24 months		Install Distribution Capacitors change conversion and East Manhattan - JEC 230 kV Distribution Transformer NLTs. Load projections have reduced
20033	621	10809	536	Line - E. Manhattan - JEC 230 kV	regional reliability		06/01/10	01/27/09	$17,085,938		24 months		
20033	623	10811	536	Line - Timber Junction - Winfield 69 kV	regional reliability	12/31/10	06/01/10	01/27/09	$7,415,000		24 months		Projections have reduced
20033	625	10813	536	Line - Rebuild Chisolm - Ripley 69 kV	regional reliability	06/01/10	06/01/10	01/27/09	$2,255,250		18 months		
20033	599	10766	536	Line - 27th & Croco - Tecumseh Hill 115 kV	regional reliability	12/31/10	06/01/09	01/27/09	$3,235,000		18 months		Project will probably defer to 2010 due to reduced load forecast. Expected in-service date is 12/1/2010.
20019	577	10738	536	Line - Kelly - Seneca 115 kV	regional reliability	12/01/10	06/01/09	11/17/08	$4,487,000		24 months		FLOWGATE 5328 Mitigation is putting the Clifton Unit (539655) on and increasing the output as needed to relive the line loading. Project has been suspended after TransCanada study determined that this line did not need to be constructed.
20006	328	10424	536	Line - Reno(Circle) - Moundridge Project 115 kV Rebuild	regional reliability	06/01/10	06/01/10	02/13/08	$5,800,000		12 months		Rebuild will be done as part of Wichita - Reno County 345 kV
20006	171	10220	536	Line - Weaver - Rose Hill 69 kV	regional reliability	12/01/10	06/01/08	02/13/08	$2,242,907		6 months		Transmission Operating Directive 1104

20006	172	10221	536	Line - Tecumseh Energy Center - Midland 115 kV	regional reliability	06/01/10	06/01/12	02/13/08	$2,100,000		6 months		Substation cost estimate $2,100,000
	173	10222	536	Line - Gill Energy Center West-Peck 69 kV Rebuild	sponsored	06/01/10			$3,684,740		12 months		Project deferred.
	182	10231	536	Line - Chase - White Junction 69 kV	sponsored	06/01/10			$5,184,701		8 months		Interim mitigation is application of existing Transmission Operating Directive 634
	328	10425	536	XFR - Reno(Circle)-Moundridge Project	sponsored	06/01/10			$1,700,000				
20034	627	10815	540	Line - Alabama - Lake Road 161 kV	regional reliability	06/01/09	06/01/10	01/27/09	$20,000		3 months		Completed
20034	628	10816	540	Line - Platte City - Smithville 161 kV	regional reliability	12/01/10	12/01/10	01/27/09	$50,000		6 months		
	331	10428	540	Line - Clinton MIPU - Clinton AECI 161 kV	sponsored	06/01/11			$2,418,750		6-12 months		
	332	10429	540	XFR - Sibley 161/69kV	sponsored	07/01/10			$2,200,000		18 months		Transformer received; engineering in progress
	192	10246	540	Line - Iatan - Platte City 161 kV Ckt 1	generation interconnect	12/31/09			$1,050,000		6 months		
	626	10814	541	Multi - Iatan 345/161 kV Sub	sponsored	12/31/09			$8,000,000		24 months		Project under construction, 66% complete
20010	382	10495	544	Line - Baxter Spring West - Hockerville 69 kV	regional reliability	06/01/10	12/01/11	02/13/08	$50,000		6 months		
	421	10547	544	Line - Sub 124 - Aurora H.T. - Sub 152 - Monett H.T. 69 kV	regional reliability	06/01/10	06/01/09	01/27/09	$5,000		6 months		CT ratio corrected in model. Correct Rate A/B: 54/65 (Summer), 72/72 (Winter). Project no longer needed.
19969	338	10435	544	Line - SUB 184 - NEOSHO SOUTH JCT. - Neosho (SWPA) 161 kV	transmission service	06/01/10	06/01/10	09/22/06	$1,215,000		12 months		Prior to BPF tariff
20011	212	10271	546	Line - Norton - Neergard 69 kV	regional reliability	06/01/10	06/01/08	02/13/08	$1,485,000		24 months		SPRM will mitigate overload by transferring load prior to reconductor completion in 2010.
	339	10436	546	XFR - SWPS Bus - SWPS #2 161 kV	sponsored	10/01/10			$3,200,000		24 months		Related to SW2 being added to the models; This wil go to the review committee
	629	10817	640	Twin Church / South Sioux City Area	regional reliability	06/01/12	06/01/12		$33,000,000				Delayed due to customer load delay, cost increase due to line routing issues JH - Need date changed to come in line with previous Nebraska planning.
	630	10818	640	Upgrade Jeffrey - Gothenburg 115kV line	regional reliability	06/01/10	06/01/10		$200,000				
			645	Line - Rebuild Sub 902 - Sub 983 69 kV	sponsored	02/26/10			$2,500,000				The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.
			Year 2011										
	284	10370	351	Line - Grandview - Osage	regional reliability - non OATT	06/01/12	06/01/09		$6,000,000		36 months		Preliminary design has begun.
	342	10439	515	Line - BULL SHOALS - BULL SHOALS 161KV	regional reliability - non OATT	01/01/10	06/01/11		$2,200,000				
20016	108	10441	520	Line - North Market - Arsenal Hill 69 kV	regional reliability	01/30/09	06/01/10	01/16/09	$3,210,000		24 months		Completed
20016	343	10440	520	Line - Winnsboro - Magnolia Tap 69 kV	regional reliability	06/01/10	06/01/10	01/16/09	$250,000		15 months		
20016	345	10442	520	Line - Magnolia - Forest Hill 69 kV	regional reliability	06/01/10	06/01/10	01/16/09	$125,000		15 months		Should be removed. Switch # 9116 at Magnolia Tap has been removed, and therefore does not need to be replaced. Summer ratings are already 73/85 MVA.
20016	346	10443	520	Line - Forest Hills - Quitman 69 kV	regional reliability	06/01/10	06/01/10	01/16/09	$100,000		15 months		
20000	347	10444	520	Line - Woodlawn - Baldwin 69 kV	regional reliability	06/01/11	06/01/11	02/13/08	$2,000,000		18 months		
20016	348	10445	520	Line - Dyess - Tontitown 161 kV	regional reliability	06/01/10	06/01/10	01/16/09	$224,000		12 months		
20027	452	10586	520	XFR - Whitney 138/69 kV	regional reliability	06/01/11	06/01/11	01/27/09	$350,000		18 months		Re-rating autotransformers. However, leave this row in because switches will need to be replaced.
20016	349	10449	520	Line - MCNAB REC - Turk 115 kV recond	transmission service	12/31/11	04/01/12	01/16/09	$540,000		60 months		Changed from PL. 2006 AG3
20016	349	10450	520	Line - McNab REC - Hope	transmission service	12/31/11	04/01/12	01/16/09	$2,170,000		60 months		SPP to confirm if AECC McNab switches and strain bus need to be replaced. Changed from PL. 2006 AG3
20016	349	10456	520	XFR - Turk 345/138 kV	transmission service	12/31/11	04/01/12	01/16/09	$7,310,000		60 months		Changed from PL. 2006 AG3
	350	10459	520	Line - Bann - Red Springs REC	generation interconnect	12/31/11			$277,000		60 months		
	349	10446	520	Line - Ashdown - Okay 115 kV	generation interconnect	06/01/11			$7,810,000		60 months		

	349	10447	520	Line - Ashdown - Patterson 138 kV	generation interconnect	12/31/11			$11,431,000		60 months		
	349	10448	520	Line - MCNAB REC - Turk 115 kV	generation interconnect	12/31/11			$1,773,000		60 months		
	349	10451	520	XFR - Okay 115/69 kV	generation interconnect	12/31/11			$3,266,000		60 months		Replacement not needed in 2009 due to re-rating, but replacement needed in 2011 due to voltage conversion associated with Turk.
	349	10452	520	Line - Okay 115 - Turk 138 kV	generation interconnect	12/31/11			$8,170,000		60 months		
	349	10457	520	XFR - Turk 138/115 kV #1	generation interconnect	12/31/11			$7,806,000		48 months		
20001	393	10511	523	XFR - Afton 161/69 kV #2 Addition	regional reliability	06/01/11	06/01/12	02/13/08	$2,500,000		24 months		
	302	10390	523	XFR - Siloam Springs Tap 345/161kV	sponsored	12/01/11			$8,019,000		24 months		
20029	354	10463	524	Line - Muldrow to 3rd St. 69 kV	regional reliability	06/01/11	06/01/09	01/27/09	$100,000		12 months		NTC date changed back original date to 6/1/2011 due to change in load. Area factory being closed. Project status needs to be changed to "Green"
20017	30158	50166	524	ARDMORE - ROCKY POINT 69KV CKT 1	transmission service	06/01/11	06/01/11	01/16/09	$1,627,500		24 months		Full BPF
20017	30162	50170	524	SUNNYSIDE - UNIROYAL 138KV CKT 1	transmission service	06/01/11	06/01/11	01/16/09	$50,000		12 months		
20017	30159	50167	524	DILLARD4 - HEALDTON TAP 138KV CKT 1	transmission service	06/01/11	06/01/11	01/16/09	$300,000		12 months		Full BPF
19951	357	10467	525	XFR- Anadarko 138/69 kV	transmission service	06/01/11	06/01/11	01/02/07	$2,000,000		16 months		
20031	632	10822	526	Multi: Legacy Interchange 69 kV Tap - 115/69 transformer -2 new lines	regional reliability	06/01/11	06/01/09	01/27/09	$3,937,500		24 months		County 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 7857 [527349 – 527339], and Open Switch 7858 [527349-527371].
20031	632	10823	526	Multi: Legacy Interchange 69 kV Tap - 115/69 transformer -2 new lines	regional reliability	06/01/11	06/01/09	01/27/09	$3,375,000		24 months		County 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 7857 [527349 – 527339], and Open Switch 7858 [527349-527371].
20031	632	10824	526	Multi: Legacy Interchange 69 kV Tap - 115/69 transformer -2 new lines	regional reliability	06/01/11	06/01/09	01/27/09	$3,093,750		24 months		County 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 7857 [527349 – 527339], and Open Switch 7858 [527349-527371].
20031	633	10825	526	Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new lines	regional reliability	04/15/11	06/01/09	01/27/09	$3,285,000		36 months		Interim Mitigations: To address the overload of one Artesia 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 4755 @ 13TH ST. SUB [527761 – 527768].
20031	633	10826	526	Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new lines	regional reliability	04/15/11	06/01/09	01/27/09	$281,250		36 months		Interim Mitigations: To address the overload of one Artesia 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 4755 @ 13TH ST. SUB [527761 – 527768].
20031	633	10827	526	Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new lines	regional reliability	04/15/11	06/01/09	01/27/09	$281,250		36 months		Interim Mitigations: To address the overload of one Artesia 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 4755 @ 13TH ST. SUB [527761 – 527768].
20031	633	10828	526	Multi: Eagle Creek 115 and 69 kV Taps - 116/69 XF - 3 new lines	regional reliability	04/15/11	06/01/09	01/27/09	$1,350,000		36 months		Interim Mitigations: To address the overload of one Artesia 115/69 kV transformer for the outage of the parallel transformer, shed load to mitigate overload, then Close Switch 4755 @ 13TH ST. SUB [527761 – 527768].
20031	696	10829	526	Line - Chaves Co - Roswell Int 69/115 kV Voltage Conversion	regional reliability	06/01/11	06/01/09	01/27/09	$4,716,600				loss of one of the 115/69 kV transformers at Roswell Interchange will cause the other to overload to 48.9 MVA, of the 40 MVA rating, or 122.4%. Load shed approximately 9 MVA until the following remedial switching is done.
20033	624	10812	536	Line - Fort Junction - West Junction City 115 kV	regional reliability	06/01/11	06/01/10	01/27/09	$4,927,500		24 months		Interim mitigation is to increase generation at AEC, McPherson, and HEC to relieve overloading.
19964	375	10488	536	XFR - Rose Hill 345/138 kV #3 Addition	transmission service	06/01/11	06/01/11	06/27/07	$8,100,000		24 months		Displacement need to make filing for displacement $
20006	369	10482	536	Line - SW Lawrence - Wakarusa 115 kV Rebuild	regional reliability	06/01/11	06/01/11	02/13/08	$2,000,000		18 months		Re-evaluating scope of project as part of a comprehensive assessment of the Lawrence load area.
20006	370	10483	536	Line - Co-op - Wakarusa	regional reliability	06/01/11	06/01/11	02/13/08	$760,000		18 months		The required date to start the project has not yet occurred; Mitigation plans not required
20033	600	10767	536	Line - 27th & Croco - 41st & California 115 kV	regional reliability	12/31/11	06/01/09	01/27/09	$3,227,500		24 months		Project will probably defer to 2011 due to reduced load forecast. Expected in-service date is 12/1/2011. Substation terminal upgrades is $475,000.
20033	267	10350	536	Multi - Halstead - Mud Creek Jct. - Mid-American Jct. - Newton 69 kV	regional reliability	12/01/10	06/01/10	01/27/09	$2,500,000		12 months		
20033	267	10351	536	Multi - Halstead - Mud Creek Jct. - Mid-American Jct. - Newton 69 kV	regional reliability	12/01/10	06/01/10	01/27/09	$360,000		12 months		UVLS operational in Newton Division. Adjustment of CTs at Halstead and Newton to increase line rating is interim mitigation. Substation terminal costs is $220,000 for Halstead and Newton.
20033	267	10352	536	Multi - Halstead - Mud Creek Jct. - Mid-American Jct. - Newton 69 kV	regional reliability	12/01/10	06/01/10	01/27/09	$1,300,000		12 months		
20033	463	10602	536	Line - East Manhattan - McDowell 115 kV to 230 kV conversion	regional reliability	06/01/12	06/01/10	01/27/09	$4,100,000		12 months		Install Distribution Capacitors change conversion and East Manhattan - JEC 230 kV Distribution Transformer NLTs. Load projections have reduced
19964	529	10674	536	Line - Rose Hill - Sooner 345 kV	transmission service	12/01/11	06/01/16	06/27/07	$84,669,696		36 months		
20033	491	10636	536	Line - Bismark - COOP	regional reliability		06/01/09	01/27/09	$2,085,000		18 months		Projections have reduced
20034	634	10830	540	Multi - Loma Vista - Montrose 161 kV - Tap into K.C. South	regional reliability	11/01/11	06/01/09	01/27/09	$2,369,625		18 months		project is an alternative to replace the reconductor projects of the Duncan Rd - Blue Spring East and Martin City-Grandview East 161 kV lines. Mitigation plan is to increase Greenwood and Dogwood generation, and/or to reduce South Harper generation as needed to eliminate contingent overloads.
20034	635	10832	540	Multi - Edmond Substation	regional reliability	07/01/10	04/01/09	01/27/09	$5,405,930		12-18 months		mitigation plan is to increase Lake Road generation to eliminate Lake Road 161/34.5 kV transformer overloads under emergency
	377	10490	541	Line - Paola - Middle Creek 161 kV	sponsored	06/01/12			$2,622,850		18 months		
	378	10491	541	Line - North Louisburg - Middle Creek 161 kV	sponsored	06/01/12			$12,179,000		24 months		TO Zonal/local upgrade. Not for SPP reliability.
19970	352	10730	544	Line - Oronogo Junction - Riverton 161 kV Recond	transmission service	06/01/11	06/01/11	01/10/08	$5,750,000		36 months		95.1% of costs BPF. 36 month lead time adequate.
19970	499	10644	544	XFR - Oronogo - 161/69 kV	transmission service	06/01/11	06/01/11	01/10/08	$4,000,000		36 months		
	609	10924	645	Build New 161 kV Substation Sub 1341	regional reliability	12/31/11	04/01/12						Change Project Name to "Build New 161 KV Substation Sub 1341"
	609	10925	645	Line - Sub 1251 - Sub 1341 161kV	regional reliability	12/31/11	04/01/12		$16,300,000				
	609	10926	645	Line - Sub 1341 - Sub 1305 161kV	regional reliability	12/31/11	04/01/12						
	287	10373	DETEC	Line - Etoile - Chireno	sponsored	06/01/11			$11,299,000				

			Year 2012										
20016	30157	50165	520	SOUTH TEXARKANA REC - TEXARKANA PLANT 69KV CKT 1	transmission service	04/01/12	04/01/12	01/16/09	$4,750,000		24 months		Full BPF
20016	30156	50164	520	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	transmission service	04/01/12	04/01/12	01/16/09	$35,000				Full BPF
20016	30155	50163	520	OKAY - TOLLETTE 69KV CKT 1	transmission service	04/01/12	04/01/12	01/16/09	$80,000				Full BPF
20016	30148	50156	520	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #2	transmission service	06/01/12	06/01/12	01/16/09	$4,225,000		24 months		Full BPF
20016	30154	50162	520	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	transmission service	06/01/12	06/01/12	01/16/09	$100,000		12 months		Full BPF
20016	30152	50160	520	LINWOOD - POWELL STREET 138KV CKT 1	transmission service	06/01/12	06/01/12	01/16/09	$456,000		15 months		Full BPF
20016	30150	50158	520	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	transmission service	12/01/12	12/01/12	01/16/09	$4,560,000		24 months		Full BPF
20016	30142	50148	520	Line - Turk - NW Texarkana 345 kV	transmission service	04/01/12	04/01/12	01/16/09			33 months		Change PID and UID (old PID 349 and old UID 10453)
20016	30142	50149	520	Line - Turk - NW Texarkana 345 kV	transmission service	04/01/12	04/01/12	01/16/09	$48,580,000		33 months		Change PID and UID (old PID 349 and old UID 10453)
20016	30142	50150	520	Line - Turk - NW Texarkana 345 kV	transmission service	04/01/12	04/01/12	01/16/09			33 months		Change PID and UID (old PID 349 and old UID 10453)
20016	288	10374	520	Line - Valliant Substation - Install 345 kV terminal equipment	transmission service	04/01/12	04/01/12	01/16/09	$3,840,000		24 months		Notification received from the SPP concurring with the new in-service date due to the delay of the Turk plant. 73% BPF
20027	392	10510	520	Line - Howell - Kilgore 69 kV	regional reliability	06/01/12	06/01/09	01/27/09	$2,700,000		18 months		Interim mitigation plan: After contingency of Lake Lamond-Greggton 69 kV, if Kilgore-Howell 69 kV overloads, open Sabine-Service Pipeline Tap with breaker 1P90 at Sabine.
20000	387	10505	520	Line - Riverside - Okmulgee 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$125,000		15 months		
20000	388	10506	520	Line - New Boston - North New Boston 69 kV	regional reliability	06/01/12	06/01/12	02/13/08	$100,000		15 months		
20000	389	10507	520	Line - SE Texarkana - Texarkana 69 kV	regional reliability	06/01/12	06/01/12	02/13/08	$122,000		15 months		
20000	391	10509	520	Line - Lone Star South - Pittsburg 138kV	regional reliability	06/01/12	06/01/12	02/13/08	$300,000		15 months		
20017	30161	50169	524	HUGO - SUNNYSIDE 345KV OKGE	transmission service	04/01/12	04/01/12	01/16/09	$75,000,000		42 months		Full BPF
20017	30163	50171	524	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	transmission service	04/01/12	04/01/12	01/16/09	$6,750,000		24 months		Full BPF
20002	395	10513	524	Line - OGE Russett - WFEC Russett 138kV	regional reliability	06/01/12	12/01/12	02/13/08	$347,073		12 months		An SPP Flowgate
20002	396	10514	524	Breaker - Bodle 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$1,000,000		12 months		Cost to install breaker plus relays at Bodle and replace relays at Caney Creek & OGE Brown.
20002	397	10515	524	Multi - Mustang - Cimarron 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$6,850,000		24 months		Project will be replaced pending an Out of Cycle review of Cimarron - Haymaker
20002	397	10516	524	Multi - Mustang - Cimarron 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$3,500,000		24 months		Project will be replaced pending an Out of Cycle review of Cimarron - Haymaker
19961	523	10668	524	Line - Rose Hill - Sooner 345 kV	transmission service	06/30/12	06/01/16	06/27/07	$45,000,000		42 months		Right-of-way being secured
	551	10837	524	Multi-3rd-Massard convert 69-161kV	regional reliability	06/01/16	06/01/17		$2,200,000		24 months		Relplaced Jonshon to 3rd Street tap with Johnson to Oak Park 161 kV
	551	10701	524	Multi-3rd-Massard convert 69-161kV	regional reliability	06/01/16	06/01/17		$2,850,000		24 months		Relplaced Jonshon to 3rd Street tap with Johnson to Oak Park 161 kV
20018	30165	50173	525	HUGO - SUNNYSIDE 345KV WFEC	transmission service	04/01/12	04/01/12	01/16/09	$45,000,000		36 months		Full BPF
20003	402	10522	525	Multi - Granfield - Cache SW 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$1,125,000		12 months		
20003	402	10523	525	Multi - Granfield - Cache SW 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$7,306,000		24 months		
20003	402	10524	525	Multi - Granfield - Cache SW 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$5,000,000		24 months		
20018	313	10405	525	Line - Valiant - Hugo 345 kV	transmission service	04/01/12	04/01/12	01/16/09	$11,000,000		24 months		73% BPF
20018	314	10406	525	XFR - Hugo 345/138 kV	transmission service	04/01/12	04/01/12	01/16/09	$5,000,000		24 months		73% BPF
20003	399	10519	525	Line - Lindsay - Wallville 69 kV	regional reliability	06/01/12	06/01/12	02/13/08	$1,347,000		12 months		
20003	400	10520	525	Line - Pharoah - Weleetka 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$225,000		6 months		
20003	401	10521	525	Line - WFEC Russell 138 kV - AEP Altus Jct Tap 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$50,000		6 months		
20006	410	10536	536	Line - Circle - Ark Valley - Tower 33 115 kV	regional reliability		06/01/12	02/13/08	$2,306,250		12 months		Line is radial.
	561	10711	536	Line - Evans - Lakeridge 138 kV ckt 1	regional reliability	06/06/12	06/01/16		$5,513,000		24 months		
20009	379	10492	541	Line - Hillsdale - Cedar Niles 161 kV	zonal reliability	06/01/15	06/01/13	02/13/08	$5,418,700		24 months		Delayed 2 year; mitigation not needed.
20009	417	10543	541	Line - Avondale- Gladstone 161 kV	regional reliability	06/01/12	06/01/12	02/13/08	$13,000		6 months		
20036	638	10839	544	Line - Sub 170 Nichols - Sub 80 Sedalia 69 kV	regional reliability	06/01/12	06/01/12	101/27/09	$3,520,000		18 months		
20036	420	10546	544	Line - Jamesville - Sub 415-Blackhawk Jct. 69 kV	regional reliability	06/01/12	06/01/17	01/27/09	$50,000		6 months		
	496	10641	544	Line - SUB 64 - JOPLIN 10TH ST. - SUB 145 - JOPLIN WEST 7TH 1	regional reliability	06/01/12	06/01/17		$55,000		6 months		

	639	10840	545	Line - Blue Valley Plant - Sub M 161 kV	regional reliability - non OATT	06/01/12	10/01/09		$2,625,000		24 months		Not under OATT
	424	10552	546	Line - Southwest - Brookline 161 kV	sponsored	06/01/09			$450,000	$444,977	24 months		Completed
	425	10553	546	Line - Southwest - Southwest Disposal 161 kV	sponsored	06/01/09			$175,000	$170,890	24 months		Completed
	426	10554	546	Line - Southwest Disposal - Battlefield 161 kV	sponsored	06/01/09			$675,000	$594,254	24 months		Completed
20011	441	10572	546	Line - Kickapoo - Sunset 69 kV	regional reliability	06/01/12	06/01/13	02/13/08	$805,000		24 months		Upgrade requirements being re-evaluated in the 2009 STEP with the Twin Oaks 69 kV 30 MVAR cap bank installed in 2014.
	386	10502	TBD	Multi - Axtell - Comanche- Wichita	sponsored	06/01/12			$47,000,000				
	386	10503	TBD	Multi - Axtell - Comanche- Wichita	sponsored	06/01/12			$180,000,000				
	636	10834	DETEC	Line-Chireno-Martinsville 138 kV	sponsored	06/01/12			$7,617,000				
20015	30143	50151	AECC	MCNAB - TURK 115KV CKT 1 AECC	transmission service	04/01/12	04/01/12	01/16/09	$165,000				Full BPF
20015	351	10460	AECC	Line - Hope - Fulton 115 kV Recond	transmission service	04/01/12	04/01/12	01/16/09	$1,512,000				Full BPF
20015	351	10461	AECC	Fulton Switching Station	transmission service	04/01/12	04/01/12	01/16/09	$440,000				Full BPF
			Year 2013+										
20027	443	10575	520	Line - Osborne - Osborne Tap	regional reliability		06/01/13	01/27/09	$2,000,000		24 months		
20027	641	10842	520	Line -Forest Hills-Quitman 69 kV Switches	regional reliability		06/01/13	01/27/09	$150,000		15 months		
20027	477	10614	520	Line - Baldwin - Karnack Tap	regional reliability		06/01/13	01/27/09	$6,900,000		24 months		
20000	450	10584	520	Multi - Flint Creek – Centerton 345 kV and Centerton- East Centerton 161 kV	regional reliability	06/01/14	06/01/14	02/13/08	$11,000,000		48 months		
20000	450	10585	520	Multi - Flint Creek – Centerton 345 kV and Centerton- East Centerton 161 kV	regional reliability	06/01/14	06/01/14	02/13/08	$30,000,000		60 months		
20000	450	10582	520	Multi - Flint Creek – Centerton 345 kV and Centerton- East Centerton 161 kV	regional reliability	06/01/14	06/01/14	02/13/08	$9,000,000		60 months		Replaces Decatur-Centerton 345 kV project. Reconductoring Flint Creek-East Centerton 161 kV by 2010 defers the need for this 345 kV project until 2014.
20027	649	10853	520	Line - Lone Star-Locus Grove 115 kV	regional reliability		06/01/14	01/27/09	$2,150,000		24 months		
20000	511	10656	520	Multi - Centerton - Osage Creek 345 kV	regional reliability	06/01/16	06/01/16	02/13/08	$11,000,000		60 months		
20000	511	10659	520	Multi - Centerton - Osage Creek 345 kV	regional reliability	06/01/16	06/01/16	02/13/08	$24,500,000		60 months		
20000	511	10660	520	Multi - Centerton - Osage Creek 345 kV	regional reliability	06/01/16	06/01/16	02/13/08	$65,500,000		60 months		
20029	642	10843	524	Line Kilgore - VBI 69 kV	regional reliability	06/01/13	06/01/13	01/27/09	$10,000		9 months		
20002	518	10663	524	Line - HSL East - HSL West 69 kV	regional reliability	06/01/16	06/01/16	02/13/08	$250,000		12 months		
20017	30160	50168	524	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	transmission service	06/01/17	06/01/17	01/16/09	$11,000,000		18 months		Full BPF
20017	30164	50172	524	VBI - VBI NORTH 69KV CKT 1	transmission service	06/01/17	06/01/17	01/16/09	$100,000		9 months		Full BPF
20031	151	10195	526	XFR - Tuco 115/69 kV	regional reliability		06/01/18	01/27/09	$1,260,000		24 months		A reconfiguration of the 69 kV loading will mitigate this contingency until 2018.
20031	153	10197	526	XFR - Potash Junction Interchange 115/69 kV	regional reliability		06/01/18	01/27/09	$600,000		24 months		No project here! Step study justified this project with a modeling error. Model correction (turning on existing capacitor bank) deferred project from 2008 to 2018.
20004	247	10316	526	Line - Curry County Interchange-Farmers Electric REC-Clovis 115 kV	regional reliability	-		02/13/08	$5,000		6 months		Fulton). This terminal upgrade is needed only after the North Clovis Substation is upgraded to the 115 kV circuit, which won't be in-service until 2010. SPS plans to have these jumpers upgraded by 12/31/2008 since other upgrades are being
20032	697	10914	531	Multi: Hutchinson Energy Center - Huntsville - St. John 115 kV Rebuild	regional reliability		06/01/15	01/27/09	$12,487,500		36 months		Investigating alternate means to mitigate overload, We have only received an NTC for a portion of this overall project. Should it be split up? Other portions of the project are tracked separately.
20033	643	10844	536	Line - Twin Valley - Altamont - Neosho 138 kV	regional reliability	06/01/13	06/01/13	01/27/09	$4,000,000		18 months		
20033	533	10678	536	XFR - Auburn Road 230/115 kV	regional reliability	06/01/13	06/01/13	01/27/09	$12,622,500		36 months		
20033	645	10846	536	XFR - 17th Street 138/69 kV second transformer	regional reliability	06/01/13	06/01/13	01/27/09	$3,375,000		24 months		
20033	534	10679	536	XFR - Halstead South 138/69 kV #1	regional reliability	06/01/14	06/01/14	01/27/09	$1,400,000		24 months		
20033	652	10857	536	Line - Hutchinson Energy Center - Huntsville 115 kV Rebuild	regional reliability	06/01/15	06/01/15	01/27/09	$12,487,500		36 months		
20033	169	10218	536	Line - Chapman - Clayton Center 115 kV Uprate	regional reliability	06/01/17	06/01/17	01/27/09	$10,000		12 months		Model error.
20034	646	10847	540	XFR - Clinton 161/69 kV	regional reliability	06/01/13	06/01/13	01/27/09	$2,000,000		12-18 months		
20036	202	10258	544	Line - Sub 436 - Webb City Cardinal - Sub 110 - Oronogo Jct. 1 69 kV	regional reliability		06/01/14	01/27/09	$400,000		12 months		
20036	537	10685	544	Line - Sub 383 - Monett 161 kV - Monett 5 161 kV	regional reliability	06/01/15	06/01/15	101/27/09	$7,369,319		48 months		
20036	537	10686	544	XFR - Monett 5 161 kV - Monett City South 69 kV	regional reliability	06/01/15	06/01/15	101/27/09	$8,000,000		36 months		
20036	203	10259	544	Line - Sub 109 - Atlas Jct. - Sub 108 - Carthage Northwest 1 69 kV	regional reliability		06/01/18	01/27/09	$1,277,935		18 months		

			Balanced Portfolio										
20040	698	10927	523	Line - Sooner – Cleveland 345 kV	Balanced Portfolio	12/31/12		06/19/09	$17,000,000				
20041	699	10929	524	Line - Sooner - Cleveland 345 kV	Balanced Portfolio	12/31/12		06/19/09	$17,000,000		32 months		
20041	700	10930	524	Line - Seminole - Muskogee 345 kV	Balanced Portfolio	12/31/13		06/19/09	$127,000,000		40 months	GREEN Hatch	
20041	700	10931	524	XFR - Seminole 345/138 kV	Balanced Portfolio	12/31/13		06/19/09	$4,000,000		22 months	GREEN Hatch	
20041	701	10932	524	Line - Tuco to Woodward 345 kV line	Balanced Portfolio	05/19/14		06/19/09	$64,000,000		40 months	GREEN Hatch	
20041	701	10933	524	XFR - Woodward 345 kV and a 50 MVAR reactor bank	Balanced Portfolio	05/19/14		06/19/09	$15,000,000		24 months	GREEN Hatch	
20041	709	10946	524	Sub - Anadarko	Balanced Portfolio	12/31/11		06/19/09	$8,000,000		24 months		
20044	705	10938	525	Line - WFEC Anadarko – OKGE Anadarko 138 kV	Balanced Portfolio	12/31/11		06/19/09	$2,000,000				
20043	704	10936	526	Line - Tuco to Woodward 345 kV line	Balanced Portfolio	05/19/14		06/19/09	$122,597,500			GREEN Hatch	
20043	704	10937	526	XFR - Tuco transformer and Mid-point Reactor Station	Balanced Portfolio	05/19/14		06/19/09	$26,130,000			GREEN Hatch	
20046	707	10940	531	Line - Spearville - Knoll 345 kV	Balanced Portfolio	06/01/13		06/19/09	$42,000,000			GREEN Hatch	
20046	707	10943	531	Line - Knoll - Axtell 345 kV	Balanced Portfolio	06/01/13		06/19/09	$66,000,000			GREEN Hatch	
20046	707	10941	531	XFR - Knoll 345/230 kV	Balanced Portfolio	06/01/12		06/19/09	$3,000,000				
20045	706	10939	534	Line - Spearville - Knoll 345 kV	Balanced Portfolio	06/01/12		06/19/09	$54,000,000				
20042	702	10934	541	Tap - Swissvale - Stilwell	Balanced Portfolio	06/01/12		06/19/09	$2,000,000				
20042	703	10935	541	Line - Iatan - Nashua 345 kV	Balanced Portfolio	06/01/15		06/19/09	$54,444,000			GREEN Hatch	
20042	703	10945	541	XFR - Nashua 345/161 kV	Balanced Portfolio	06/01/15		06/19/09	$4,620,000			GREEN Hatch	
20047	708	10942	640	Line - Knoll - Axtell	Balanced Portfolio	06/01/13		06/19/09	$71,377,000			GREEN Hatch	

SPP 3rd Quarter 2009 Project Tracking List - Device

Blue	Complete.
Green	On Schedule.
Green	On Schedule - Later in 10yr horizon.
Yellow	Behind schedule, interim mitigation provided or project may change but time permits the implementation of project.
Red	Delayed beyond the RTO Determined need date and no mitigation plan provided
$ / months	Project lead time and cost estimated by SPP staff

Project types "sponsored" and "regional reliability - non OATT" do not receive NTCs and are not filed at FERC but are being tracked because they are expected to be built in the near term

NTC_ID	PID	UID	Area	Project Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Letter of Notification to Construct Issue Date	Cost Estimate	Final Cost	Project Lead Time	Project Status	Project Status Comments
		Year 2008											
19985	30012	50018	525	Device - Rush Springs 69 kV	regional reliability	11/01/08	06/01/06	02/02/07	$90,000		8 months		Shed load at Rush Springs Substation (up to 5MW in 2007 Summer Peak). MW values mentioned are typical for a Summer Peak case. Mitigation Plan under review by SPP staff.
20003	30036	50042	525	Device - Marietta Cap 138 kV	regional reliability	11/01/08	06/01/08	02/13/08	$675,000		12 months		WFEC will move load to Russett Substation to relieve loading in case of low voltage
20003	30037	50043	525	Device - Sweet Water Cap 69 kV	regional reliability	03/01/08	06/01/08	02/13/08	$243,000		10 months		
20003	30043	50049	525	Device - Twin Lakes Cap 69 kV	regional reliability	06/01/08	06/01/08	02/13/08	$108,000				Replaces Cashion cap, which received an LOA on 2/7/07
19986	30023	50029	536	Device - Parsons	regional reliability	01/07/08	06/01/07	02/02/07	$949,847		14 months		
19987	30019	50025	526	Device - San Andress Sub	regional reliability			02/02/07	$750,000				Needs further analysis - Seminole project may mitigate. Project deferred beyond the planning horizon as per 2007 Exapnsion plan.
19986	30082	50088	536	Device - 3rd & VanBuren	regional reliability	06/01/11	06/01/11	02/02/07	$500,000		18 months		Project is schedule for completion by 6/1/2011
20007	30061	50067	539	Device - Pratt Cap 115 kV	regional reliability	08/01/09	06/01/08	02/13/08	$1,350,000				Construction has been started. Mitgation is to have City of Pratt generate to raise voltage.
		Year 2009											
	30029	50035	520	Figure Five	sponsored	06/01/09			$873,000				Completed
	30170	50178	520	Delivery point- Hull	sponsored	10/31/09			$654,000		15 months		
20028	30074	50080	523	Device - Tahlequah West 69 Cap kV	regional reliability	07/01/12	06/01/09	01/27/09	$779,000		12 months		Replaces Tahlequah City#1 and City #2 Cap 69. In the event of a contingency that caused a true voltage violation which regulators would not mitigate we would shed load in the city of Talequah. This project will be deferred because the violations occurred in models that didn't use system transformer LTCs, when voltage regulation is utilized it defers this project.
	30171	50179	523	Device - Chelsea 69 kV Cap	sponsored	06/01/09			$586,000		12 months		
	304	50148	524	Device - Madill Industal 138 kV	sponsored	03/01/11			$264,000		12 months		Part of multi-upgrade project for new arc furnance near Arbuckle (See branch tab for more details and cost estimate)
20003	30044	50050	525	Device - Gypsum Cap 69 kV	regional reliability	04/01/09	04/01/08	02/13/08	$150,000		12 months		Mitigation: Temporary Op Guide provided.
20030	30172	50180	525	Device Eagle Chief 69 kV Capacitor	regional reliability	06/01/10	06/01/09	01/27/09	$300,000		12 months		Mitigation: Temporary Op Guide provided.
20033	30060	50066	536	Device - Sunset 69 kV Capacitor	zonal reliability	08/15/09	06/01/09	01/27/09	$1,220,913		18 months		Voltage issue around Gale area was identified in the 2006 STEP, and the Sunset 10 MVAR Capacitor was the identified as the solution. A Letter of Authorization was sent February 2, 2007 with a needed in-service date of June 2007. In the 2007 STEP, Sunset Cap was not included in the base model on TO request, and voltage problems in the Gale did not until 2013 at which time the 2007 STEP recommended installing a 6 MVAR Capacitor at Sedwick Co Koch 69 kV instead of the Sunset 10 MVAR Cap. SPP issued a Notice To Construct Febuary 13, 2008 for the Sedwick Co Koch Cap. Project cancelled by BOD in July 2008.
20033	30173	50181	536	Device - Walnut Street Capacitor	zonal reliability	10/01/09	06/01/09	01/27/09	$580,000		18 months		Current plan is to place in service last quarter of 2009.
20033	30128	50134	536	Device - Rock Creek 69 kV Capacitor	zonal reliability		06/01/09	01/27/09	$427,000		18 months		Project is being re-evaluated due to load shifting between substations.
20007	30062	50068	539	Device - Harper Cap 138 kV	regional reliability	10/01/09	06/01/08	02/13/08	$1,100,000		12 months		Construction has been started. Mitigation is to adjust the LTC on the Medicine Lodge 138/115 kV transformer, adjust generation at Fort Dodge, and request SPS to adjusts the flow on the Texas Co Phase shifter.
20034	30185	50187	540	Device - Butler 161 kV Capacitor	regional reliability	06/01/13	06/01/09	01/27/09	$405,000		12 months		Butler is not AREA 540 sub, should be AECI/KAMO, but the model was wrong on it; The real low voltage issue at Adrain/Butler for the outage of Archie Jct-Adrain 161 kV line was missed due to the invalid contingency list, which has been corrected. KCPL and AECI will work with SPP to find an alternative. Mitigation plan is to turn on Navada generation and adjust the tap position of Butler 161/69 kV transformer as needed.
20034	30174	50182	540	Device - Craig 69 kV Capacitor	regional reliability		06/01/09	01/27/09	$350,000		12 months		Believe this violation caused by model error, incorrect transformer tap setting; have requested this NTC not be included in 2009 STEP. No mitigation plan is needed in near term.
20009	30077	50083	541	Device - Craig Cap 161 kV	zonal reliability	06/01/10	06/01/08	02/13/08	$1,057,630		12 months		project budgeted for 2009; mitigation plan will change summer transformer taps to 0.975 tap. SPP staff to review RTO reliability need date for the project.
20036	30067	50073	544	Device - Quapaw Cap 69 kV	regional reliability	12/01/09	06/01/18	01/27/09	$1,500,000		18 months		Project under study. Will be complete once 2008 series models are released. Distribution transformer taps to be adjusted accordingly to serve load adequately until the project can be implemented/energized.
	30085	50091	546	Device - Mentor Substation	sponsored	09/01/09			$1,800,000		24 months		
		Year 2010											
	30070	50076	520	Sugar Loaf	sponsored	07/01/10			$500,000				
20028	30072	50078	523	Device - Afton Cap 69 kV	regional reliability	06/01/10	06/01/09	01/27/09	$800,000		18 months		This voltage violation is at an NEO/REC substation that is on the end of a NEO/REC radial line out of the Afton substation. In the event of a voltage violation that cannot be mitigated with regulators we would shed this load. This project will be deferred because the violations occurred in models that didn't use system transformer LTCs, when voltage regulation is utilized it defers this project.
20003	30079	50085	525	Device - Carter Cap 69 kV	regional reliability	06/01/10	06/01/10	02/13/08	$324,000		12 months		
19986	30057	50063	536	Device - Nortonville 69 kV Cap	regional reliability	12/31/10	06/01/07	02/02/07	$715,000		18 months		Project funding was removed in May 2009. Current plan is to reprioritize project for possible 2010 completion.
20006	30056	50062	536	Device - Seneca Cap 115 kV	zonal reliability	06/01/10	06/01/08	02/13/08	$588,600		18 months		Second capacitor bank identified for addition of TransCanada load. Required by summer 2010. Addition of Knob Hill - Steele City 115 kV identified for TransCanada. Capacitor bank will be installed at TransCanada.
20010	30078	50084	544	Device - Riverside Sub Cap 161kV	zonal reliability	12/01/10	06/01/09	02/13/08	$2,600,000		24 months		Project under study, will be complete once 2008 series models are released.Dist. Xfmr taps to be adjusted accordingly to serve load adequately until the project can be implemented/energized

		Year 2011											
20001	30086	50092	523	Device - Jay Cap 69 kV	regional reliability	06/01/11	06/01/11	02/13/08	$800,000		18 months		This project will be deferred because the violations occurred in models that didn't use system transformer LTCs, when voltage regulation is utilized it defers this project.
20032	30176	50184	531	Device - Kinsley Capacitor 115 kV	regional reliability	06/01/11	06/01/11	01/27/09	$225,000		18 months		
20007	30090	50096	539	Device - Russell 115 kV	regional reliability	06/01/11	06/01/11	02/13/08	$750,000		12 months		Currently in engineering design and cost review. Request City of Russell to generate to raise voltage.
		Year 2012											
19985	30041	50047	525	Device - Comanche	regional reliability	06/01/12	06/01/12	02/02/07	$350,000		12 months		Shed load at Loco Substation (up to 3.5MW in 2007 Summer Peak) Shed load at Empire Substation (up to 5MW in 2007 Summer Peak). MW values mentioned are typical for a Summer Peak case. Mitigation Plan under review by SPP staff.
20003	30093	50099	525	Device - Latta Cap 138 kV	regional reliability	06/01/12	06/01/12	02/13/08	$324,000		12 months		
20003	30094	50100	525	Device - Mustang Cap 69 kV	regional reliability	06/01/12	06/01/12	02/13/08	$162,000		12 months		
20006	30096	50102	536	Device - Eudora Cap 115 kV	zonal reliability	06/01/12	06/01/12	02/13/08	$580,000		18 months		
20007	30098	50104	539	Device - Plainville Cap 115 kV	regional reliability	06/01/12	06/01/12	02/13/08	$1,500,000		12 months		Engineering esign to begin in 4th quarter of 2010. Construction to beginin first quarter of 2011.
		Year 2013+											
20028	30177	50185	523	Device - Tahlequah West #2 Capacitor	regional reliability		06/01/13	01/27/09	$291,600		12 months	GREEN hatch	GRDA is requesting that this project is removed and will be replaced by an AECI/KAMO 161/69 Xfrmr and new 69 kV line wich will terminate at Peggs.
20030	30178	50186	525	Device - Electra 69 kV Capacitor	regional reliability	06/01/13	06/01/13	01/27/09	$240,000		12 months	GREEN hatch	
20030	30039	50045	525	Device - Esquandale Cap 69 kV	regional reliability	06/01/14	06/01/14	01/27/09	$243,000		12 months	GREEN hatch	WFEC will move ahead line project: Cache to Grandfield to mitigate voltage problem. Short term mitigation until line can be built will be transfering load from Hulen Substation to Empire and Duncan Substations
20006	30105	50111	536	Device - Springhill Cap 115 kV	zonal reliability	06/01/13	06/01/13	02/13/08	$1,000,000		18 months	GREEN hatch	
20034	30076	50082	540	Device - Warsaw 2 69 kV Capacitor	regional reliability		06/01/13	01/27/09	$409,900		12 months	GREEN hatch	Believe this violation caused by model error, incorrect transformer tap setting; have requested this NTC not be included in 2009 STEP. No mitigation plan is needed in near-term.

SPP Priority Projects Phase II Final Report

MAINTAINED BY
SPP Engineering/Planning

SPP Board Approved
April 27, 2010

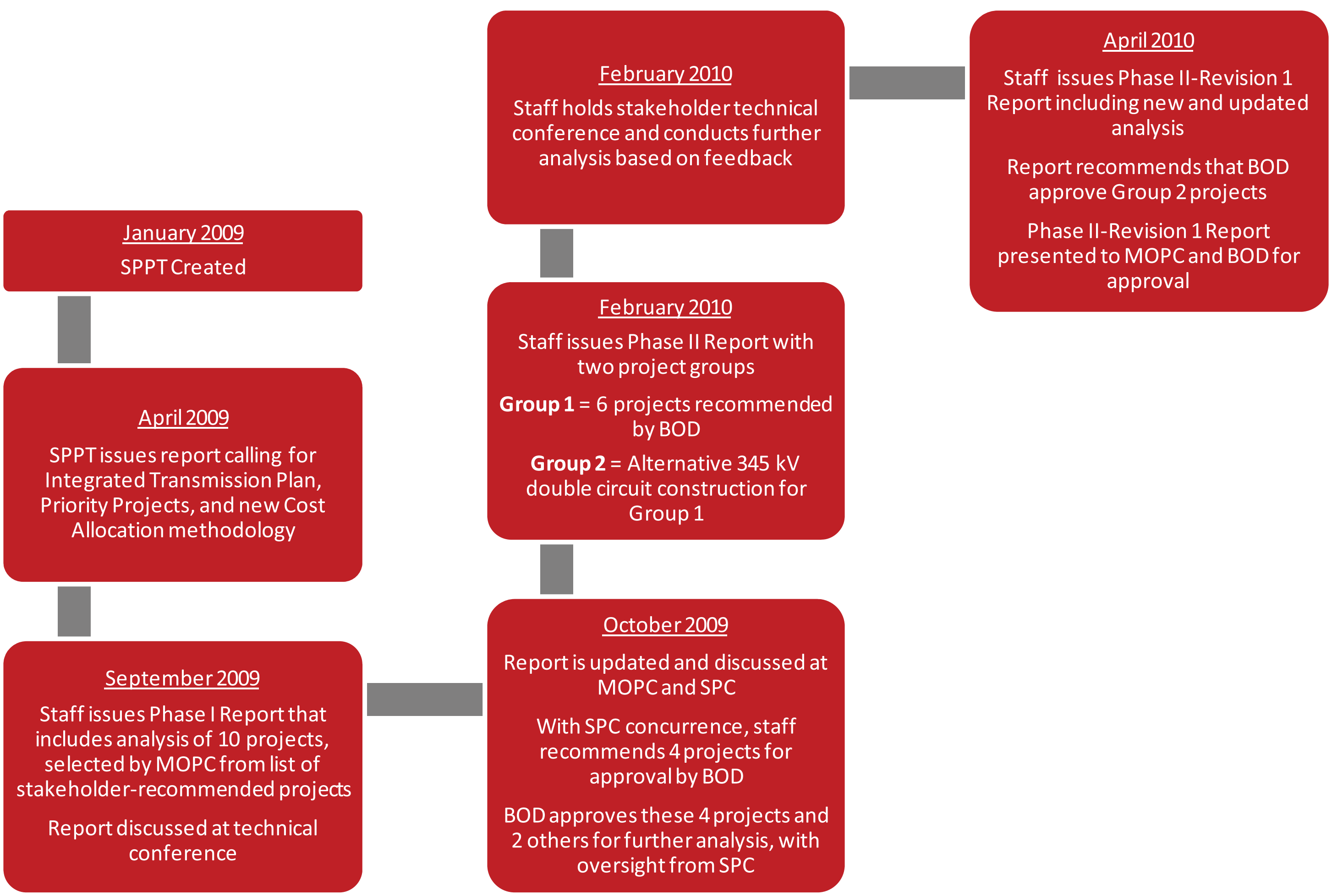
Southwest Power Pool

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.

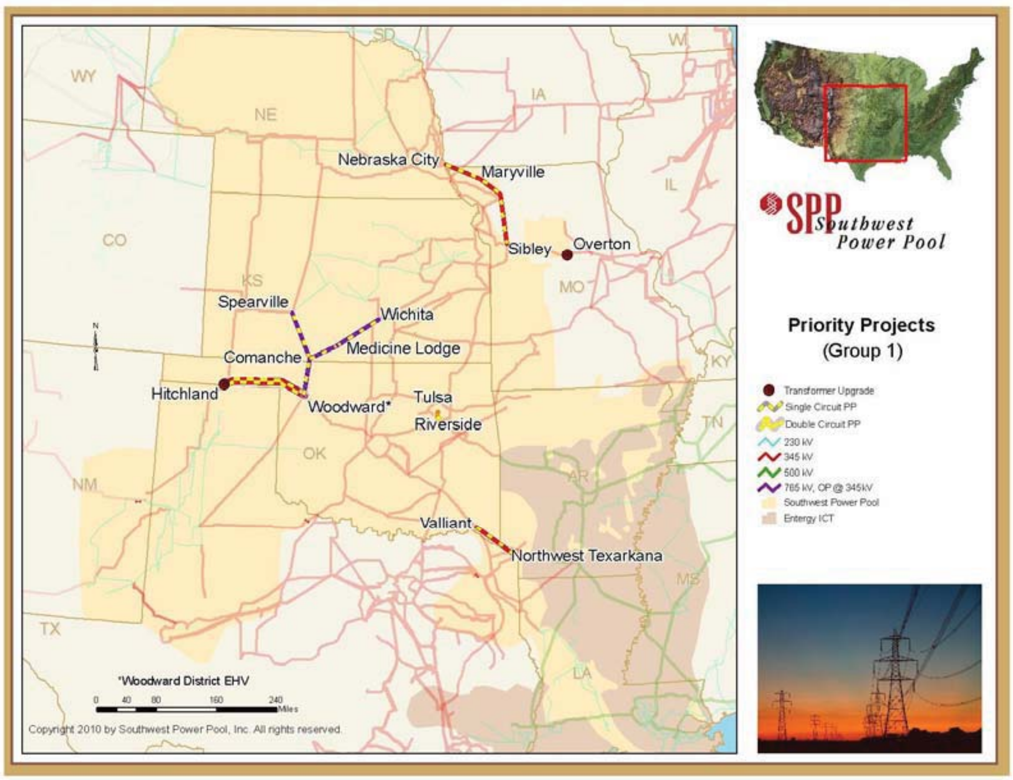
SPP was charged with identifying, evaluating, and recommending Priority Projects that will improve the SPP transmission system and benefit the region, specifically projects that will reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's 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.

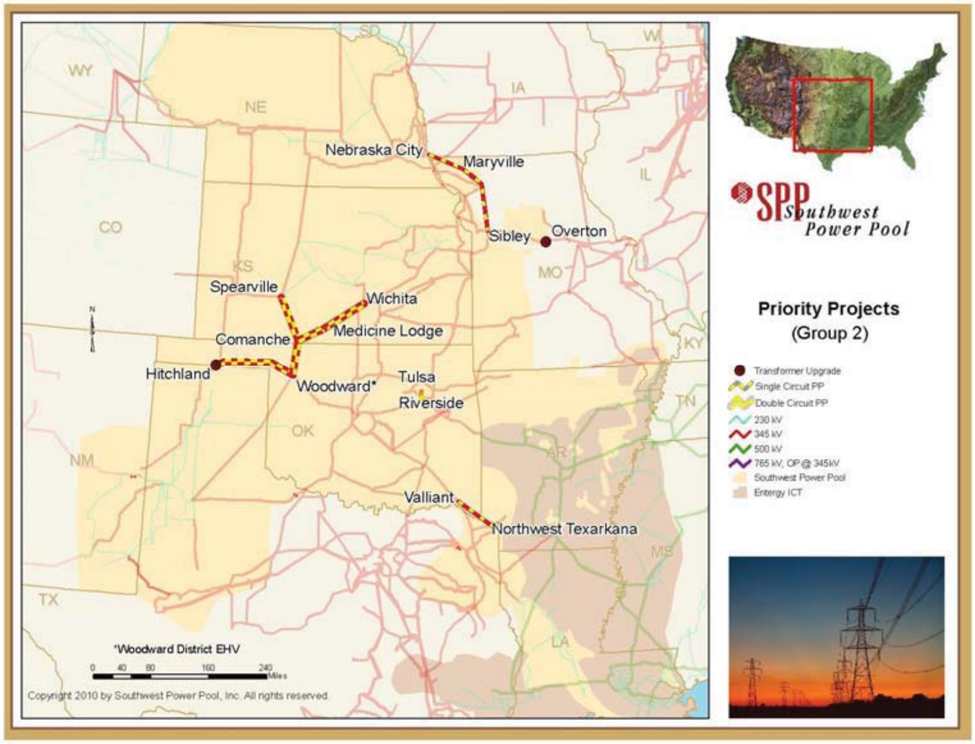
Group 1 has estimated engineering and construction costs of $1.26 billion:



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

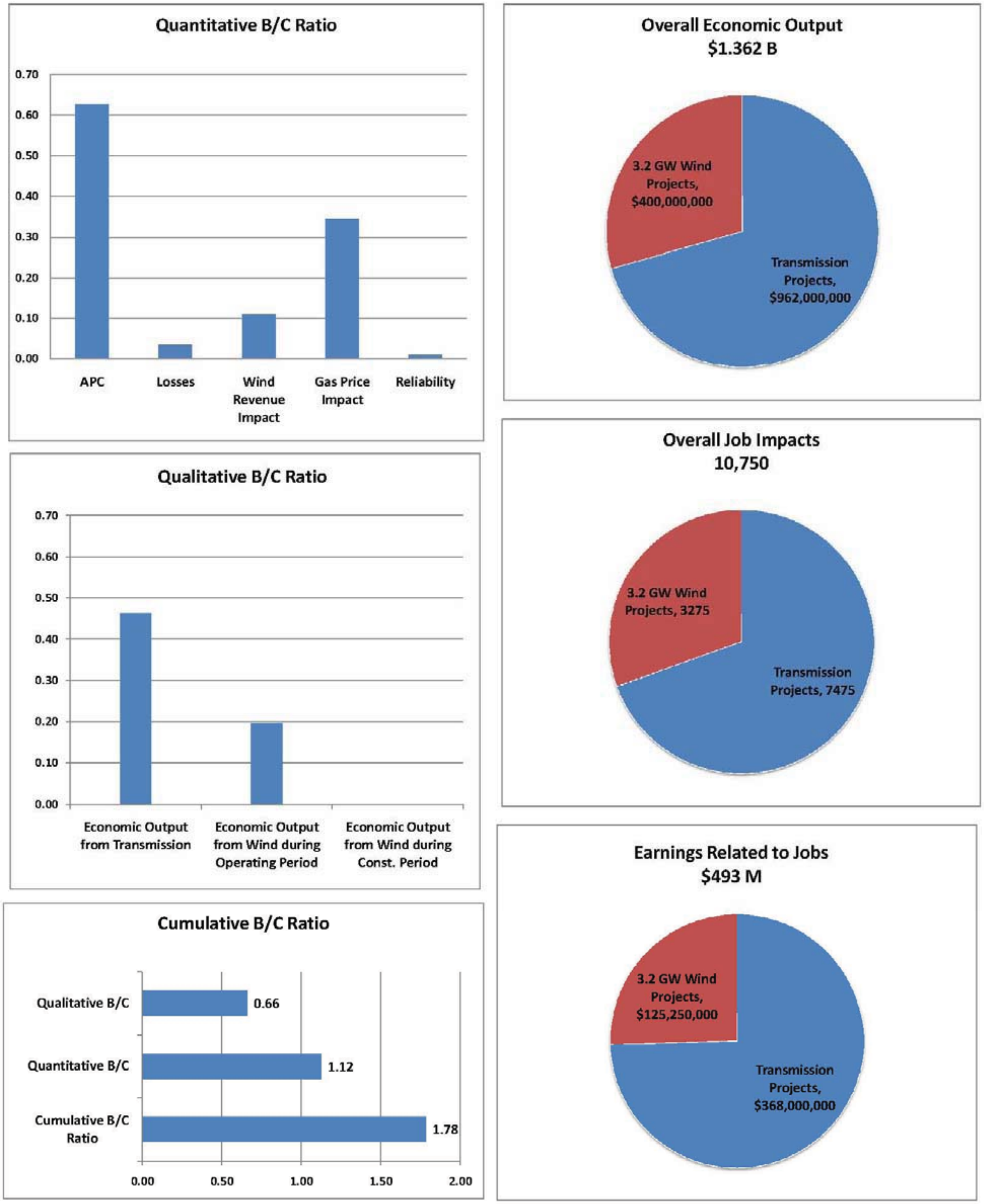


Figure 1

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.

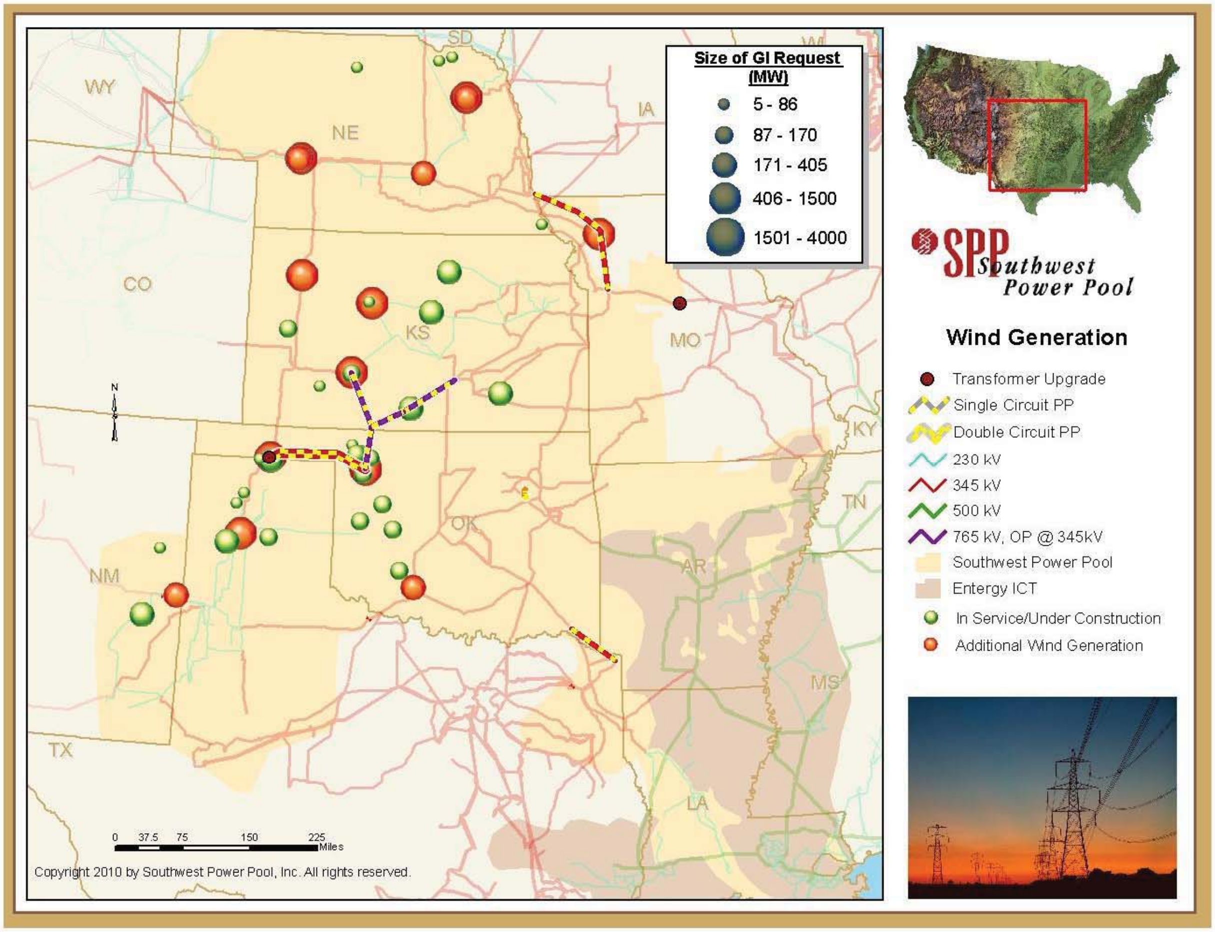


Figure 2: Wind Generation Modeled at 7 GW

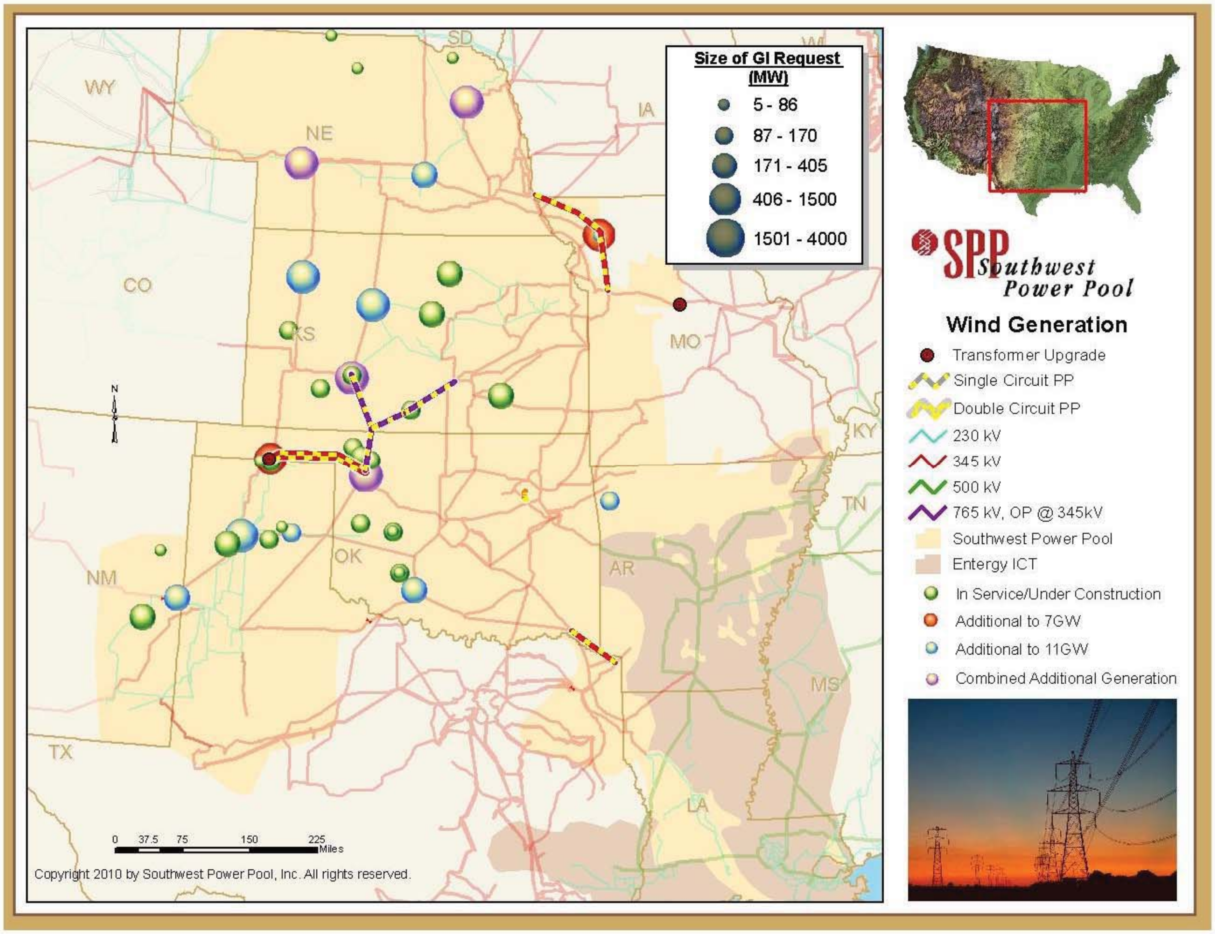


Figure 3: Wind Generation Modeled at 11 GW

- **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 $\text{LMP}_{\text{Gen Weighted}}$
and
Cost of Purchases = MW Import x Zonal $\text{LMP}_{\text{Load Weighted}}$

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.

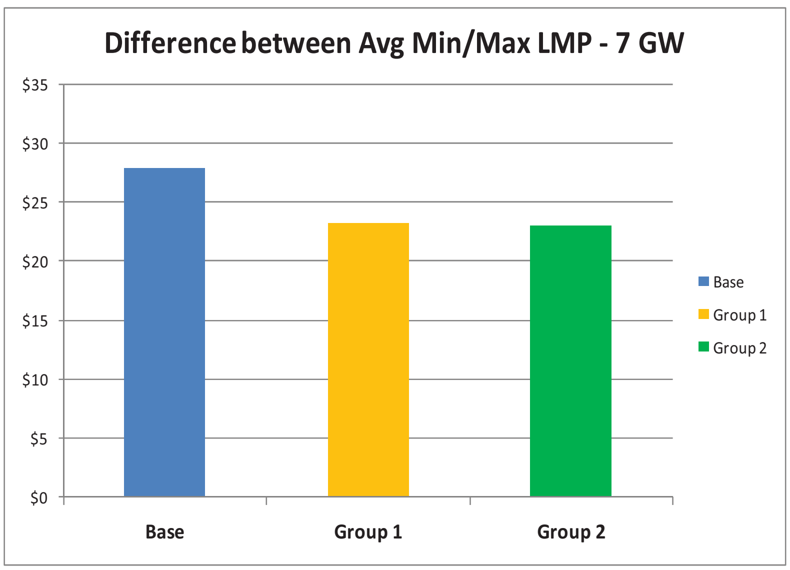


Figure 4: Spread of Avg Min/Max LMPs - 7 GW

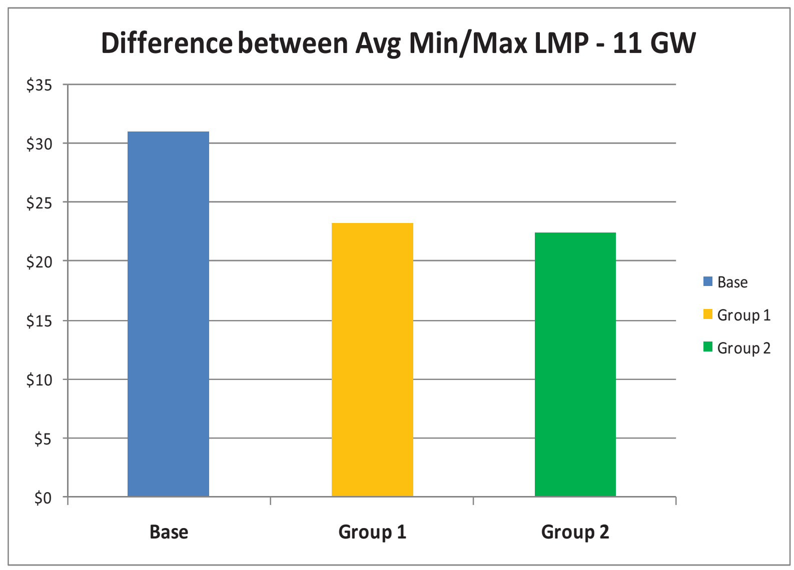


Figure 5: Spread of Avg Min/Max LMPs - 11 GW

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.

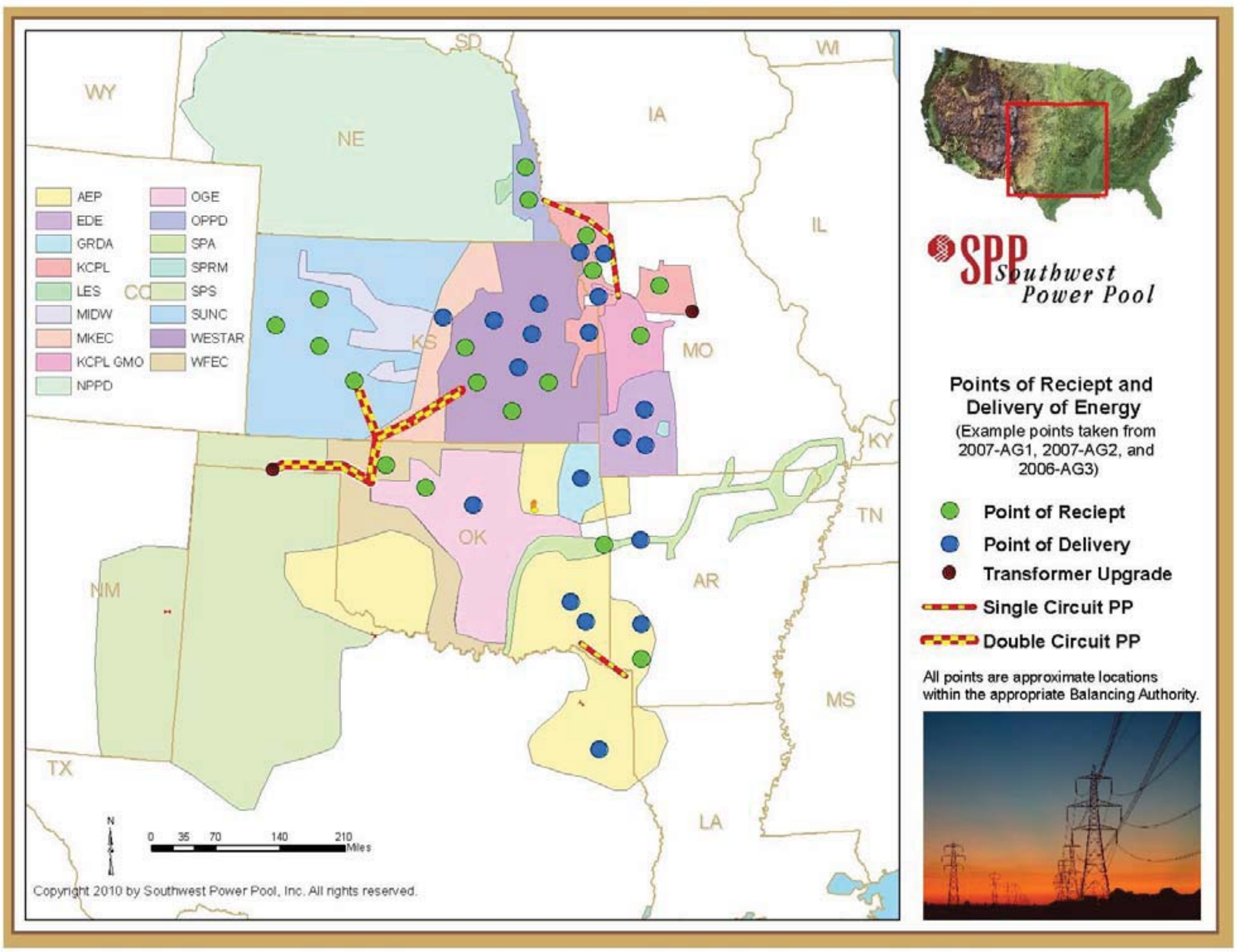


Figure 6

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:

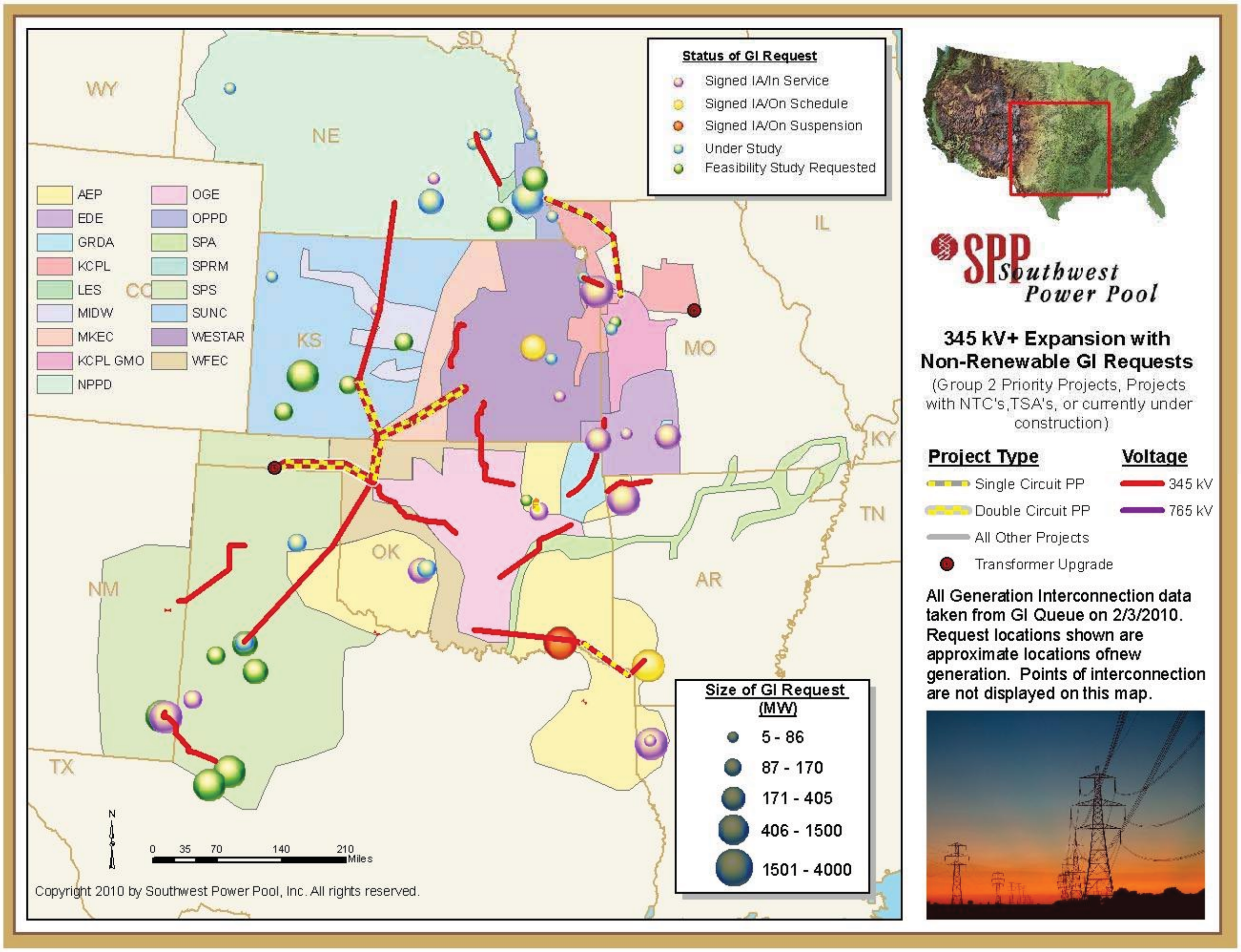


Figure 7: Non-Renewable GI Requests

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:

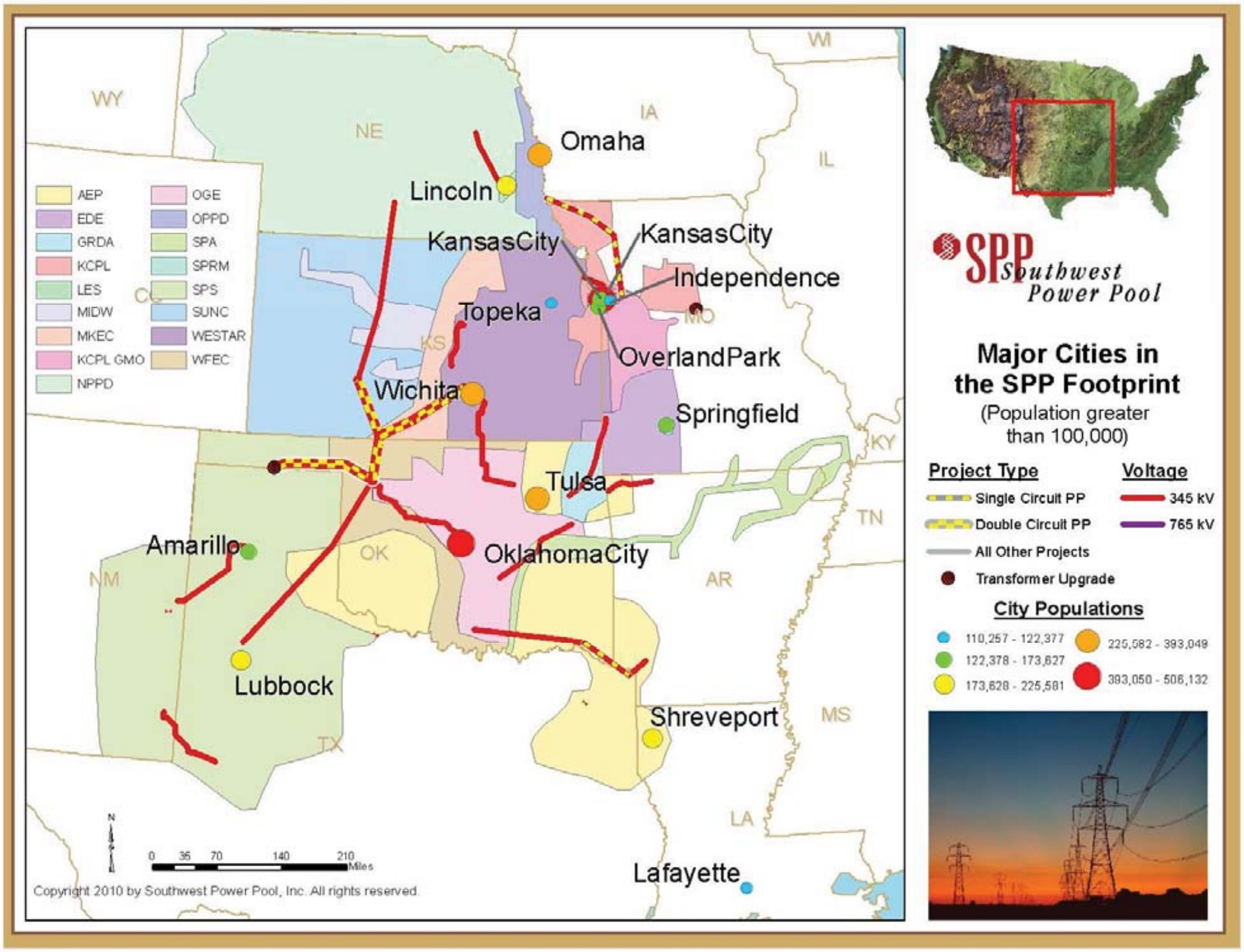


Figure 8: Major Cities in the SPP Footprint

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.

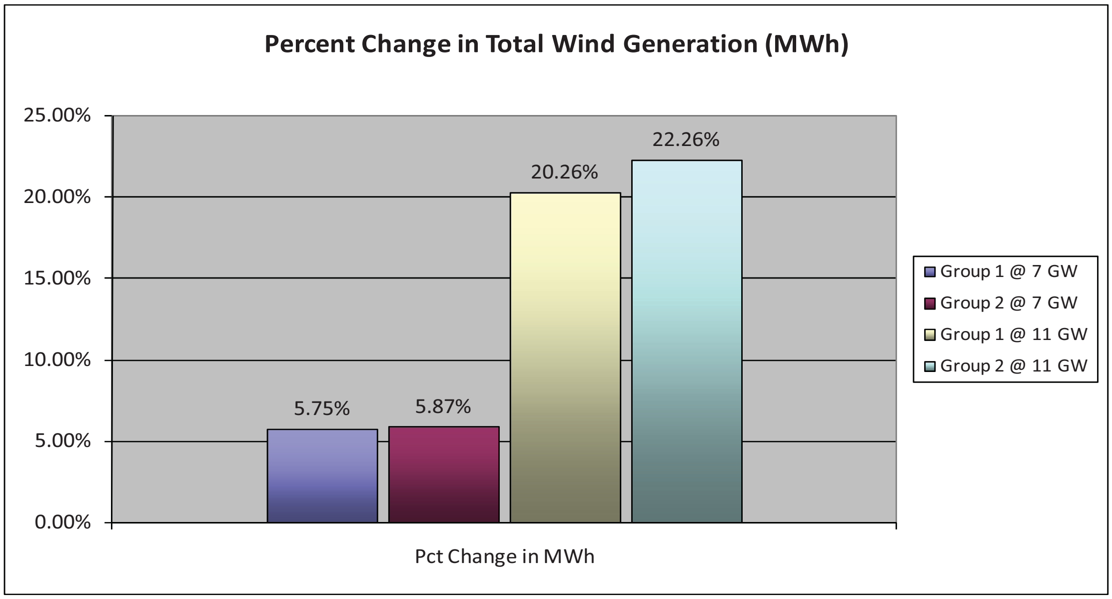


Figure 9: % Change in Total Wind Generation

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.

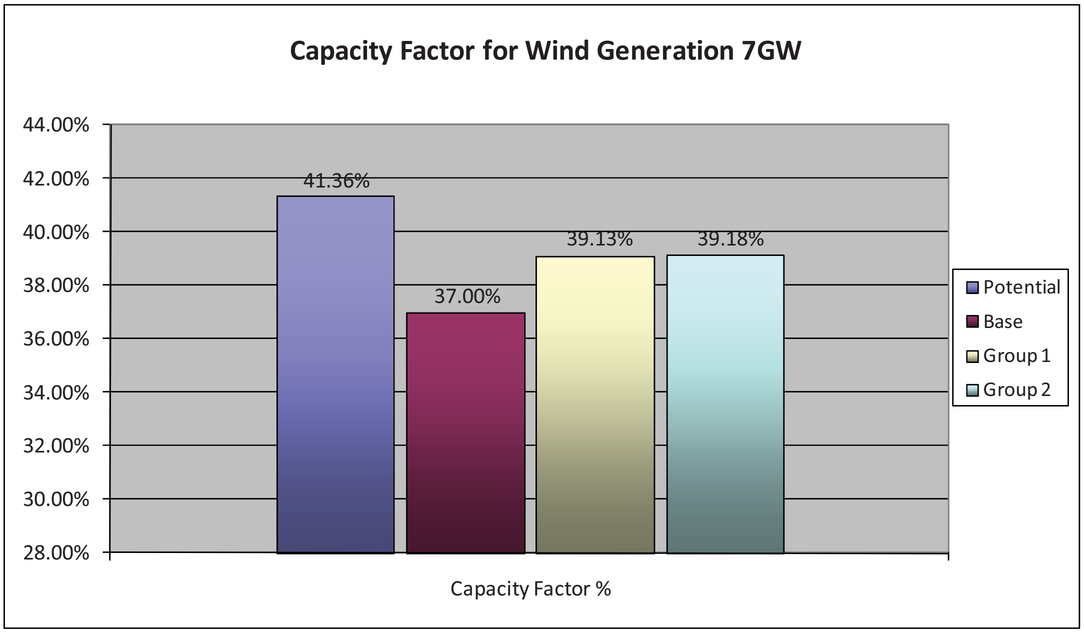


Figure 10: Wind Capacity Factor Changes – 7 GW

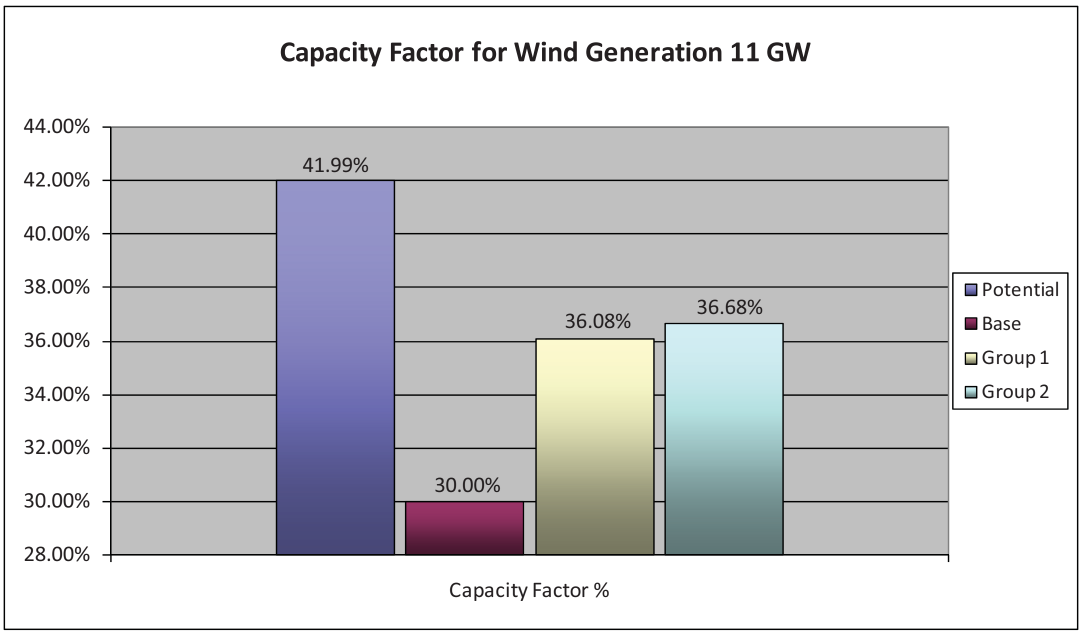


Figure 11: Wind Capacity Factor Changes – 11 GW

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.

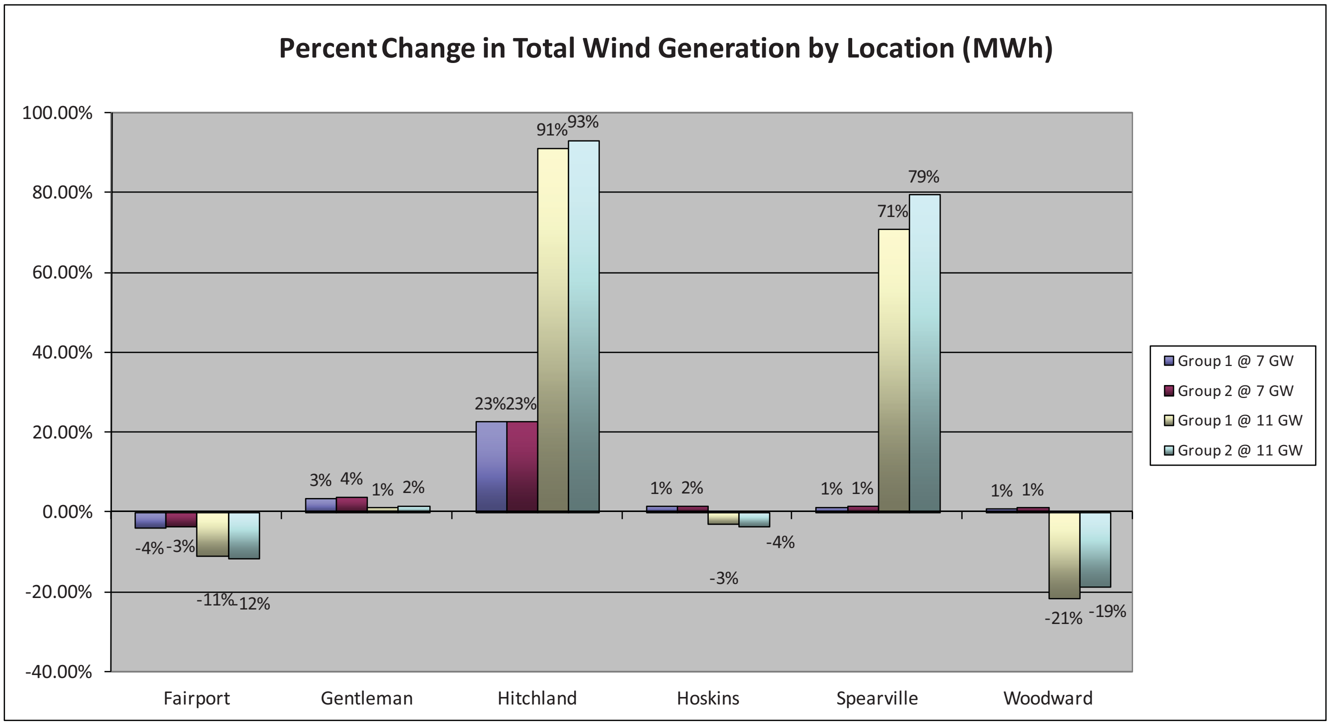


Figure 12: % Change in Wind Generation by Location

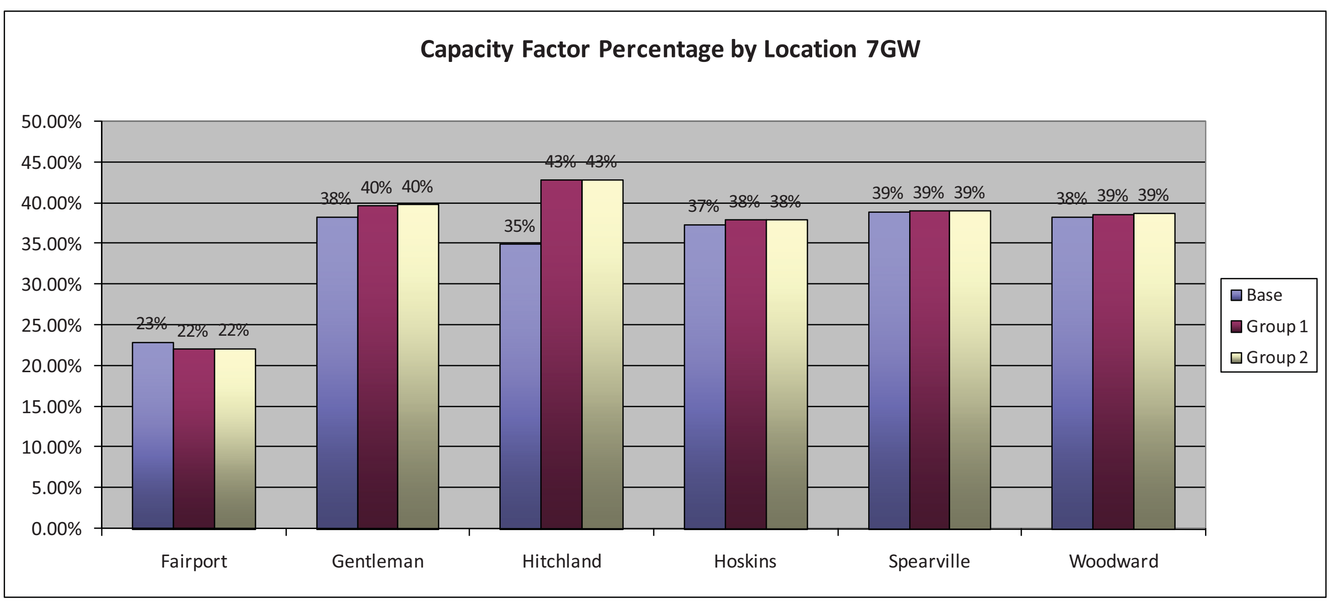


Figure 13: Capacity Factor by Location - 7 GW

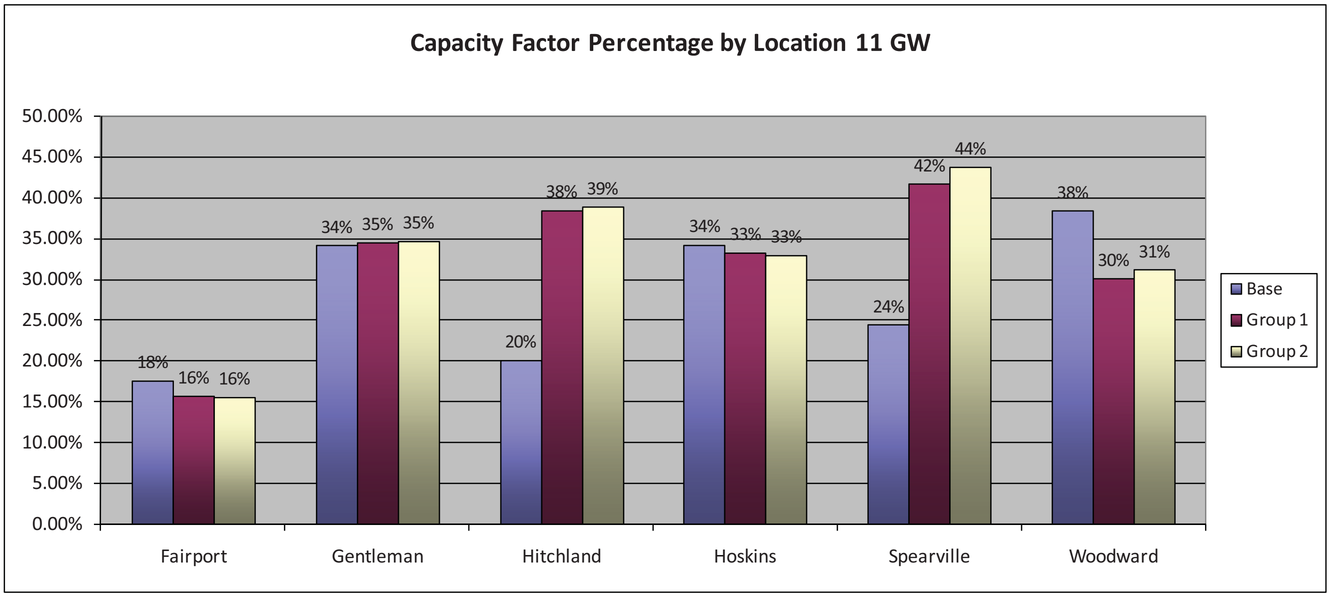


Figure 14: Capacity Factor by Location - 11 GW

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.

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						

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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.

	7 GW *Study Group 1 (765 kv @ 345 kV)*								
Area	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.

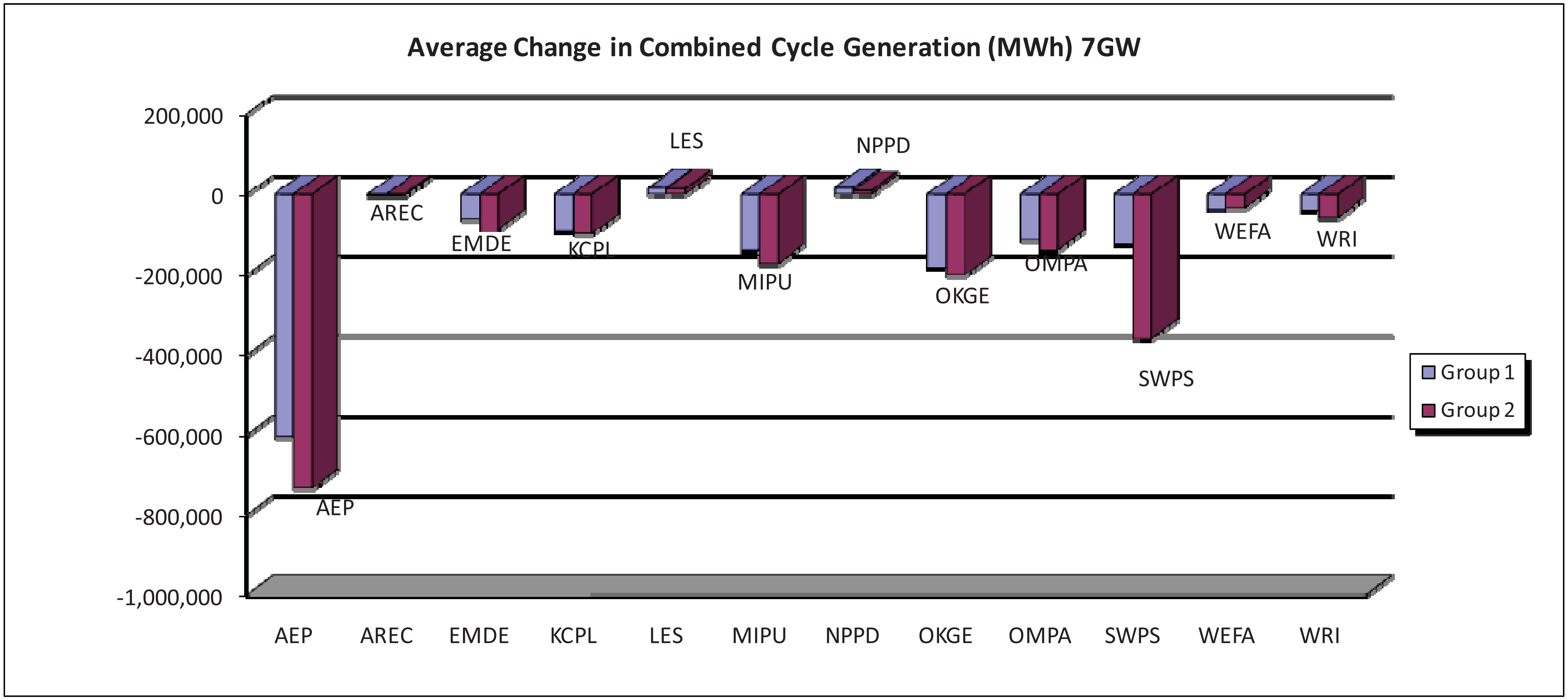

Figure 20: Avg Change in Combined Cycle Generation - 7 GW

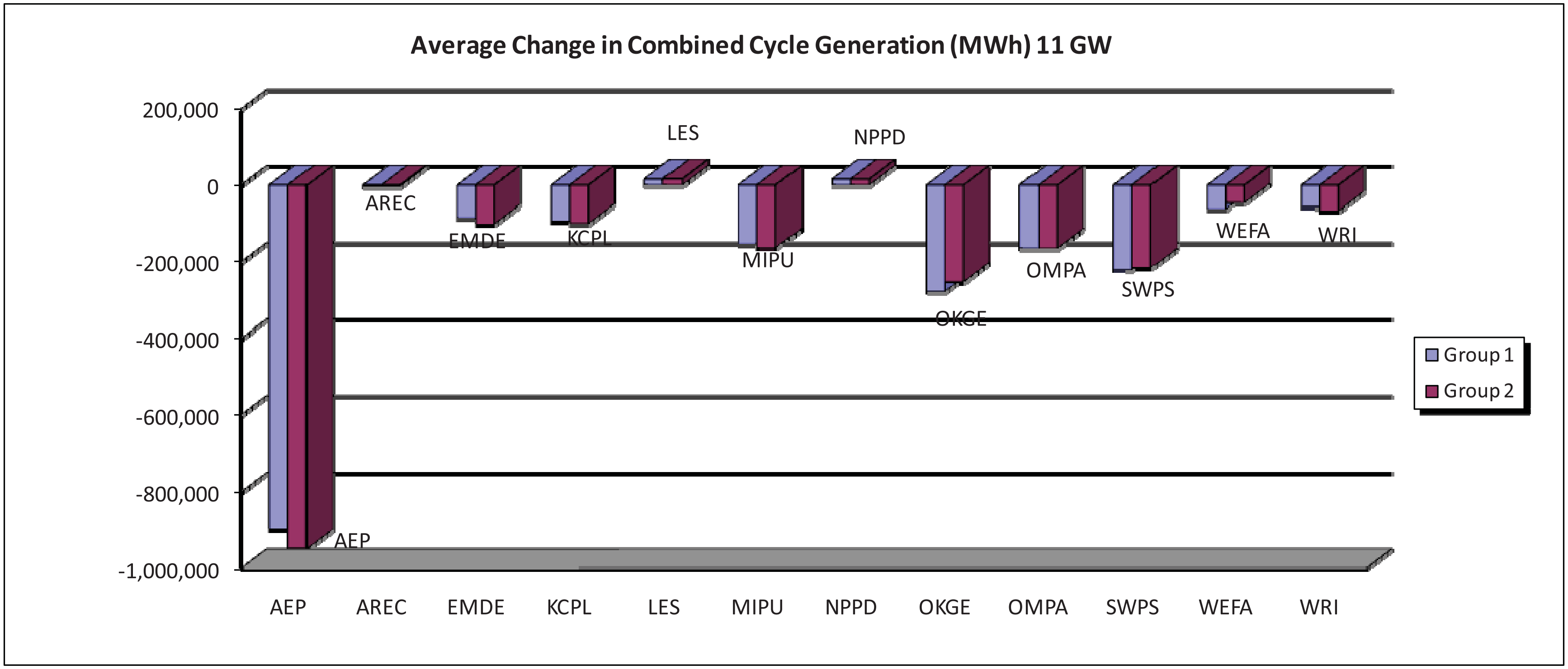

Figure 21: Avg Change in Combined Cycle Generation - 11 GW

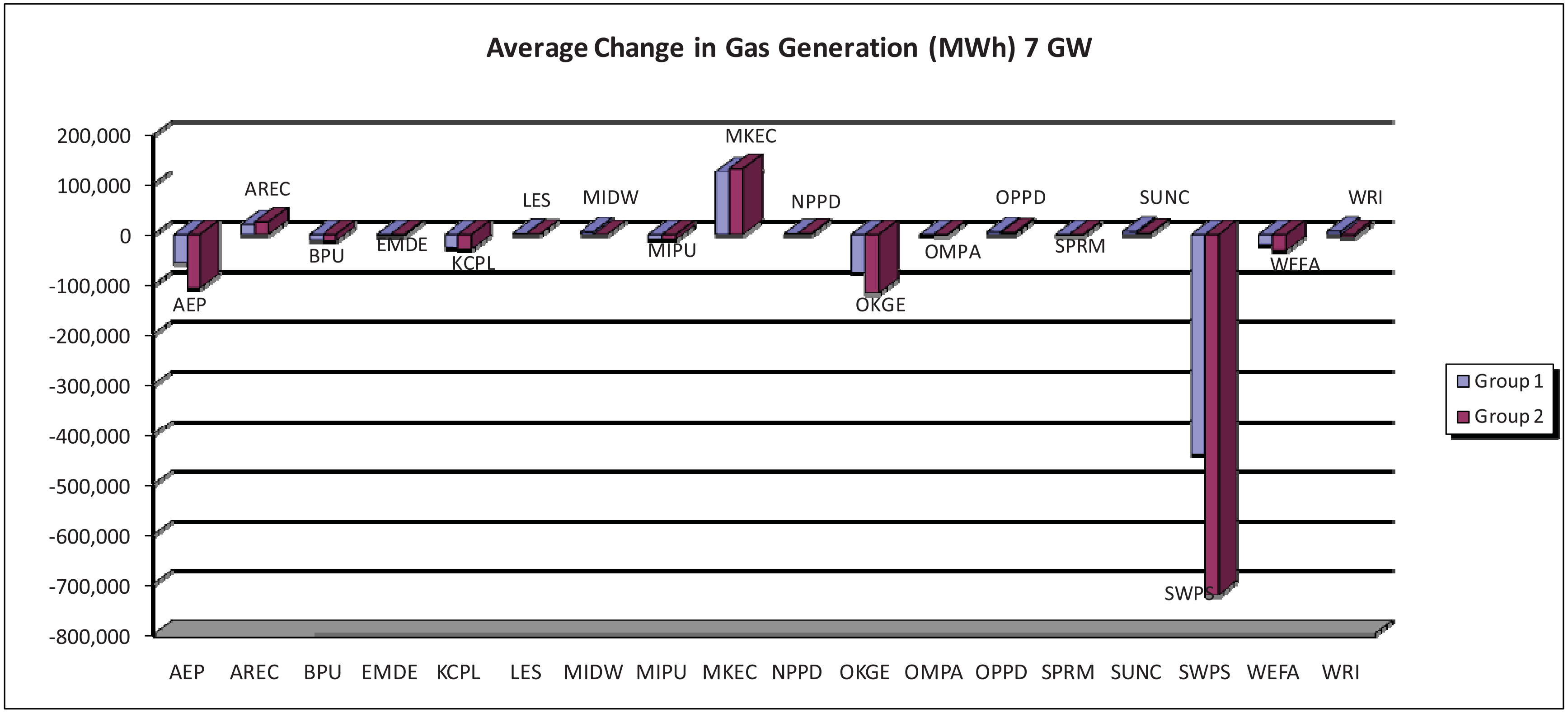

Figure 22: Avg Change in Gas Generation - 7 GW

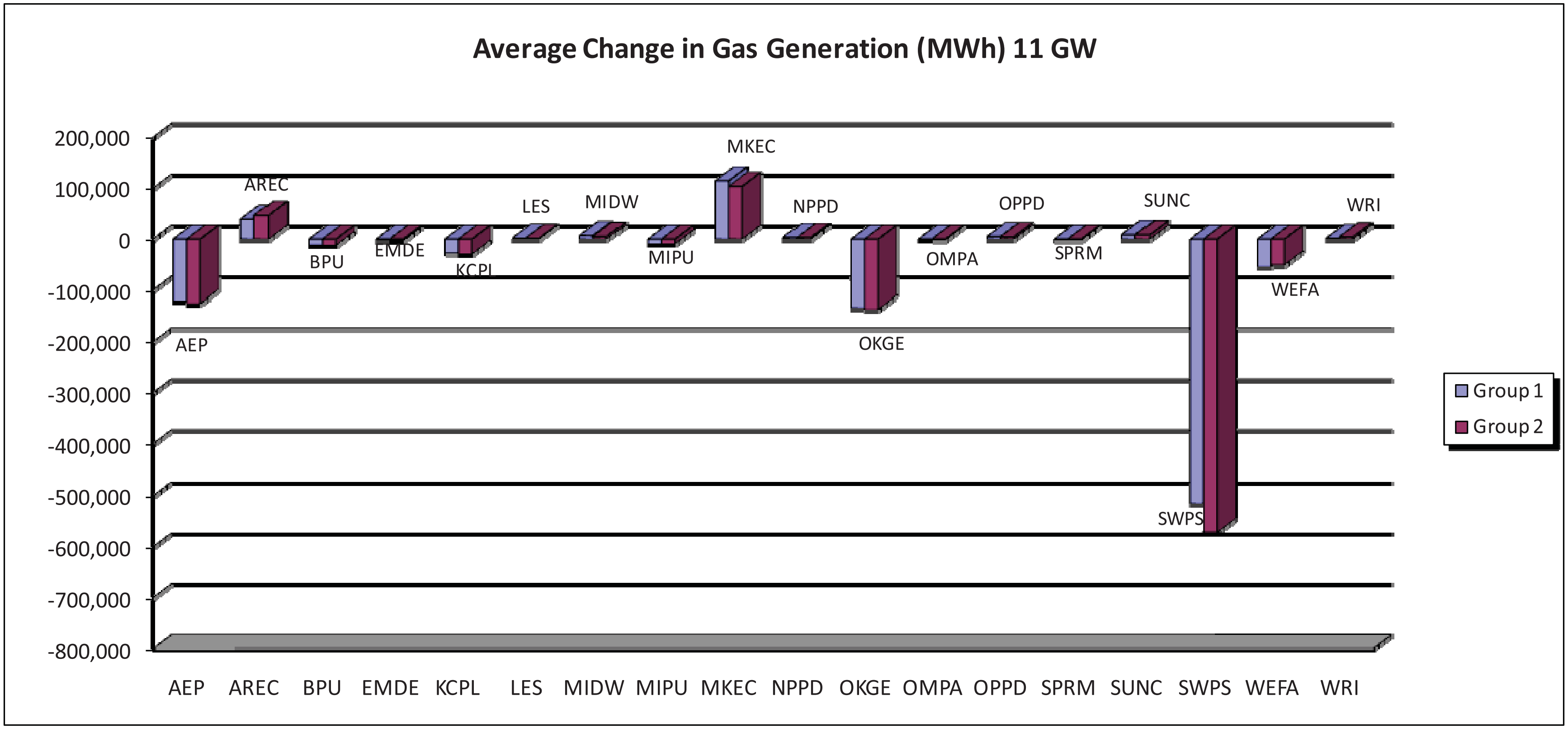

Figure 23: Avg Change in Gas Generation - 11 GW

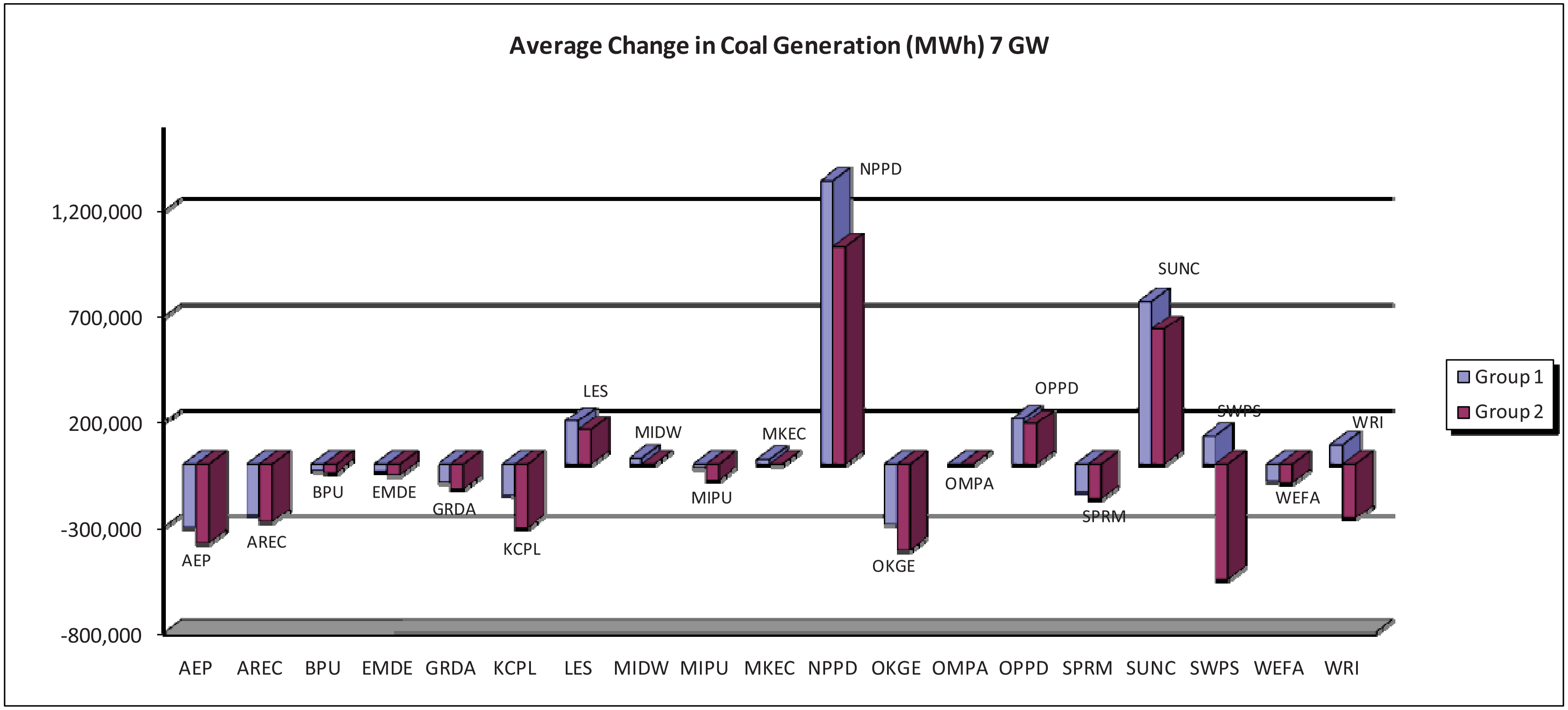

Figure 24: Avg Change in Coal Generation - 7 GW

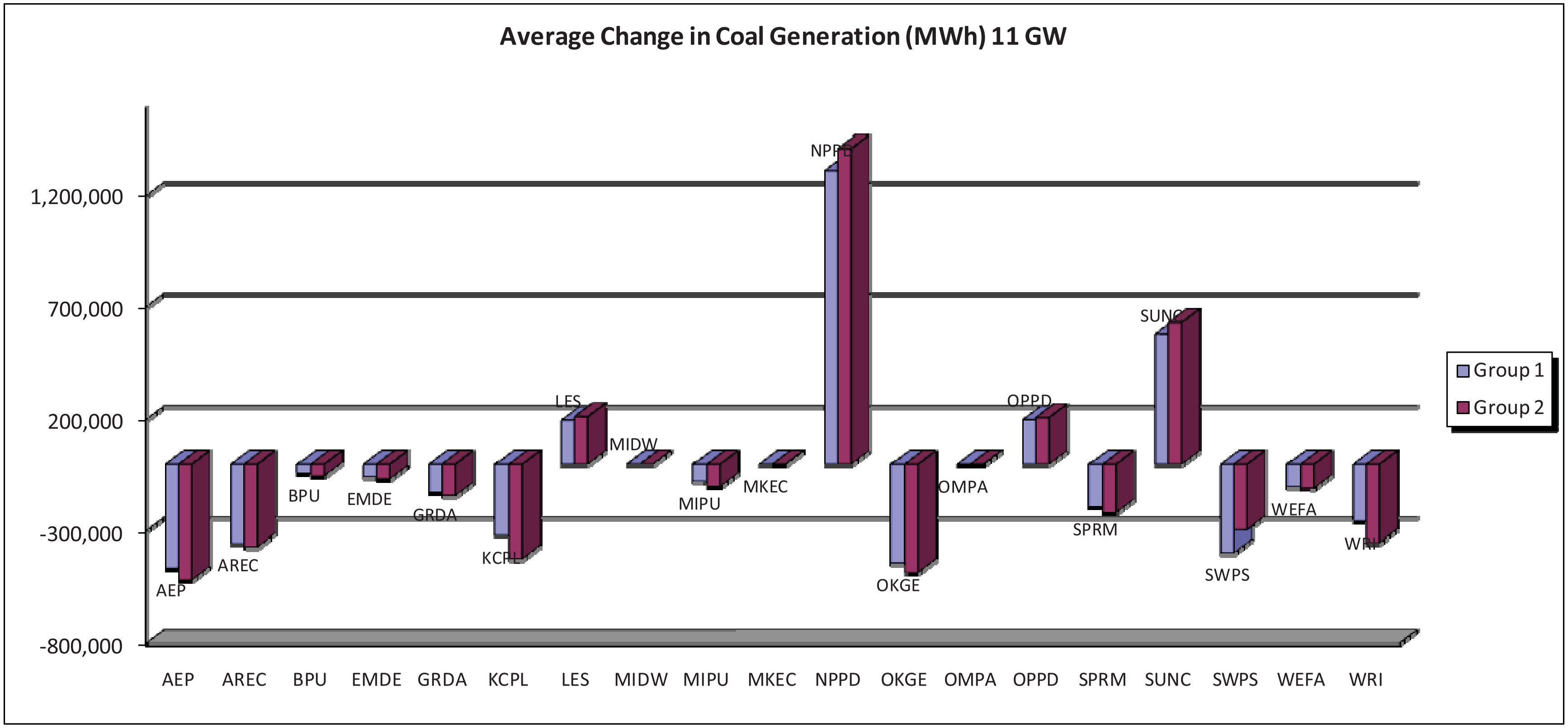

Figure 25: Avg Change in Coal Generation - 11 GW

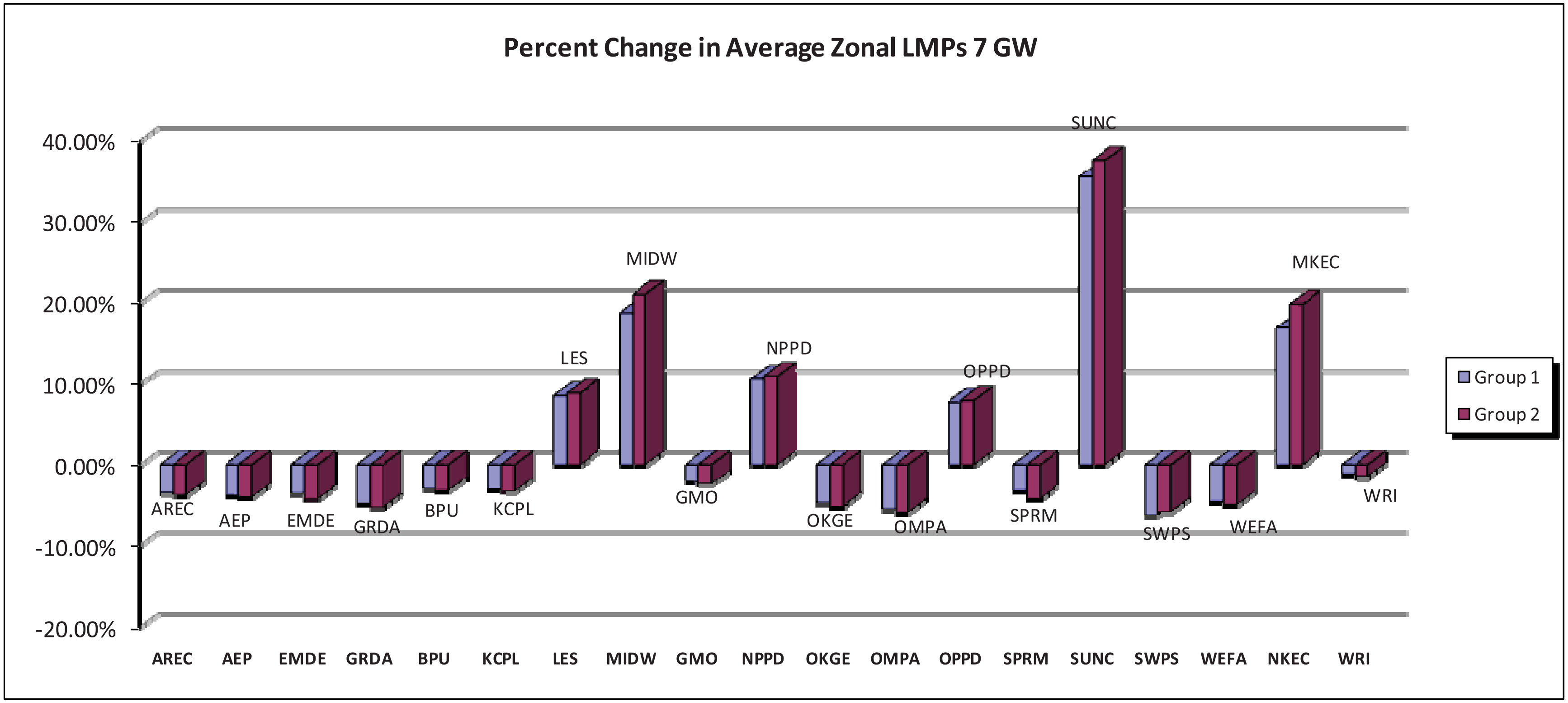

Figure 26: % Change in Avg Zonal LMPs - 7 GW

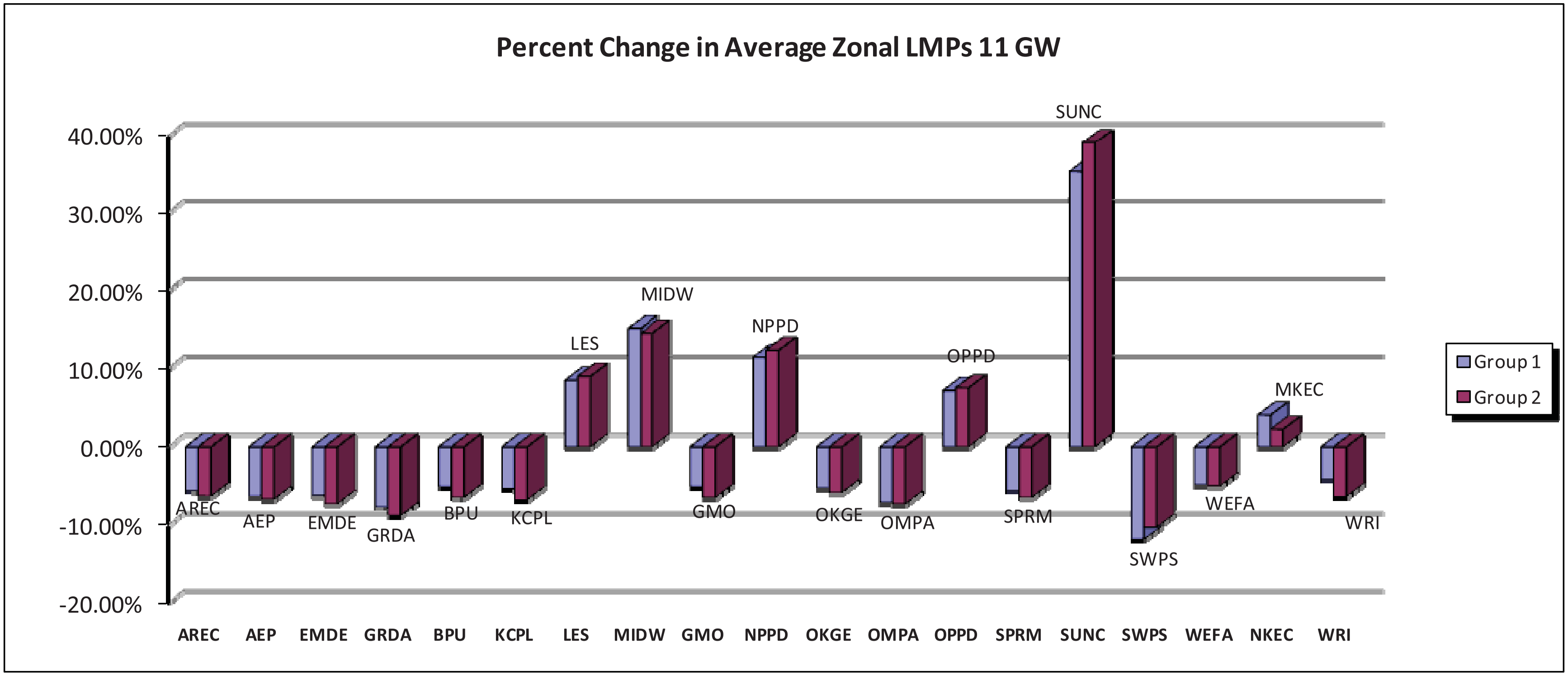

Figure 27: % Change in Avg Zonal LMPs - 11 GW

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.

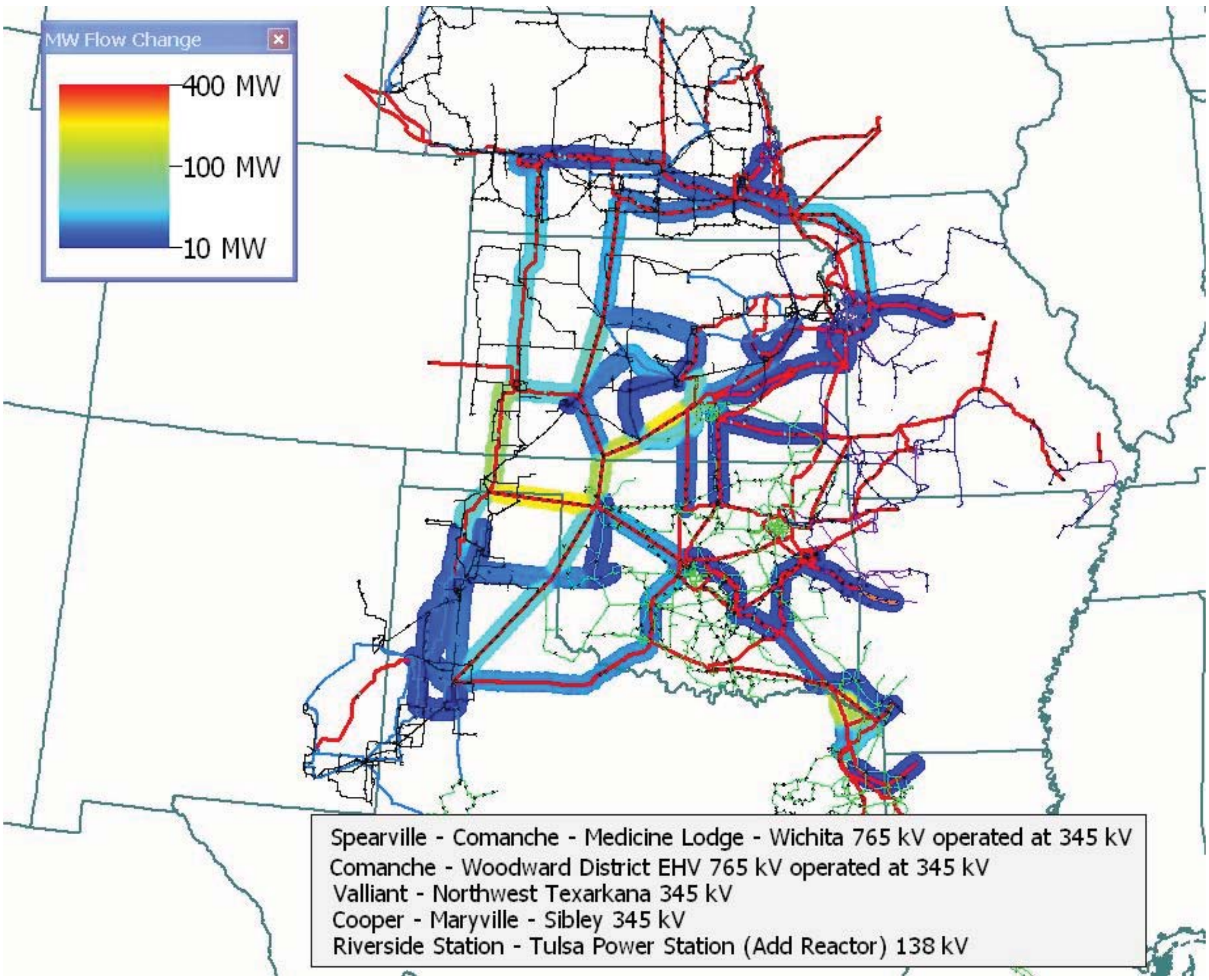

Figure 32: Priority Projects Group 1

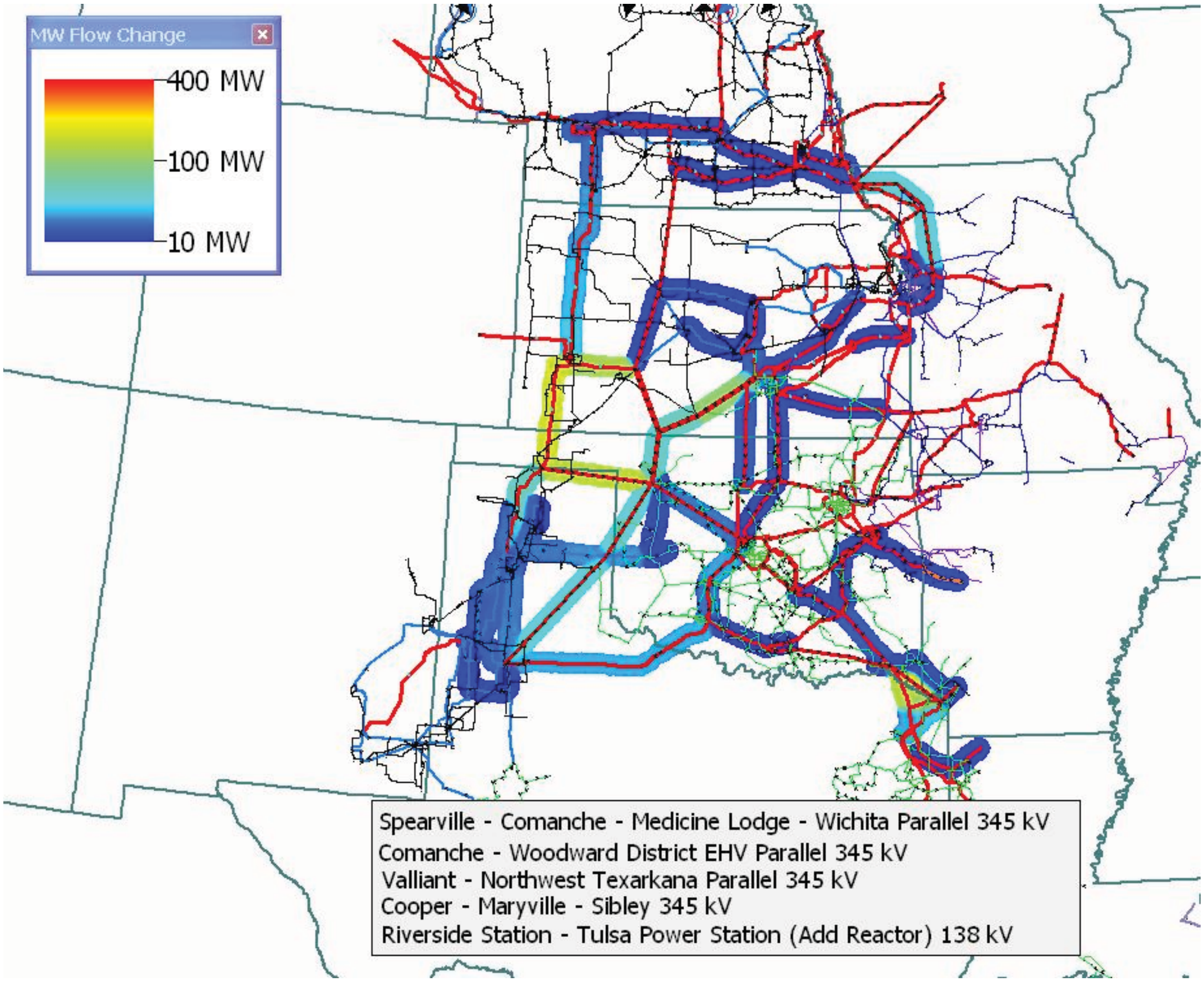

Figure 33: Priority Projects Group 2

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

2018 STEP

2018 SPP Transmission Expansion Plan Report

January 5, 2018

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
01/05/2018	SPP	Initial Draft
01/17/2018	SPP	Endorsed by MOPC
01/30/2018	SPP	Approved by the SPP BOD

Table of Contents

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List of Tables

Section 1: Executive Summary

The 2018 SPP Transmission Expansion Plan (STEP) is a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. Projects included in the 2018 STEP are:

- Upgrades required to satisfy requests for Transmission Service;
- Upgrades required to satisfy requests for Generator Interconnection Service;
- Approved projects from the Integrated Transmission Planning (ITP) 20-Year,10-Year and Near-Term Assessments;
- Approved Balanced Portfolio Upgrades;
- Approved High Priority Upgrades;
- Endorsed Sponsored Upgrades; and
- Approved Interregional Projects.

The 2018 STEP consists of 445 upgrades with a total cost of $4.96 billion.

We invite stakeholders and all interested parties to submit any written comments on the projects included in the STEP via our Request Management System (RMS). SPP solicits feedback on proposed solutions to transmission needs through stakeholder working groups and planning summits as well as through meetings, teleconferences, web conferences, and via email or secure web-based workspace. These meetings provide an open forum where all stakeholders have an opportunity to provide advice and recommendations to SPP to aid in the development of the STEP. In addition to these opportunities, we also invite stakeholders to provide SPP with any transmission needs they deem to be beneficial to the transmission planning process through our website or RMS.

The chart below illustrates the cost distribution of the 2018 STEP based on project type. More detail on the total portfolio is listed in Section 10.

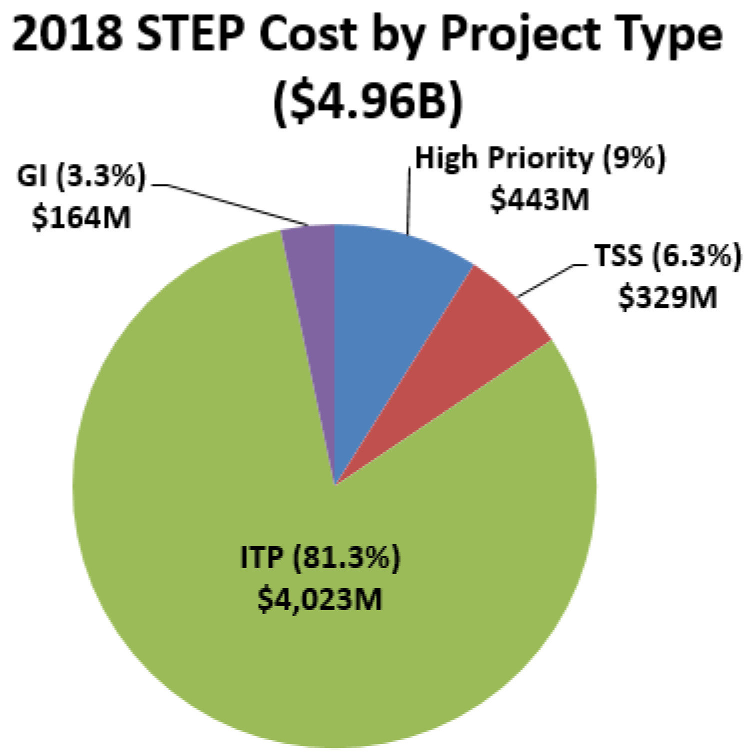


Figure 1-1: Cost by Project Type - 2018 STEP

After the SPP Board of Directors approves transmission expansion projects or once Service Agreements are executed, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners. A list of the NTCs issued in 2017 can be found in Section 11. A breakdown of the total list of NTCs issued in 2017 is shown below in Figure 1-2.

In 2017, SPP issued 30 NTC letters with estimated construction costs of $263.2 million for 71 projects to be constructed over the next five years through 2023. Of this $263.2 million, the upgrade cost breakdown is as follows:

- $110 thousand for Generator Interconnection (GI);
- $140.9 million for Transmission Service (TSS);
- $28.7 million for High Priority (HP); and
- $93.5 million for Integrated Transmission Planning (ITP) projects.

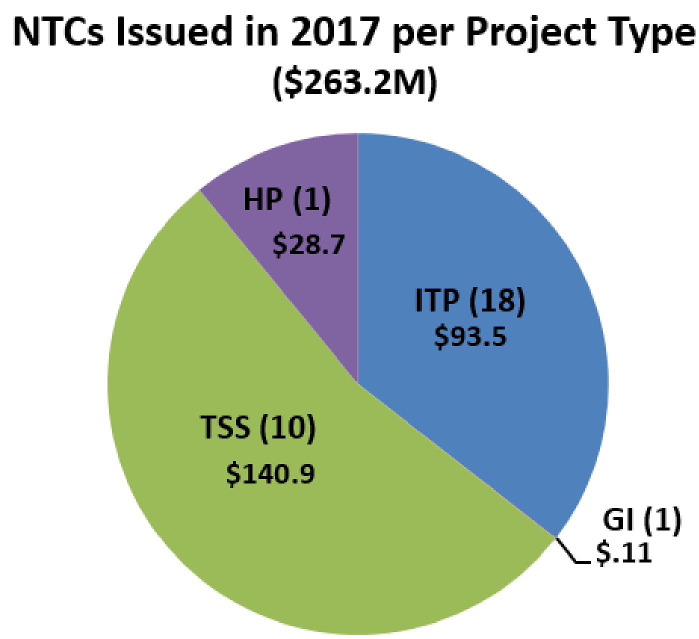


Figure 1-2: NTCs Issued in 2017 per Project Type

SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of December 20, 2017, 36 upgrades totaling approximately $245.6 million were completed during the year. The breakdown includes:

- 19 ITP - $163.9 million
- 3 TSS - $26.6 million
- 13 GI - $43.4 million
- 1 HP - $11.7 million

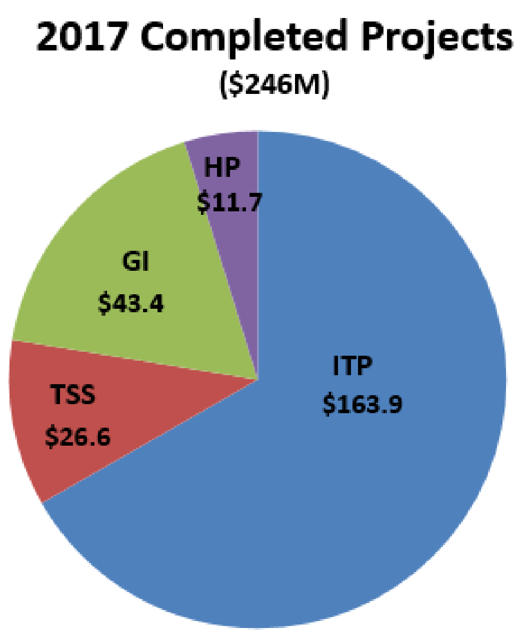


Figure 1-3: 2017 Completed Projects

Section 2: Transmission Services

2.1: Transmission Service 2017 Overview

SPP conducts the Aggregate Transmission Service Study (ATSS) process to determine if the SPP transmission system and neighboring Transmission Providers can accommodate requests for long-term firm Transmission Service. SPP combines all long-term point-to-point and long-term network integration transmission service requests received during a specified period of time into a single ATSS in order to develop a more efficient expansion of the transmission system that provides the necessary Available Transfer Capability (ATC) to accommodate all such requests at the minimum total cost.

During 2017, SPP completed two Aggregate Facilities Studies within the165-day study completion deadline in Attachment Z1 of the SPP Tariff. There were a combined 81 requests with a requested capacity of 5,076 MW. Below is a link to the Transmission Service Studies page where the studies can be further reviewed:

http://sppoasis.spp.org/documents/swpp/transmission/TRPAGE.cfm

Currently, the 2017-AG2 Aggregate Facility Study is underway and will be posted to the Transmission Service Studies page by May 14, 2018. There are 28 requests with a requested capacity of 1,561 MW in this study.

The graph below shows the total estimated cost of Transmission Service projects included in the 2018 STEP as compared to previous STEP Reports. Fluctuations in the annual STEP estimates may be influenced by the number of new projects identified in completed Transmission Service Studies either having been issued NTCs or approved and awaiting the issuance of an NTC, the completion of Transmission Service related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

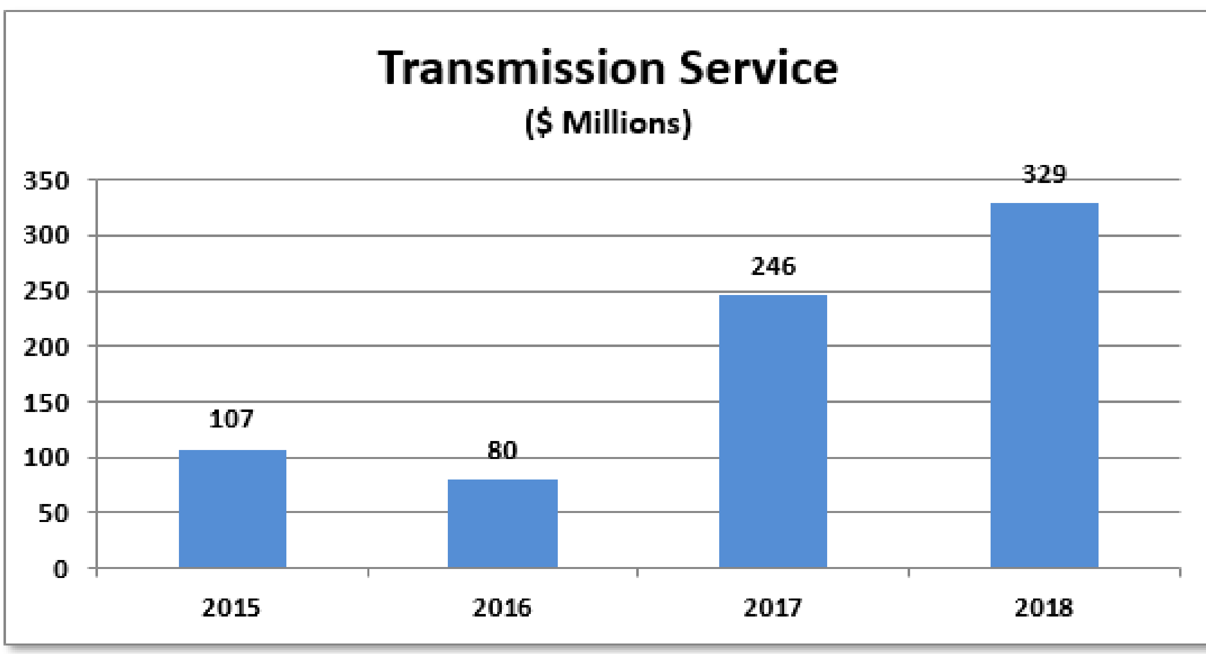


Figure 2-1: STEP Cost Estimate Comparison for Transmission Service Projects – 2015-2018

Transmission Service projects completed in 2017 can be found in the Completed Projects table in Section 12.

2.2: Tariff Attachments AQ and AR

Attachment AQ

SPP Tariff Attachment AQ defines a process through which delivery point additions, modifications, or abandonments can be studied without having to go through the Aggregate Study process. Delivery points submitted through the process are examined in an initial assessment to determine if a project is likely to have a significant effect on the transmission system. If necessary, a full study is then performed on the requested delivery points to determine any necessary upgrades. There were two NTCs issued in 2017 as a result of the Attachment AQ study process.

The number of requests and required studies are summarized in Table 2-1 below.

Study Year	Delivery Point Requests	Full Studies Required	Load Increase
2013	87	22	882 MW
2014	96	19	1,032 MW
2015	89	13	1,271 MW
2016	129	21	1,021 MW
2017	106	21	1,196 MW

Table 2-1: AQ Study Summary – 2013-2017

Attachment AR

Attachment AR defines a screening process used to evaluate potential Long-Term Service Request (LTSR) options or proposed Delivery Point Transfers (DPT). The LTSR option provides customers with a tool to assess possible availability of transmission service. The DPT screening study option enables customers to implement a DPT via issuance of a Service Agreement, more expediently pending the results of the screening. Both of these screening tools allow for a more streamlined ATSS process by reducing the number of requests in the ATSS process.

During 2017, seven DPT studies were posted and service was granted for six of the studies. There were no LTSR studies requested in 2017, but there were nine studies posted in 2017 resulting from 2016 requests.

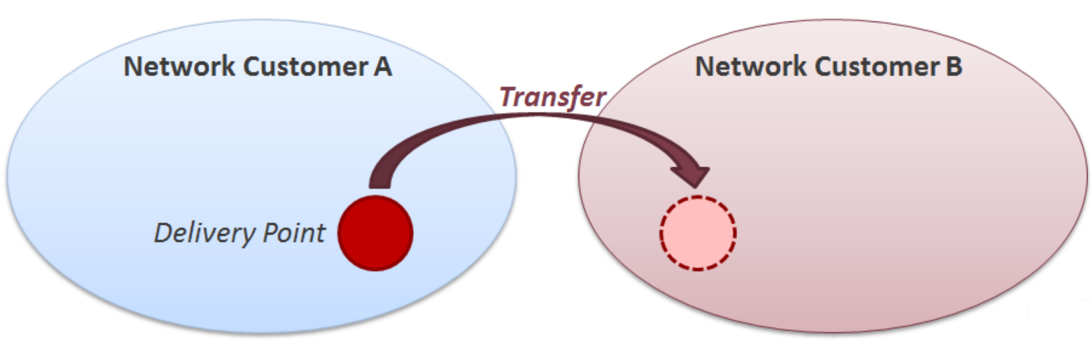


Figure 2-2 DPT Study Process

Section 3: Generator Interconnection

3.1: Generator Interconnection Overview

A GI study is conducted pursuant to Attachment V of the SPP Tariff whenever a request is made to connect new generation to the SPP transmission system. GI studies are conducted by SPP in collaboration with affected Transmission Owners and neighboring Transmission Providers to determine the required modifications to the transmission system, including cost and scheduled completion dates required to provide the service.

From January 1, 2017 to December 15, 2017 SPP received 239 GI requests and twenty-four (this includes both withdrawn and incomplete) affected system GI requests, compared to the 184 GI requests and nine affected system study requests received through the same period in 2016. As of December 15, 2017, there were 406 active[1] GI queue requests under study for 74,306 MW, and 9 requests had been removed from "study" status either from being withdrawn by the Customer or SPP or by the Customer executing a Generator Interconnection Agreement (GIA). The affected system study requests were made by neighboring Transmission Providers requesting SPP's evaluation of the impact of the requests on SPP's transmission system.

The graph below shows the total estimated cost of GI projects included in the 2018 STEP as compared to previous STEP Reports. Fluctuations in the annual STEP estimates may be influenced by the number of new projects identified in completed Generator Interconnection Studies that have either been issued NTCs or are approved and are awaiting the issuance of an NTC, the completion of Generator Interconnection related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

[1] Active GI requests includes those with an OASIS status of: FEASIBILITY STUDY STAGE, PISIS STAGE, DISIS STAGE, FACILITY STUDY STAGE, or IA PENDING, and those that have been submitted but not yet validated.

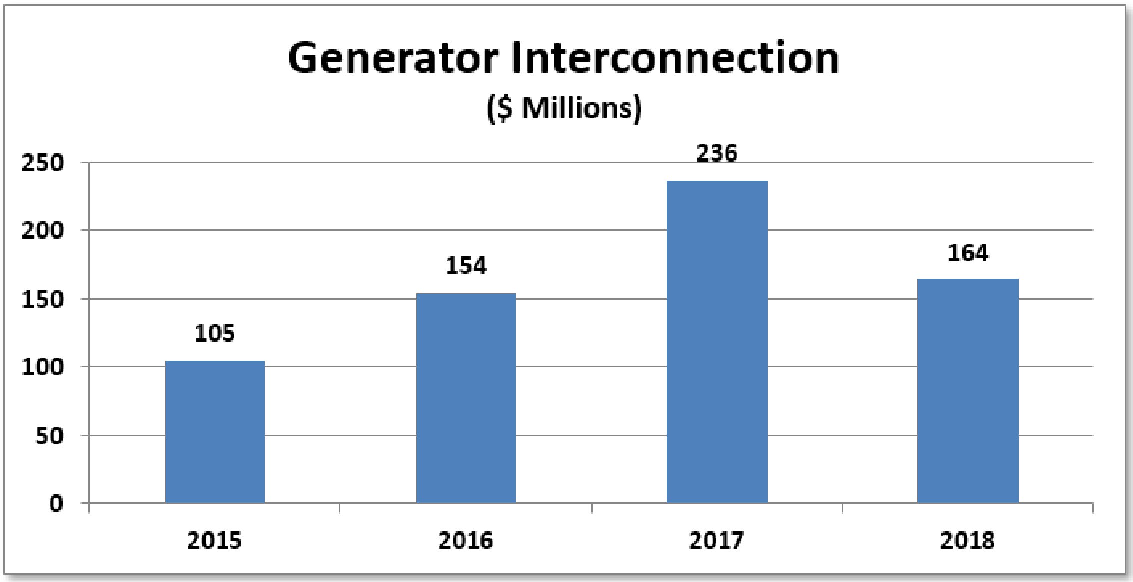


Figure 3-1: STEP Cost Estimate Comparison for Generator Interconnection Projects – 2015-2018

GI projects completed in 2017 can be found in the Completed Projects table in Section 12.

Section 4: Integrated Transmission Planning

4.1: 2017 ITP Near-Term (ITPNT)

During 2017, the 2017 ITPNT Assessment was completed and approved by the SPP Board of Directors in April. The 2017 ITPNT analyzed the SPP region's immediate transmission needs over the near-term planning horizon. The ITPNT assessed: a) regional upgrades required to maintain reliability in accordance with the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards and SPP Criteria in the near-term horizon; b) zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near-term horizon; and c) coordinated projects with neighboring Transmission Providers. ITPNT projects are reviewed by SPP's Transmission Working Group (TWG) and Markets and Operations Policy Committee (MOPC) and approved by the SPP Board of Directors. Following Board of Directors' approval, SPP issued NTC letters for upgrades that required a financial commitment within the next four-year timeframe.

SPP performed analyses identifying potential bulk power system reliability needs. These findings were presented to Transmission Owners and the TWG to solicit transmission solutions to the potential issues identified. Also considered were transmission solutions from other SPP studies, such as the Aggregate Transmission Service Study and Generator Interconnection processes. From the resulting list of potential solutions, SPP identified the cost effective regional solutions for potential reliability needs. Through this process, SPP developed a draft list of 69 kV and above solutions necessary to provide reliable service in the SPP region in the near-term planning horizon.

For information on the 2017 ITPNT Assessment, see the full report (SPP.org > Engineering > Transmission Planning>2017 ITPNT Report).

The maps in Figures 4-1 and 4-2 show the draft ITPNT thermal and voltage solutions in correlation to the areas identified with reliability criteria violations.

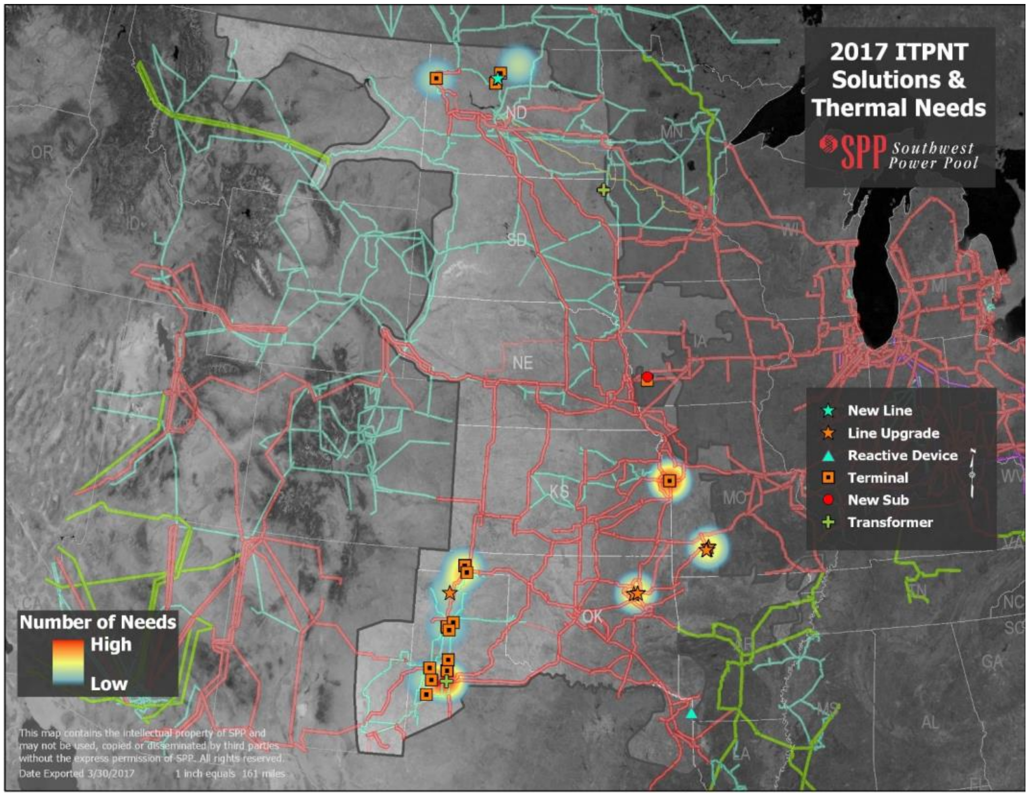


Figure 4-1: 2017 ITPNT Thermal Needs and Solutions

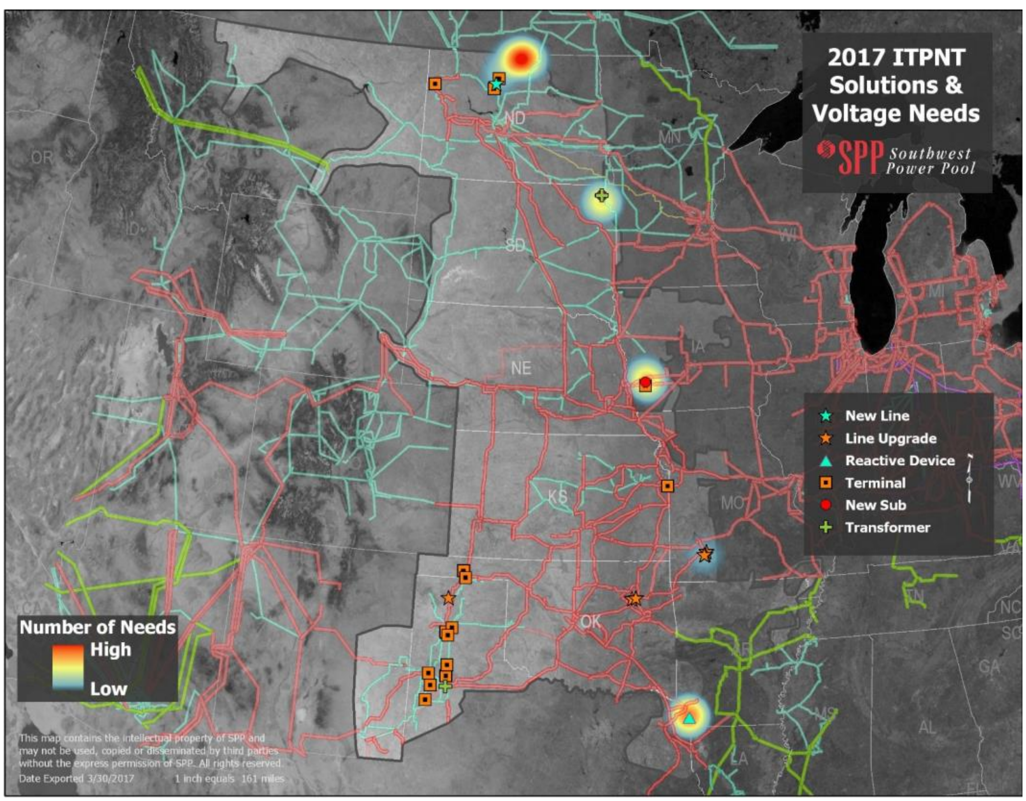


Figure 4-2: 2017 ITPNT Voltage Needs and Solutions

The net total study STEP impact of the 2017 ITPNT project plan is estimated to be $23.45M. There are 25 proposed upgrades making up 16 projects in the project plan. Of the 16 proposed projects, 15 will be recommended for issuance of new NTCs. One project had been identified as needing a Modified NTC (NTC modify). That net impact includes $60.34M for new projects, $184K in NTC Modify projects, and a reduction of $37M for withdrawn NTCs identified in the 2017 ITPNT Assessment. The 25 upgrades that received an NTC, NTC-C or NTC Modify solved 40 thermal and 68 voltage needs on the SPP transmission system. Project plan mileage consists of 26 miles of new transmission line and 35 miles of rebuild/reconductor line.

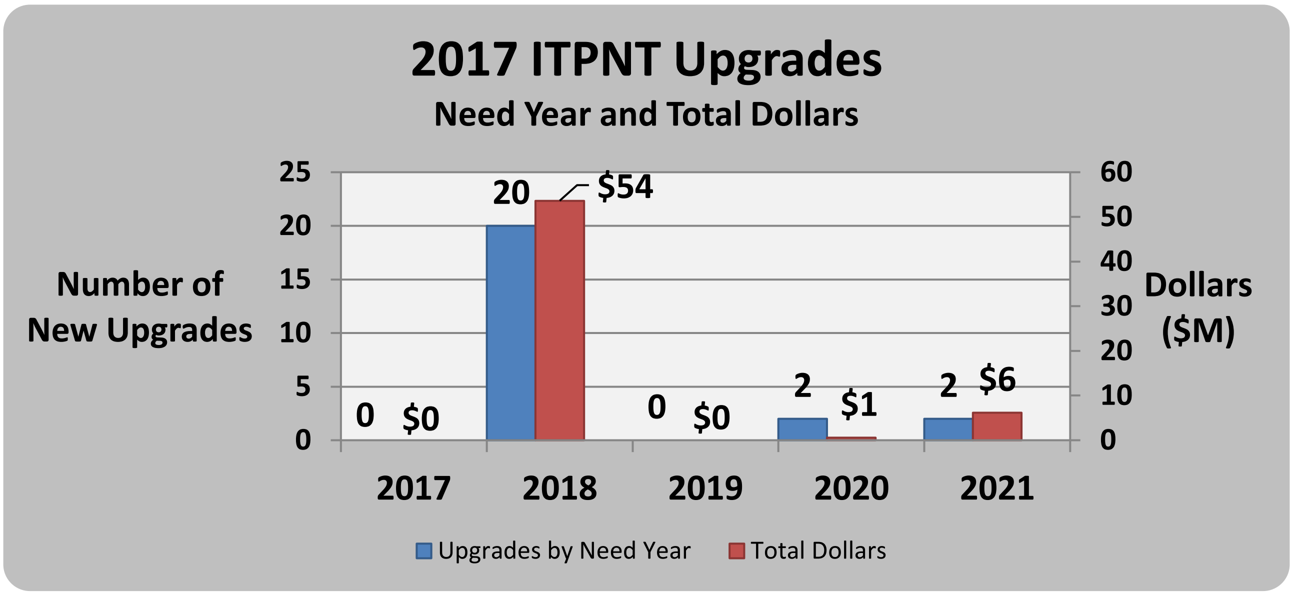


Figure 4-3: 2017 ITPNT Upgrades by Need Years and Dollars

Voltage Class	New Line (miles)	Rebuild/Reconductor (miles)
138 kV	0	9
115 kV	24	11
69 kV	2	15

Table 4-1: 2017 ITPNT Project Plan Mileages

The 2018 ITPNT assessment is currently in progress and SPP intends to finalize the Report and Portfolio in July 2018.

4.2: 2017 ITP10

The 2017 ITP10 was summarized in the 2017 STEP report which included a list of proposed projects. NTCs from the 2017 ITP10 were issued in 2017 and the table below summarizes the projects.

NTC ID	PID	Project Name	Facility Owner	Current Cost Amount
200428	31085	Northeast - Charlotte - Crosstown 161 kV Reactor	KCPL	$500,000
200429	31127	Knoll - Post Rock 230 kV New Line Ckt 2	MIDW	$409,012
	31127	Knoll Sub 230kV Terminal		$1,652,257
	31127	Post Rock Sub Addition		$1,245,091
200430	31082	Butler - Altoona 138 kV Terminal Upgrades	WR	$238,640
	31083	Neosho - Riverton 161 kV Terminal Upgrades	WR	$111,370
200431	31131	Siloam Springs - Siloam Springs City 161 kV Ckt 1 Rebuild (AEP)	AEP	$4,780,000
200432	31131	Siloam Springs - Siloam Springs City 161 kV Ckt 1 Rebuild (GRDA)	GRDA	$279,400
200433	31144	Tupelo 138 kV Terminal Upgrades	WFEC	$100,000
200434	31150	Lula- Tupelo Tap 138 kV Terminal Upgrades	OGE	$16,000
200444	31079	Tuco - Stanton 115 kV Terminal Upgrades	SPS	$356,757
	31080	Stanton - Indiana 115 kV Terminal Upgrades		$302,133
	31081	Indiana - SP-Erskine 115 kV Terminal Upgrades		$294,764
	41189	Martin - Pantex North 115 kV Terminal Upgrades		$335,157
	41189	Pantex South - Highland Tap 115 kV Terminal Upgrades		$335,697
200467	31082	Butler - Altoona 138 kV Terminal Upgrades	WR	$247,332

Table 4-2: 2017 ITP10 NTCs Issued

4.3: 2017 ITP10 Potter to Tolk 345 kV Additional Analysis

SPP staff proposed the construction of a 345 kV transmission line from the Potter 345 kV substation to the Tolk 345 kV substation as a part of their recommended 2017 ITP10 assessment portfolio. The MOPC approved the portfolio at its January 2017 meeting. During the 2017 SPP Board meeting, concerns were brought to the Board by stakeholders and Members Committee. With this feedback, the Board directed staff to further evaluate the project and report back to the Board at its April 2017 meeting.

With review and requested feedback from the TWG and ESWG, staff developed a study scope that contained the following elements:

- Perform a review of the third party study estimate used in the 2017 ITP10 assessment
- Perform economic model input sensitivities on the following:
  - Conventional resource assignment and siting
  - Renewable additions and siting
  - Load and gas price forecasts
- Substantiate future avoided reliability projects
- Calculate 40-year benefits

Staff presented their findings[2] to the Board during its April 2017 meeting with a recommendation for the removal of the Potter to Tolk 345 kV transmission line from the 2017 ITP10 portfolio. The TWG-, ESWG-, and MOPC-approved recommendation was approved by the Board and the project was removed from the portfolio.

[2] A presentation regarding the analysis can be found in the background materials of the April 25, 2017 Board meeting. Materials can be found at the following link: https://www.spp.org/documents/49913/bod_materials_20170425_pgd.pdf

Section 5: High Priority Studies

Figure 5-1 below is a comparison of the cost estimates for projects coming out of High Priority Studies. High Priority Studies projects completed in 2017 can be found in the Complete Project table in Section 12. Study details follow in sections 5-1 and 5-2.

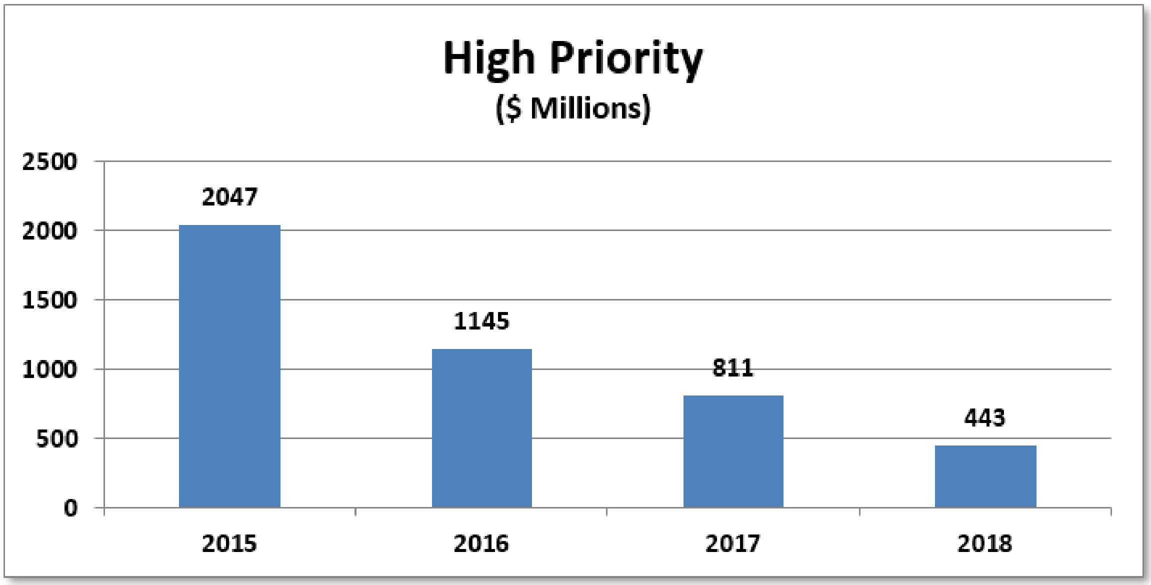


Figure 5-1: STEP Cost Estimate Comparison for High Priority Projects – 2015-2018

5.1: SPP Priority Projects

As referenced in the 2017 STEP Report, the final three projects associated with SPP's 2010 Priority Projects assessment were all place in-service in mid-December 2016. The projects are listed below in Table 5-1. For information on Priority Projects, see the full report (SPP.org > Engineering > Transmission Planning>Local Area Planning and High Priority Studies).

NTC ID	Project ID	Project Owner	Project Name
20096	936	AEP	Northwest Texarkana – Valliant 345 kV Ckt 1
20097	938	TSMO	Multi – Nebraska City – Mullin Creek – Sibley 345 kV (GMO)
20098	939	OPPD	Line – Nebraska City – Mullin Creek 345 kV (OPPD)

Table 5-1: Priority Projects

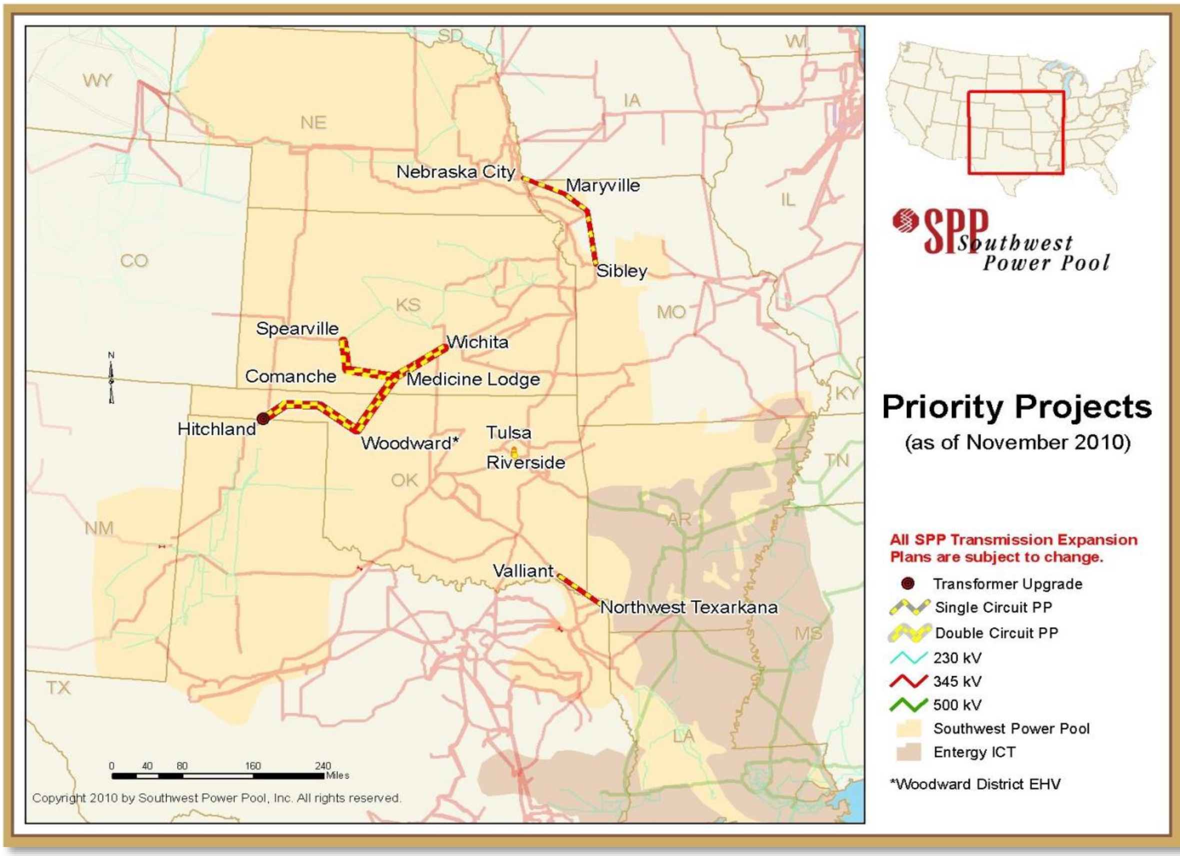


Figure 5-2: SPP Priority Projects

5.2: High Priority Incremental Load Study (HPILS)

HPILS projects included in the 2018 STEP List are listed in Table 5-2 below.

For information on the HPILS assessment, see the full report (SPP.org > Engineering > Transmission Planning>Local Area Planning and High Priority Studies).

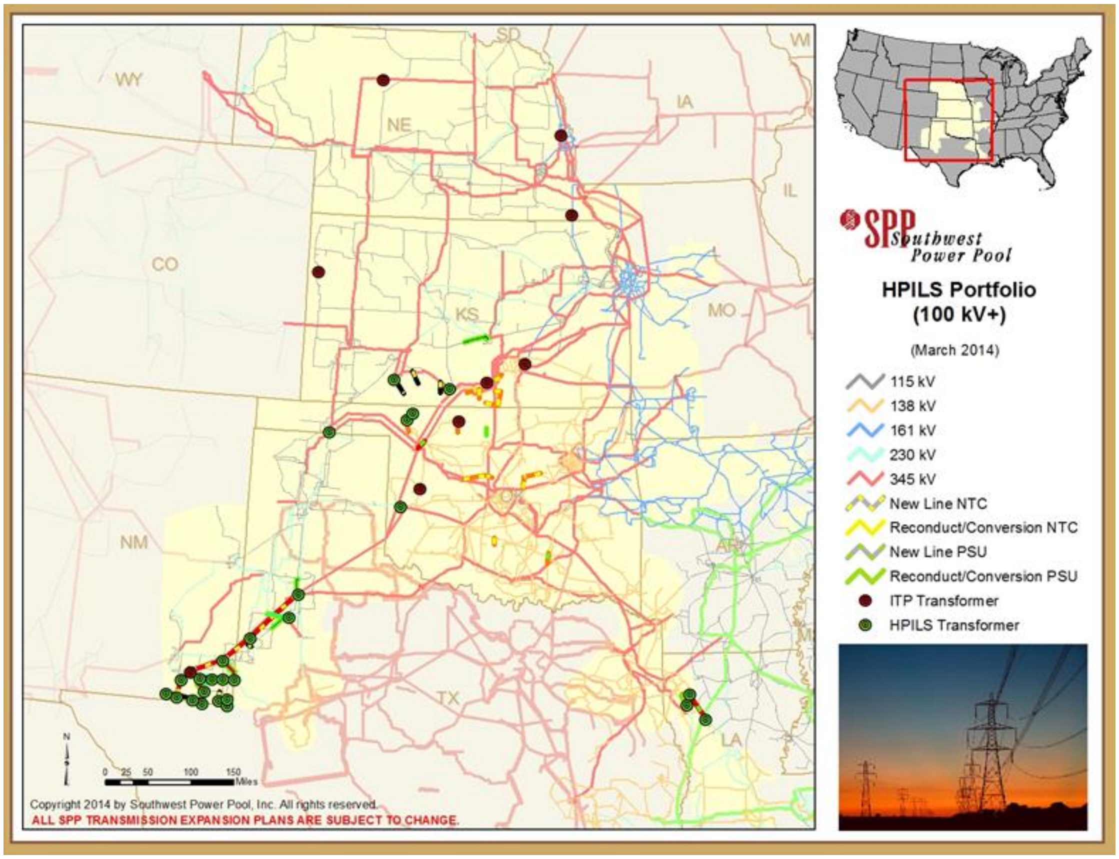


Figure 5-3: Finalized HPILS Portfolio (100 kV and above)

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
200276	30645	MKEC	Line - Harper - Rago 138 kV Ckt 1	$12,625,134
200277	30678	NPPD	XFR - Thedford 345/115 kV	$10,236,801
200282	30675	200282	Multi - China Draw - Yeso Hills 115 kV	$15,776,480
200282	30672	SPS	Multi - Dollarhide - Toboso Flats 115 kV	$5,062,341
200282	30694	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$5,222,364
200309	30376	SPS	Multi - Hobbs - Yoakum 345/230 kV Ckt 1	$104,655,870
200309	30638	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$72,457,140
200309	30637	SPS	Multi - Hobbs - Kiowa 345 kV Ckt 1	$58,767,041
200309	30639	SPS	Multi - Potash Junction - Road Runner 345 kV Conv. and Transformers at Kiowa and Road Runner	$23,991,024
200309	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$8,497,695
200436	30695	SPS	Multi - Livingston Ridge - Sage Brush - Lagarto - Cardinal 115 kV	$19,630,000
200311	30622	OGE	Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	$30,844,580
200335	30644	MKEC	Line - Anthony - Harper 138 kV Ckt 1	$11,949,636

NTC ID	Project ID	Project Owner	Project Name	Current Cost Estimate
200362	30732	MKEC	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$40,320,264
200363	30732	WR	Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1	$3,915,388
200411	30694	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$5,000,000
200411	30825	SPS	Line - China Draw - Wood Draw 115 kV Ckt 1	$14,200,000

Table 5-2: HPILS Projects

Section 6: Sponsored Upgrades

No Sponsored Upgrades were completed and no new Sponsored Upgrades were approved in 2017.

Section 7: Regional Cost Allocation Review (RCAR)

SPP filed Docket No. ER17-2229 with the Federal Energy Regulatory Commission (FERC) on August 2, 2017 requesting revision to Attachment J, Section III.D.1 of its OATT. SPP, with review and/or approval of the RARTF, RTWG, CAWG, MOPC and the RSC, requested the timeline for performing the RCAR analysis be revised from the current three-year mandatory requirement to six years. An effective date of October 1, 2017 was also requested. The FERC issued an Order[3] on September 29, 2017 accepting the tariff revision.

The RARTF is currently exploring options for the RCAR III assessment. The next scheduled meeting is for January 15, 2018 at the AEP offices in Dallas, TX.

[3] https://www.ferc.gov/CalendarFiles/20170929091320-ER17-2229-000.pdf

Section 8: Interregional Coordination

8.1: Interregional Planning

Throughout 2017, SPP continued participation in joint planning and coordination processes with three different neighboring entities. SPP's respective Joint Operating Agreements (JOA) with Associated Electric Cooperative Inc. (AECI) and Midcontinent Independent System Operator (MISO) outline the requirements for joint and coordinated planning procedures, each of which result in the production of a Coordinated System Plan (CSP) which concluded in 2017. Addendum 4 to Attachment O of the Tariff outlines the requirements of the joint coordination procedures with the Southeastern Regional Planning Transmission group (SERTP).

2016 SPP-AECI JCSP

The SPP-AECI Joint Operating Agreement (JOA) requires a Joint Coordinated System Plan (JCSP) study be performed every other year to assure the reliable, efficient and effective operation of the transmission system along the SPP-AECI seam. SPP and AECI, along with SPP stakeholders, collaborated throughout 2016 on the performance of a JCSP to identify potential joint transmission projects that are mutually beneficial to both entities. The study concluded in January 2017 with the SPP-AECI Joint Planning Committee approving two projects.

Morgan Transformer Project

The project includes the addition of a new 345/161 kV transformer at AECI's existing Morgan substation in addition to an uprate of the 161 kV line between Morgan and Brookline. The analysis performed in the 2016 SPP-AECI JCSP showed significant benefit across multiple models used for the study. SPP and AECI utilized real-time Emergency Management System (EMS) modeling data to mimic the known and chronic operational issues in a planning model. These models allowed SPP to test potential transmission solutions to address the overloading issues at Brookline. An adjusted 2017 ITPNT model was also used to recreate the problem using a No Hydro Scenario. By turning off all of Southwestern Power Administration's (SPA) hydro generation and City Utilities of Springfield (CUS) JTEC units, SPP was able to recreate the overloading issues in a severe planning case. Table 8-1 illustrates the results of the Brookline overloading issues.

2016 SPP-AECI JCSP	Brookline Transformer %Overloaded (EMS Model)	Brookline Transformer %Overloaded (No Hydro Model)
Base case	102.8%	129.4%
Morgan Transformer	84.2%	99.5%

Table 8-1: Brookline Overloading Issues

In addition to the benefit shown in the joint study with AECI, this project also was recommended as an economic solution to address congestion in the 2017 SPP ITP10 study. The project's estimated engineering and construction costs is $13.75M. SPP and

AECI agreed to a cost share where SPP would be responsible for 89% of the project or $12.25M.

Brookline Reactor Project

The project includes the addition of a 50 MVAR reactor at SPP's existing Brookline 345 kV substation. The analysis performed in the 2016 SPP-AECI JCSP showed significant benefit for the project by reducing the voltage levels to be under SPP's criteria of 1.05 per unit (pu). The analysis also demonstrated that voltage levels would be lower on two AECI buses located at Huben and Morgan. SPP and AECI utilized real-time EMS modeling data to mimic the known and chronic operational high voltage issues in a planning model. These models allowed SPP to test potential transmission solutions to address the issue. Table 8-2 illustrates the results of the Brookline high voltage issues.

2016 SPP-AECI JCSP	Brookline High Voltages (pu)	Huben High Voltages (pu)	Morgan High Voltages (pu)
Base case	1.051	1.057	1.053
Brookline Reactor	1.039	1.054	1.046

Table 8-2: Brookline High Voltage Issues

In addition to the joint study with AECI, SPP also performed a regional review of this project in 2017. The project's estimated engineering and construction costs is $5M that would be allocated to SPP and AECI. SPP and AECI agreed to a cost share where SPP would be responsible for 97% of the project or $4.85M.

Regional Review of the 2016 SPP-AECI JCSP

SPP follows the stakeholder approved Regional Review Methodology to confirm the benefits to the SPP transmission system. The Morgan Transformer Project was not required to go through a regional review process because it was previously approved through an SPP regional planning process.

Regional Review of the Brookline Reactor Project

The TWG developed and approved the Brookline Reactor Regional Review Scope. The scope included evaluating the project in a planning model, reviewing the work done in the 2016 SPP-AECI JCSP, and confirming the project addressed a persistent operational need.

SPP utilized the 2017 ITP Near-Term supplemental model(s), which include the 2017 ITP10 approved projects, Generation Interconnection and Transmission Service approved projects and known model corrections, to evaluate the effectiveness of the project to provide voltage relief on the facilities in the area. As discussed in previous sections, no high voltage criteria violations in the area were identified in either the base or change case runs as this need is not typically identified in traditional planning studies.

SPP also presented an in-depth review of the analysis completed in the joint study with AECI to provide the benefits identified to SPP. The purpose of this was to provide stakeholders who had not been involved in the joint portion of the study with the study results and the benefit identified to SPP.

Lastly, SPP utilized the Persistent Operations Issues Criteria document that was approved within SPP's regional stakeholder groups to provide details highlighting the presence of the chronic operational issues the project is addresses. High voltage issues in the document are described below:

- High/Low Voltage issues (Reliability)
    - Transmission Operating Guides that require reconfiguration, documenting mitigations for high and low voltage issues, will be reviewed from the last cycle and related voltage issues will be added to the ITP needs list. The mitigation to avoid the high/low voltage issue must be implemented 10% of the time of the year due to non-outage issues. Transmission Operating Guides that will be considered will only include transmission reconfiguration or potential load shed events. Switched shunts and generator Mvar adjustments will be optimized prior to needs being identified.

SPP provided the data to show the high voltage needs this project addresses are indeed a persistent operational issue. The mitigation to relieve the high voltage needs was active 22.47% of the time in 2016.

The SPP SSC, TWG, MOPC, and Board of Directors all approved the Brookline Reactor Project out of the regional review process.

FERC Filings

On August 7, 2017, SPP submitted filings to FERC for i) approval of the joint SPP and AECI projects; ii) the cost sharing approach negotiated between SPP and AECI; and iii) the regional cost allocation of the SPP responsible costs. This filing also included the negotiated agreement between SPP and AECI. SPP had requested an October 6, 2017 effective date.

On October 6, 2017, FERC issued an order rejecting the cost allocation for proposed Morgan Transformer and Brookline Reactor transmission projects identified pursuant to the joint planning process contained in the Commission-approved Joint Operating Agreement between SPP and AECI, and in so doing rejecting the proposed projects.

In the Order, FERC stated that "SPP has not shown that the proposed cost allocation for these specific non-Order No. 1000 projects, and the allocation of SPP's share of the costs of these projects on a region-wide, load-ratio share basis, is roughly commensurate with the projects' benefits…" and continued "Our rejection of SPP's proposal in these dockets does not preclude SPP from making a filing with the Commission demonstrating that the Morgan Transformer Project and Brookline Reactor Project provide regional benefits or proposing an alternative allocation of its share of the costs of these transmission projects that is roughly commensurate with the benefits"

SPP staff is evaluating the Commission's order and developing next steps for cost allocation of the two joint projects.

2016 SPP-MISO CSP

SPP continued interregional planning activities with MISO in 2017. SPP and MISO continued the 2016 CSP study pursuant to the joint planning procedures contained in Article 9 of the SPP-MISO JOA. The CSP was formally initiated on May 31, 2016, when the SPP-MISO Joint Planning Commission (JPC) voted in favor of performing a 2016 CSP Study. The purpose of the 2016 CSP study was to jointly evaluate seams transmission issues and identify transmission solutions that efficiently address the identified issues to the benefit of both SPP and MISO. The study consisted of an economic evaluation of seams transmission issues previously identified in SPP and MISO regional planning processes. This was accomplished by leveraging transmission needs identified in the SPP Integrated Transmission Planning (ITP) studies (2017 ITP10) and the MISO Transmission Expansion Planning (MTEP) process (2016 MTEP). The goal of the approach was to determine if interregional transmission solutions exist that were more efficient and cost effective than what each Regional Transmission Organization (RTO) could do regionally to address these needs. The interregional portion of the study concluded in April of 2017 with one project being recommended by the SPP-MISO JPC.

Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls

The proposed Interregional Project, Loop One Split Rock to Lawrence 115 kV Ckt into Sioux Falls, was a proposed new transmission project located near Sioux Falls, South Dakota. This project had an estimated in-service date of 2021. This project is also referred to as "I-18".

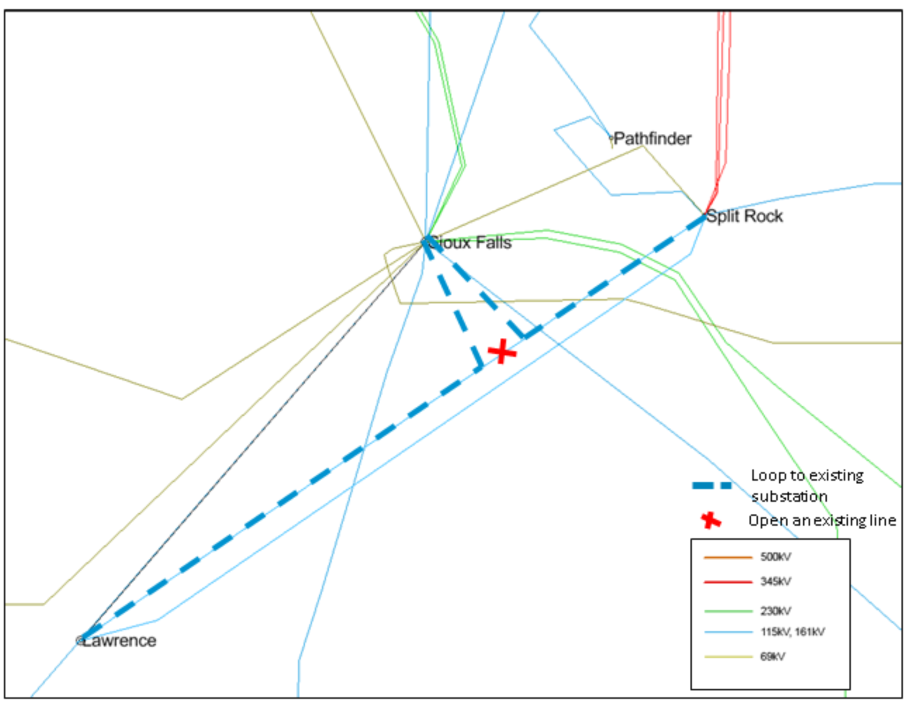


Figure 8-1: Loop One Split Rock to Lawrence 115 kV Ckt into Sioux Falls

The 2016 CSP study demonstrated this project provides APC benefits to both MISO and SPP that exceed the cost of the project over the initial 20 years of the project's life. As a result the Loop One Split Rock to Lawrence 115kV circuit into Sioux Falls project was recommended by MISO and SPP to the Interregional Planning Stakeholder Advisory Committee (IPSAC) for endorsement to move from the interregional portion of the study into the regional review process of each respective region. Both the MISO and SPP portion of the IPSAC endorsed this recommendation with no opposition. Based on that recommendation, the MISO-SPP Joint Planning Committee (JPC) voted in favor of approving this project for review in both the MISO and SPP regional review processes.

This project was proposed to relieve congestion on the Sioux Falls to Lawrence 115 kV FTLO Sioux Falls to Split Rock 230 kV flowgate. MISO and SPP's analyses showed the project completely relieves the congestion on this flowgate and provides benefit to both parties.

The estimated a scoping level cost estimate was approximately $6.15 million for this project. Assuming the in-service date of 2021, the $6.15 million cost resulted in a 20-year present value cost of $7.51 million. MISO and SPP's 20-year present value benefit analysis showed that MISO and SPP are estimated to collectively receive $27.83 million in APC benefit over the first 20 years of the project's life, resulting in a B/C ratio of 3.71. Of the $27.83 million of APC benefit, SPP is estimated to receive $5.15 million with MISO receiving $22.68 million. Since the proportion of cost paid by MISO and SPP is based on the proportion of benefits, the individual B/C ratio for both MISO and SPP is 3.71. Both MISO and SPP supported the recommendation of this project into the regional review process.

Regional Review of the Loop One Split Rock to Lawrence 115 kV Circuit into Sioux Falls

SPP's regional review analyses evaluated the Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls project's benefit to the SPP transmission system. Similar to the results seen in the interregional portion of the CSP, the project was shown to be beneficial to SPP. In accordance with SPP's Regional Review Methodology, the SSC and the Economic Studies Working Group (ESWG) are the SPP stakeholder groups responsible for oversight of the regional review. The ESWG is responsible for developing and approving the study scope. The regional review scope approved by the ESWG included calculating 1 year APC benefits using the 2017 ITP10 Sidebar Models. The analyses included evaluating both Future 1 and Future 3 scenarios.

- Future 1: Regional Clean Power Plan Solution - This Future assumes that the EPA CPP will be implemented at the regional level by meeting emission targets within the SPP footprint and each of its neighboring regions. Future 1 includes all assumptions from Future 3 with an increase in large-scale solar development and minimal distributed solar development.
- Future 3: Reference Case - This Future assumes no major changes to policies that are currently in place. Future 3 will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Renewable Policy Survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. Additional significant features of this Future include competitive wind and high availability of natural gas.

In addition to evaluating I-18, SPP's regional review also evaluated the SPP benefits of operating the Sioux Falls to Lawrence 115 kV line as open. The ESWG approved the additional analyses as an amendment to the regional review scope. The results from the analyses are shown in the table below.

Project	Future	SPP 1-yr Nominal NPCC Cost	2025 Sidebar Model w/ 2017 ITP10 Portfolio	
			SPP 1-yr Benefit	SPP 1-yr B/C
I18	F1	$212,009.74	$3.5M	$16.49
I18	F3	$212,009.74	$0.17M	$0.80
Open Line	F1	$0.00	$3.73M	N/A
Open Line	F3	$0.00	($-0.24M)	N/A

Table 8-3: Analysis Results of Sioux Falls-Lawrence 115 kV Line

SPP's analyses determined both solutions evaluated were potentially beneficial to the SPP transmission system, but only I-18 would provide long-term benefit to SPP. While operating the Sioux Falls to Lawrence line as open does provide SPP benefit in Future 1, it does not provide SPP with positive benefit across all the sensitivities evaluated in the regional review. Additional analysis also showed opening the line has the potential of shifting congestion to other constraints in the area demonstrating operating the line as open is not a long-term solution for SPP. Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls was determined to fully relieve congestion on the study need across all sensitivities and provides positive benefit to SPP across all sensitivities as well. Additional analysis of I-18 demonstrated potential congestion relief under multiple different contingencies in the area, demonstrating the potential to provide a more robust solution to opening the line, which SPP views as a better long-term solution to address congestion.

The project was endorsed by SPP's Seams Steering Committee (SSC) as a result of the interregional process and the SPP MOPC endorsed the report given to them at their October 2017 meeting. The SSC and MOPC endorsements were a result of the projects inability to be an approved Interregional Project due to MISO's prior determination not to recommend the project move forward. MISO and SPP will continue to explore process improvements to the RTOs' joint planning processes with the goal of performing more meaningful and beneficial joint studies.

Section 9: Project Tracking

9.1: NTC Letters Issued in 2017

After the SPP Board of Directors approves transmission expansion projects or once Service Agreements are executed, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners.

In 2017, SPP issued 30 NTC letters with estimated construction costs of $263.2 million for 71 projects to be constructed over the next five years through 2023. Of this $263.2 million, the upgrade cost breakdown is as follows:

- $110 thousand for Generator Interconnection (GI);
- $140.9 million for Transmission Service (TSS);
- $28.7 million for High Priority (HP); and
- $93.5 million for Integrated Transmission Planning (ITP) projects.

9.2: Projects Completed in 2017

After the SPP Board of Directors approves transmission expansion projects, SPP issues NTC letters to appropriate Transmission Owners. SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of December 20, 2017, 36 upgrades totaling approximately $245.6 million were completed during the year. The breakdown includes:

- 19 ITP - $163.9 million
- 3 TSS - $26.6 million
- 13 GI - $43.4 million
- 1 HP - $11.7 million

9.3: ITP20 Projects

ITP20 assessments were performed in 2010 and 2013. While the projects proposed by those studies are incorporated into the STEP Project List, they are not included in SPP's project tracking effort as part of the Quarterly Tracking Report. A list of active ITP20 projects will be maintained in the STEP Report and Project List. The current ITP20 projects are listed in the table below.

Name	Type	Size	Cost Estimate	Source Study
Post Rock 345/230 kV transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Mingo-Post Rock 345 kV	New Line	345	$121,500,000	2010 ITP20
Iatan-Jeffery Energy Center 345 kV	New Line	345	$79,875,000	2010 ITP20
Spearville - Mullergren 345 kV	New Line	345	$85,840,000	2010 ITP20
Mullergren - Circle 345 kV	New Line	345	$85,840,000	2010 ITP20

Name	Type	Size	Cost Estimate	Source Study
Circle - Reno 345 kV	New Line	345	$6,519,500	2010 ITP20
Keystone - Ogallala 345 kV	New Line	345	$5,625,000	2010 ITP20
Ogallala Transformer 345/230 kV	Transformer	345	$6,000,000	2010 ITP20
Mullergren 345/230 kV Transformer	Transformer	345	$6,000,000	2010 ITP20
Circle 345/230 kV transformer	Transformer	345	$6,000,000	2010 ITP20
Grand Island - Holt Co 345 kV	Rebuild/Re-Conductor	345	$64,125,000	2010 ITP20
Holt Co. - Shell Creek 345 kV	New Line	345	$69,750,000	2010 ITP20
Shell Creek 345/230 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Holt - Neligh 345 kV	New Line	345	$30,656,000	2010 ITP20
Columbus East 345/115 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Hoskins 345/230 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Hoskins 345/115 kV Transformer Ckt 2	Transformer	345	$6,000,000	2010 ITP20
Hoskins - Ft. Calhoun 345 kV	New Line	345	$193,380,000	2010 ITP20
Ft Calhoun - S3454 345 kV	New Line	345	$46,875,000	2010 ITP20
Cass Co. - S.W. Omaha (aka S3454) 345 kV Ckt1	New Line	345	$33,126,800	2010 ITP20
S3459 345/161 kV Transformer Ckt 2	Transformer	345	$12,600,000	2010 ITP20
Hitchland-Potter 345 kV Ckt 2	New Line	345	$133,875,000	2010 ITP20
Wichita-Viola 345 kV	New Line	345	$54,000,000	2010 ITP20
Viola-Rose Hill 345 kV Ckt 1	New Line	345	$54,000,000	2010 ITP20
South Fayetteville 345/161 kV Transformer Ckt1	Transformer	345	$12,600,000	2013 ITP20
Chamber Springs - South Fayetteville 345 kV Ckt1	New Line	345	$21,295,800	2013 ITP20
Maryville 345/161 kV Transformer Ckt1	Transformer	345	$12,600,000	2013 ITP20
Nashua 345/161 kV Transformer Upgrade Ckt11	Transformer	345	$12,600,000	2013 ITP20
Keystone - Red Willow 345 kV Ckt1	New Line	345	$130,141,000	2013 ITP20
Tolk - Tuco 345 kV Ckt1	New Line	345	$75,718,400	2013 ITP20
Holcomb 345/115 kV Transformer Ckt2	Transformer	345	$12,600,000	2013 ITP20
Neosho - Wolf Creek 345 kV Ckt1	New Line	345	$117,126,900	2013 ITP20
Clinton - Truman 161 kV Ckt1 Reconductor	Rebuild/Re-Conductor	161	$15,701,325	2013 ITP20
North Warsaw - Truman 161 kV Ckt1 Reconductor	Rebuild/Re-Conductor	161	$1,082,850	2013 ITP20
Auburn 345/115 kV Transformer Ckt2	Transformer	345	$12,600,000	2013 ITP20
Auburn - Swissvale 345 kV Ckt1 Voltage Conversion	Voltage Conversion	345	$20,112,700	2013 ITP20

Name	Type	Size	Cost Estimate	Source Study
Auburn - Jeffrey EC 345 kV Ckt1 Voltage Conversion	Voltage Conversion	345	$35,493,000	2013 ITP20
Muskogee/Pecan Creek 345 kV Terminal Upgrades	Substation	345	$34,605,675	2013 ITP20

Table 9-1: ITP20 Projects

Section 10: STEP Project List

The 2017 STEP Project List includes a comprehensive listing of transmission projects identified by the SPP RTO. All SPP BOD-approved projects are included in the 2016 STEP Project List. The list also includes SPP Tariff study projects, economic projects, and zonal projects.

Projects in the list are categorized in the column labeled "Project Type" by the following designations:

- Generator Interconnection – Projects associated with a FERC-filed Generator Interconnection Agreement
- High Priority – Projects identified in the high priority process
- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP study processes
- Transmission Service – Projects associated with a FERC-filed Service Agreement
- Interregional – Projected identified in SPP's joint planning and coordination processes
- Sponsored – Entity requested and funded project reviewed and approved by SPP

The complete Network Upgrade list includes two dates.

1. In-service: Date Transmission Owner has identified as the date the upgrade is planned to be in-service.
2. SPP Need Date: Date upgrade was identified as needed by SPP.

A copy of the *2018 SPP Transmission Expansion Plan Report Project List* can be found at the following location: spp.org>engineering>transmission-planning>documents

10.1: Facility owner abbreviations used in the STEP List

Abbreviation and Identification	
AEP	American Electric Power
BEPC	Basin Electric Power Cooperative
ETEC	East Texas Electric Cooperative
GRDA	Grand River Dam Authority
ITCGP	ITC Great Plains
KCPL	Kansas City Power and Light Company
GMO	KCP&L Greater Missouri Operations Company
LEA	Lea County Cooperative
LES	Lincoln Electric System
MKEC	Mid-Kansas Electric Company
MIDW	Midwest Energy, Incorporated
NPPD	Nebraska Public Power District
OGE	Oklahoma Gas and Electric Company

Abbreviation and Identification	
OPPD	Omaha Public Power District
SWPA	Southwestern Power Administration
SPS	Southwestern Public Service Company
SEPC	Sunflower Electric Power Corporation
TSMO	Transource Energy
WFEC	Western Farmers Electric Cooperative
WR	Westar Energy

10.2: Upgrades: Information breakdown

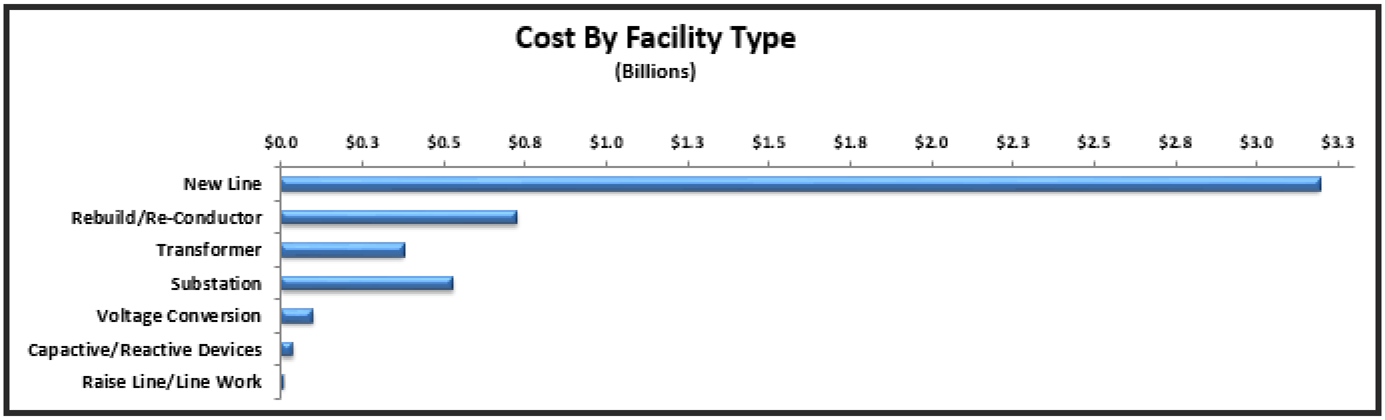


Figure 10-1: Total Cost by Facility Type

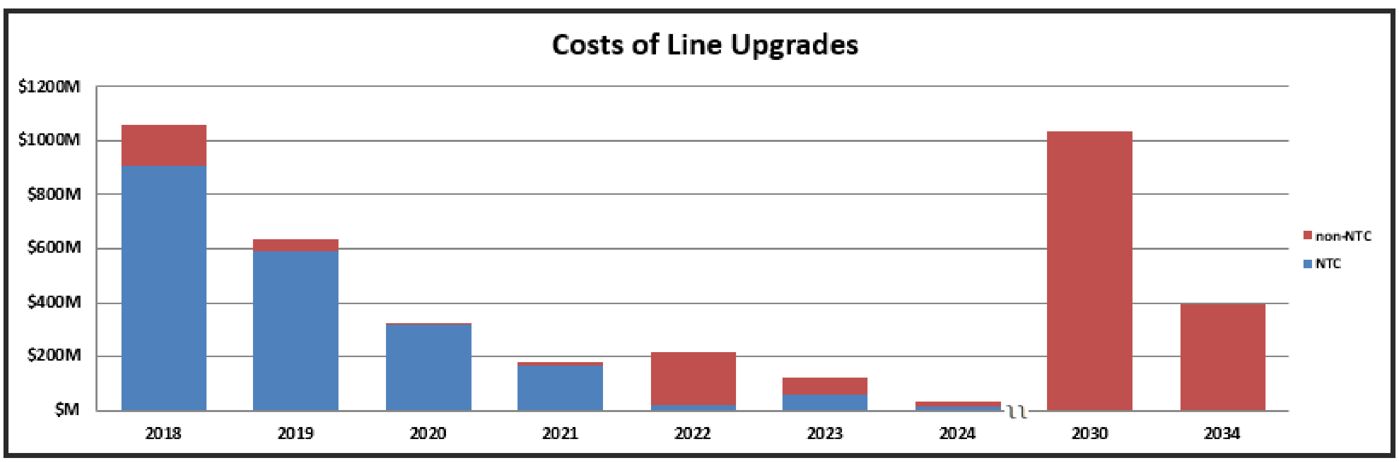


Figure 10-2: Total Cost of Line Upgrades

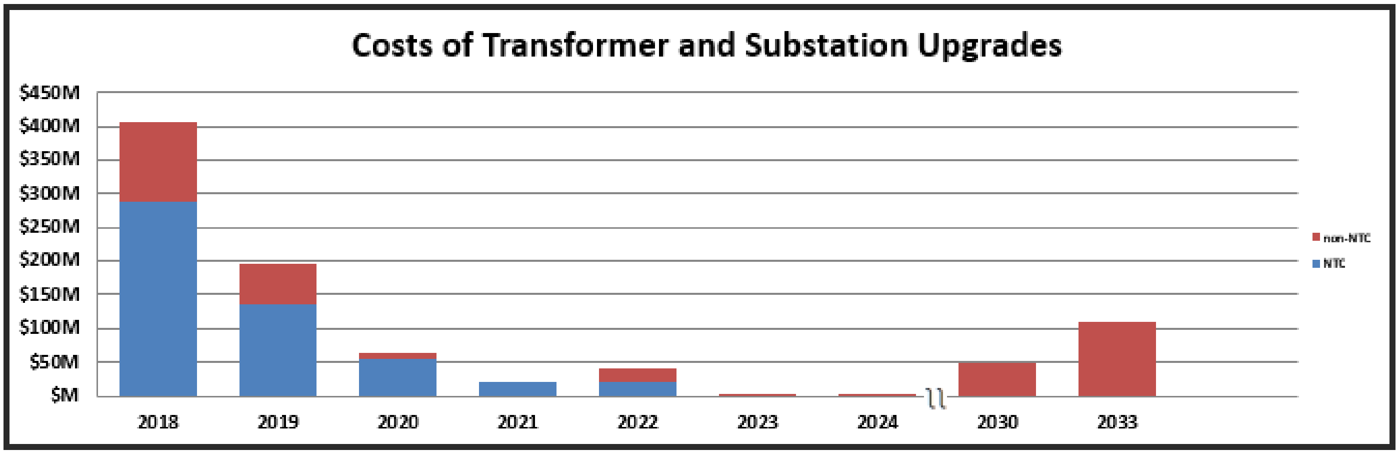


Figure 10-3: Total Cost of Transformer and Substation Upgrades

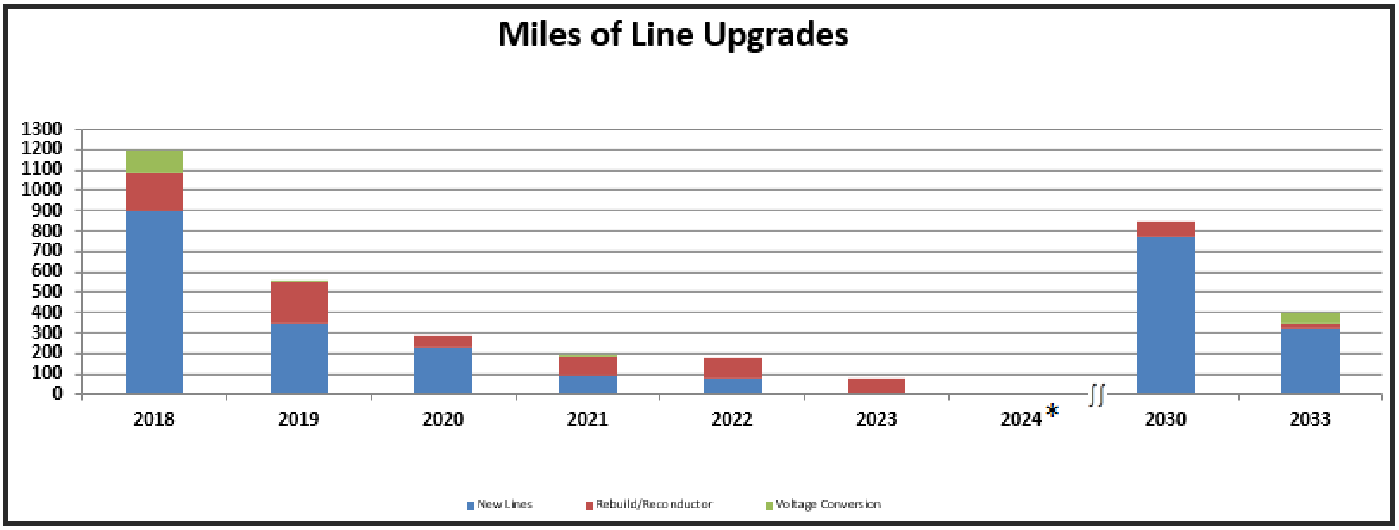


Figure 10-4: Total Miles of Line Upgrades by Project Type

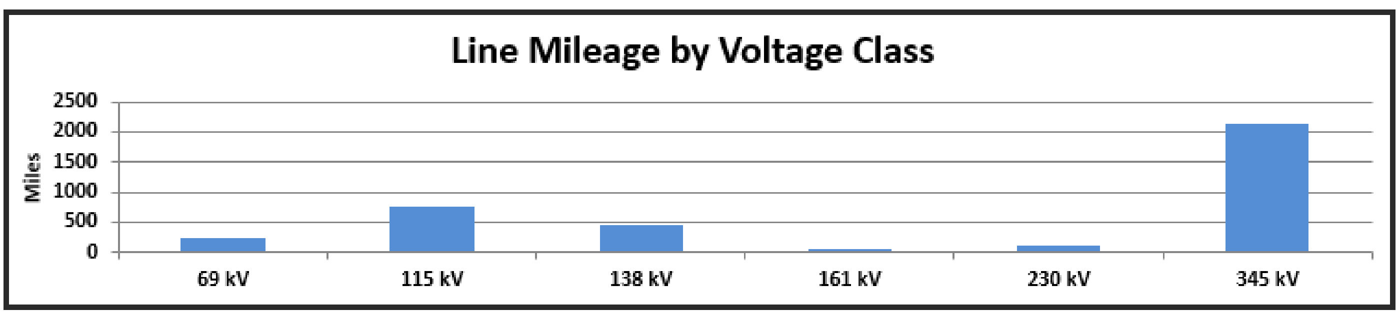


Figure 10-5: Total Line Mileage by Voltage Class

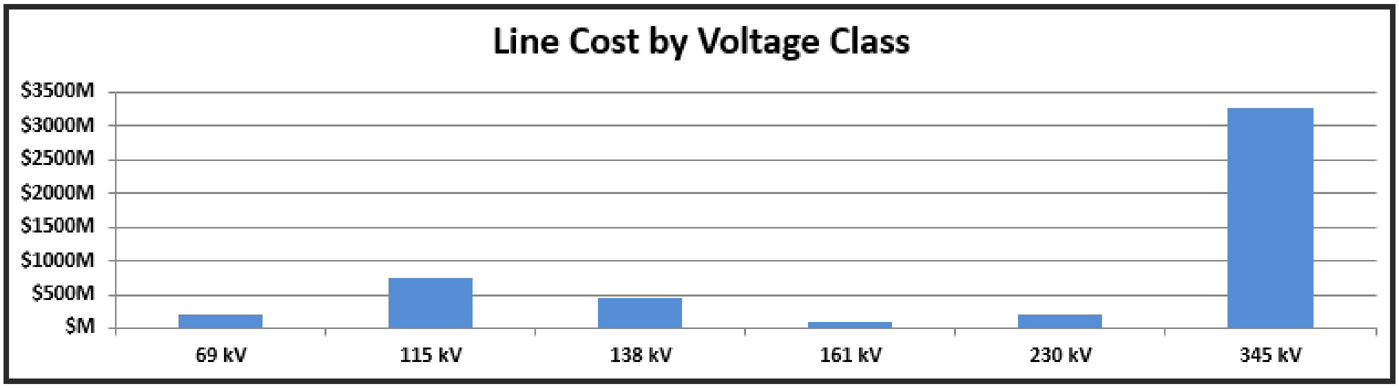


Figure 10-6: Total Line Cost by Voltage Class

Section 11: NTCs Issued in 2017

NTC ID	PID	Project Name	Facility Owner	Current Cost Amount
200420	30513	Potash Junction 230/115 kV Transformer Upgrade	SPS	$5,778,860
	30699	Northwest - Rolling Hills 115 kV Rebuild Ckt 1		$4,161,895
	31061	Livingston Ridge - Wipp 115 kV Ckt 1 Rebuild		$0
	31062	Pecos 230/115 kV Transformer Upgrade		$3,423,416
	31063	Carlsbad - Pecos 115 kV Terminal Upgrades		$767,347
200421	30693	Wolfforth 230/115 kV Ckt 1 Transformer	SPS	$3,790,207
200422	31184	Jeffrey Energy Center - Hoyt 345 kV Ckt 1	WR	$23,683,317
200423	31183	Hancock - Muskogee 161 kV Ckt 1 Terminal Upgrades	OGE	$37,638
200426	31109	Blaisdell 230/115 kV Transformer	BEPC	$5,778,860
	31174	Neset 230/115 kV Transformer Ckt 1		$5,778,860
200428	31085	Northeast - Charlotte - Crosstown 161 kV Reactor	KCPL	$500,000
200429	31127	Knoll - Post Rock 230 kV New Line Ckt 2	MIDW	$409,012
	31127	Knoll Sub 230kV Terminal		$1,652,257
	31127	Post Rock Sub Addition		$1,245,091
200430	31082	Butler - Altoona 138 kV Terminal Upgrades	WR	$238,640
	31083	Neosho - Riverton 161 kV Terminal Upgrades	WR	$111,370
200431	31131	Siloam Springs - Siloam Springs City 161 kV Ckt 1 Rebuild (AEP)	AEP	$4,780,000
200432	31131	Siloam Springs - Siloam Springs City 161 kV Ckt 1 Rebuild (GRDA)	GRDA	$279,400
200433	31144	Tupelo 138 kV Terminal Upgrades	WFEC	$100,000
200434	31150	Lula- Tupelo Tap 138 kV Terminal Upgrades	OGE	$16,000
200436	30672	Toboso Flats 115 kV Substation	SPS	$822,700
	30695	Livingston Ridge - Sage Brush 115 kV Ckt 1		$13,187,417
	30695	Lagarto 115 kV Substation		$1,200,057
	30695	Largarto - Sage Brush 115 kV Ckt 1		$6,186,323
	30695	Cardinal - Lagarto 115 kV Ckt 1		$7,315,580
200437	31073	Heizer 115/69 kV Ckt 4 Transformer	MIDW	$2,663,963
200444	31079	Tuco - Stanton 115 kV Terminal Upgrades	SPS	$356,757
	31080	Stanton - Indiana 115 kV Terminal Upgrades		$302,133
	31081	Indiana - SP-Erskine 115 kV Terminal Upgrades		$294,764
	41189	Martin - Pantex North 115 kV Terminal Upgrades		$335,157
	41189	Pantex South - Highland Tap 115 kV Terminal Upgrades		$335,697
200446	31186	IPC 138 kV Cap Bank	AEP	$1,298,049
	41202	T.S.E.-4 - E.61ST- 138 kV Rebuild		$6,014,381
	41233	Broken Arrow North - Lynn Lane East 138kV Ckt 1 Reconductor		$5,714,095
200448	41209	NIC170 2 - REP345 2 69 kV Reconductor	EDE	$4,050,000
	41209	REP345 2 - REP451 2 69 kV Reconductor		$1,450,000
	41209	REP451 2 - REP359 2 69 kV Reconductor		$800,000
200450	51236	Roberts County - Sisseton 69 kV New Line	EREC	$733,000
200451	51237	Redundancy Relaying at Stilwell	KCPL	$147,500
200452	41200	WILISTN7 115 kV Terminal Upgrades	WAPA	$350,000
	51236	ROBERTS CO7 115kV Substation	EREC	$3,957,000
	51236	XFR - Roberts County-ER8 115/69 Transformer	EREC	$1,300,000

NTC ID	PID	Project Name	Facility Owner	Current Cost Amount
200454	51253	L-10 Southern 69kV Terminal Upgrades	NIPCO	$573,452
	51253	J16 69kV Substation		$833,125
200455	30755	Tuco 230/115 kV Ckt 1 Transformer	SPS	$183,814
	41188	Hale County 115 kV Terminal Upgrades		$741,329
	41192	Coulter 115 kV Terminal Upgrades		$268,490
	41194	Plant X 230 kV Terminal Upgrades		$217,734
	41194	Sundown 230 kV Terminal Upgrades		$341,745
	41198	Upgrade ckt 1 terminal equipment TEXAS_CNTY 3 - Hitchland 115 kV at Texas County 115 kV bus		$98,639
	41198	Upgrade ckt 2 terminal equipment TEXAS_CNTY 3 - Hitchland 115 kV at Texas County 115 kV bus		$108,430
	51246	Nichols 230 kV Terminal Upgrades		$490,000
	41199	Etter to Moore 115kV line		$9,037,903
200456	41223	East Ruthville - SW Minot 115 kV New Line	CPEC	$20,745,000
	41223	East Ruthville - SW Minot 115 kV line Terminal Upgrades		$1,035,000
200457	30690	Plant X 230/115 kV Ckt 2 Transformer	SPS	$5,778,860
	31175	Cox Interchange - Hale Co Interchange 115 kV Ckt 1		$14,589,157
	31176	Hockley County Interchange 115 kV Terminal Upgrades		$324,585
200458	31086	DePaul - Girard Jct 69 kV	WR	$9,142,063
	31086	Franklin - Sugar Creek 69 kV		$6,666,094
200460	51254	Monolith 345 kV Substation	NPPD	$12,692,888
	51254	Monolith 345/115 kV Transformer #1		$5,179,657
	51254	Monolith 345/115 kV Transformer #2		$5,179,657
	51254	Monolith 115 kV Substation Upgrades		$11,271,233
	51254	Sheldon - Monolith 115 kV Ckt 1 New Line		$1,273,506
	51254	Sheldon 115 kV Terminal Upgrades		$3,703,266
200462	41223	East Ruthville - SW Minot 115 kV New Line	CPEC	$20,745,000
	41223	East Ruthville - SW Minot 115 kV line Terminal Upgrades		$1,035,000
200463	31075	Tap Centerville-Marmaton 161kV GEN-2015-016 Addition (WERE)	WR	$110,000
200466	51249	City of Winfield - Rainbow 69 kV Ckt 1	WR	$1,467,084
	51249	Oak - Rainbow 69 kV Ckt 1		$1,870,532
	51252	Creswell (CRSW TX-1) 138/69/13.2 kV Transformer Ckt 1		$2,961,462
	51252	Creswell (CRSW TX-2) 138/69/13.2 kV Transformer Ckt 1		$2,961,462
200467	31082	Butler - Altoona 138 kV Terminal Upgrades	WR	$247,332

Section 12: Upgrades Completed in 2017

UID	Facility Owner	Upgrade Name	SOURCE STUDY	Cost Estimate
10583	AEP	Chamber Springs - Farmington REC 161 kV Ckt 1	2013 ITPNT	$ 12,705,537
10600	WR	East Manhattan - Jeffrey Energy Center 230 kV Ckt 1 Rebuild	2014 ITPNT	$ 41,100,000
10604	WR	Arkansas City - Paris 69 kV Terminal Upgrades	Ag Studies	$ 228,364
10649	AEP	Brownlee - North Market 69 kV Ckt 1	2013 ITPNT	$ 16,401,035
50168	OGE	FT SMITH 500/161KV TRANSFORMER CKT 5	Ag Studies	$ 25,635,637
50520	SEPC	Mingo 345/115 kV Ckt 2 Transformer	2015 ITPNT	$ 8,597,207
50533	GRDA	Kerr - 412 Sub 161 kV Ckt 1 Terminal Upgrades	2014 ITPNT	$ 161,100
50600	WFEC	Hazelton 69 kV Capacitor	DPA Studies	$ 728,843
50608	NPPD	Bobcat Canyon 345/115 kV Transformer Ckt 1	2014 ITPNT	$ 5,928,480
50609	NPPD	Bobcat Canyon - Scottsbluff 115 kV Ckt 1	2014 ITPNT	$ 23,700,242
50616	NPPD	Bobcat Canyon 345 kV Terminal Upgrades	2014 ITPNT	$ 4,072,936
50718	AEP	Broadmoor - Fort Humbug 69 kV Ckt 1 Rebuild	2014 ITPNT	$ 6,695,986
50719	AEP	Daingerfield - Jenkins REC T 69 kV Ckt 1 Rebuild	2014 ITPNT	$ 2,819,806
50721	AEP	Hallsville - Marshall 69 kV Ckt 1 Rebuild	2014 ITPNT	$ 16,571,092
50738	OGE	Wildhorse 69 kV Cap Bank	2014 ITPNT	$ 740,254
50759	AEP	Letourneau 69 kV Cap Bank	2016 ITPNT	$ 1,409,347
50802	AEP	Darlington - Roman Nose 138 kV Ckt 1 (AEP)	HPILS	$ 11,652,107
51146	GRDA	Claremore 161 kV Terminal Upgrades	2015 ITPNT	$ 11,200
51180	SEPC	Mingo 345 kV Terminal Upgrades	2015 ITPNT	$ 4,332,021
51187	AEP	Southwestern Station - Carnegie 138 kV Ckt 1 Rebuild	2015 ITPNT	$ 9,397,311
51209	SEPC	Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades	2015 ITPNT	$ 3,892,077
51300	ITCGP	Clark County 345kV Switching Station GEN-2012-024 Addition	GI Studies	$ 1,940,084
51331	NPPD	Antelope - County Line - 115kV Rebuild	GI Studies	$ 2,047,174
51340	NPPD	Battle Creek - County Line 115kV Rebuild	GI Studies	$ 1,952,826
51396	AEP	Leonard 138kV Switching Station (TOIF)	GI Studies	$ 668,626
51397	AEP	Leonard 138kV Switching Station (NU)	GI Studies	$ 6,996,176
51398	OGE	Leonard 138kV Switching Station (NU - OGE)	GI Studies	$ 20,000
51402	TSMO	Sub - Tap Nebraska City - Mullin Creek 345kV (Holt County) POI for GEN-2014-021 (TOIF)	GI Studies	$ 600,000
51403	TSMO	Sub - Tap Nebraska City - Mullin Creek 345kV (Holt County) POI for GEN-2014-021 (TSMO NU)	GI Studies	$ 1,840,000
51405	TSMO	Sub - Tap Nebraska City - Mullin Creek 345kV (Holt County) POI for GEN-2014-021 (SANU)	GI Studies	$ 16,570,000

51425	OGE	Woodward EHV 138kV Phase Shifting Transformer circuit #1	GI Studies	$ 7,103,971
51474	OGE	Minco 345kV Substation GEN-2014-056 Addition (TOIF)	GI Studies	$ 5,000
51509	BEPC	Berthold - Southwest Minot 115 kV Ckt 1 Reconductor	2016 ITPNT	$ 2,876,720
51570	BEPC	Stegall 345 kV Terminal Upgrades	2014 ITPNT	$ 2,499,727
51603	ITCGP	Clark County 345kV Switching Station GEN-2012-024 Addition (TOIF)	GI Studies	$ 859,686
71925	OGE	Tap Coyote-Medford Tap 138kV - GEN-2015-015 Addition (NU)	GI Studies	$ 2,840,000

Section 13: Glossary of Terms

Abbreviation and Identification	
AECI	Associated Electric Cooperative Inc.
ATC	Available Transfer Capability
ATSS	Aggregate Transmission Service Study
B/C	Benefit-to-Cost
BOD	Board of Directors
CBA	Consolidated Balancing Authority
CPP	Clean Power Plan
CUS	City Utilities of Springfield
DPT	Delivery Point Transfers
EHV	Extra High Voltage
EMS	Emergency Management System
EPA	Environmental Protection Agency
ESWG	Economic Studies Working Group
FERC	Federal Energy Regulatory Committee
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
HP	High Priority
HPILS	High Priority Incremental Load Study
IPSAC	Interregional Planning Stakeholder Advisory Committee
ITP	Integrated Transmission Planning
ITP10	10-Year Integrated Transmission Planning Assessment
ITP20	20-Year Integrated Transmission Planning Assessment
ITPNT	Near-Term Integrated Transmission Planning Assessment
JCSP	Joint Coordinated System Plan
JOA	Joint Operating Agreement
LTSR	Long-Term Service Request
MDWG	Model Development Working Group
MISO	Midcontinent Independent System Operator
MOPC	Markets and Operations Policy Committee
MTEP	MISO Transmission Expansion Planning

Abbreviation and Identification	
NERC	North American Electric Reliability Corporation
NTC	Notifications to Construct
OATT	Open Access Transmission Tariff
RARTF	Regional Allocation Review Task Force
RCAR	Regional Cost Allocation Review
RMS	Request Management System
RSC	Regional State Committee
RTO	Regional Transmission Organization
RTWG	Regional Tariff Working Group
SERTP	Southeastern Regional Transmission Planning
SPA	Southwestern Power Administration
SPC	Strategic Planning Committee
STEP	SPP Transmission Expansion Plan
TPITF	Transmission Planning Improvement Task Force
TPL	Transmission Planning
TSS	Transmission Service
TWG	Transmission Working Group
WECC	Western Electricity Coordinating Council

2018 INTEGRATED TRANSMISSION PLANNING NEAR-TERM ASSESSMENT

SPP Southwest Power Pool

July 31, 2018

ENGINEERING

REVISION HISTORY

DATE	AUTHOR	CHANGE DESCRIPTION	COMMENTS
6/21/2018	SPP staff	Initial Draft	
6/28/2018	SPP staff	Incorporated member feedback	TWG Approval
7/13/2018	SPP staff	Incorporated additional NTC withdrawals in Section 6.2	Posted in Additional MOPC Background Materials
7/17/2018	SPP staff	No changes	MOPC Approval of Recommendation
7/18/2018	SPP staff	Updated report cover	Based on feedback from Communications
7/31/2018	SPP staff	No changes	SPP Board of Directors Approval

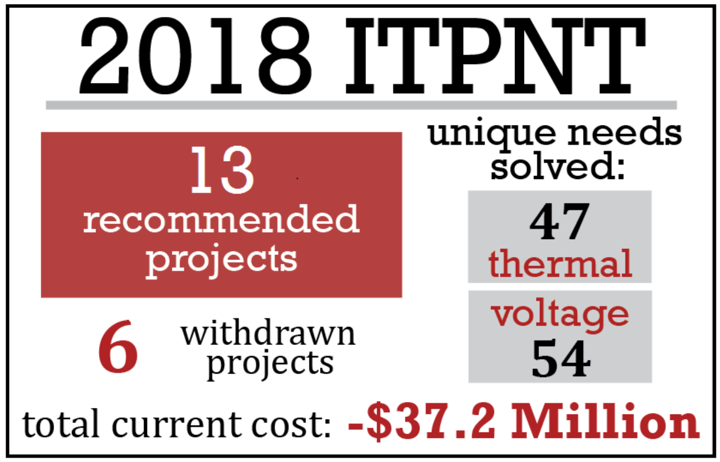
CONTENTS

FIGURES

TABLES

SECTION 1: EXECUTIVE SUMMARY

The ITP process promotes transmission investment that will meet reliability, economic and public policy needs[1] intended to create a cost-effective, flexible and robust transmission network that will improve access to the region's diverse generating resources. The ITP Near-Term assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near-term planning horizon to address reliability needs. This report documents the ITP Near-Term (ITPNT) assessment that concludes in July 2018.



The 2018 ITPNT differs from previous ITPNT assessments in several specific areas. These areas include significant generation retirements [~1.7 gigawatts (GW)], implementation of the base reliability (BR) model methodology, addition of the Brookline high-voltage operational need, inclusion of DC-tie sensitivity cases modeling the northern DC ties with an opposite powerflow bias, and additional scrutiny of scenario 5 summer needs. This report provides insight to the additional analysis and considerations discussed through our stakeholder process to be evaluated with the collaboration from our stakeholders to determine the most optimal project.

1.1: THE ITPNT PROCESS

The ITPNT assessment generates a cost effective near-term plan for the SPP regional transmission organization (RTO) planning region by identifying solutions to reliability criteria exceedances for system intact and contingency conditions.

The ITPNT assesses:

- Regional upgrades required to maintain reliability in the near-term horizon in accordance with SPP Criteria and the North American Electric Reliability Corporation

[1] The highway/byway cost allocation approving order is *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010). The approving order for ITP is *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).

(NERC) Reliability Standard TPL-001-4 planning events that do not allow for non-consequential load loss (NCLL) or interruption of firm transmission service (IFTS).

- Zonal upgrades required to maintain reliability in accordance with company-specific local planning criteria in the near-term horizon.
- Coordinated projects with neighboring transmission providers.

ITPNT projects are reviewed and approved by SPP's Transmission Working Group (TWG) and the Markets and Operations Policy Committee (MOPC) and approved by the SPP Board of directors (Board). Upon Board approval, staff will issue NTC letters for upgrades that require a financial commitment within the next four-year timeframe.

1.2: THE 2018 ITPNT

The 2018 ITPNT included four separate scenario models — Scenarios 0 (S0), Scenario 5 (S5), SPP balancing authority (BA) and base reliability (BR) — built across multiple years and seasons to evaluate power flows across the grid and account for various system assumptions. The S0, S5 and BR models allow only resources with firm transmission service to be dispatched with the preferred order submitted by SPP members, while the BA model allows for resources without firm transmission service to be dispatched in addition to firm resources subject to system constraints similar to the SPP Integrated Marketplace.

SPP's transmission system performance was assessed from different perspectives designed to identify solutions necessary to accomplish the reliability objectives of the SPP RTO:

- Avoid exposure to NERC Reliability Standard TPL-001-4 planning events that do not allow for NCLL or IFTS during the operation of the system under high stresses
- Contribute to the voltage stability of the system
- Reduce congestion associated with persistent operational issues

Voltage Class (kV)	New Line (miles)	Rebuild/Reconductor (miles)
345	0	0
230	0	0
161	5.6	0
138	0	0
115	0	3
69	0	5.5

Table 1: 2018 ITPNT Project List Breakdown – New and Rebuilt Line Miles by Voltage Class

Voltage Class (kV)	New Transformer
345/230	0
345/138	0
345/115	0
345/69	0
230/115	3
138/69	0
115/69	0

Table 2: 2018 ITPNT Project List Breakdown – New Transformer by Voltage Class

New projects identified in the 2018 ITPNT assessment account for a total of $47.4 million. Select projects previously issued a notification to construct (NTC) were re-evaluated in this assessment and resulted in a total reduction of $84.6 million for withdrawn NTCs. The estimated net total cost of the 2018 ITPNT project plan is estimated to be a reduction of $37.2 million due to NTCs withdrawals produced by the study.

Reliability Project(s)	Project Area(s)	Cost	Need Date
New Lakeview 69-kV substation. New 14.4 MVAR switched shunt capacitor at Lakeview 69-kV	**EREC**	**$5,617,000**	**6/1/2019**
Reconductor 3 miles of 115-kV line from Richland to Lewis	**WAPA/Basin**	**$105,000**[2]	**6/1/2019**
Replace the 230/115-kV transformer at Lawrence Hill	**WERE**	**$4,896,108**	**6/1/2019**
Construct a new 5.6 mile 161-kV line from Blue Valley to Crosstown	**KCPL**	**$8,951,824**	**6/1/2020**
Replace terminal equipment on the 161-kV line from Olathe to Switzer	**KCPL**	**$1,088,000**	**6/1/2019**
Replace terminal equipment on the 161-kV line from Brookridge to Overland Park	**KCPL**	**$538,000**	**6/1/2019**

[2]The total MDU, WAPA, and Basin estimated cost is $1,105,001.

New 50 MVAR switched shunt reactor at Brookline 345-kV. Brookline 345-kV Substation expansion	**SPRM**	**$4,175,203**	**6/1/2019**
Rebuild 1.25 miles of 69-kV line from Nixa Downtown to Nixa Espy	**SWPA**	**$1,108,561**	**6/1/2019**
Rebuild 4.2 miles of 69-kV line from VBI North to Figure Five	**AEP**	**$3,409,700**	**6/1/2019**
Tap Moore-Potter 230-kV line and Exell Tap-Fain 115- kV line and tie into a new substation at McDowell **Install a new 230/115-kV transformer at McDowell**	**SPS**	**$13,204,182**	**6/1/2019**
Replace terminal equipment on the 115-kV line from Carlisle to Murphy	**SPS**	**$319,760**	**6/1/2022**
Replace terminal equipment on the 115-kV line from Clauene to Terry County	**SPS**	**$520,574**	**6/1/2019**
Replace the 230/115-kV transformer at Sundown	**SPS**	**$3,434,979**	**6/1/2019**

Table 3: 2018 ITPNT Projects

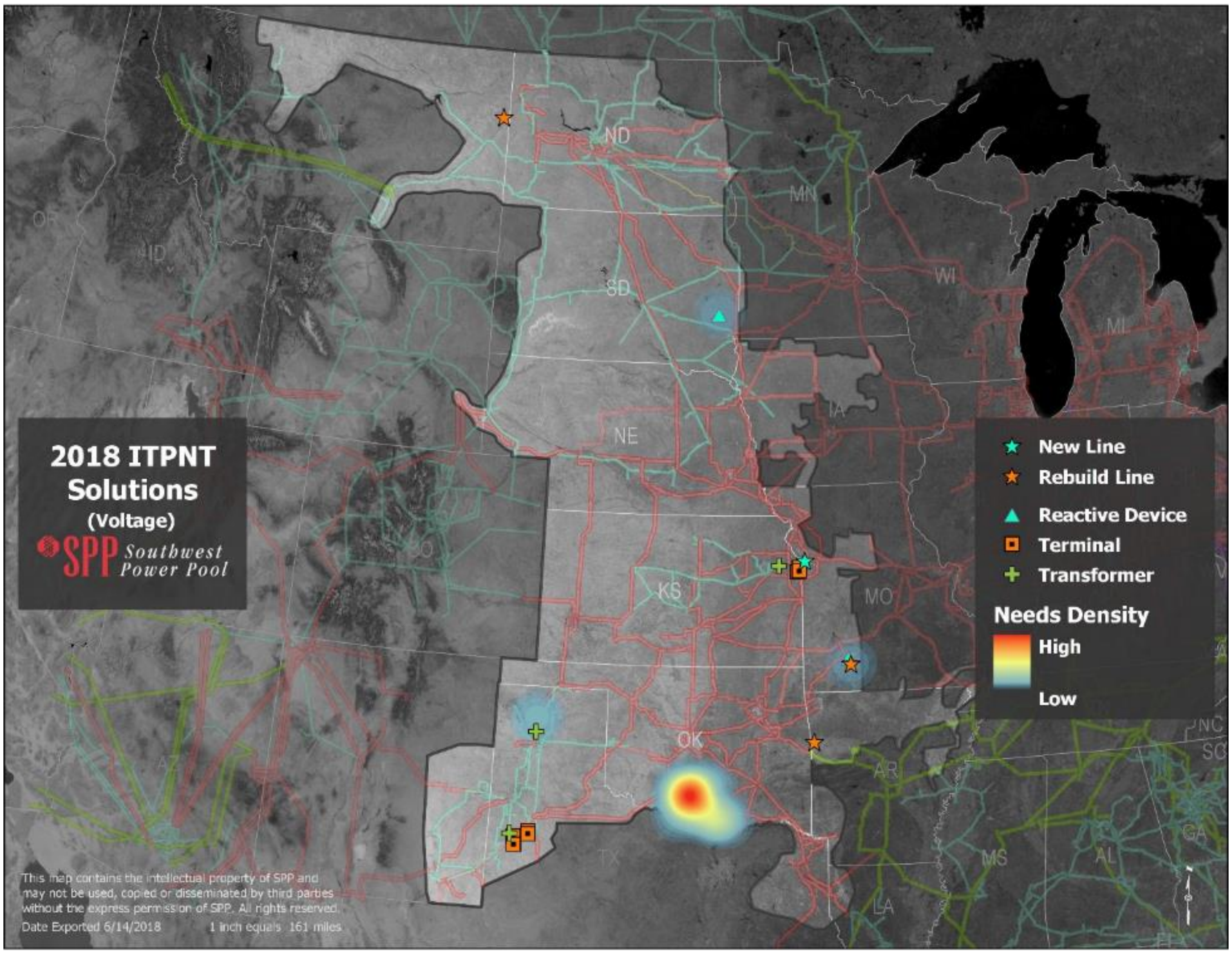


Figure 1: 2018 ITPNT Voltage Needs and Solutions. The needs in southern Oklahoma are being mitigated through TO action instead of a project in the area. See Section 7.2 for further details

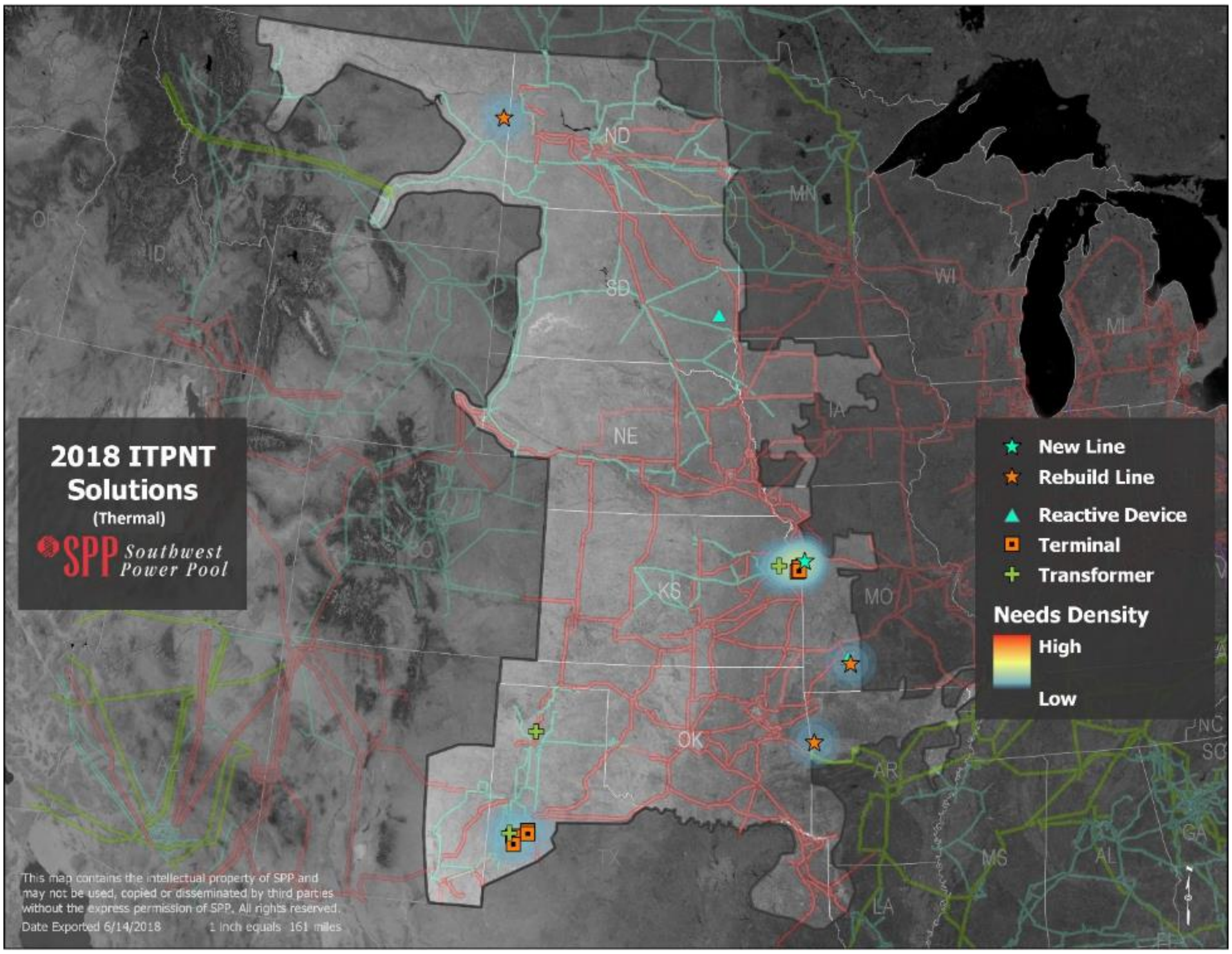


Figure 2: 2018 ITPNT Thermal Needs and Solutions

SECTION 2: INTRODUCTION

2.1: THE ITP NEAR-TERM

The ITPNT is designed to evaluate the near-term reliability of the SPP transmission system and identify needed upgrades through stakeholder collaboration. The ITPNT focuses primarily on solutions required to meet the reliability criteria defined in the SPP Open Access Transmission Tariff (tariff), Attachment O, Section III.6. The process coordinates the ITP 20-Year assessment (ITP20), 10-Year assessment (ITP10), Aggregate Transmission Service Studies (ATSS), Attachment AQ Studies (AQ) and the Generator Interconnection (GI) transmission plans by communicating potential solutions between processes and using common solutions when appropriate.

The 2018 ITPNT process produces a reliable near-term plan for the SPP footprint by identifying solutions to potential issues for system intact and contingency conditions.

The ITPNT process is open and transparent, allowing for stakeholder input throughout the assessment. Study results are coordinated with other entities, including those embedded within the SPP footprint and neighboring first-tier entities.

GOALS

The goals of the ITPNT are to:

- Focus on local, regional and interregional needs.
- Evaluate the response of the system to NERC Reliability Standard TPL-001-4 planning events that do not allow for NCLL or IFTS, with respect to SPP and company-specific criteria.
- Identify and analyze transmission-system needs over the five-year horizon.
- Identify cost-effective 69 kilovolt (kV) and above solutions that achieve, but are not limited to, the following:
    - Resolve reliability criteria needs
    - Improve access to markets
    - Improve interconnections with SPP's neighbors
    - Meet expected load-growth demands
    - Facilitate or respond to expected facility retirements
    - Synergize with the GI, ATSS and AQ processes and the ITP10 and ITP20 assessments
    - Address persistent operational issues as defined in the scope

The 2018 ITPNT is intended to provide solutions to ensure the reliability of the transmission system during the study horizon, which includes modeling of the transmission system five years out (*i.e.*, 2022). The specific near-term requirements of Attachment O are:

- The transmission provider shall perform the near-term assessment on an annual basis

- The near-term assessment will be performed on a shorter planning horizon than the 10-year assessment and shall focus primarily on identifying solutions required to meet the reliability criteria defined in Section III.6
- The assessment study scope shall specify the methodology, criteria, assumptions and data to be used to develop the list of proposed near-term upgrades
- The transmission provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope. The study scope shall take into consideration the input requirements described in Section III.6
- The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan (STEP) report
- In accordance with the assessment study scope, the transmission provider shall analyze potential solutions, including those upgrades approved by the Board from the most recent 20-year and 10-year assessments, following the process set forth in Section III.8

2.2: HOW TO READ THIS REPORT

This report focuses on the years 2019 and 2022 and is divided into multiple sections.

- Sections 2 through 5 address the concepts behind this study's approach, key procedural steps in development of the analysis and overarching assumptions used in the study
- Sections 6 through 8 address the specific results, describe the projects that merit consideration and contain recommendations and costs

SPP FOOTPRINT

Within this study, any reference to the SPP footprint refers to the set of legacy BAs and transmission owners (TO) whose transmission facilities are under the functional control of the SPP RTO, unless otherwise noted.

SUPPORTING DOCUMENTS

The development of this study was guided by the supporting documents noted below. These documents provide structure for this assessment:

- SPP 2018 ITPNT Scope
- SPP ITP Manual

All referenced reports and documents contained in this report are available on SPP.org.

CONFIDENTIALITY AND OPEN ACCESS

Proprietary information is frequently exchanged between SPP and its stakeholders in the course of any study and is extensively used during the ITP development process. This report does not contain confidential marketing data, pricing information, marketing strategies or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities and plans for new facilities that are considered non-sensitive data.

SECTION 3: STAKEHOLDER COLLABORATION

Assumptions and procedures for the 2018 ITPNT analysis were developed through SPP stakeholder meetings that took place in 2016, 2017 and 2018. The assumptions were presented and discussed through a series of meetings with members, liaison members, industry specialists and consultants to facilitate a thorough evaluation. Groups involved in this development included the following:

- TWG
- MOPC
- Board

SPP staff members served as facilitators for these groups and worked closely with each group's chairman to ensure all views were heard and SPP's member-driven value proposition was followed.

The TWG provided technical guidance and review for inputs, assumptions and findings. Policy-level considerations were tendered to appropriate organizational groups including the MOPC. Stakeholder feedback was instrumental in the selection of the 2018 ITPNT projects.

The TWG was responsible for technical oversight of the load forecasts, transmission-topology inputs, constraint-selection criteria, reliability assessments, transmission projects and the study report.

3.1: PLANNING SUMMITS

In addition to the standard working group meetings, multiple transmission planning summits were conducted to elicit further input and provide stakeholders with a chance to interact with SPP staff members on all related planning topics.

PROJECT COST OVERVIEW

Conceptual estimates were prepared by SPP staff members and were based on historical cost information submitted by TOs through the project-tracking process. Refined cost estimates expected to be accurate within a ±30 percent bandwidth were prepared by a third-party vendor and incumbent TOs. All cost estimates utilized in the 2018 ITPNT were developed in accordance with SPP Business Practice 7060, NTC and Project Cost Estimating Processes effective Jan. 1, 2012, and SPP Business Practice 7660, Upgrade Determination and Short-Term Reliability Project Process.

If a project meets the requirements in Attachment Y, Sections I and II to be a competitive upgrade, SPP is responsible for providing the cost estimates for the project via a third party. If the project did not meet the requirements in Attachment Y, Sections I and II, SPP requests cost estimate information from the incumbent TO.

SECTION 4: STUDY DRIVERS

4.1: INTRODUCTION

Drivers for the 2018 ITPNT were discussed and developed through the stakeholder process in accordance with the 2018 ITPNT Scope and involved stakeholders from several diverse groups. Stakeholder load, generation and transmission were carefully considered in determining the need for, and design of, transmission solutions.

4.2: MODEL DEVELOPMENT

SCENARIO 0 (S0)

S0 assumes projected usage of long-term firm transmission service between SPP customers and dispatches each entity's generation to meet their load and obligations. S0 emphasizes high conventional generation commitment and dispatch. Renewable generation is set to match the Model Development Working Group (MDWG) 2017 models.

SCENARIO 5 (S5)

S5 expands on S0 by maximizing long-term firm transmission service. S5 emphasizes higher wind transfers by dispatching all wind generation to maximum long-term firm service amounts. All remaining reservations are set to maximum firm service, not to exceed forecasted load. In the event forecasted load is not enough to maximize use of all inter-customer transmission service commitments, those reservations are generally scaled down on a pro-rata basis.

BALANCING AUTHORITY (BA)

To account for the impacts of the Integrated Marketplace on the SPP footprint, a BA scenario model was developed as part of the 2018 ITPNT assessment. The BA scenario modeled SPP as a single BA while assuming no change to power transfers across the SPP seams.

To simulate changes that will occur to the SPP portion of the NERC Book of Flowgates due to upgrades coming into service during the defined study period of the 2018 ITPNT assessment, a constraint assessment was completed to determine if any system constraints should be added, removed or modified before the economic dispatch (SCED) cases were created.

Making use of the economic data from the 2017 ITP10, PowerGEM software, TARA, was used to perform a DC SCED with AC verification on the SPP footprint to deliver the most economical power to load, dispatching around SPP base case and N-1 constraints 69 kV and above.

BASE RELIABILITY (BR)

The base reliability scenario assumes expected usage of long-term firm transmission service usage. Renewable resources are dispatched at each facility's latest five-year average for the SPP coincident summer peak, not to exceed each facility's firm service amount.

4.3: LOAD OUTLOOK

LOAD FORECAST

Future energy usage was forecasted by utilities in the SPP footprint and collected and reviewed through the efforts of the MDWG. This assessment used summer peak (SP), winter peak (WP) and light load (LL) seasons to assess the performance of the grid in peak and off-peak conditions. Figure 3 shows the SPP regional load amounts for each analyzed season.

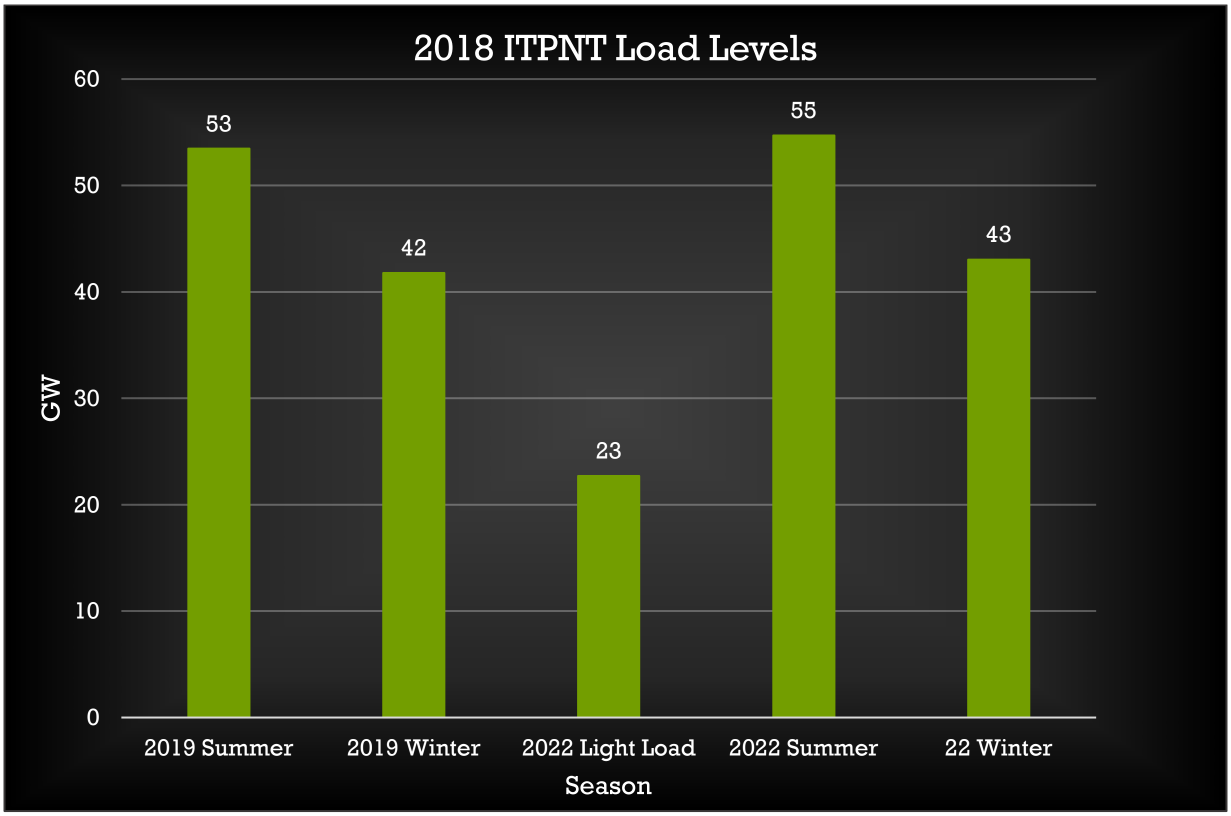


Figure 3: 2018 ITPNT Load Levels

LOAD FORECAST TRENDS

While load forecasts continue to show an average growth of 0.9 percent per year for the SPP region, yearly updates to those projections have continued to trend downward when compared to previous studies. Figure 4 shows the load forecast trends since the 2015 ITPNT.

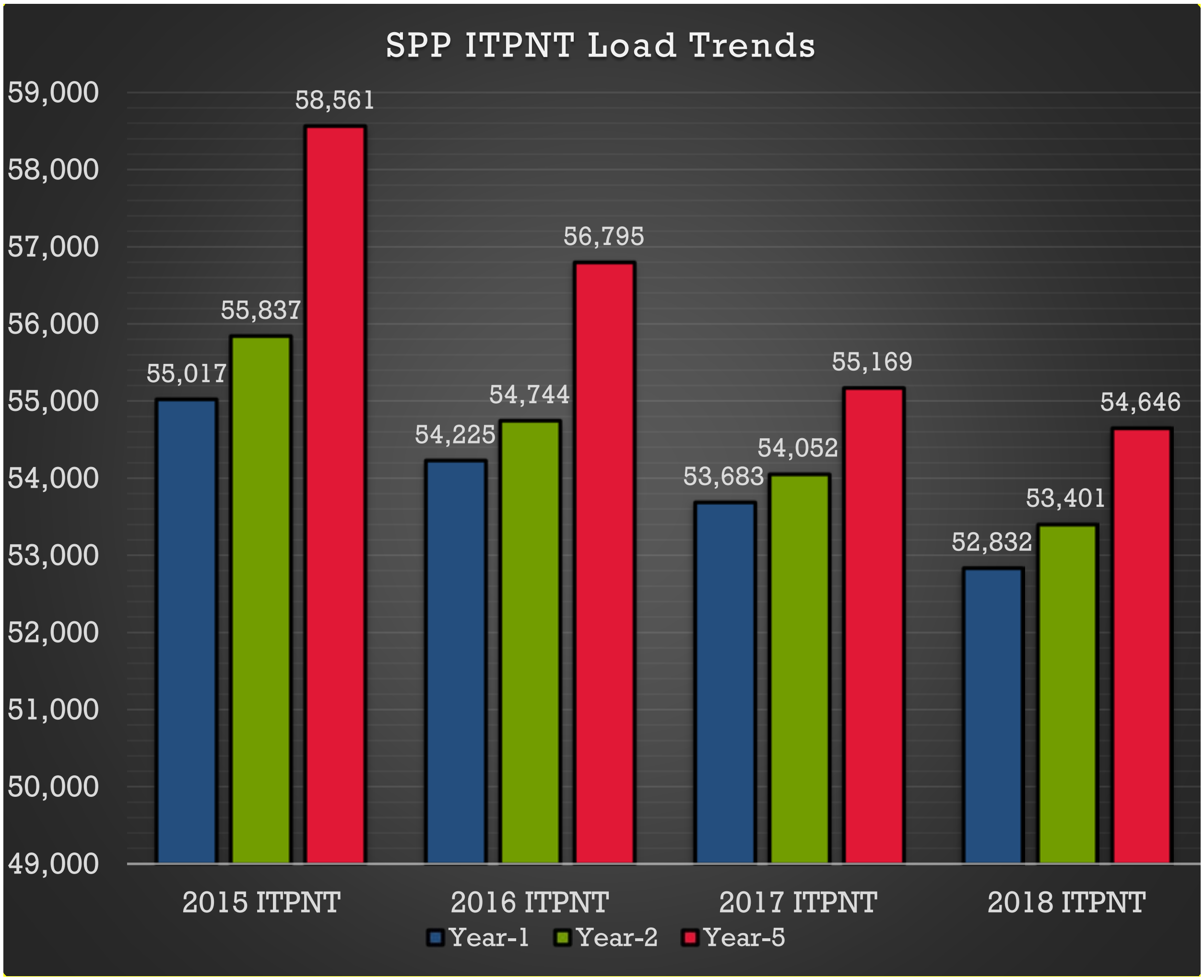


Figure 4: SPP ITPNT Load Trends

4.4: GENERATION

The four figures below show the difference in generation dispatch between the S0, S5, BA and BR scenario models for each season. Note the significant difference in the wind output for the S5 models. The BA scenario dispatch methodology is discussed earlier in this report.

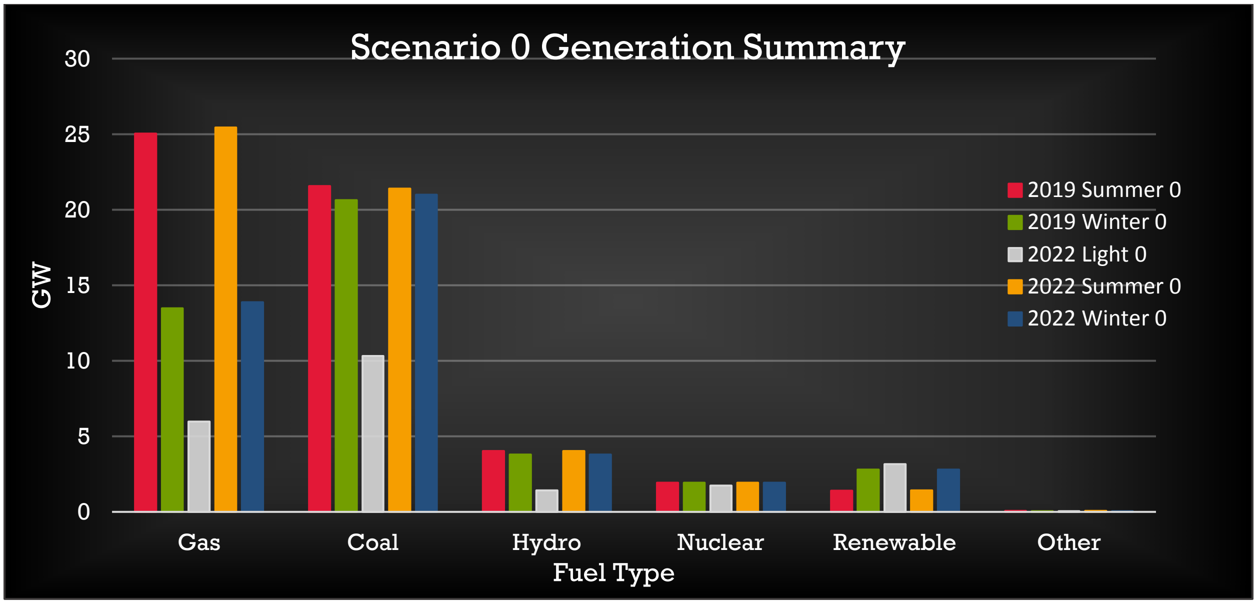


Figure 5: Scenario 0 Generation Summary

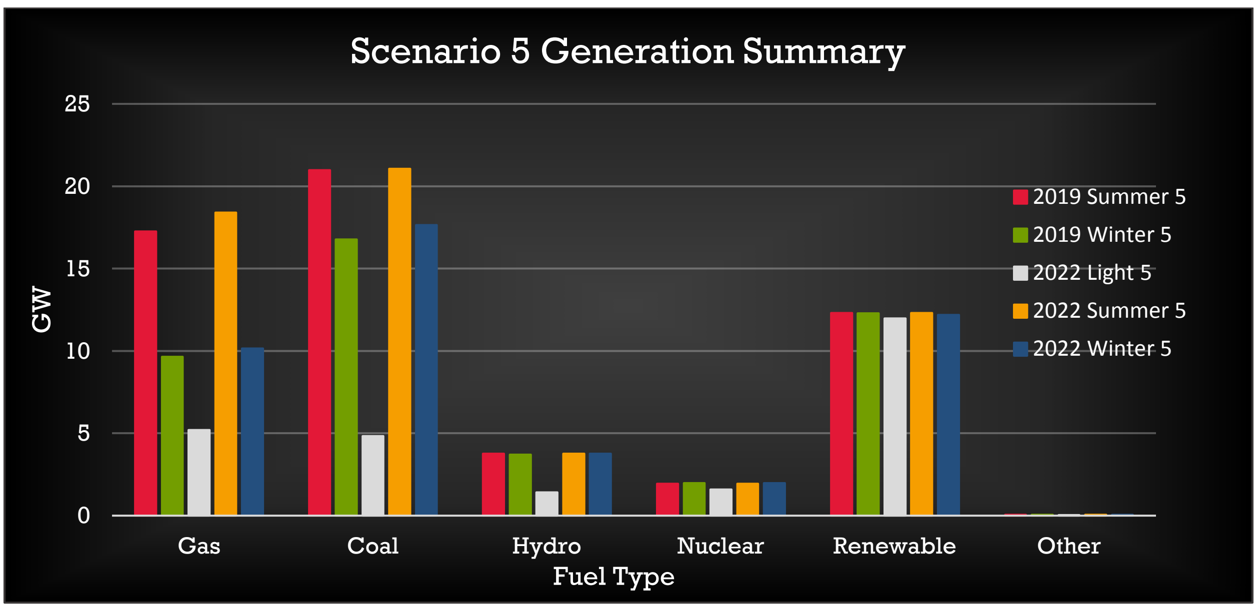


Figure 6: Scenario 5 Generation Summary

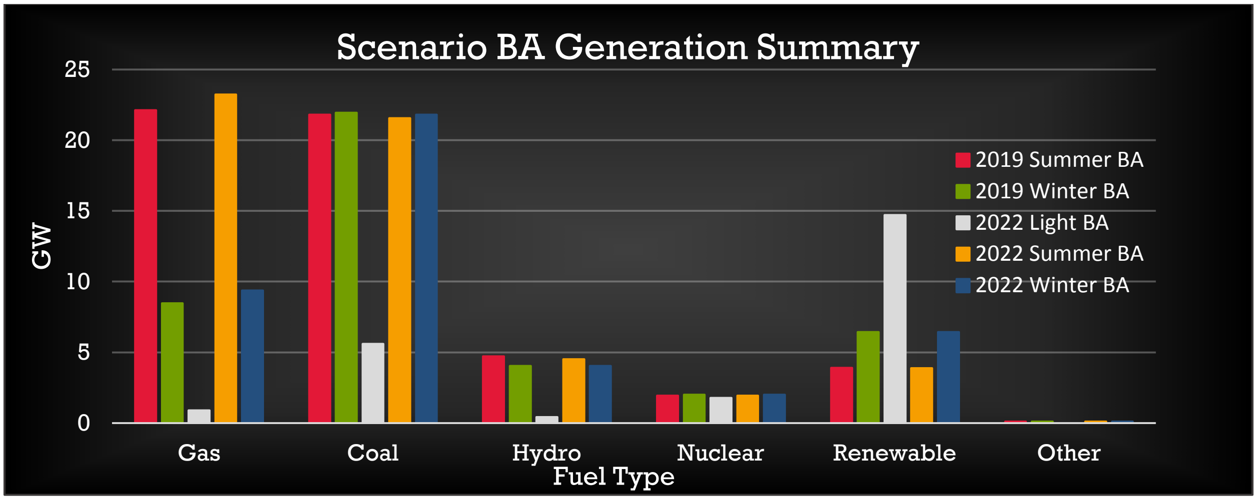


Figure 7: Scenario BA Generation Summary

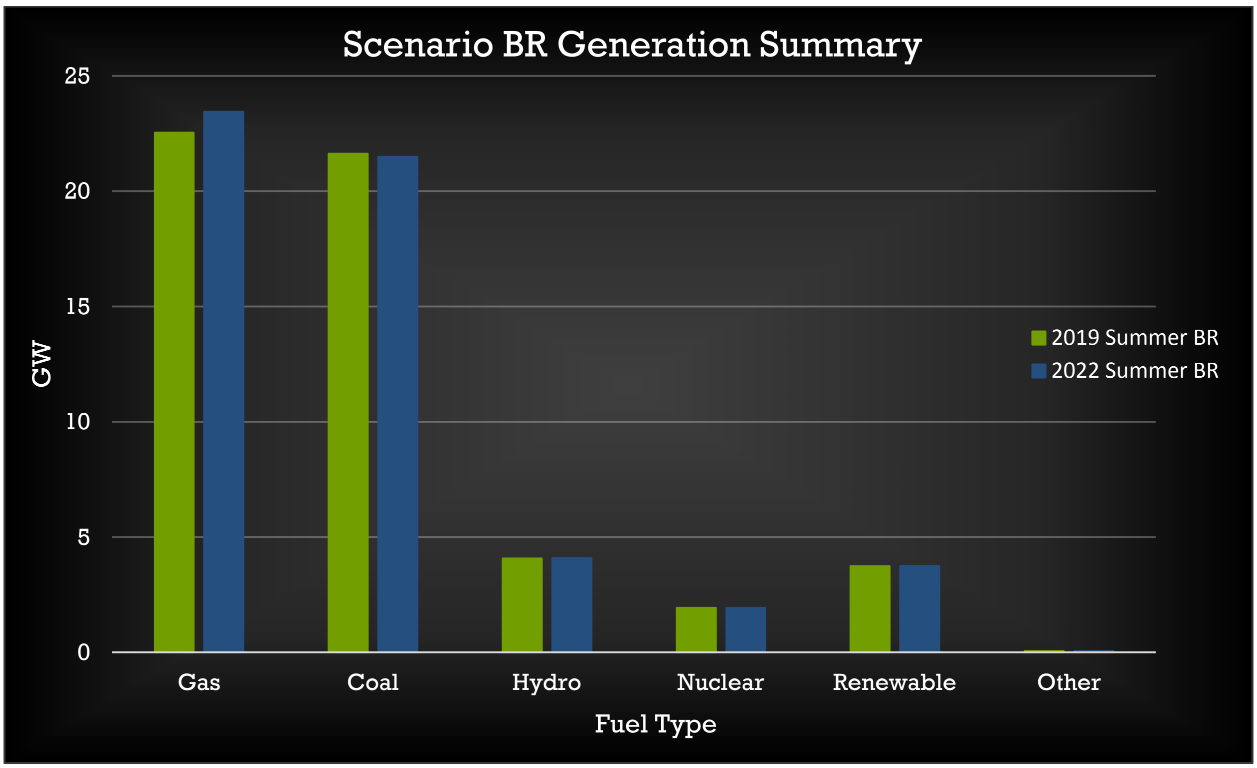


Figure 8: Scenario BR Generation Summary

SECTION 5: ANALYSIS

5.1: STEADY-STATE ANALYSIS

Analysis of the transmission system under system-intact and contingencies of SPP facilities at 69 kV and greater and at 100 kV and greater for first-tier control areas was performed on the 2018 ITPNT violations. The specific contingencies and the scenarios they were assessed against are defined in the study scope document. Reliability needs are identified for facilities with greater than 100 percent thermal loading or voltage below 0.9 or greater than 1.05 per unit for under-contingency conditions and voltage below 0.95 per unit for base-case conditions. Company-specific planning criteria also were considered to identify transmission needs, when more stringent than SPP criteria. All facilities in first-tier control areas were monitored at 100 kV and above for informational purposes and potential seams project opportunities. After performing the initial reliability assessment to identify the transmission system issues, thermal and voltage needs were posted on the GlobalScape and TrueShare sites for stakeholder accessibility.

During the course of the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments, model adjustments, and identification of invalid contingencies, non-load-serving buses, and facilities not under functional control of SPP via Attachment AI of the SPP Tariff. Figure 9 summarizes the number of remaining thermal needs (unique monitored facility) that were unable to be mitigated during the screening process.

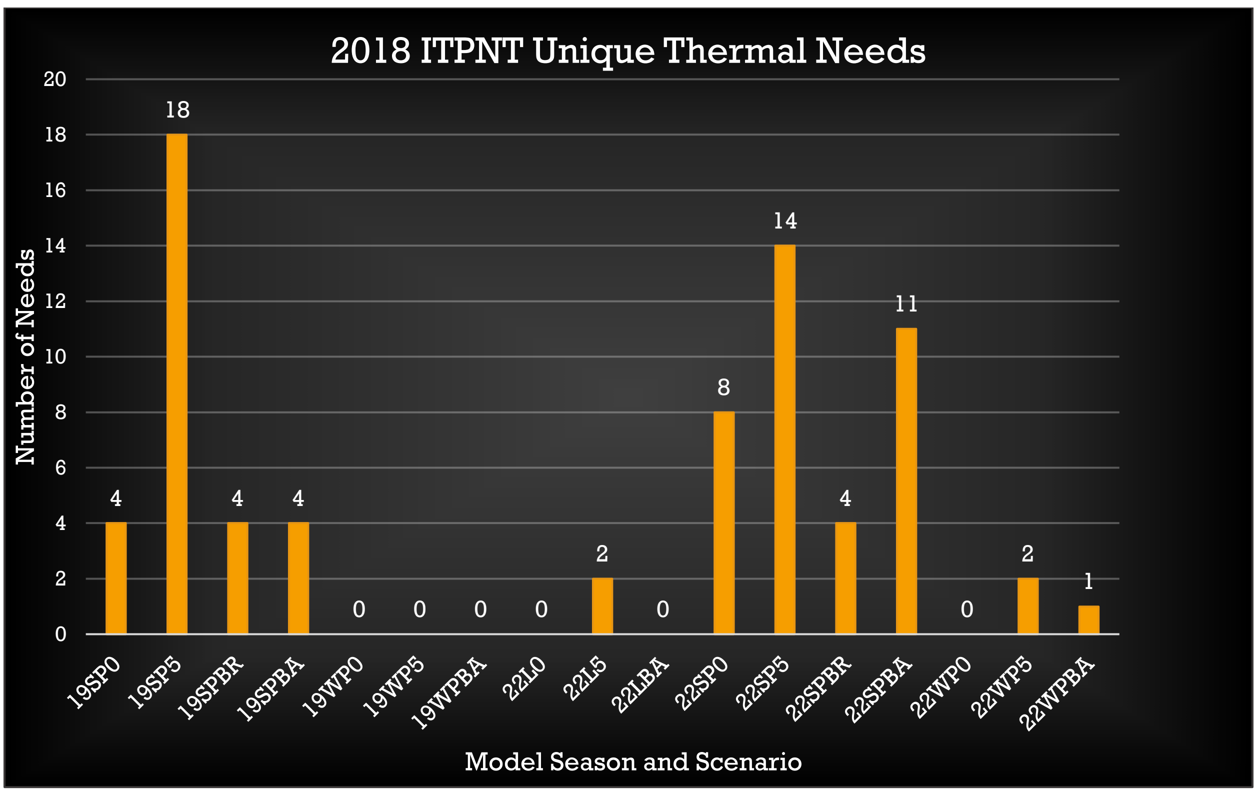


Figure 9: 2018 ITPNT Unique Thermal Needs

Figure 10 summarizes the number of remaining voltage needs (unique monitored facility) by year, season and scenario.

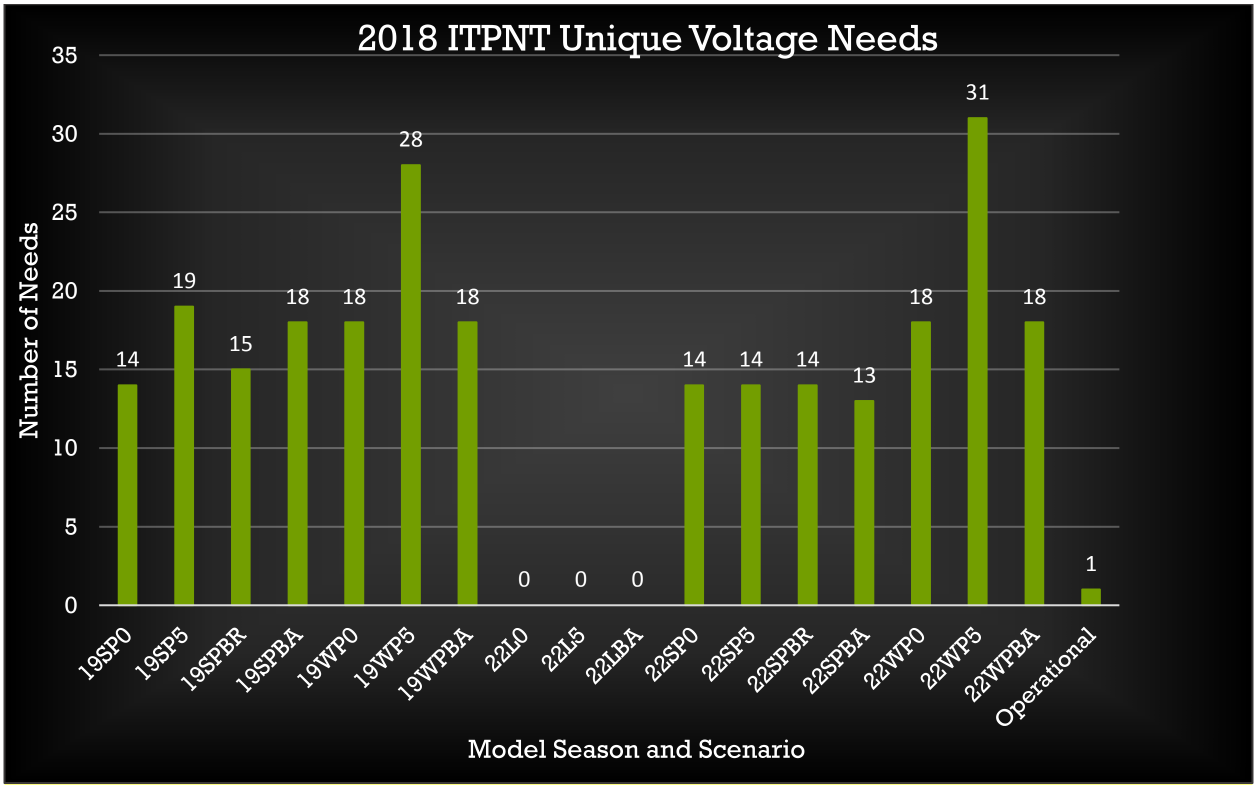


Figure 10: 2018 ITPNT Unique Voltage Needs

PROJECT SCREENING

Stakeholders submitted 310 Detailed Project Proposals (DPP) through the Order 1000 process, which included 48 modeling corrections, 18 non-transmission solutions and 10 transmission operating guides. In addition to the DPPs and other submissions, 157 SPP staff solutions and mitigations were considered to address the reliability needs. Altogether, 467 solutions were evaluated.

SPP Staff evaluated all submitted and created projects that would solve identified reliability needs. Further, each individual project's ability to mitigate each reliability need identified in the needs assessment was assessed using PSS®E.

A conceptual cost estimate also was developed for each project to utilize during screening. SPP staff members developed a standardized conceptual cost template for assigning project costs to all stakeholder-submitted and SPP staff-developed projects.

Once a project was identified as solving a reliability need and assigned a conceptual cost, a set of reliability metrics was calculated. The reliability metrics (metrics) were developed by SPP staff and stakeholders and approved by the TWG for use as a tool to aid in project selection. The metrics coincide with thermal and voltage reliability needs. The first metric is cost per loading relief (CLR), which relates the amount of thermal loading relief for the cost of a project for a need. The second metric is cost per voltage relief (CVR), which relates the amount of voltage support for the cost of a project for a need.

After the metrics were calculated, the projects were ranked for each need by the lowest CLR or CVR. The project with the highest ranking (lowest CLR or CVR) was identified as the most optimal project to address the particular need.

PROJECT SELECTION

To perform a comparison of the metric results for an extensive number of projects, SPP staff utilized a programmatic solution. Using this project selection software, a subset of projects was generated by considering project cost as related to the amount of targeted relief the project could provide. Displacement of lower-voltage projects by higher-voltage projects occurred when a higher-voltage project solved needs at a lower voltage level. During this activity, SPP staff applied engineering judgment to begin development of a draft list of selected and high-performing alternate solutions with regard to the metrics. SPP stakeholders posted this draft project list for review and study-level cost estimates were requested from either the incumbent TO or the third-party cost estimator. As staff received feedback from members on the draft project list, including the study-level cost estimates, the draft project list was reviewed using this new information.

During the planning summit on May 3, 2018, staff discussed the first draft portfolio of projects to address the needs of the 2018 ITPNT with the stakeholders. This discussion included system characteristics driving the need and how the draft portfolio project addresses those issues. Once the summit was completed, staff issued a second request for study-level cost estimates and considered feedback from the stakeholder to develop a final recommended portfolio to cost-effectively address the needs observed in the 2018 ITPNT assessment.

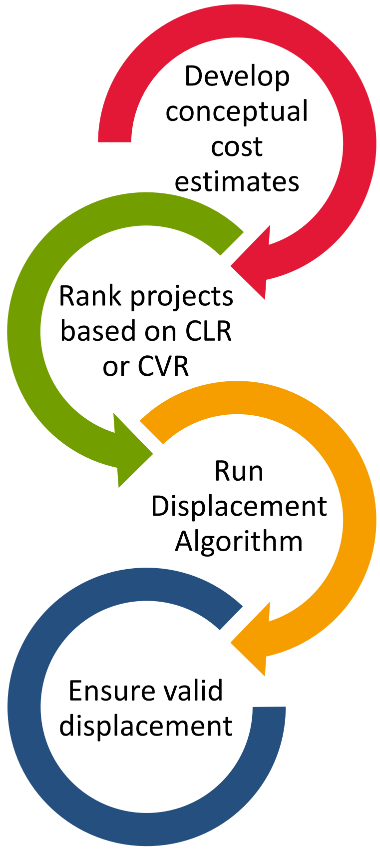


Figure 11: Project Selection Methodology

PROJECT STAGING

Need dates for the selected projects were determined using linear interpolation of percent line loading or per-unit voltage between model years 2019 and 2022. For example, to determine a need date for a solution due to a 2022 potential overload, SPP interpolated percent line loadings between the 2019 and 2022 models to determine the year when the loading is projected to exceed 100 percent. The day and month of the need date coincide with the definition of the start of the season in which the need was identified. Projects only addressing needs resulting from the additional P2, P3, P4 and P5 events were given a need date of the season in which the violation was observed for the year 2022.

5.2: ADDITIONAL ANALYSIS

As part of staff's effort to provide the most cost-effective set of solutions to address needs in the 2018 ITPNT assessment, additional analysis and consideration were evaluated during the project selection phase of the study. Some facilities were identified in the needs assessment meeting multiple of the criteria below for additional consideration. As each of these issues was discussed, the recommendation to move forward or move on from a specific need or project was discussed relevant to that topic. For example, assume a transmission facility was observed to be overloaded in 2019 and 2022 summer peak S5 and the 2019 summer peak BR models. As discussed below, after the TWG determined the S5 summer models should be removed from consideration in the 2018

ITPNT assessment, the remaining violation occurred in 2019 summer of the BR model. Once the TWG made the determination not to move forward with needs observed only in 2019, there was no longer a remaining need to address an issue on the transmission facility in question.

ANALYSIS OF S5 SUMMER NEEDS

In July 2017, the Board added the consideration of the S5 summer models to the scope of the 2018 ITPNT assessment. For any projects driven by needs that were unique to the S5 summer models, SPP staff sought additional merits to support the need for the project. These additional merits analyzed by SPP staff included each project's ability to address historical and/or projected market congestion[3], potential economic benefit[4] due to congestion relief, and ability to address auction revenue rights (ARR) feasibility issues. During the needs review, staff identified 22 unique thermal needs and one unique voltage need present only in the S5 summer models.

The first step in this analysis was to identify areas of geographical or electrical overlap between the thermal violations unique to S5 summer and congestion seen either historically in the SPP Integrated Market, or in models utilized for the annual auction of SPP's congestion hedging process. The historical congestion of interest was identified utilizing one of the criteria approved to define persistent operational needs in the new ITP process which consisted of flowgates with a total congestion cost of $10M or greater over the last 24 months. The time period defined for this analysis was 2016-2017. The congestion of interest in the ARR analysis was identified from the June and winter 2017 on peak models used for round 1 of the 2017 annual ARR allocation. Figure 12 shows the initial comparison between the issues identified from the three different sources.

[3] In all of the models used in the different analyses described in this section, congestion is created when power flows must be reduced or rerouted in order to protect a defined flowgate against thermal violation. Historical congestion is based on real-time operational data from situations occurring in the past while congestion in ARR analyses the planning horizon and are projected and driven by modeling assumptions.

[4] Economic benefit generally equates to energy cost savings for these assessments. In the operational assessment it is the savings that could have actually been realized by lowering generator production costs calculated based on market bids. In the planning assessment it is potential future Adjusted Production Cost (APC) savings calculated by the methodology defined here: https://www.spp.org/Documents/36481/2017%20ITP10%20APC%20Calculation%20(2-29-2016).pdf

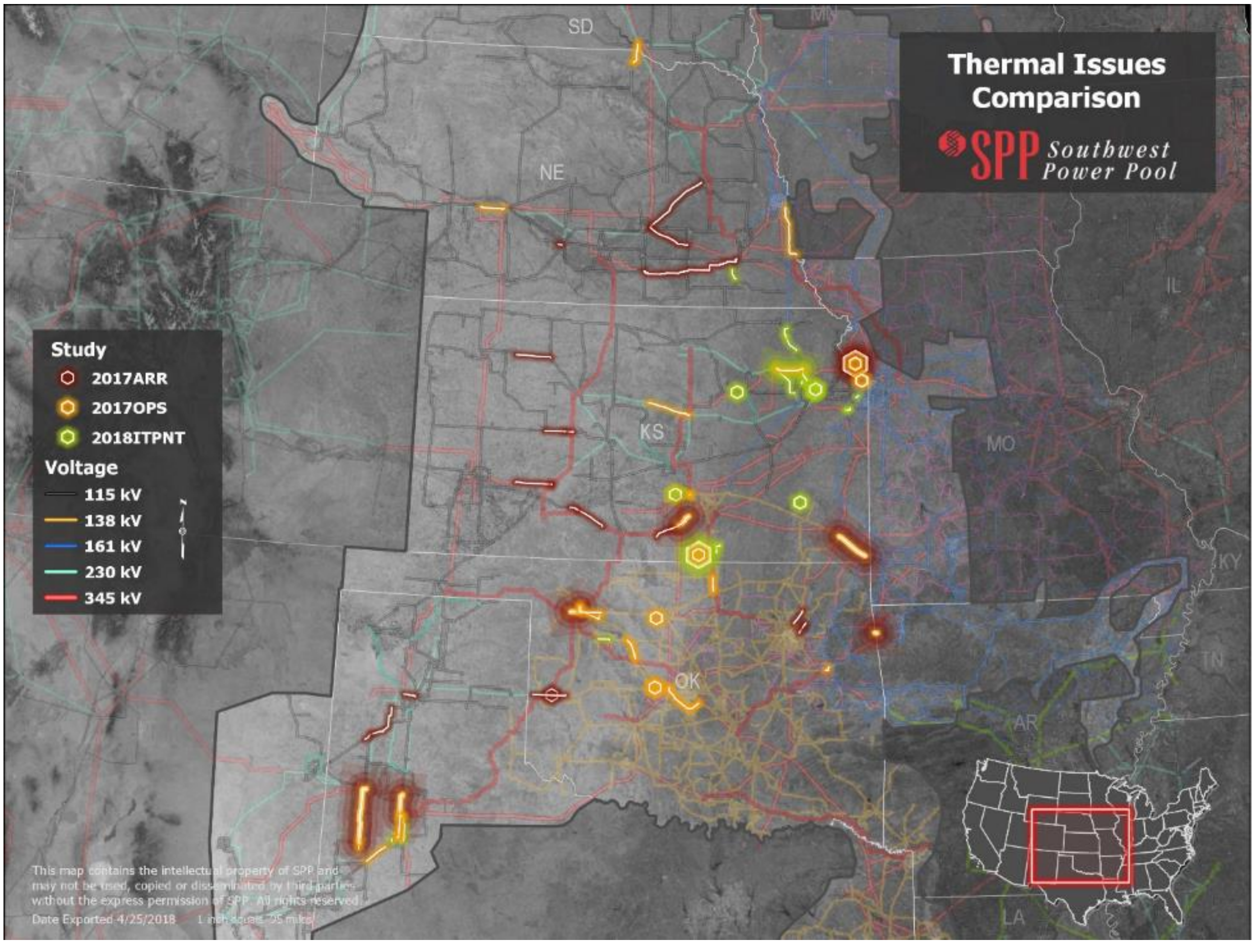


Figure 12: Scenario 5 Summer Analyses Comparison

The next step in the analysis was to assess the ability of approved future transmission projects to mitigate the issues identified. This was first performed quantitatively for the ARR allocation issues and qualitatively for the historical congestion. Figure 13 below shows the remaining overlap between issues not expected to be resolved by future transmission.

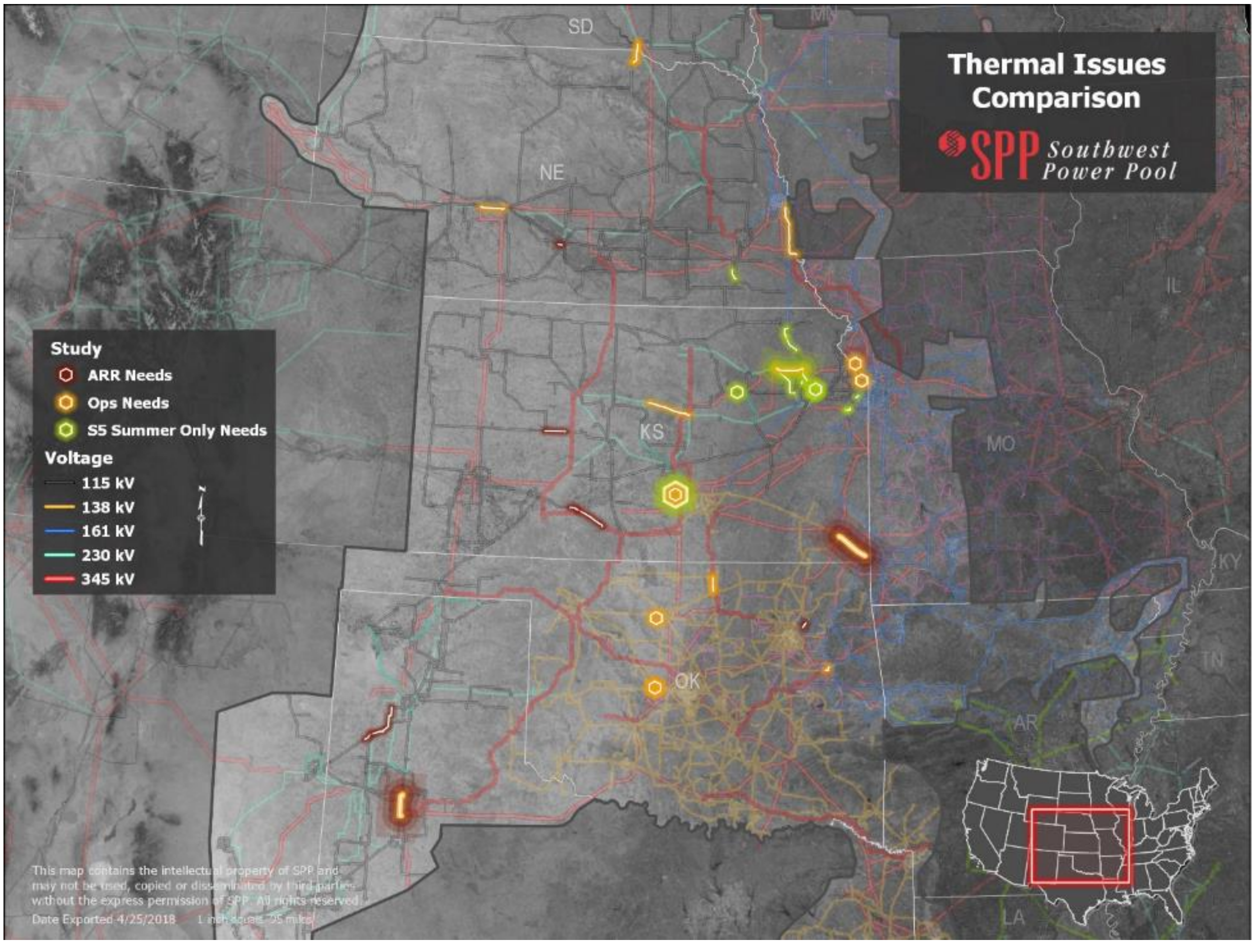


Figure 13: Scenario 5 Summer Needs Overlap

As shown in the figure above, limited synergies between the needs present in the 2018 ITPNT assessment and the other issues evaluated remain. After determining that the only overlap between the S5 summer and other issues were with historical congestion in Kansas, SPP staff began discussions with the TWG to focus the evaluation of additional merit to the Wichita, Kansas and northeast Kansas area. After obtaining agreement from the TWG to focus on those two geographical areas, staff quantitatively analyzed the ability of potential transmission projects to alleviate historically congested flowgates. SPP operations staff developed models based on historical snapshots where congestion occurred and performed a reliability analysis of selected projects to determine if the congestion was relieved and the project did not create additional issues on the transmission system. Models were developed for the following flowgates:

- Wichita 345/138-kV
- JEC – Hoyt 345-kV
- Hawthorne 345/161-kV
- Nashua 345/161-kV

Two projects were tested in the model developed for the Wichita 345/138-kV transformer: a replacement of the existing transformers and a new project to add a new source into Wichita by installing a substation and 345/138-kV transformer at Buffalo Flatts and converting the existing 69-kV feed into Cowskin to 138-kV. Both solutions were able to address the congestion and did not create any additional violations. However, SPP staff believes that a project's ability to relieve congestion alone, without weighting its cost against potential economic benefits is not enough to justify approval for construction.

Due to the location of the Hawthorne and Nashua transformers to S5 summer needs, a large solution was evaluated for its ability to address the three remaining issues. A new line from JEC to Iatan 345-kV was tested and found to address the JEC – Hoyt 345-kV congestion but did not resolve loading on the two transformers. A second project was tested to address the JEC – Hoyt 345-kV line, a rebuild of the existing line as a double circuit. This project was found to address the historical congestion but created a new issue on the 345/115-kV transformer at Hoyt under a contingency of the Hoyt – Stranger 345-kV line.

The second phase of operational analysis was intended to be a quantification of potential economic benefit of a new project through its ability to resolve historical congestion, but technical limitations proved this analysis infeasible at this time.[5] Due to the inability to quantify economic benefit of these projects from an operational perspective, SPP Staff determined there was insufficient data to determine if a new transmission project was needed.

Analysis was also performed to evaluate potential future economic benefit that could be realized from the ability of new transmission to relieve congestion in the planning horizon. The latest available economic planning models were those from the 2017 ITP10 assessment, of which the 2020 and 2025 future 3 (reference case future) models were deemed most applicable. The following projects were tested to determine these potential benefits:

- Replace both 345/138-kV transformers at Wichita
- New Wolf Creek – Emporia 345-kV
- Tap JEC – Morris and build a new line from the tap to Swissvale 345-kV
- New JEC – Iatan 345-kV
- Auburn – JEC – Swissvale 230-kV rebuild to 345-kV specifications
- Rebuild Buffalo Flatts – Goddard – Cowskin 69-kV at 138-kV, and install 345/138-kV and 138/69-kV transformers at Buffalo Flatts
- New Viola – Rose Hill 345-kV
- New JEC – Hoyt 345-kV second circuit

[5] These limitations will be discussed with the Economic Studies Working Group for a future resolution.

- Rebuild JEC – Hoyt 345-kV as a double circuit

All of these solutions were found to have limited economic benefit from congestion relief.[6] Based on these and the previous results, SPP staff was unable to identify additional potential merits to address the needs unique to the S5 summer models.

As an additional merit for consideration of these needs, Westar Energy staff brought further analysis to staff and the TWG to consider the improvement in fault-induced voltage recovery in the Wichita area, where Westar energy is expected to retire generation later in 2018, with the implementation of the aforementioned Buffalo Flatts solution.

After thorough deliberation, the TWG approved the removal of the needs resulting from S5 summer models from consideration in the 2018 ITPNT assessment.

ANALYSIS OF SCENARIO BA-ONLY NEEDS

The BA powerflow models were added to the near-term assessments to simulate the effects of the Integrated Market on the SPP footprint. During the course of the 2018 ITPNT, SPP staff identified potential issues with utilization of the BA models for this type of assessment that generated concerns with addressing the needs from these models with new transmission. This included technical limitations of the process to achieve the goal of fully simulating the effects of the Integrated Market, as well as potential policy concerns with the needs generated from this analysis.

The technical limitations center around two key aspects of the Integrated Market that are not able to be fully replicated in an assessment of this type. The first is the inability to redispatch external non-SPP generation to help alleviate potential violations on the SPP seam. The current process to develop the BA powerflow models is limited in that only SPP generation is redispatched to alleviate SPP issues. While this may have not specifically driven all violations seen in the BA models, all of the violations identified were near the eastern seam of SPP and potentially could have been mitigated by external generation redispatch. The other technical issue is the inability to fully replicate a security-constrained unit commitment. While generators are able to be turned on or off during the security-constrained economic dispatch, this action is limited and does not fully account for generator startup costs or variables in the time domain such as generator ramp rates or forecasted system demand that would be accounted for in the Integrated Market.

The policy concern is in regards to performing regional reliability analysis on a model that contains non-firm generation. These models contain a certain level of generation that has not been studied in the SPP ATSS process to gain firm transmission service. The other scenario models of the near-term assessment only dispatch generation that has been studied through the aforementioned process in order to confirm capacity and energy deliverability of firm resources backed by network and point-to-point service. One goal of the regional planning study is to maintain the rights of long-term firm resources by identifying new transmission to support the continued deliverability of firm

[6] These results are specific to the futures developed for the 2017 ITP10 and do not guarantee that potential APC benefit will not warrant proposed construction in future ITP studies

resources. While non-firm resources may not be directly driving the needs seen in the BA models, they are displacing other firm generation that could be used to potentially alleviate those issues.

Due to these and other issues, SPP opted to perform further analysis on needs appearing only in BA models to gain additional justification for any projects. The approach was to couple the issues with other dispatch scenarios and information that will be used in future studies. A subset of these thermal needs were facilities identified as highly loaded in other dispatch scenarios or expected to be a future need in another dispatch scenario based on changing model assumptions. As a result of this analysis, the following projects were included in the recommended portfolio and are discussed in more detail in 7.1: Final Project Portfolio:

- Rebuild 4.2 miles of 69-kV line from VBI North to Figure Five
- Rebuild 1.25 miles of 69-kV line from Nixa Downtown – Nixa Espy

Two other needs were identified to be unique to the BA models but were not highly loaded in other dispatch scenarios and are not expected to be a future issue. Therefore, these thermal issues were deemed invalid for this study:

- Figure Five – Cedarville Tap 69-kV
- Baldwin – Woodlawn 69-kV

ANALYSIS OF SHORT-TERM NEEDS

SPP staff identified several projects to address needs only present in the 2019 models. Both staff and stakeholders expressed concerns about issuing NTCs for needs that show to be mitigated within the model set. SPP staff recommended not moving forward with projects that only solve early-year issues. The TWG approved staff's recommendation not to move forward with projects to solve thermal violations on the following facilities because the issues could be mitigated via system changes in later years:

- Prairie Lee – Blue Springs 161-kV line
- Blue Springs East – Blue Springs South 161-kV line
- Circleville – King Hill – Kelly 115-kV line
- Wichita 345/138-kV transformer
- Ainsworth 115-kV bus

ANALYSIS OF TRANSMISSION OPERATION GUIDES (TOGS)

TOGs are tools used to mitigate issues in the daily management of the transmission grid. TOGs may be used as alternatives to planned projects. Staff is required to evaluate TOGs in accordance with Attachment O of the OATT and Appendix B of the ITP Manual. TOGs were evaluated in the ITPNT process to determine effectiveness in addressing thermal and voltage needs. During the course of the 2018 ITPNT assessment, staff discussed the use of TOGs with the TWG and the transmission owner/operator.

The TWG, in agreement with the transmission owner/operator, voted to approve the use of TOGs to address the following issues:

- Watford 230/115-kV Transformer
- Low Voltage in Rugby/Rollette Area
- Richland – Fairview 115-kV
- Morrill – Gering 115-kV
- Georgia 115/69-kV Transformer
- Lawrence Park – Georgia 69-kV

The TWG, in agreement with the transmission owner/operator citing real-time issues and ineffectiveness[7] of the TOGs, voted in favor of transmission solutions in the 2018 ITPNT instead of the use of TOGs. This vote the resulted in the following projects[8]:

- Replace the 230/115-kV transformer at Lawrence Hill
- Construct a new 5.6-mile 161-kV line from Blue Valley to Crosstown

The TWG and the transmission owner/operator were not in agreement on the use of a TOG for one facility, the Wolf Creek 345/69-kV transformer located at the Wolf Creek Plant. A set of TOGs have been developed to reduce the MW output of the plant when any of the 345-kV lines are outaged for any reason. The TOGs were developed to protect the system from angular stability issues that occur under N-1-1 contingency conditions when more than one of the 345-kV lines leaving the plant are outaged. These angular stability issues have been observed in various studies. The rating of the Wolf Creek 345/69-kV transformer is found to be in violation in the 2019 and 2022 winter peak S5 models, in which the Wolf Creek Plant and the Waverly wind farm are both dispatched at almost full output. A large portion of the energy from these generators flows from west to east across the Waverly - LaCygne 345 kV-line. When that line is outaged, almost 800 MVA of energy is redirected across the remaining facilities connected to the Wolf Creek 345-kV bus. This redirection of flow causes loading on the 345/69-kV transformer at Wolf Creek to surpass its emergency limit.

The transmission owner recommended to the TWG a long-term Extra High Voltage (EHV) solution was necessary to address the both thermal loading and angular stability issues around Wolf Creek. The need for the EHV solution was because the TOG did not include a short-term emergency rating and the angular stability margins around Wolf Creek have been steadily declining as more renewable generation has been installed and dispatched in the SPP Integrated Market.

Staff completed additional analysis to address the violation on the Wolf Creek transformer to provide the TWG with as much information as possible to make an informed decision. This included analysis of a higher-rated replacement transformer and a new 345-kV line from Wolf

[7] See Appendix B of the 2016 ITP Manual.

[8] More information regarding specifics of the project can be found in Section 7 of this report

Creek to Emporia Energy Center. Analysis completed by staff for consideration by the TWG included:

- Steady state assessment to determine if either the larger transformer or new 345-kV line causes new violations on the system
- Transient stability analysis on a new 345-kV line from Wolf Creek to Emporia Energy Center to determine if angular stability limitations were improved
- Economic analysis on a new 345-kV line from Wolf Creek to Emporia Energy Center to determine potential APC savings

The steady state assessment on the possible solutions of the larger transformer and new 345-kV line were done in similar fashion to the Final Reliability Assessment as discussed in Section 7.3 of this report. The recommended portfolio was applied to the model with and without either of the aforementioned solutions. Contingency analysis was completed equivalent to the needs assessment. The implementation of either project in conjunction with the recommended portfolio resulted in no new potential violations on the transmission system.

Transient analysis was performed to determine the effect of a new 345-kV line from Wolf Creek to Emporia on the existing angular stability limit for the Wolf Creek Plant under different contingency conditions. The analysis was performed on the 2017 MDWG Dynamics cases being used in SPP's 2018 TPL-001 Planning Assessment to give an indicative result of the increase in angular stability margin the new line would be able to provide. Analysis showed an increase in the angular stability margin near Wolf Creek. However, a new limit could not be confirmed.

Lastly, economic analysis was performed to evaluate the potential adjusted production cost savings of the removal of the TOG over the course of an entire year. To evaluate this an 8,760 hour economic assessment was done using approved Future 3 2017 ITP10 economic models. A comparison between a base case and change case was done to determine the potential APC savings. The base case was updated to reflect an increased usage of the TOG which reduces the available generation from the Wolf Creek Plant due the decreasing angular stability margins, while the change case removed the use of the TOG and added the 345-kV line from Wolf Creek to Emporia Energy Center. Indicative APC savings observed in the economic analysis resulted in a 1-year benefit-to-cost (B/C) ratio of ~0.5[9]. This savings is a result of the increased availability of low cost energy to the SPP footprint by not mandating a reduction in availability of the Wolf Creek Plant. No APC savings as a result of decreased congestion were observed.

After much discussion, the TWG approved a motion in disagreement with the host transmission owner, determining the TOG should be used to address issues observed in the 2018 ITPNT. The motion included an acknowledgment of the current angular stability and thermal loading issues around the Wolf Creek and requested continued discussion of how to evaluate the issues around Wolf Creek.

[9] The 1 year B/C ratio criteria project must meet to be considered an economic project is 0.9 B/C as noted the 2017 ITP10 Scope.

ANALYSIS OF BROOKLINE HIGH-VOLTAGE OPERATIONAL NEED

In 2016, SPP and Associated Electric Cooperatives, Inc. (AECI) performed a Joint Coordinated System Plan (JCSP) study to evaluate potential seams projects. During the course of that study, a persistent high-voltage need was identified in the Brookline area; however, prior to being issued an NTC, an SPP tariff study must have identified the need and recommended solution for SPP Board approval. As a result, the MOPC directed staff to confirm the Brookline high voltage issue meets the criteria for a persistent operational need for inclusion in the study. The need was found to still be valid, which led to the evaluation of solutions for the Brookline high voltage need in the 2018 ITPNT assessment.