June 21, 2007

Final Report on the
Southwest Power Pool (SPP) EHV Overlay Project

Prepared for: Southwest Power Pool

Prepared by: InfraSource Technology, a Division of InfraSource Corporate Services, LLC, and PowerWorld Corporation

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1 Executive Summary

This project provided a long-range strategic assessment regarding long-term reliability and capacity needs through the use of a 345 kV, 500 kV, and 765 kV or higher transmission system to overlay the SPP footprint, to assess the potential integration with neighboring systems, to address future transmission needs required by SPP and to ensure an efficient and optimal transmission system to address long-term future transmission needs. To assess the effectiveness of these project proposals, this project evaluated the performance of steady state analysis to verify that the final recommended package of projects satisfies reliability criteria and to identify reinforcements that may be necessary on underlying, lower-voltage facilities.

This project had 3 phases:

1. Phase One developed consensus on criteria, goals, objectives, assumptions between SPP and its members and stakeholders.
2. Phase Two used the information developed in the Phase One to develop models and scenarios to test project alternatives and develop a recommendation for SPP.
3. Phase Three provided a constructability assessment of the final recommended package of projects.

The team used a screening methodology to test many different line configurations. Detailed analysis was performed on six different alternatives. Based upon the analysis performed by the team, the top performing alternative was judged to be Alternative 5, a 765 kV plan shown in Figure 9 of this report. The detailed analysis of the Alternatives was performed using on-peak cases.

As the team evaluated the top performing alternatives, patterns started to emerge regarding the SPP system. Reinforcement points near load centers performed very well. Loops and networks performed well in handling the various contingencies, even given the heavy wind concentration in the model.

The team has selected Alternative 5 for the following reasons:

- provides an EHV backbone to maintain reliability for the SPP members & communities
- highest rated using the selection methodology described in section 4
- lowest line losses on peak
- 2^{nd} lowest construction costs of alternatives that include Ozark reinforcements
- excellent import and export capability to ERCOT, WECC and the eastern interconnect
- lowest on-peak hourly operating cost (determined using OPF) of the top 3 performing alternatives

InfraSource Technology and PowerWorld Corporation would like to thank SPP for selecting us to work on this important and exciting project. We also acknowledge and thank SPP, its members, stakeholders and regulators for the invaluable assistance they provided to the project team in developing the assumptions and models.

2 Project Background

This project provided a long-range strategic assessment regarding long-term reliability and capacity needs through the use of a 345 kV, 500 kV, and 765 kV or higher transmission system to overlay the SPP footprint, to assess the potential integration with neighboring systems, to address future transmission needs required by SPP and to ensure an efficient and optimal transmission system to address long-term future transmission needs. The project evaluated the performance of steady state analysis to verify that the final recommended package of projects satisfies reliability criteria and to identify reinforcements that may be necessary on underlying, lower-voltage facilities.

The tasks in this project occurred in 3 main phases:

4. Phase One developed consensus on criteria, goals, objectives, assumptions between SPP and its members and stakeholders.

5. Phase Two used the information developed in the Phase One to develop models and scenarios to test project alternatives and develop a recommendation for SPP.

6. Phase Three provided a constructability assessment of the final recommended package of projects.

The team used a screening methodology to test many different line configurations. Detailed analysis was performed on six different alternatives. Based upon the analysis performed by the team, the top performing alternative was judged to be Alternative 5, a 765 kV plan shown in Figure 9 of this report.

2.1 Milestones

There are two project milestones established by the RFP:

1. April 11, 2007 - the due date for the interim report.
2. June 13, 2007 - the due date for the final report.

2.2 Project Deliverables

The Statement of Work identifies the following project deliverables:

- A report on relevant industry wide reliability & economic criteria and relevant policy developments. (Provided in the Interim Report)

- A white paper on stakeholder process. (Provided on January 25, 2007 & included as Appendix 1 of the Interim report)
- A finalized list of criteria, goals, objectives, modeling assumptions, relevant futures & scenarios. (Updated discussion it this Final Report)
- An Interim Report (completed) to discuss the following items:
  - review of stakeholder process
  - assumptions
  - objectives
  - relevant futures & scenarios
  - status of teams' work and
  - leading project contenders.

- This Final Report which includes:
  - updated interim report content
  - final recommended package of projects
  - cost estimates
  - constructability assessment
  - overlay drawing with the proposed transmission system, and
  - one-line diagram of transmission overlay including modifications to the sub-voltage systems.

3 Dynamics of the SPP System in 2026

This section has been added to provide a context to better understand the EHV project and the challenges SPP faces if the future envisioned by SPP and its stakeholders plays out.

The SPP system in 2026 has some interesting dynamics at work. In 2026, there will be an increased reliance on the SPP transmission system to satisfy its core task of maintaining reliability while simultaneously satisfying the increasing demands on the system.

If the future plays out as currently envisioned by SPP and its stakeholders, these demands will driven by the following issues:

- Increased energy efficiency and demand side management penetration.
- Environmental issues such as the recently proposed carbon tax that will affect the existing and future generation fleet.
- Extensive demand for renewable energy in the US electric system. This will occur throughout the eastern interconnect and especially along the eastern seaboard.
- Massive wind development will occur in the SPP footprint to serve this demand in the western parts of Oklahoma, Kansas, eastern New Mexico and the panhandle of Texas. Ultimately, nameplate capacity of 20,000 MWs or more of wind power could be installed on the SPP system. (Note for this study the team modeled 13,000 MWs of nameplate wind capacity.)
- Significantly increased gas generation in the southeastern and central part of the SPP system.
- Renewed interest in nuclear power which may result in an expansion of the Wolf Creek nuclear station.
- Higher than the SPP average load growth in the following pockets:
    - Ozarks
    - Kansas City
    - Oklahoma City
    - Wichita
    - Tulsa
- Emerging and expanding energy markets in the SPP footprint and other areas of the eastern interconnection.
- Increased interchanges of energy between SPP, MISO and other areas of the eastern interconnection.
- Increased interchanges of energy between SPP and ERCOT and SPP and WECC.

Figure 1 gives some insights into the transmission reinforcements that may be needed. This figure represents the SPP transmission system as planned through 2016 (i.e., no additional transmission lines have been added to the model) dealing with the peak load dynamics created in 2026 by the above assumptions.[1]

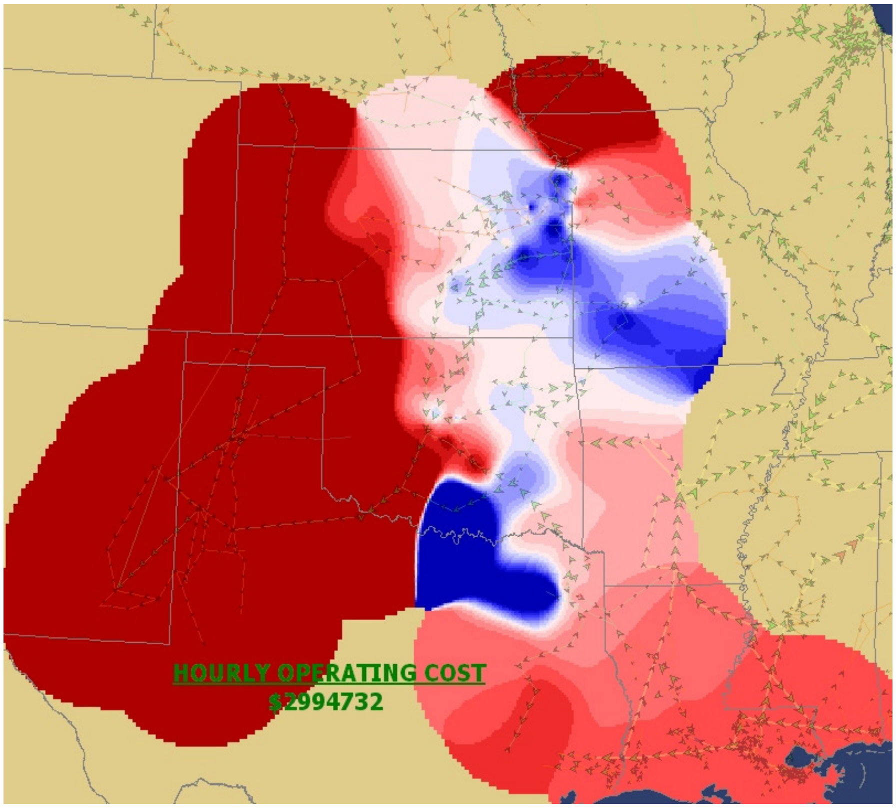


Figure 1: Costs in 2026 w/o reinforcements

This figure shows the cost boundaries that could emerge in the SPP footprint. Interestingly, this OPF run shows that wind developments in the west are trapped, relying on combustion turbines to alleviate the resultant congestion. [2]

To assist in the analysis for this project, the team, using concepts developed by PowerWorld, devised a sensitivity methodology that was based upon congestion inherent in the system. This method created a measure called Aggregate MVA Contingency Overload (AMVACO). AMVACO identifies potential locations for transmission line terminations. Figure 2 shows the AMVACO measures for this same un-reinforced SPP system in 2026.

[1] Figure 1 was created by performing an Optimal Power Flow ("OPF") run for one hour at peak load. The costs used were supplied by PowerWorld and are based upon publicly available energy cost databases.
[2] While an hourly operating cost is calculated and shown above, this slide does not represent a real operating cost for the entire SPP footprint. Instead it represents the operating costs of the units that have been turned on for control within the OPF run. Therefore, this cost is best used as comparative with similar runs for EHV transmission reinforcement alternatives.

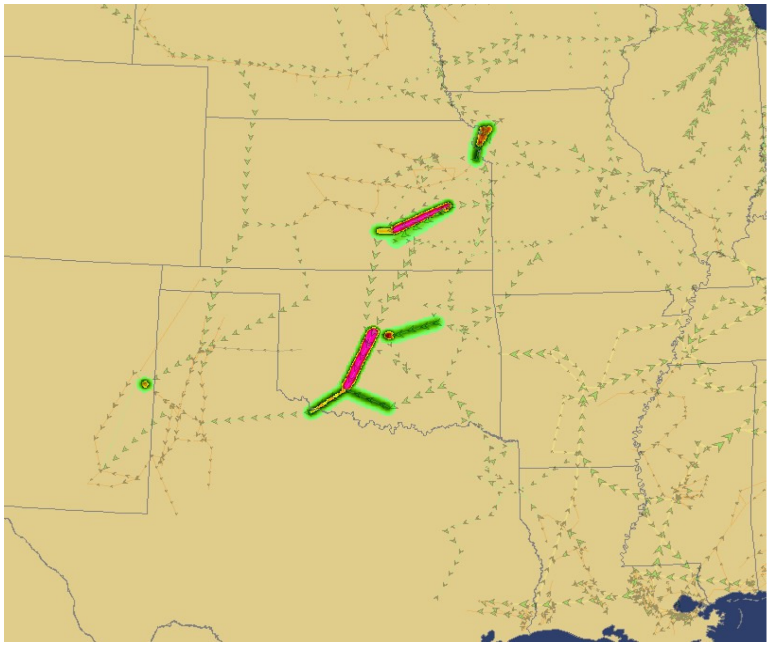


Figure 2: Reinforcement Needs on SPP System in 2026

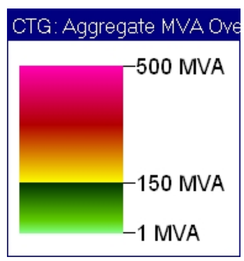


Figure 3: Key

These results may be interpreted as identifying key areas for a planner to consider transmission additions to alleviate the congestion occurring in the system under this peak load condition under all of the N-1 contingency scenarios that could occur. Key substations identified by in this figure are Wolf Creek, Wichita, Oklaunion, Oneok, and Iatan. (A detailed description of this process is provided in Appendix E.)

Figures 1 and 2 illustrate some of the congestion points and flow patterns that were studied by the team when developing the EHV alternatives.

4 Alternatives

Stakeholder input was critical to development of the EHV Alternatives that were studied. The assumptions the team developed in Phase One guided the model development & helped establish a regional and interconnect wide perspective for the team.

The location of new generation was used to select the starting points for the Alternatives. These locations were modified by the engineers as the started to study these alternatives in the model to minimize costs and optimize performance.

In addition, the team used the sensitivity studies as a check on the manual planning process (and vice versa – the manual planning studies helped to establish the veracity of the sensitivity results). One alternative (Alternative 3) was created solely from the sensitivity runs so that team could compare its results with other manually optimized plans.

Following is a description of the Alternatives that were studied by the team.

4.1 Ozark Reinforcements

During the course of the EHV project, the team evaluated the impact of EHV reinforcement in the Ozarks area.

For this evaluation, the team focused on EHV reinforcements that could serve as a possible modification or augmentation to some of the plans for the Ozarks that SPP has developed and presented to the stakeholders. The reinforcements discussed in this section should not be considered a replacement for the projects developed by SPP in these other studies. Rather the team's analysis shows that EHV reinforcements in Ozarks may also provide benefits for the SPP system as a whole. Therefore, SPP may wish to consider EHV options in future studies of the area using the configuration developed by the project team as a starting point for further analysis.

The analysis of the team indicated that this configuration performed well as a stand alone package as well as part of a bigger EHV overlay plan.

Figure 4 shows the suggested Ozark reinforcements.

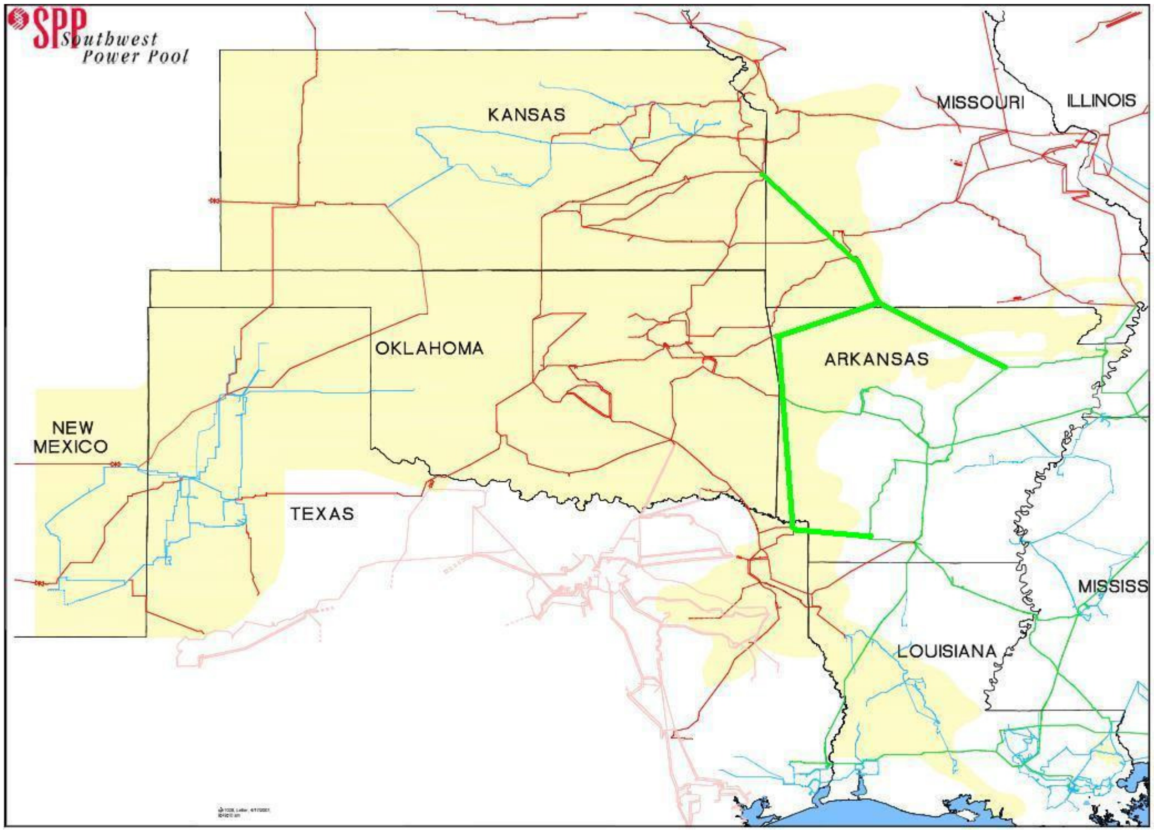


Figure 4: Ozark Reinforcements

For the Ozark reinforcements, the lines are terminated as follows:

Ozark 500 kV Loop			
From	**To**	**Voltage (kV)**	**Miles**
Lacygne	Brookline	500	115
Brookline	Table Rock	500	55
Table Rock	Independence SES	500	144
Table Rock	Flint Creek	500	84
Flint Creek	Ft. Smith	500	72
Ft. Smith	NW Texarkana	500	140

These reinforcements are used in all Alternatives studied with the exception of Alternative 3.

4.2 Alternative 1

Alternative 1 is a 500 kV loop with 500 kV lines extending to AEP to the northeast, SERC to the southeast, and to the panhandle of Texas in the southwest.

The general concept of this plan was to design a collector system for wind and gas generation in the heart of SPP. A "spur" was extended to further provide the ability to deliver wind energy in New Mexico and the panhandle of Texas. In addition, a connection was added to the 765 kV system in Chicago. The Collins terminal was because it carried more energy in the basecase runs than a Sullivan termination in Indiana.

Figure 5 shows the topology of Alternative 1.

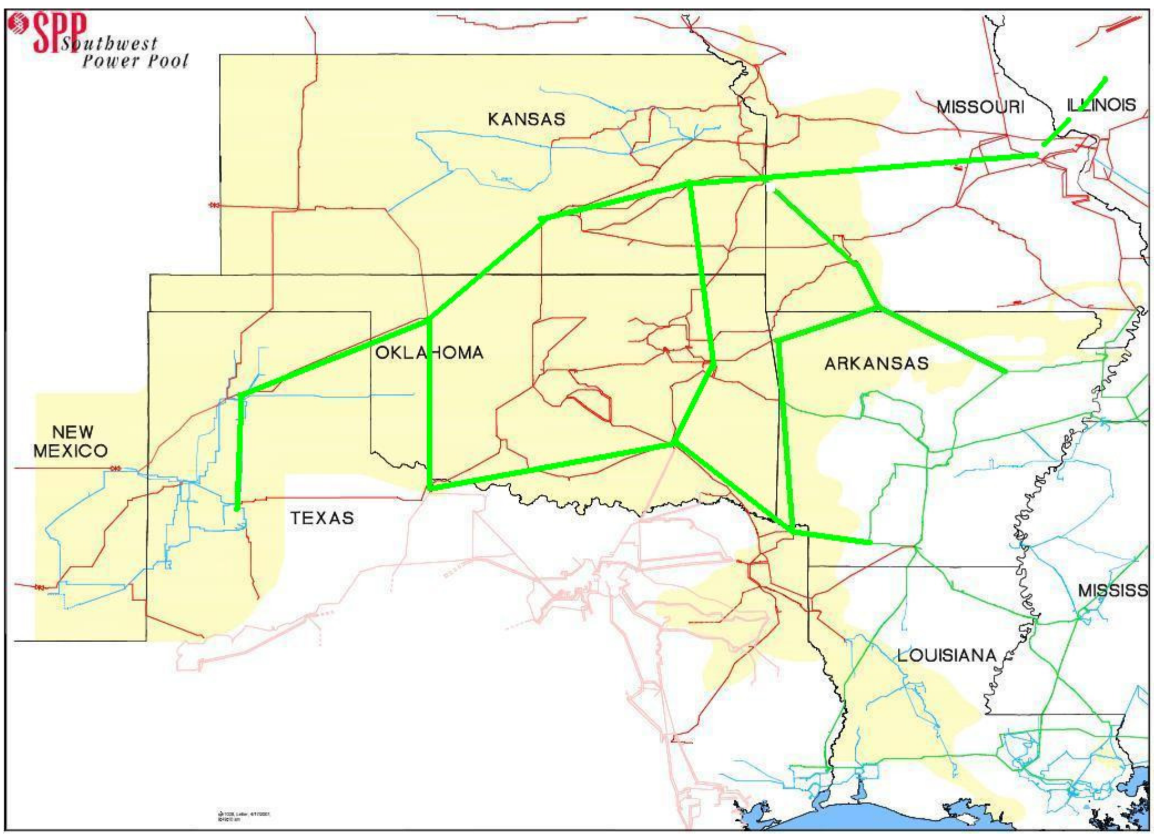


Figure 5: Alternative 1

For Alternative 1, the lines are terminated as follows:

From	To	Voltage (kV)	Miles

Labadie	Collins	500	250
Wolf_Creek	Labadie	500	270
Wolf_Creek	Wichita	500	120
Wichita	Mooreland	500	150
Mooreland	OKU	500	150
OKU	Pittsburg	500	220
Pittsburg	Muskogee	500	85
Muskogee	Wolf Creek	500	170
Pittsburg	Texarkana	500	140
Texarkana	McNeil	500	70
Mooreland	Harrington	500	175
Harrington	Tuco	500	95

Ozark 500 kV Loop			
From	**To**	**Voltage (kV)**	**Miles**
Lacygne	Brookline	500	115
Brookline	Table Rock	500	55
Table Rock	Independence SES	500	144
Table Rock	Flint Creek	500	84
Flint Creek	Ft. Smith	500	72
Ft. Smith	NW Texarkana	500	140

4.3 Alternative 2

Alternative 2 is a modification of Alternative 1. Again, the general concept of the plan was to design a collector system for wind and gas generation in the heart of SPP. A "spur" was extended to further provide the ability to deliver wind energy in New Mexico and the panhandle of Texas. In addition, a connection was added to the 765 kV system in Chicago. The Collins terminal was because it carried more energy in the basecase runs than a Sullivan termination in Indiana.

In Alternative 2 the loop and the link to St. Louis and onto Chicago use 765 kV lines. Figure 6 shows the configuration of Alternative 2.

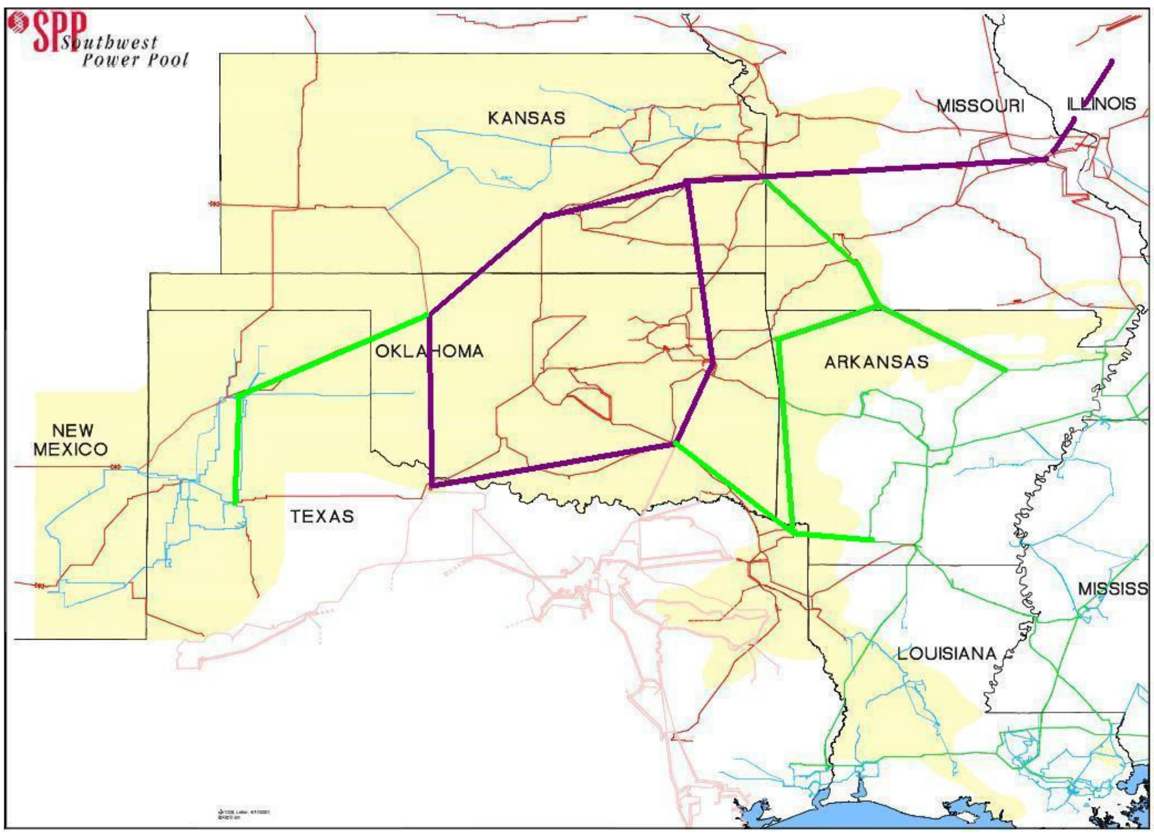


Figure 6: Alternative 2

For Alternative 2, the lines are terminated as follows:

From	To	Voltage (kV)	Miles
Labadie	Collin	765	250
Wolf_Creek	Labadie	765	270
Wolf_Creek	Wichita	765	120

Wichita	Mooreland	765	150
Mooreland	OKU	765	150
OKU	Pittsburg	765	220
Pittsburg	Muskogee	765	85
Muskogee	Wolf_Creek	765	170
Mooreland	Harrington	500	175
Harrington	Tuco	500	95

Ozark 500 kV Loop			
From	**To**	**Voltage (kV)**	**Miles**
Lacygne	Brookline	500	115
Brookline	Table Rock	500	55
Table Rock	Independence SES	500	144
Table Rock	Flint Creek	500	84
Flint Creek	Ft. Smith	500	72
Ft. Smith	NW Texarkana	500	140

4.4 Alternative 3

Alternative 3 was created using the WTII method as a screening tool. The team used the WTII results as a guide in creating a loop around the SPP system. In this case, the Ozark reinforcement described above is not included. The rational was to use the WTII methodology to address all congestion in the system and compare its results. Also, the congestion identified by the program focused on SPP footprint; therefore it did not drive connections to the external system. Figure 7 shows the topology of Alternative 3.

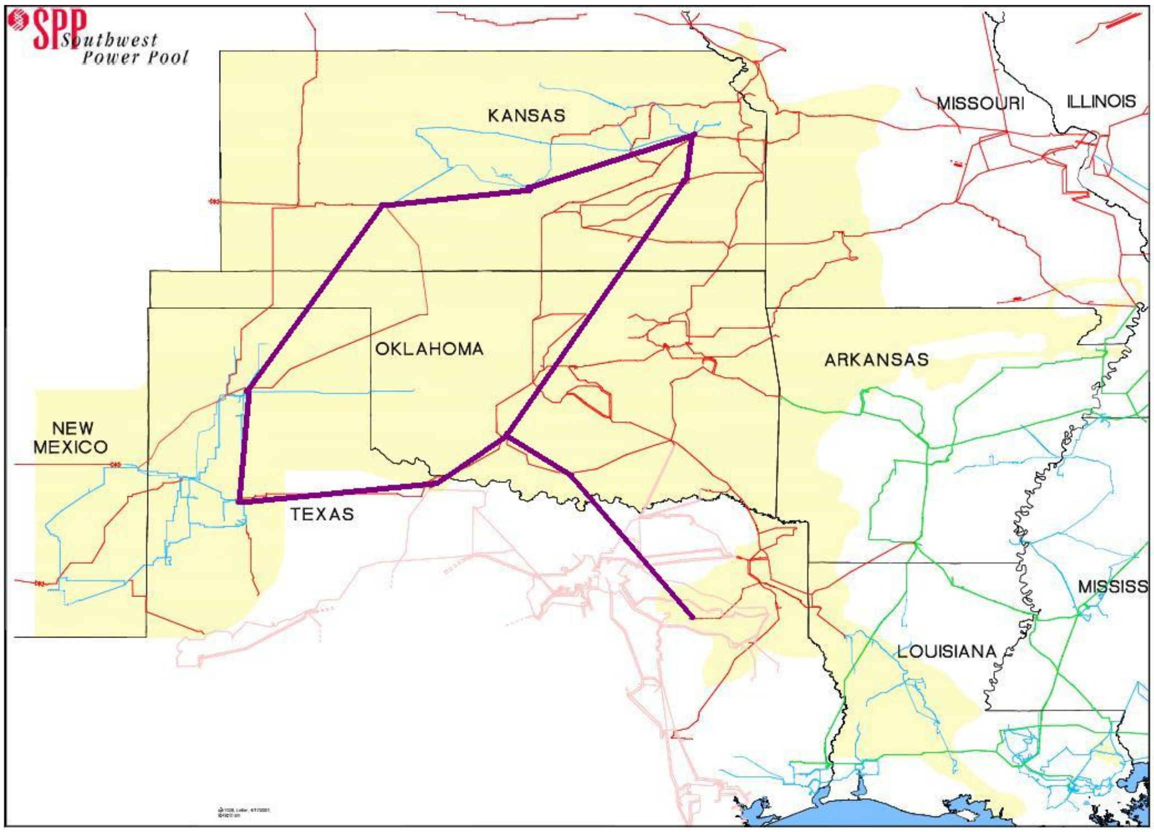


Figure 7: Alternative 3

The terminal ends for Alternative 3 are as follows:

From	To	Voltage (kV)	Miles
Wolf_Creek	Swissvile	765	36
Swissvile	Reno	765	150
Reno	Spearville	765	138

Spearville	Potter	765	216
Potter	Tuco	765	96
Tuco	OKU	765	180
OKU	LES	765	72
LES	Sunnyside	765	72
Sunnyside	Barton	765	168
LES	Wolf_Creek	765	276

4.5 Alternative 4

Alternative 4 was created as a possible ultimate build out for SPP, even beyond the 2026 time frame. It is the most extensive (and expensive) alternative studied by the team. The design was guided by current plans available from other locations such as MISO (though the MISO EHV conceptual plan was not included in our model) and other publicly released EHV plans. The plan builds connections in all directions and includes a loop in the heart of SPP, again to act as a collector of the wind and gas generation that is expected to develop.

Figure 8 shows the topology of Alternative 4.

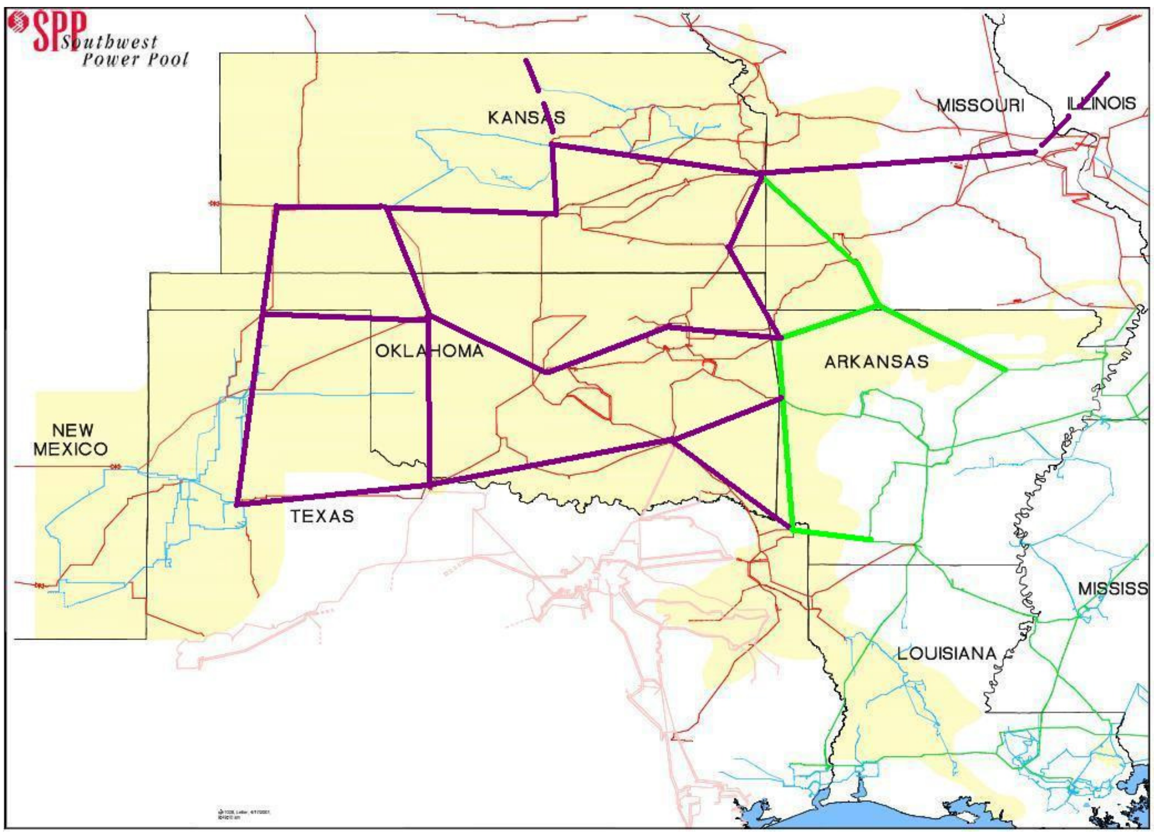


Figure 8: Alternative 4

The terminal ends for Alternative 4 are:

From	To	Voltage (kV)	Miles
Labadie	Collins	765	250
Lacygne	Labadie	765	270

Pauline	Summit	765	192
Summit	LaCygne	765	120
Spearville	Holcomb	765	66
LaCygne	Neosho	765	55
Neosho	Flint_Creek	765	60
Spearville	Mooreland	765	80
Mooreland	OKU	765	125
OKU	Pittsburg	765	180
Pittsburg	Ft. Smith	765	140
Pittsburg	Texarkana	765	130
Wichita	Spearville	765	125
Mooreland	Northwest	765	100
Northwest	Tulsa North	765	100
Tulsa North	Flint_Creek	765	80
Tuco	OKU	765	150
Mooreland	Harrington	765	140
Tuco	Harrington	765	75
Holcomb	Harrington	765	150

Ozark 500 kV Loop			
From	**To**	**Voltage (kV)**	**Miles**
Lacygne	Brookline	500	115
Brookline	Table Rock	500	55
Table Rock	Independence SES	500	144
Table Rock	Flint Creek	500	84
Flint Creek	Ft. Smith	500	72
Ft. Smith	NW Texarkana	500	140

4.6 Alternative 5

Alternative 5 represents an optimization of the loop described in Alternative 2 based upon the evaluation of the team. It differs from Alternative 2 in that Pittsburg is replaced as a termination point by Seminole. This results in EHV being closer to the high load area of Oklahoma City. In addition, the line to Texarkana to Pittsburg was removed since it didn't carry much power in the basecase or in the N-1 contingency. The 500 kV line from Texarkana to Ft. Smith performed adequately in moving power out of Louisiana into the rest of SPP.

Figure 9 shows the topology of Alternative 5.

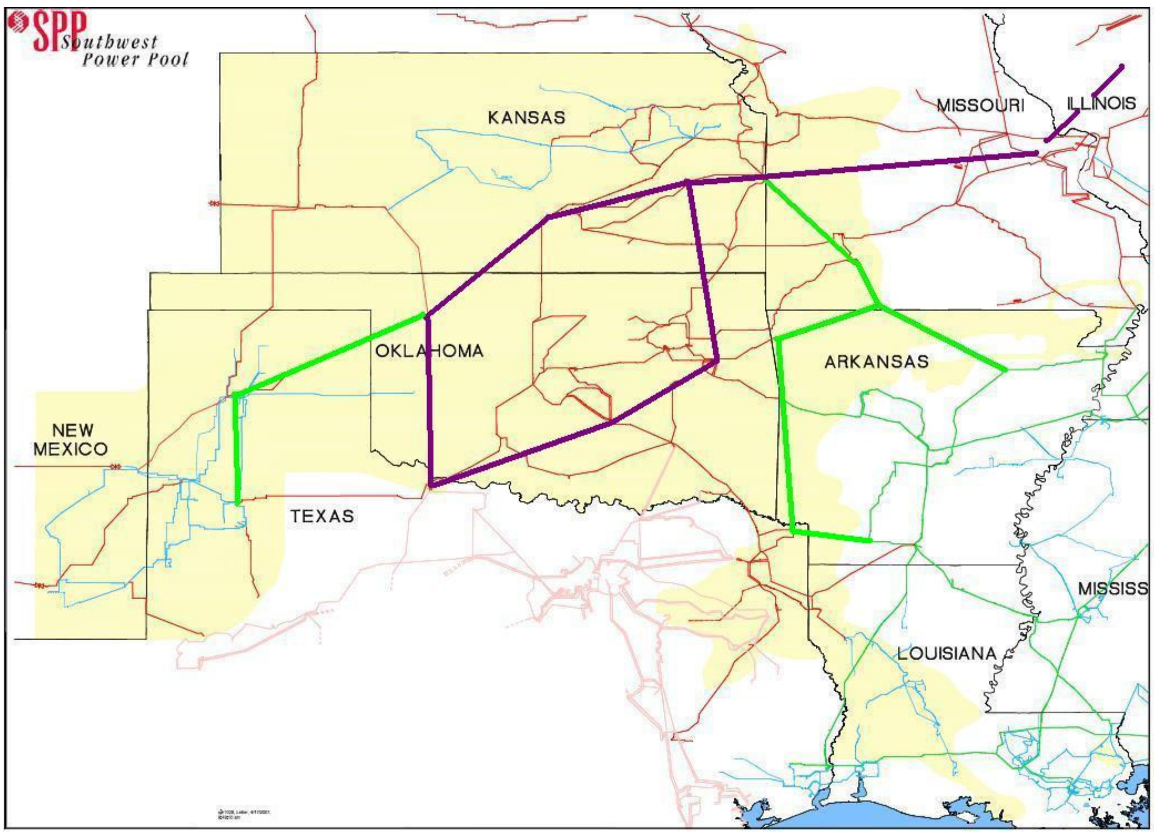


Figure 9: Alternative 5

The terminal ends for Alternative 5 are as follows:

From	To	Voltage (kV)	Miles
Labadie	Collins	765	250
Wolf_Creek	Labadie	765	270

Wolf_Creek	Wichita	765	120
Wichita	Mooreland	765	150
Mooreland	Oklaunion	765	150
Oklaunion	Seminole	765	220
Seminole	Muskogee	765	85
Muskogee	Wolf_Creek	765	170
Mooreland	Harrington	500	140
Harrington	Tuco	500	70

Ozark 500 kV Loop			
From	**To**	**Voltage (kV)**	**Miles**
Lacygne	Brookline	500	115
Brookline	Table Rock	500	55
Table Rock	Independence SES	500	144
Table Rock	Flint Creek	500	84
Flint Creek	Ft. Smith	500	72
Ft. Smith	NW Texarkana	500	140

4.7 Alternative 6

Alternative 6 was added by the team to add another 500 kV EHV alternative. It used the optimized topology studied in Alternative 5.

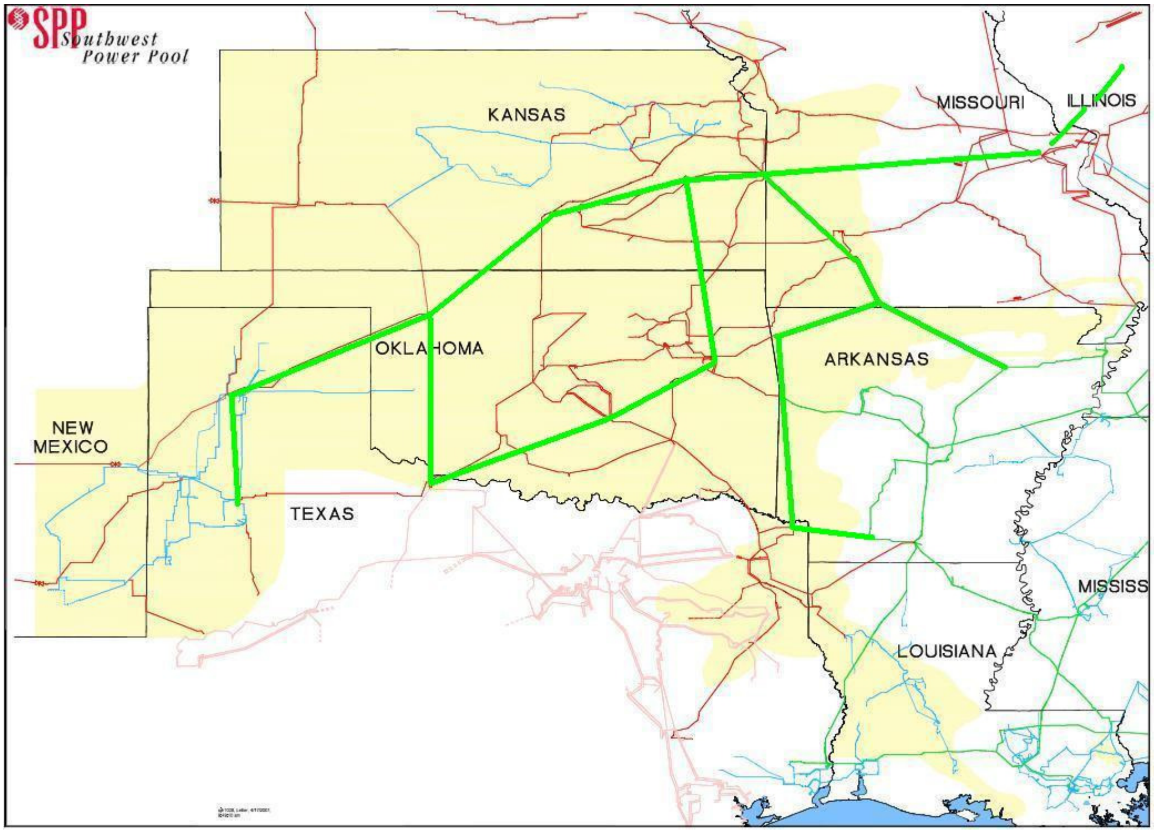


Figure 10: Alternative 6

For Alternative 6, the terminal ends are as follows:

From	To	Voltage (kV)	Miles
Labadie	Collins	500	250
Wolf_Creek	Labadie	500	270
Wolf_Creek	Wichita	500	120
Wichita	Mooreland	500	150
Mooreland	OKU	500	150
OKU	Seminole	500	220
Seminole	Muskogee	500	85
Wolf_Creek	Collins	500	270
Mooreland	Harrington	500	140
Harrington	Tuco	500	70

Ozark 500 kV Loop			
From	**To**	**Voltage (kV)**	**Miles**
Lacygne	Brookline	500	115
Brookline	Table Rock	500	55
Table Rock	Independence SES	500	144
Table Rock	Flint Creek	500	84
Flint Creek	Ft. Smith	500	72
Ft. Smith	NW Texarkana	500	140

5 Selection Criteria

5.1 Scoring

To rank and compare the Alternatives, a ranking process was used that scored the Alternatives on key performance indicators and created an overall score for ranking purposes.

Alternative 1

Cost: $ 4,881
Hourly Operating Cost (from OPF): $2,082,676

	Base	High Nuclear Future	No New Nuclear Future	High Gas	Average Score	Cost/MW
Weighting Factor:	40%	20%	20%	20%		
Max Imports:						
ERCOT	1800	2200	1600	1600	1800	$ 2,712
East Interconnet	5700	5700	5700	5700	5700	$ 856
WECC	2800				2800	$ 1,743
Max Exports:						
ERCOT	2800	3600	3600	2900	3140	$ 1,554
East Interconnect	5500	5500	5500	5500	5500	$ 887
WECC	1550				1550	$ 3,149
Losses	1956	1994	1892	1768	1913.2	
Sensitivities:						
Inc load	1	5	1	1	2.25	
Dec load	1	5	1	1		
Inc wind capacity	1	5	2.5	2.5		
Coal Retirements 100 MWs						
Coal Retirements 250 MWs	2.5	5	2.5	2.5		

Figure 11: Scoring Method Alternative 1

Figure 11 shows the scoring for Alternative 1. Maximum imports and exports were calculated between:

- SPP and ERCOT
- SPP and Eastern Interconnect[3]
- SPP and WECC

A weighted average was then calculated of these import and export values across all of the futures studied for each Alternative 1 (see Appendix D for a discussion of the study design).

[3] The SPP imports from and exports to the eastern interconnect and WECC were performed only on the base future.

The losses were calculated for SPP for each Alterative and then a weighted average for the loss was also computed.

Finally, the N-1 contingency runs for each sensitivity run described in Appendix D was performed for each Alternative and each future (6 x 4 x 4 = 96 runs). The results of the sensitivity runs were scored as follows:

- If no violations were observed, a 1 was recorded.
- If minor violations were observed, a 2.5 was recorded.
- If major violations which required significant additional investment were observed, a 5 was recorded.
- If the sensitivity resulted in unsolvable contingencies, a 10 was records.

Once these were completed, an overall weighted average sensitivity score was computed for the alternative.

Scores for Alternatives 2 through 6 are shown in the Figures 12 through 16.

Alternative 2

Cost: $ 5,394

Hourly Operating Cost (from OPF):

	Base	High Nuclear Future	No New Nuclear Future	High Gas	Average Score	Cost/MW
Weighting Factor:	40%	20%	20%	20%		
Max Imports:						
ERCOT	1800	1600	2100	2500	1960	$ 2,752
East Interconnet	7300	7300	7300	7300	7300	$ 739
WECC	3300				3300	$ 1,635
Max Exports:						
ERCOT	4900	4900	4900	4900	4900	$ 1,101
East Interconnect	5700	5700	5700	5700	5700	$ 946
WECC	1550				1550	$ 3,480
Losses	1956	1948	1921	1770	1910.2	
Sensitivities:						
Inc load	1	1	1	1	1.225	
Dec load	1	1	1	1		
Inc wind capacity	1	1	1	1		
Coal Retirements 100 MWs						
Coal Retirements 250 MWs	2.5	2.5	1	1		

Figure 12: Alternative 2 Score

Alternative 3

Cost: $ 3,385
Hourly Operating Cost (from OPF):

	Base	High Nuclear Future	No New Nuclear Future	High Gas	Average Score	Cost/MW
Weighting Factor:	40%	20%	20%	20%		
Max Imports:						
ERCOT	1500	1500	1500	1500	1500	$ 2,257
East Interconnet	5500	5500	5500	5500	5500	$ 615
WECC	2800				2800	$ 1,209
Max Exports:						
ERCOT	3400	5700	3500	3500	3900	$ 868
East Interconnect	4200	4200	4200	4200	4200	$ 806
WECC	1450				1450	$ 2,334
Losses	1956	1982	1897	1758	1909.8	
Sensitivities:						
Inc load	1	2.5	2.5	2.5	1.825	
Dec load	1	2.5	2.5	2.5		
Inc wind capacity	1	2.5	1	1		
Coal Retirements 100 MWs						
Coal Retirements 250 MWs	2.5	2.5	2.5	1		

Figure 13: Alternative 3 Score

Alternative 4

Cost: $ 7,037
Hourly Operating Cost (from OPF):

	Base	High Nuclear Future	No New Nuclear Future	High Gas	Average Score	Cost/MW
Weighting Factor:	40%	20%	20%	20%		
Max Imports:						
ERCOT	4000	4100	4000	4000	4020	$ 1,750
East Interconnet	5700	5700	5700	5700	5700	$ 1,235
WECC	3400				3400	$ 2,070
Max Exports:						
ERCOT	7100	7000	7000	7000	7040	$ 1,000
East Interconnect	8500	8500	8500	8500	8500	$ 828
WECC	2200				2200	$ 3,199
Losses	1918	2134	1843	1783	1919.2	
Sensitivities:						
Inc load	1	5	1	1	1.8	
Dec load	1	5	1	1		
Inc wind capacity	1	5	1	1		
Coal Retirements 100 MWs						
Coal Retirements 250 MWs	1	5	1	1		

Figure 14: Alternative 4 Score

Alternative 5

Cost: $ 4,904
Hourly Operating Cost (from OPF): $ 2,042,982

	Base	High Nuclear Future	No New Nuclear Future	High Gas	Average Score	Cost/MW
Weighting Factor:	40%	20%	20%	20%		
Max Imports:						
ERCOT	1900	1700	2100	2500	2020	$ 2,428
East Interconnet	6300	6300	6300	6300	6300	$ 778
WECC	3800				3800	$ 1,291
Max Exports:						
ERCOT	4800	4800	4800	4800	4800	$ 1,022
East Interconnect	5400	5400	5400	5400	5400	$ 908
WECC	1500				1500	$ 3,269
Losses	1926	1915	1906	1754	1885.4	
Sensitivities:						
Inc load	1	1	1	1	1.225	
Dec load	1	1	1	1		
Inc wind capacity	1	1	1	1		
Coal Retirements 100 MWs						
Coal Retirements 250 MWs	2.5	2.5	1	1		

Figure 15: Alternative 5 Score

Alternative 6

Cost: $4,707
Hourly Operating Cost (from OPF): $2,082,604

	Base	High Nuclear Future	No New Nuclear Future	High Gas	Average Score	Cost/MW
Weighting Factor:	40%	20%	20%	20%		
Max Imports:						
ERCOT	1500	1500	1600	1700	1560	$ 3,017
East Interconnet	5600	5600	5600	5600	5600	$ 841
WECC	3800				3800	$ 1,239
Max Exports:						
ERCOT	3200	3200	3300	3200	3220	$ 1,462
East Interconnect	5300	5300	5300	5300	5300	$ 888
WECC	1500				1500	$ 3,138
Losses	1932	1981	1896	1766	1901.4	
Sensitivities:						
Inc load	1	2.5	1	1	1.675	
Dec load	1	2.5	1	1		
Inc wind capacity	1	2.5	2.5	2.5		
Coal Retirements 100 MWs						
Coal Retirements 250 MWs	2.5	2.5	1	2.5		

Figure 16: Alternative 6 Score

5.2 Ranking

Once scoring was completed, the Alternatives were ranked against each other. This was performed by averaging the rankings for the sensitivities, imports, and exports. The average ranks were then compared and an overall raw ranking was established. The raw rankings are shown in Figure 17.

	Raw Rankings				
Alternative Description	Sensitivities	Imports	Exports	Average Rank	**Rank Order**
Alternative 1	6	5	4	5.0	**5.0**
Alternative 2	1	3	2	2.0	**2.0**
Alternative 3 (1)	5	6	6	5.7	**6.0**
Alternative 4	4	2	1	2.3	**3.0**
Alternative 5	1	1	3	1.7	**1.0**
Alternative 6	3	4	5	4.0	**4.0**

Figure 17: Raw Ranking

As can be seen from Table 17, the raw rankings are as follows:

1. Alternative 5
2. Alternative 2
3. Alternative 4
4. Alternative 6
5. Alternative 1
6. Alternative 2

In addition to the raw rank calculated for each alternative (shown in the last column of Figure 17), the team calculated a variety of cost factors for each of the alternatives. These cost factors are shown in Figure 18.

	Cost Factors				
Alternative Description	Delta Capital Cost	Cost/MW Imports	Cost/MW Exports	Ratio of Cost	Delta from least Avg Mw losses
Alternative 1	$ 174	$ 1,770	$ 1,328	1.04	27.8
Alternative 2	$ 687	$ 1,708	$ 1,048	1.15	24.8
Alternative 3 (1)	$ (1,322)	$ 1,359	$ 847	0.72	24.4
Alternative 4	$ 2,330	$ 1,689	$ 941	1.50	33.8
Alternative 5	$ 197	$ 1,497	$ 983	1.04	0
Alternative 6	$ -	$ 1,694	$ 1,267	1.00	16

Figure 18: Cost Factors

To gauge the comparative investment of the alternatives, the team calculated the delta cost from Alternative 6 (the lowest cost alternative with the Ozarks reinforcements and the linkages to the rest of the system). A ratio of alternative costs to the Alternative 6 cost was also calculated.

In addition, the team computed the Cost/MW of imports and Cost/MW exports for each alternative to give a comparative value of the alternative.

Finally the team also calculated the delta of system losses comparing each alternative to the alternative with the lowest losses (Alternative 5).

6 Recommendation

6.1 Congestion Relief

To supplement the raw rankings discussed above, the team compared the OPF runs of some of the top ranked alternatives to help gauge their economic performance. OPF runs are not a substitute for detailed economic benefits analysis. Economic benefits will be evaluated by SPP upon the completion of this study. For this project, the team used an OPF on some of the ranked alternatives to develop a sense of how the various alternatives alleviate congestion during peak load periods.

Figure 19 shows the hourly operating cost contour for Alterative 5.

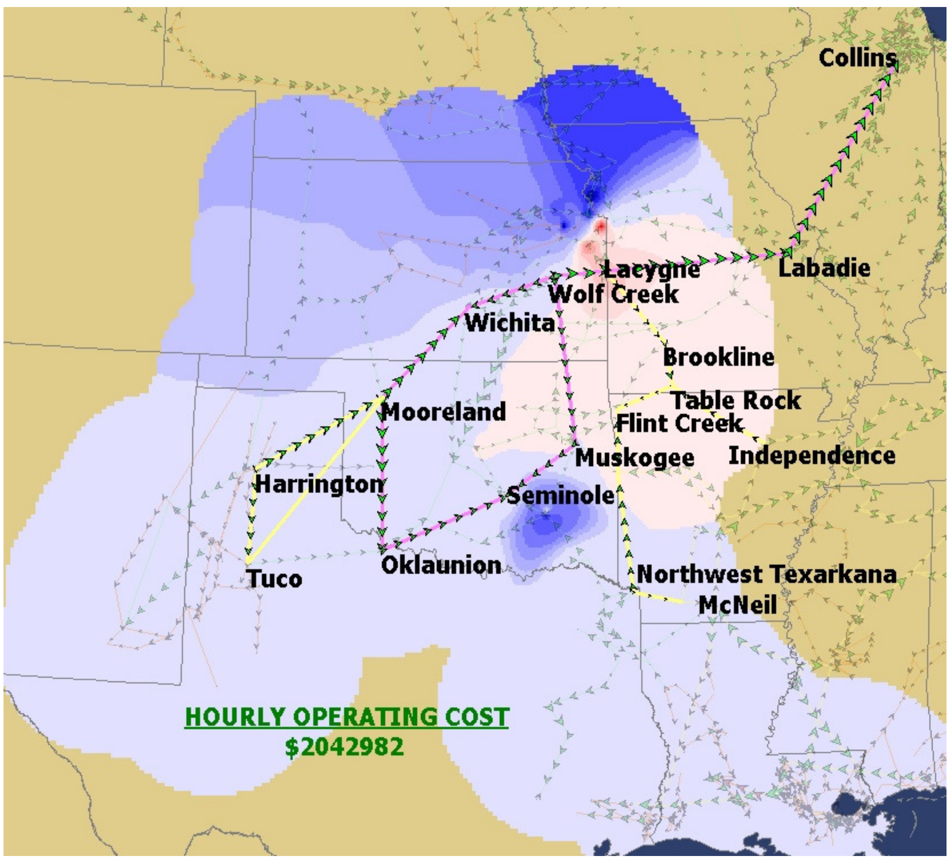


Figure 19: Hourly Operating Cost Alternative 5

Comparisons with Figure 1 show the elimination of the cost differentials between the western part of SPP and the east. In addition, the operating cost for this alternative has dropped by $990,000.

The AMVACO rating for Alternative 5 was also computed. It is shown in Figure 20.

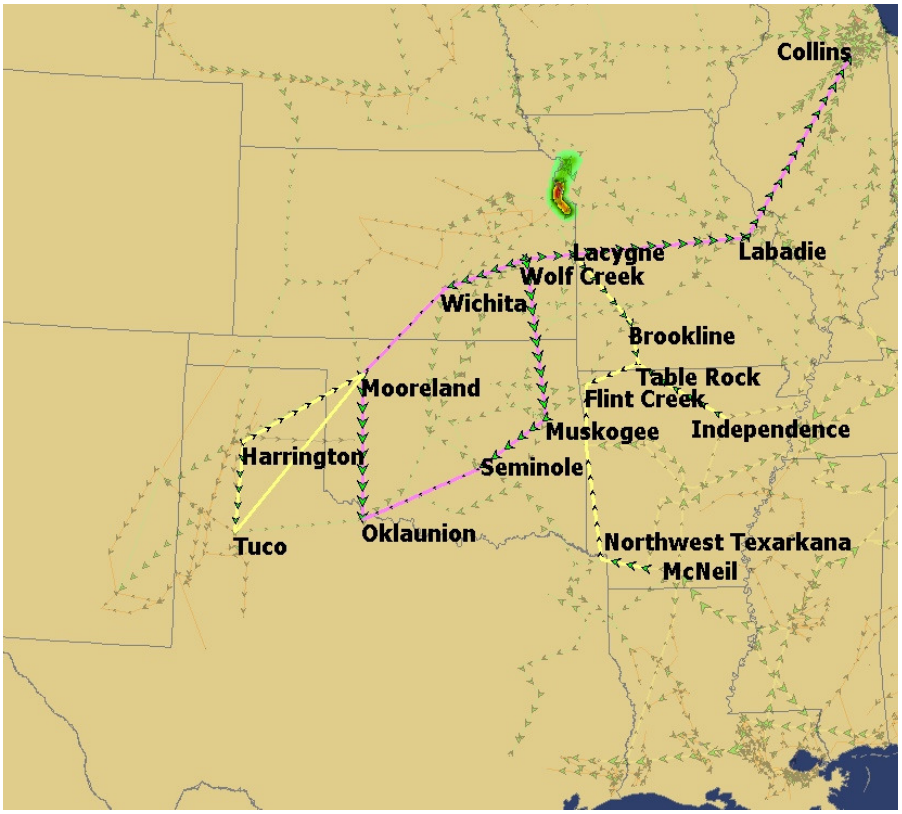


Figure 20: AMVACO Alternative 5

With the exception of the Kansas City, MO area, the N-1 congestion points identified in Figure 2 above have been eliminated by Alternative 5.

To compare 765kV with 500 kV solutions, Figures 21 and 22 are included which show the OPF results and AMVACO for Alternative 6, the top performing 500 kV alternative.

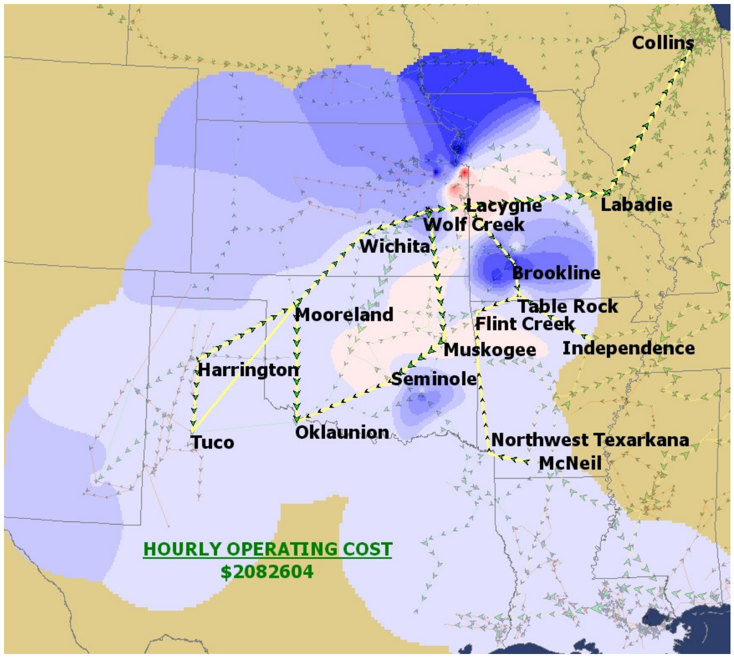


Figure 21: Hourly Costs for Alternative 6

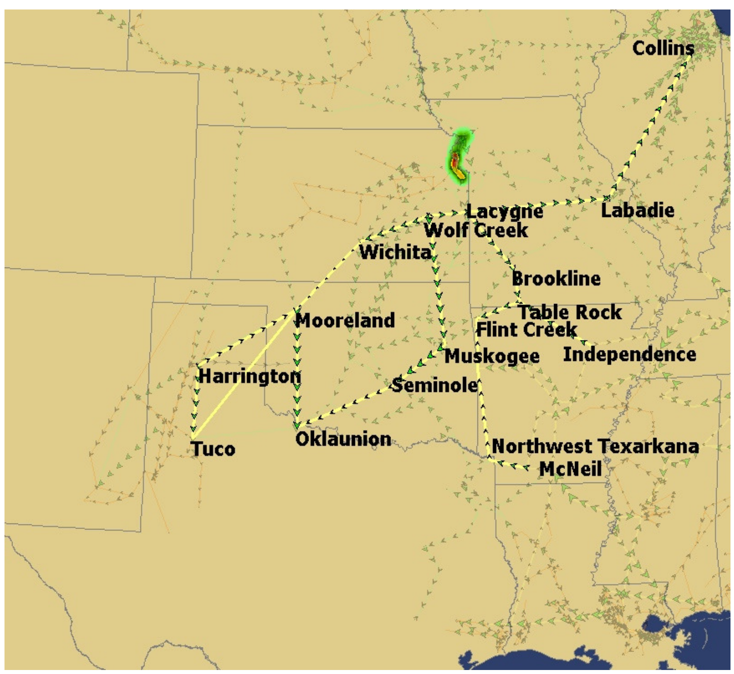


Figure 22: AMVACO for Alternative 6

Comparisons to Figures 1 and 2 shows that Alternative 6 also reduces the hourly peak operating cost and alleviates much of the N-1 congestion.

Comparing the 500 kV with the 765 kV runs shows that the 765kV alternative saves about $40,000 more per hour than the 500 kV alternative. The OPF analysis shows that economic performance of 765kV may be significantly better than 500 kV. This can be verified in the subsequent full economic analysis.

Special Note on Kansas City: Figures 19 through 22 shows that congestion still remains in the Kansas City area. The team debated whether or not this should be treated as local area congestion or as an area to extend the EHV system.

For this report, the area is treated as local area congestion that would be alleviated by SPP through their ten year planning process. However, the team recommends that SPP further consider the congestion in the Kansas City area as it develops its final EHV decisions.

6.2 Overall Recommendation

A package of projects should not be selected just on performance alone. While reliability performance establishes the minimum expectations, other factors such as cost, economic value, timing of need, constructability, etc. should also be considered when making a final selection.

It should also be noted that by the scope of the project, the team focused solely on techniques based upon steady state powerflow analysis and supplemental analysis using linearization techniques and standard OPF algorithms.

Within the context of this limited study, the team feels that all of the Alternatives performed very well. When the team considered overall cost, scope of the alternative (i.e., did it include the Ozarks?), losses, import/exports MW normalized per dollar invested and the OPF results. Therefore, we feel the following overall ranking is warranted:

1) Alternative 5
2) Alternative 2
3) Alternative 6

Special Note on Alternative 4: Alternative 4 (Figure 9) performed the best on exports to ERCOT – by a significant margin. This may be an especially relevant result given the current CREZ hearings conducted by the PUCT. SPP may glean some useful insights into different ways to deliver wind energy from the Texas panhandle by taking a closer look at this alternative.

7 Reinforcements of Underlying System

To address reinforcements of the underlying system, the team ran N-1 contingencies for all 500 kV and 765 kV lines and transformers in the Alterative 5 base future with a 1750 MW export to the eastern interconnection.

An additional contingency run was performed on all transformers at 300 kV and above. This run was performed to study the distribution of flows on the underlying 345 kV system.

During these contingency runs, the system was monitored for problems down to the 200 kV level.

Based upon this analysis, the following appear to be needed to support Alternative 5 EHV additions:

- Additional 500 kV transformer at Ft. Smith.
- Additional 345 kV transformer at Tuco.
- Additional 345 kV transformer at Flint Creek.
- Additional 230 kV transformer at Auburn.
- Additional 230 kV transformer at Holly.

The contingency results for EHV contingencies are shown in Appendix F.

The contingency results for transformers at 345 kV and above are shown in Appendix G.

8 Thoughts on the SPP X-Plan

SPP has also developed a 345 kV reinforcement plan called the "X-Plan". The team would like to provide some insights on the X-plan based upon our studies.

Based upon our analysis, we saw good performance with the 345 kV Mooreland to Spearville line and the 345 kV Potter to Roosevelt lines. These lines complimented the top performing alternatives.

If SPP proceeds with the EHV Alternative 5, it appears that the 345 kV line from Wichita to Mooreland could be replaced with the 765 kV line between the same terminals.

We also noted that if SPP builds Alternative 5 that we didn't identify a need to build the 345 kV line from Mooreland to Northwest for reinforcement of the Oklahoma City area. Instead it appeared that running 765 kV into Seminole may provide sufficient reinforcement.

Finally, the team feels that further study is needed to determine whether or not the 345 kV Moorland to Potter/Tuco line is needed. In our studies, we found good performance with running this 345 kV line from Moorland to Potter along with a 500 kV line between the same terminals. Further study would provide insight into whether or not that 345 kV line is needed and to determine the optimal termination (i.e., Potter or Tuco).

9 Nebraska Seam Discussion

Alternative 4, which did include 765 kV lines to the north, was studied in detail. This analysis did not reveal a clear indication of need to take EHV to north. It should be noted that the models used by the EHV team did not include any of the MISO or AEP conceptual EHV plans that have recently been announced.

It is the teams feeling the top rated alternatives in this report should support EHV expansion to north as MISO or other plans are solidified. However, further study will need to be performed to determine how to best interconnect, should plans MISO move forward in their planning & stakeholder processes. Also the team noted significant congestion by the year 2026 in the Kansas City, MO area and suggests that extensions to the north include examination of routes near that part of the SPP should be included in the study in order to provide needed reinforcement to that part of the system.

10 Constructability Assessment

See Addendum 1 for the constructability assessment of Alternatives 1, 2, 5 & 6.

11 Project Cost Estimates

The following items were used to develop the cost estimates for the alternative packages:

- ROW and easement acquisition
- Permitting
- Material
- Labor for engineering, design & construction.
- Environmental efforts in various terrains and climates.

Figure 23 shows the engineering, construction and material costs used the transmission lines in the project:

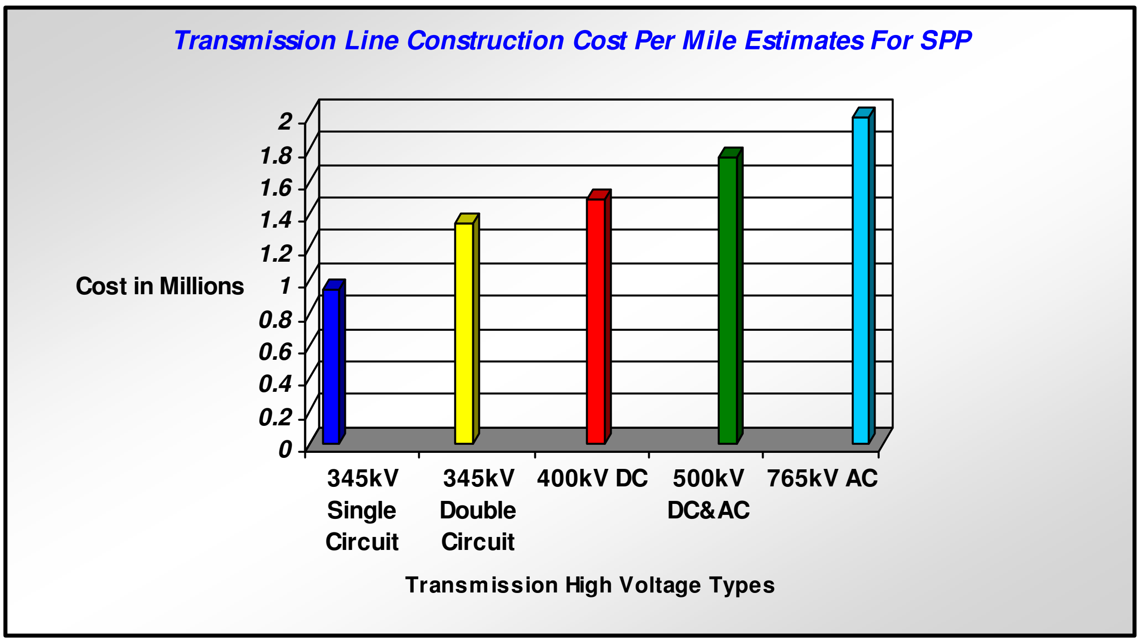


Figure 23

The team derived transmission right of way ("ROW") costs by calculating the ROW per mile of Sunrise Powerlink, a 500 kV, 150 mile project in California[4]. The ROW cost per mile for Sunrise Powerlink was further reduced by 2/3^{rds} to reflect the building conditions in the SPP service territory. The resultant cost used in the estimates was $65,000/mile.

Transformer costs were solicited from manufactures who provided the following cost estimates:

[4] http://www.sdge.com/sunrisepowerlink/info/CAISODR1response4-16-07.doc , see attached PDF file showing project cost breakdown.

- 765/345 kV, 1050 MVA: **$5,800,000.00/unit** (budget cost delivered in the first half of 2009)
- 500/345 kV, 1050 MVA: **$4,000,000/unit** (budget cost delivered in the first half of 2009)

Breaker costs were provided Real Time Engineering, an InfraSource Company, and were estimated as follows:

- 345 kV breaker: $200,000
- 500 kV breaker: $500,000
- 765 kV breaker: $750,000

Substation construction was priced as single breaker, ring bus configurations using a spreadsheet developed by Real Time Engineering, an InfraSource company. This spreadsheet is shown at the end of Appendix E.

Please note that these costs represent estimates only and discretion should be used in their use. Actually costs could vary by as much as +/- 33% or more to account for necessary adjustments due to items such as abnormal construction and tree clearing.

The total cost estimate for each package was calculated as shown in Appendix E.

12 Recommended Next Steps

The project teams analysis utilized steady state tools such Powerfow, OPF and DC linearizations. The team recommends that additional study of these options be performed before develop begins. These additional studies recommended include economic analysis using year round security constrained dispatch algorithm, dynamic stability analysis, transient analysis, operational planning analysis to effective operation of the large wind farms, and torsional shaft analysis of nearby large generators.

In addition, the team would like to highlight additional items for SPP to investigate in their planning efforts.

- **Kansas City Congestion**
  As noted above, Kansas City will require reinforcements. The Iatan and St. Joseph substations, in particular, showed up repeatedly in the sensitivity runs as an area needed transmission. Additional study should be performed in SPP's planning efforts to determine if area reinforcements are more effectively served by routing an EHV line through that area.

- **Losses**
  It was interesting to note that SPP system losses were similar among all the alternatives. During the economic evaluation phase, close attention should be paid to losses to ensure a defendable quantification of the economic benefits attributed to loss savings from 765 kV.

- **Finalizing the Ozark Reinforcements**
  The EHV overlay developed for the area verified the needs in the Ozarks as well as the support a system in that area can provide to the rest of the SPP system. Our analysis seems to compliment the SPP analysis in the area. Further study is needed to merge the results and finalize an overall plan that may include EHV as part of the solution.

- **Linking the 765 kV Loop with the Ozarks in Alternative 5**
  Based upon the scenarios developed by the team, the 500 kV Ozark reinforcements did not need to be tied back into the 765 kV loop in the center of SPP. This result may be due to the method used to model exports and imports between SPP and the eastern interconnect (i.e., transfers between AEPW and AEP). The need for linking the two areas of the SPP should be further explored. If a tie appears necessary, the logical location is connecting the 500 kV with the 765 kV at Lacygne substation.

- **ERCOT and/or WECC Synchronization**
  Since the team started with the MMWG models used for the eastern interconnection, the models were not detailed enough to test synchronous operation in the context of this study.

- **Construction staging**

While the team gained some insights into how to stage the construction of the EHV packages that were studied, additional analysis is necessary to fully develop a workable construction outage schedule.

- **X-Plan**
  The observations discussed above in section 8 should be evaluated by SPP using their more detailed models to finalize an overall EHV design for the SPP grid.

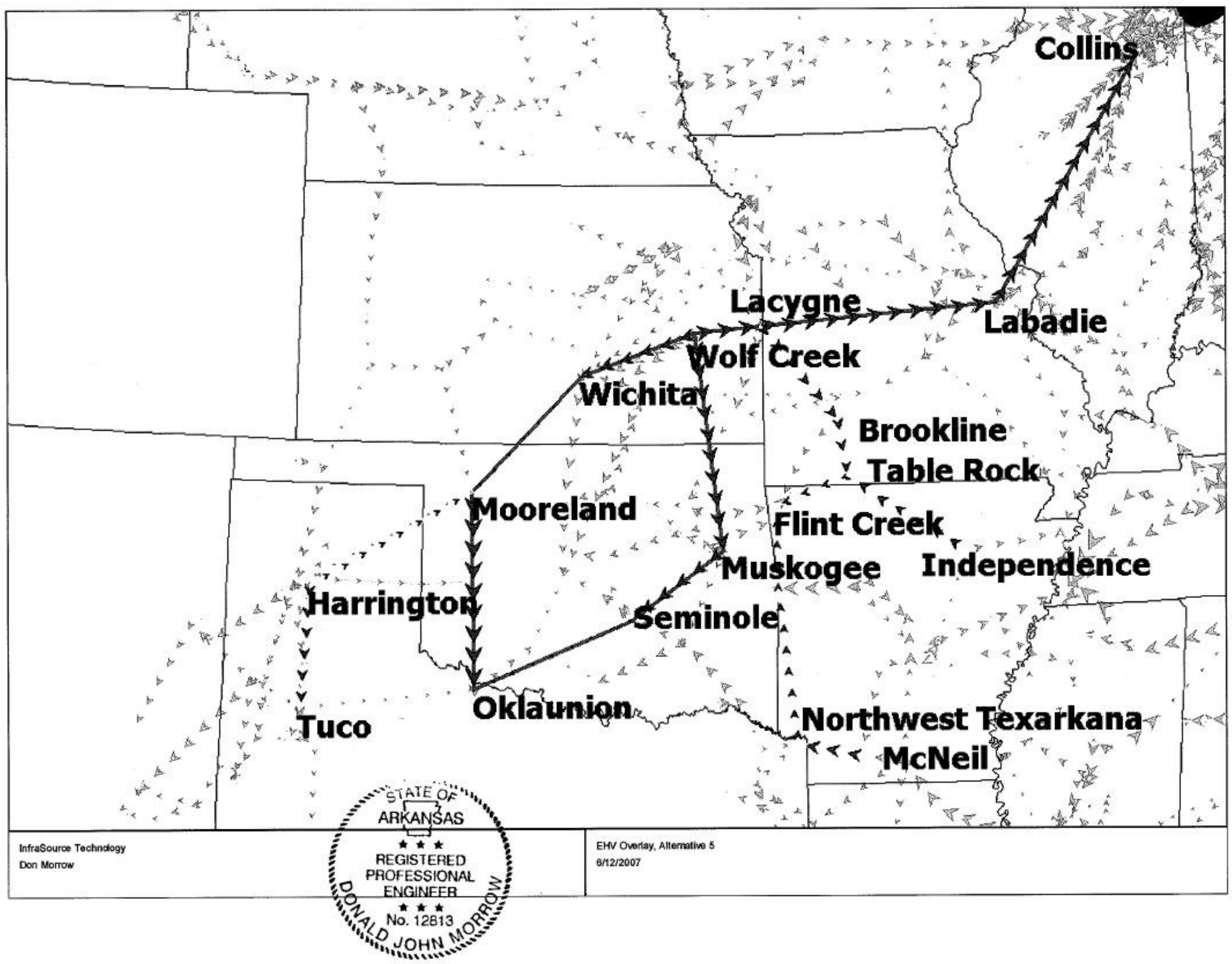
13 References

[1] S. Grijalva, A. M. Visnesky, "The Effect of Generation on Network Security: Spatial Representation, Metrics, and Policy", *IEEE Transactions on Power Systems*, Vol. 21, No. 3, August 2006, pp. 1388-1395.

[2] "AEP Interstate Project: Why 765 kV AC?", American Electric Power, August 24, 2006.

[3] http://www.sdge.com/sunrisepowerlink/info/CAISODR1response4-16-07.doc , see attached PDF file showing project cost breakdown.

Appendix A: Stamped Drawing



Appendix B: Assumptions

A copy of the Stakeholder Process White Paper is included in Appendix XX of this report.

B.1 Assumptions Developed with Stakeholder Input

Don Morrow met with SPP and certain stakeholders on February 7, 2007 at the Transmission Working Group meeting in Tulsa, OK. At that meeting, he described the EHV project and led a discussion among these stakeholders about key assumptions necessary for the EHV project. A copy of the minutes from this meeting is found in Appendix 2 of this report.

Based upon these discussions, a draft set of key assumptions was developed. These draft assumptions were circulated to SPP stakeholders for comment. The assumptions were finalized on March 1, 2007.

Load Growth Assumptions

The team used the embedded forecasted load growth rates between 2006 and 2016 for the SPP footprint from the ten year analysis performed by SPP. These forecasts were cross checked with the LSEs to verify appropriateness.

Demand Side Assumptions

The project team used a lower load growth sensitivity to explore the impacts of aggressive demand side management programs in the future.

Gen Retirement Assumptions

The team did not retire any units in the base case. Instead sensitivity runs were performed on coal unit retirements as follows:

- Coal plants over 40 years & less than 100 MWs.
- Coal plants over 40 years & less than 250 MWs.

The process used to implement generation retirements was to first run the 250 MW retirement assumption. If the case did not solve or required significant investment to resolve N-1 violations, then the 100 MW retirement assumption was performed.

New Transmission Line Assumptions

SPP and the project team discussed this issue on a conference call on 2/12/07. As a result of this discussion, the team kept all lines in the SPP Transmission Expansion Plan 2006-2016. 230kV and 345kV projects that are proposed in the plan for 2010 and beyond were further evaluated in our studies.

The SPP lines considered were:

- East Centerton to Flint Creek 345kV
- Hugo Power Plant 345kV reinforcements
- Summit to Reno County 345kV
- Dianna to Barton Chapel 345kV
- Potter to Roosevelt 345kV
- Roosevelt County 230kV Interchange
- Mooreland to Spearville 345kV
- Mooreland to Potter 345kV

Within the context of the EHV study, we suggest that SPP consider constructing the Mooreland to Potter 345kV line at 500 kV instead of 345 kV. The final decision should be made using the more detailed models SPP has available for its reliability planning purposes.

Regional Fuel Assumptions

The team did not consider ethanol as a generation fuel. Therefore, for the purposes of this study, ethanol was not considered a renewable energy source.

When developing the models, the project team assumed that 15% of energy consumed in the eastern interconnection came from renewable resources.

The team used this 15% energy assumption to determine how much renewable energy would be needed by the eastern interconnect in 2026, determined how much of this market would be served by the SPP footprint, and then estimated the capacity contribution by these new wind farms based upon average wind speeds at peak load times.

As a result of this analysis, cases were designed to support a base level of exports of about 1750 MWs to the rest of eastern interconnect.

Incremental Generation Base Load Assumptions

The project team assumed that the basecase mixture was 60% coal, 20% nuclear & 20% natural gas. Sensitivity studies were designed to test changes to this mix.

Other Economic Assumptions

- Fuel prices from publicly available sources
- Energy markets developing throughout the entire eastern interconnect

Note: energy storage was mentioned in the Interim Report as a candidate for study. The team did not have time to fully explore this issue and suggests future studies explicitly looking into this issue from the perspective of operation of large wind farms.

Integrated Resource Planning Assumption

The team used load growth sensitivities to capture the effects of deeper penetration of the DSM programs and/or new technologies gains for efficiency improvement, conservation efforts, smart meters, and innovative rate designs.

After discussion with stakeholders, consensus was reached that while load bidding into energy markets is likely to occur at some point in the future, however the effects would be generally be localized and, therefore, were ignored for the purposes of this study.

DOE NIETC Congestion Report Assumptions

SPP Congestion identified by the DOE Congestion Study was addressed by this project within base case design.

Green House Gas Assumptions

The team will assume that Kyoto Protocols will be in effect, however since the economic analysis was removed from the proposal this assumption was not utilized during the analysis.

B.2 ERCOT & WECC Model Assumptions

The model used by the team was the same approach used by SPP in their 2016 cases.

ERCOT model:
ERCOT was connected to the SPP through two HVDC corridors. These two interconnections are located in Oklaunion and East DC 7. The model is set to export 1200 MWs from SPP to ERCOT. This 1200 MW export is split by exporting 900 MWs through Oklaunion and 300 MWs through East DC 7. ERCOT is represented by two generators in Oklaunion and East DC 7 that demand 900 MW and 300 MW from SPP respectively.

WECC model:
WECC is connected to the SPP through three HVDC corridors. These three interconnections are located at Lamar 6, PNM-DC6, and EPTNP 7. The model is set to export 200 MW in total to WECC. The WECC model is represented by three generators in Lamar 6, PNM-DC6, and EPTNP 7 that demand 0 MW, 200 MW, and 0 MW power respectively.

B.3 Import/Export Methodology

For the N-1 analysis performed during this part of the study, it was assumed that emergency ratings could be utilized. To simulate emergency ratings in the model, 10% was added to the normal rating.

SPP Imports from ERCOT:
In order to estimate the maximum import capacity from ERCOT to SPP the following process is performed:

A generator that represent the ERCOT import is added to Oklaunion EHV bus, the Oklaunion 345 kV generators that represent the ERCOT network are opened, the highest loaded line on Oklaunion bus is assumed as the worse contingency and is opened. Next the import from ERCOT is increased gradually by increasing the generating capacity of the added generator till one of the elements is violated. The violation is considered maximum 110% overload of any EHV elements.

SPP Exports to ERCOT:
In order to estimate the maximum export capacity from SPP to ERCOT the following process is performed:

A 900 MW export on Oklaunion substation and 300 MW export on East DC 7 substation is kept in the model. Since East DC 7 power exchange is limited an additional 200 MW demand is added to it. A generator that represents the ERCOT export capability is added to Oklaunion EHV bus. The highest loaded line on Oklaunion bus is assumed as the worse contingency and is opened. Next the SPP power export is increased gradually by increasing the demand capacity of the added generator till one of the elements were violated. The violation is considered maximum 110% overload of any EHV elements.

SPP Imports from WECC:
In order to estimate the maximum import capability from WECC to SPP the following process is performed:

Three generators that represent the SPP import from WECC are added to Lamar7, PNM-DC6, and Eddy Co substations and the original units that represent the WECC network are opened. On Lamar7 interconnection the highest loaded line that represents the worse contingency are evaluated and opened. Next the import from Lamar 7 is increased gradually by increasing the generating capacity of the added generator till one of the elements is violated. Then the opened line is closed and the same process is preformed for PNM-DC6, and Eddy Co interconnections. The maximum import is calculated by adding these three values. The violation is considered maximum 110% overload of any EHV elements.

SPP Exports to WECC,
In order to estimate the maximum export capacity from SPP to WECC the following process is performed:

Three generators that represent SPP export to WECC are added to Lamar7, PNM-DC6, and Eddy Co substations, and the original units that represent the WECC network are opened. On Lamar7 interconnection the highest loaded line that represents the worse contingency are evaluated and opened. Next the export power to Lamar 7 is increased gradually by increasing the demand capacity of the added generator till one of the elements is violated. Then the opened line is closed and the same process is preformed for PNM-DC6, and Eddy Co interconnections. The maximum export is computed by adding these three values. The violation is considered maximum 110% overload of any EHV elements.

SPP Imports/Exports from/to Eastern Interconnection:
In order to estimate the maximum import/export capacity between Eastern Interconnect and SPP the following process is performed:

The MISO, MRO, SERC, TVA, and PJM are defined as Eastern Interconnect super area. The power exchange between SPP and Eastern Interconnect super areas (a feature in PowerWorld Simulator) are regulated by specifying the power transaction between these two super areas, for this purpose one area in each of those super areas is chosen (AEP and AEPW) and by setting the power transaction between these to area, power flow between two desired super areas is controlled by moving all units in the super area support the desired transaction.

To estimate the maximum import/export rating the power transaction is increased gradually, and the worse EHV (N-1) contingency is defined and simulated. The import/export limit is increased to simulate the emergency rating limit i.e. 10% overload for EHV elements in the model.

B.4 Other Assumptions

- AEP design parameters for 765 kV and 500 kV were used for modeling.[5]
- Cost estimates provided InfraSource engineering companies and ABB.[6]
- SPP transmission ROW costs were set to 1/3 California ROW cost estimates from the Sunrise Powerlink project.[7]
- Exports to eastern interconnection were modeled as a transaction between AEPW and AEP.
- All costs are estimated in 2006 dollars.

[5] "AEP Interstate Project: Why 765 kV AC?", American Electric Power, August 24, 2006, page 5.
[6] ABB budgetary quote in letter dated June 12, 2007.
[7] http://www.sdge.com/sunrisepowerlink/info/CAISODR1response4-16-07.doc

Appendix C: Study Design

Futures

2026 Basecase

Based upon the assumptions developed in Phase One, the project team developed the 2026 base case as follows:

- Load in the case will be determined by using the load growth rates from SPP's 2016 ten year case, projected into 2026.
  - The appropriateness of using this rate for the period from 2016 to 2026 will be verified with the LSEs within the SPP footprint.
  - These load growth assumptions will be applied to first tier neighbors plus Southern Company & PJM.
- Wind plants will be modeled to the amounts currently in SPP's generation queue, approximately 12,000 MWs.
- Capacity contribution from wind farms will be set to 10% of name plate capacity.
- New generation will added be added to the model from SPP's generation queue only if there is a signed Interconnection Agreement ("IA"), a signed IA is pending, or construction has begun.
- No nuclear plants will be retired.
- No coal plants will be retired.
- Additional generation needed to meet load is determined by taking SPP's planning reserve requirement, less wind capacity, less installed generation & less queue capacity.
- This additional generation will be allocated as 60% coal, 20% nuclear, and /20% gas
- 15% of the energy consumed in the Eastern interconnection will be provided by renewable energy sources.

In addition to the 2026 basecase, the following alternative futures will be modeled.

High Nuclear Generation Future

In this future, the only difference from the 2026 basecase is that additional generation is allocated as 40% coal, 40% nuclear, and 20% gas.

No New Nuclear Generation Future

In this future, the only difference from the 2026 basecase is that additional generation is allocated as 60% coal and 40% gas.

High Gas Generation Future

In this future, the only difference from the 2026 basecase is that additional generation is allocated as 40% coal, 20% nuclear, and 40% gas.

For the purposes of this study, each of these futures will be treated as a separate basecase.

Sensitivity Runs

In addition to the 2026 basecase and alternative futures, sensitivity runs will be performed to test the performance of each EHV alternative.

Higher than Forecasted Load Growth

This sensitivity is designed to address stronger than anticipated economic growth during the 20 year period.

Lower than Forecasted Load Growth

This sensitivity is designed to address increased efficiency, demand effectiveness, distributed generation advancements and/or weak economic growth.

Renewable Energy Portfolio

Us a 20% renewable energy portfolio requirement for eastern interconnect and increase SPP wind installed nameplate capacity to 24,000 MWs. This sensitivity is designed to addresses the recent policy activity at the state level in response to global warming concerns.

Coal Retirements Less than 100 MWs

Retire coal plants that are 40 years old as of 2006 and less than 100 MWs. This sensitivity is designed to address aging units & improved environmental performance to meet possibly tightened emissions requirements.

This sensitivity was performed only if the 250 MW coal retirement sensitivity studies showed either a divergence in the study or additional major capital investment necessary to support the retirements.

Coal Retirements Less than 250MWs

Retire coal plants that are 40 years old as of 2006 and less than 250 MWs. This sensitivity is designed to address aging units & improved environmental performance to meet possibly tightened emissions requirements.

Increased Wind Capacity

Increase the wind capacity contribution to 20%. This sensitivity is designed to address improvements in wind turbine design & the emerging tendency toward building higher towers.

Operational Tests

Export Capability Test

This test will provide insights into regional adequacy benefits and maximum market contribution. The test is designed to determine the maximum export capability without incurring overloads under single contingency. Max exports to ERCOT, WECC, and the Eastern Interconnect were determined.

Import Capability Test

This test will provide insights into SPP adequacy benefits & SPP market supply. The test is designed to determine the maximum import capability without incurring overloads under single contingency. Max imports from ERCOT, WECC, and the Eastern Interconnect were determined.

Wind Variability Test

To test the variability of the wind, wind output was studied up to 80% of nameplate capacity for the on-peak studies. The alternatives were designed to ensure that the system would operate under that high level of wind with exports to the eastern interconnect of about 2000 MWs and exports to ERCOT of about 1000 MWs.

Resource Models

A market assessment of future resources was initiated from the existing generation data in the 2016 SPP base case as follows:

1. Starting point was the total capacity in the SPP 2016 case. This was approximately 64,000 MW including studies requested, set to begin & in progress; IA agreements executed & pending; impact studies in progress & complete; and withdrawn requests.

2. The percent increase of total forecasted demand growth by zone for 2026 was calculated and multiplied by a 12% planning reserve criteria margin less the existing generating capacity within SPP in 2006. This resulted in approx. 18,000 MW of capacity need in 2026 beyond existing generation in SPP today.

Wind Capacity Calculations

1. Assumed 15% for renewable eastern interconnect wide driven by state and federal renewable energy mandates (approximately 795 GWh of energy).

2. Assumed 50% of the 15% of this renewable came from wind energy.

3. Assumed 45% capacity factor for wind energy, of which 10% is capacity contribution.

4. Assumed 25% of this wind energy contribution is within SPP.

5. Calculated wind nameplate capacity within SPP (approx. 25,000 MW) and compared it to total wind capacity in the SPP interconnection queue (approx. 12,000 MW).

Base Case Resource Breakdown (Summer Peak)

1. Took the approximately 18,000 MW of additional capacity needed in 2026 and subtracted the wind capacity needed (approximately 2,500 MW with a 10% capacity factor) to determine a generation need of about 15,500 MW.

2. Subtracted the capacity that was in the interconnection queue with executed and completed IA's (roughly 5,100 MW) to come up with a total net generation need in 2026 of about 10,300 MW.

3. The total net generation was allocated as follows: 60% coal capacity, 20% nuclear capacity and 20% gas capacity.

4. This resource mix capacity was adjusted as 40% coal, 40% nuclear, and 20% gas for the high nuclear future case and 60% coal and 40% gas for the no nuclear future case.

5. For the high gas future case the resource mix was adjusted to 40% gas, 20% nuclear and 40% coal.

Plant Siting

Based on the market assessment plants were sited as follows:

1. New wind capacity locations were selected based upon withdrawn wind capacity requests in SPP's interconnection queue. Efforts were made to site wind next to a CT when feasible. New wind capacity was interconnected at the nearest 230 kV bus or above.

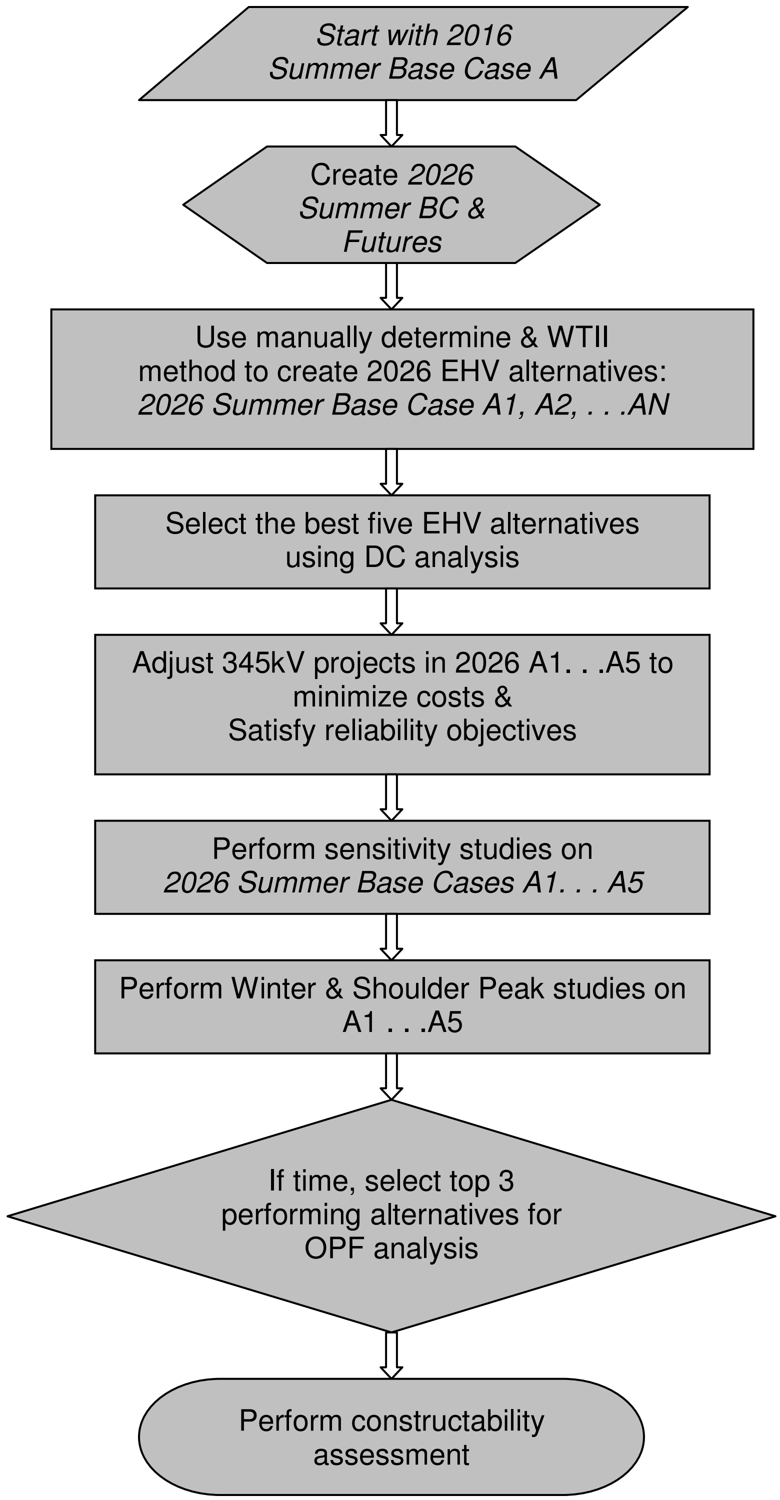
2. Additional nuclear capacity sited at Wolf Creek bus.

3. Coal siting philosophy was to place new coal capacity on the closest HV bus and placing it within 1 mile of a railroad when feasible.

4. CT and CC siting philosophy was to site it at locations that were close to potential gas wells and reserves and within 10 miles of a gas pipeline or within 25 miles of a major urban area when feasible.

Study Process

The project team currently envisions the study process to occur as follows:



Appendix D:

Transmission Injection Impact Methodology

Based upon earlier work performed by PowerWorld Corporation, a leading indicator metric was developed to identify top-performing EHV connections that yield the best reduction in contingency overloading per unit capital cost. This section describes the derivation of the metric and how it was used to automate selection of proposed EHV connections.

1. Calculation of Security Enhancement Measure

One measure of system security is the amount of overloading that occurs during a set of simulated contingencies or forced outages. The level of contingent overloading may be expressed as the sum of MVA overloads across all monitored transmission elements and simulated contingencies, or the Aggregate MVA Contingency Overload (AMVACO), defined as follows:

$$AMVACO = \sum_{contingencies_c} \sum_{lines_{ij}} \left(\text{Flow}_{line_{ij} contingency_c} - \text{Rating}_{line_{ij}} \right) \Big|_{\text{Flow}_{line_{ij}} > \text{Rating}_{line_{ij}}}$$

Thus for a given line *ij* and contingency *c*, the contribution to the AMVACO would be the amount of MVA that the flow on line *ij* exceeded its limit or contingency rating. If the line operates within its limits for all contingencies, then its contribution to AMVACO is zero. A desirable goal of any transmission upgrade or expansion would be to improve the system security as measured by the AMVACO.

In this analysis, the set of monitored lines *ij* included all non-radial lines and transformers in SPP with a maximum nominal voltage of at least 230-KV. The set of contingencies *c* included the following:

1. Loss of single line or transformer (N-1) in SPP with minimum nominal voltage of at least 345 kV.
2. Loss of single largest generator at all plants in SPP with capacity of at least 100 MW.
3. All outages represented in the list of SPP-supplied flowgates, not included in 1 or 2.

As described in [1], the Bus Weighted Transmission Loading Relief (WTLR) value represents the locational impact of generation on network security. Because of confusion surrounding the term “TLR” (some think of it as a line relief procedure as opposed to the calculation), we have changed the term to “Transmission Impact of Injection (TII)”. The calculation method of the WTLR term in [1] and the calculation method of the Weighted Transmission Impact of Injection (WTII) used for this project are identical. It corresponds to the expected system AMVACO change if 1 MW is injected at the corresponding bus. This bus Weighted Transmission Impact of Injection (WTII) value can be applied to each end of a proposed transmission line to linearly estimate the total expected AMVACO change expected from the addition of a new transmission branch.

The first step in calculating a proposed line's AMVACO impact is estimating its flow if it was placed in service. Fortunately this can be quickly calculated using Line Closure Distribution Factors (LCDF) and can be automated with Contingent Interfaces in PowerWorld Simulator. Assume the flow expected in the direction of bus k toward bus m is P_{km}. Approximating the system as lossless and linear within a range defined by the incremental flow on the proposed line, adding the proposed line is equivalent to placing a generator at bus k with output $-P_{km}$ and a generator at bus m with output $+P_{km}$, as illustrated in the figure below. The impedance parameters of the proposed line have a significant effect on the value of P_{km} in that a lower per unit impedance yields a larger P_{km}.

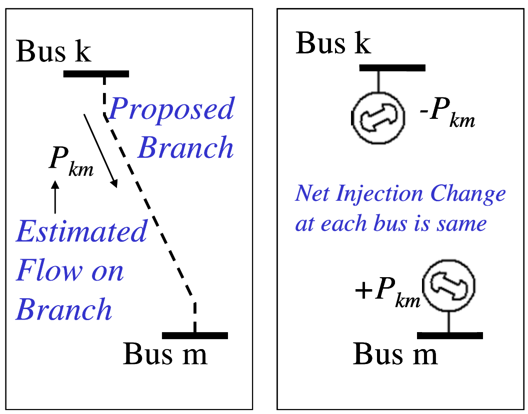


Figure D-1: Network Equivalents

Because these two figures are equivalent, the bus-based Weighted Transmission Impact of Injection (WTII) values may be applied to estimate the AMVACO impact or Security Enhancement Measure, as follows:

$$\text{Security Enhancement Measure} = P_{km}(-WTII_k + WTII_m).$$

2. Estimation of Flow on Potential New Lines

The estimate of flow on each candidate transmission line was made with linearized techniques in PowerWorld Simulator. The first step was to identify a list of candidate transmission branches and assign impedance parameters to each. Candidate lines included all pairs that connect 230 kV and higher buses within SPP and 345 kV and higher buses within SPP's Tier 1 neighbors. There were 356 buses in this set. Candidates were screened by distance as well, assuming that EHV lines longer than 500 miles would be impractical for power transmission and lines shorter than 30 miles would not provide enough marginal benefit to justify the investment in EHV terminations. Each remaining pair was eligible for 765-kV single-circuit, 500-kV double-circuit, or 500-kV single-circuit connections, yielding approximately 82,000 candidate EHV lines.

Line impedances were calculated with characteristics found in Table 1 of [2], though it was assumed that most line charging capacitance would be compensated with switched inductors if required. Each line was then added to the power system model as an *open* branch and interfaces were created in PowerWorld Simulator for each potential new transmission line with two elements as follows:

1. Monitor the flow on the new line
2. Contingency Close in the new line

Solving the power flow then yields a linearized estimate of the flow on each proposed line *after* it is individually closed. The following figure shows the estimate of flow on a proposed Muskogee – Fort Smith branch.

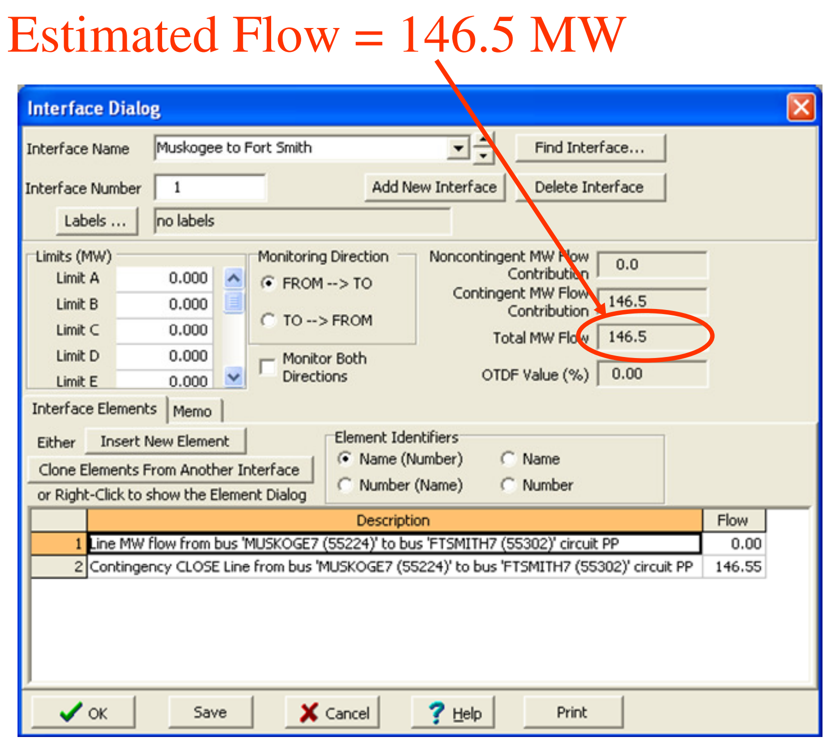


Figure D-2: Estimated Flow

3. Calculation of Cost/Security Ratio

The Security Enhancement Measure by itself does not take into account the feasibility or cost of adding in the potential new transmission line. Also, the Security Enhancement Measure will be biased toward higher voltage lines because higher nominal voltage yields lower per unit impedance and higher post-closure flow on the branch.

In order to overcome these limitations, estimates were made of the capital cost of building the proposed transmission line, using per mile costs in Appendix C. A proposed line's Cost/Security Ratio was calculated as follows.

$$\text{Cost/Security Ratio} = \frac{\text{Cost}}{\text{Security Enhancement Measure}} = \frac{\text{Cost}}{P_{km}(-WTII_k + WTII_m)}$$

The units on this measure are dollars per MW. The Cost/Security Ratio value represents the investment required per 1 MW reduction in expected AMVACO. The lower this ratio, the greater the estimated cost effectiveness of the proposed line in relieving overloading.

4. Selection Process

1. Build a list of candidate EHV transmission lines (approximately 82,000).
2. Do until security criteria are met:
    a. Perform contingency analysis on the SPP system
    b. Calculate bus-based WTII values
    c. Estimate flows on candidate lines
    d. Calculate line-based Cost/Security Ratios
    e. Select the candidate line with the lowest Cost/Security Ratio and insert it into the system
    f. Repeat.

5. Review of Results

The automated line selections were reviewed and the best performing selections were considered for inclusion in the EHV alternative grids. Some selections actually worsened the AMVACO security measure by causing new base case or contingent overloads. An increase in AMVACO by itself does not indicate that a proposed line should not be considered. Sometimes new overloads were relieved by subsequent connections which continue the proposed line to the next substation. Where the AMVACO is worsened by a line selection and not restored to a lower level within a few subsequent selections, it may be concluded that the line has an adverse impact on system security.

Table 1 below shows the results from a sequence of automated Weighted Transmission Impact of Injection-based line selections using the 2026 Base Case Future. The initial AMVACO was 3,469. After inserting the sequence of 18 lines, the AMVACO was reduced to 0, resulting in an N-1 secure case.

Table 1 – Automated WTII-based Selection, 2026 Base Case Future

Line#	AMVACO	Connection	Config.	WTII From Bus	WTII To Bus	Est. Flow (MW)	Actual Flow (MW)	Estimated Cost ($000)	SEM	Cost Security Ratio ($000/ SEM)
0	3,469									
1	2,490	Iatan-St. Joseph	765 kV SCT	-1.777	0.285	1024	1032	72,153	2,112	34
2	989	Swissvale-Wolf Creek	500 kV DCT	0.159	-2.885	-1179	-1219	99,951	3,589	28
3	880	Flanders-Wells	500 kV DCT	0.813	-0.209	-644	-637	63,106	658	96
4	912	Craig-Iatan	765 kV SCT	0.356	-0.185	-1138	-1162	95,427	617	155
5	1,623	Wolf Creek-Tecumseh EC	500 kV DCT	-0.408	1.337	465	477	135,197	812	166
6	1,147	Reno-Tecumseh EC	500 kV DCT	-0.008	-1.270	-847	-849	88,287	1,069	83
7	777	Summit-E. McPherson	500 kV DCT	0.126	1.047	337	334	72,460	311	233
8	474	Brookline-Huben	500 kV DCT	-0.840	-0.168	424	428	110,961	285	389
9	406	Reno-Swissvale	765 kV SCT	0.232	-0.498	-492	-495	113,672	359	317
10	315	Wolf Creek-Circle	500 kV DCT	-0.122	0.371	459	462	260,388	226	1,151
11	235	Dolet Hills-Fisher	500 kV DCT	-0.257	-0.025	245	242	96,144	57	1,688
12	124	Arsenal Hill-Grimes	500 kV DCT	-0.791	0.140	148	145	392,182	137	2,854
13	110	S.W. Shreveport-Arsenal Hill	500 kV DCT	-0.551	0.086	202	198	222,285	128	1,731
14	102	Paola-Plainville	500 kV DCT	-0.076	-0.009	382	388	71,141	26	2,771
15	87	Arsenal Hill-Sunnyside	500 kV DCT	-0.284	0.004	167	163	344,109	48	7,138
16	40	Lawton Eastside-Sunnyside	500 kV DCT	-0.067	-0.207	-251	-249	167,205	35	4,739
17	4	Pirkey-Fancy Point	500 kV DCT	0.206	0.009	-430	-432	508,480	85	5,986
18	0	Midland Jct-Tecumseh EC	500 kV DCT	0.157	-0.197	-170	-172	67,299	60	1,120

The estimated flow, based on line closure distribution factors, and the actual flow after each selected line was inserted, are also shown. Positive numbers denote MW flow from the first named substation to the second named substation in the connection column. The SEM column denotes the value of the Security Enhancement Measure for the selected line, as described above.

6. Limitations

The Weighted Transmission Impact of Injection methodology enables an easily automated process for selecting a sequence of new EHV transmission lines. However, it should not be used as the sole consideration in designing a system-wide EHV overlay. Several important considerations cannot be adequately addressed by the automated Weighted Transmission Impact of Injection-based selection process.

An EHV overlay should facilitate multiple transfers of power over the future grid, but the automated process can only evaluate one dispatch and load pattern at a time. Furthermore, it only has visibility to the next connection in the sequence. It can estimate which single connection will have the greatest marginal benefit to system security, but it cannot assess multiple connections simultaneously. After each new transmission line selection, the AMVACO and WTII must be recalculated to assess actual system security changes and incorporate any newly created overloads. Some proposed connections may worsen system security, even following several subsequently proposed connections. Also, the Weighted Transmission Impact of Injection calculations are sensitive to the set of monitored transmission element and contingencies. Assumptions have a significant impact on results.

Also, minimizing the cost and maximizing performance of the entire system often requires consolidating connections in a given locality around as few substations as possible. Because the automated process can only evaluate the cost of the next connection, it may not recognize such opportunities for consolidation. The process may also propose connections with external liabilities, such as those that cross environmentally sensitive areas.

Finally, it may not be feasible or cost effective to relieve all forms of congestion with new EHV lines. For example, if a transformer is slightly overloaded, it may be more cost effective to add another transformer in parallel, rather than redirect flow away from its substation with an EHV line. Similarly, some individual lines that become slightly overloaded may be effectively upgraded with reconductoring. Still other security problems may be averted with special protection schemes, especially those that occur rarely or only under specific circumstances. EHV expansion as an enabler of system security is most effective where several regional issues may be remediated with a few new EHV connections.

Thus the automated Weighted Transmission Impact of Injection-based selection process is very effective when used with prudent engineering judgment, as one input to the transmission expansion planning process.

Appendix E: Project Cost Estimates

ALTERNATIVE 1 COSTS:

Alternative 1 Costs:							
From	**To**	**Voltage (kV)**	**Cost/Mile in MM**	**Miles**	**Total Cost in MM**	**Transmission ROW Estimate/mile**	**Transmission Line Cost with ROW in MM**
Labadie	Collins	500	$1.75	250	$437.50	$65,000.00	$453.75
Wolf_Creek	Labadie	500	$1.75	270	$472.50	$65,000.00	$490.05
Wolf_Creek	Wichita	500	$1.75	120	$210.00	$65,000.00	$217.80
Wichita	Mooreland	500	$1.75	150	$262.50	$65,000.00	$272.25
Mooreland	OKU	500	$1.75	150	$262.50	$65,000.00	$272.25
OKU	Pittsburg	500	$1.75	220	$385.00	$65,000.00	$399.30
Pittsburg	Muskogee	500	$1.75	85	$148.75	$65,000.00	$154.28
Muskogee	Wolf_Creek	500	$1.75	170	$297.50	$65,000.00	$308.55
Pittsburg	Texarkana	500	$1.75	140	$245.00	$65,000.00	$254.10
Texarkana	McNeil	500	$1.75	70	$122.50	$65,000.00	$127.05
Mooreland	Harrington	500	$1.75	175	$306.25	$65,000.00	$317.63
Harrington	Tuco	500	$1.75	95	$166.25	$65,000.00	$172.43

Ozark 500 kV Loop - Line Costs							
From	**To**	**Voltage (kV)**	**Cost/Mile in MM**	**Miles**	**Total Cost in MM**	**Transmission ROW Estimate/mile**	**Transmission Line Cost with ROW in MM**
LACYGNE	BRKLINE	500	$1.75	115	$201.25	$65,000.00	$208.73
BRKLINE	TABLE-ROCK	500	$1.75	55	$96.25	$65,000.00	$99.83
TABLE-ROCK	ISES	500	$1.75	144	$252.00	$65,000.00	$261.36
TABLE-ROCK	FL-CRK	500	$1.75	84	$147.00	$65,000.00	$152.46
FL-CRK	FT-SMITH	500	$1.75	72	$126.00	$65,000.00	$130.68
FT-SMITH	NW-TEXARKAN	500	$1.75	140	$245.00	$65,000.00	$254.10

		Substation Cost 765 kV	Substation Cost 500 kV
Total Line Costs	$4,546.58	$21,576,000.00	$17,644,000.00
500 kV Transformer	$176.44		
500 kV Transformer	$158.80		
Total Costs in Millions	**$4,881.81**		

ALTERNATIVE 2 COSTS:

Alternative 2 Costs							
From	**To**	**Voltage (kV)**	**Cost/Mile in MM**	**Miles**	**Line Cost in MM**	**Transmission ROW Estimate/mile**	**Transmission Line Cost with ROW in MM**
Labadie	Collin	765	$2.00	250	$500.00	$65,000.00	$516.25
Wolf_Creek	Labadie	765	$2.00	270	$540.00	$65,000.00	$557.55
Wolf_Creek	Wichita	765	$2.00	120	$240.00	$65,000.00	$247.80
Wichita	Mooreland	765	$2.00	150	$300.00	$65,000.00	$309.75
Mooreland	OKU	765	$2.00	150	$300.00	$65,000.00	$309.75
OKU	Pittsburg	765	$2.00	220	$440.00	$65,000.00	$454.30
Pittsburg	Muskogee	765	$2.00	85	$170.00	$65,000.00	$175.53
Muskogee	Wolf_Creek	765	$2.00	170	$340.00	$65,000.00	$351.05
Mooreland	Harrington	500	$1.75	175	$306.25	$65,000.00	$317.63
Harrington	Tuco	500	$1.75	95	$166.25	$65,000.00	$172.43

Ozark 500 kV Loop - Line Costs							
From	**To**	**Voltage (kV)**	**Cost/Mile in MM**	**Miles**	**Total Cost in MM**	**Transmission ROW Estimate/mile**	**Transmission Line Cost with ROW in MM**
LACYGNE	BRKLINE	500	$1.75	115	$201.25	$65,000.00	$208.73
BRKLINE	TABLE-ROCK	500	$1.75	55	$96.25	$65,000.00	$99.83
TABLE-ROCK	ISES	500	$1.75	144	$252.00	$65,000.00	$261.36
TABLE-ROCK	FL-CRK	500	$1.75	84	$147.00	$65,000.00	$152.46
FL-CRK	FT-SMITH	500	$1.75	72	$126.00	$65,000.00	$130.68
FT-SMITH	NW-TEXARKAN	500	$1.75	140	$245.00	$65,000.00	$254.10
PITTSBURG	NW-TEXARKAN	500	$2.00	140	$280.00	$65,000.00	$289.10
NW-TEXARKAN	MCNEIL	500	$2.00	70	$140.00	$65,000.00	$144.55

		Substation Cost 765 kV	Substation Cost 500 kV
Total Line Costs	$4,519.18	$21,576,000.00	$17,644,000.00
765 kV Transformers	$215.76		
500 kV Transformers	$229.37		
Total Costs in Millions	**$4,964.31**		

ALTERNATIVE 3 COSTS:

Alternative 3 Costs:							
From	**To**	**Voltage (kV)**	**Cost/Mile in MM**	**Miles**	**Total Cost in MM**	**Transmission ROW Estimate/mile**	**Transmission Line Cost with ROW in MM**
Wolf_Creek	Swissvile	765	$2.00	36	$72.00	$65,000.00	$74.34
Swissvile	Reno	765	$2.00	150	$300.00	$65,000.00	$309.75
Reno	Spearville	765	$2.00	138	$276.00	$65,000.00	$284.97
Spearville	Potter	765	$2.00	216	$432.00	$65,000.00	$446.04
Potter	Tuco	765	$2.00	96	$192.00	$65,000.00	$198.24
Tuco	OKU	765	$2.00	180	$360.00	$65,000.00	$371.70
OKU	LES	765	$2.00	72	$144.00	$65,000.00	$148.68
LES	SunnySD	765	$2.00	72	$144.00	$65,000.00	$148.68
SunnySD	Barton	765	$2.00	168	$336.00	$65,000.00	$346.92
LES	Wolf_Creek	765	$2.00	276	$552.00	$65,000.00	$569.94

		Substation Cost 765 kV	Substation Cost 500 kV
Total Line Costs	$2,899.26	$21,576,000.00	$17,644,000.00
765 kV Transformer Costs	$345.22		
500 kV Transformer Costs	$141.15		
Total Costs in Millions	**$3,385.63**		

ALTERNATIVE 4 COSTS:

Alternative 4 Costs:							
From	To	Voltage (kV)	Cost/Mile in MM	Miles	Total Cost in MM	Transmission ROW Estimate/mile	Transmission Line Cost with ROW in MM
Labadie	Collins	765	$2.00	250	$500.00	$64,998.00	$516.25
Wolf_Creek	Labadie	765	$2.00	270	$540.00	$64,999.00	$557.55
Pauline	Summit	765	$2.00	192	$384.00	$65,000.00	$396.48
Summit	LaCygne	765	$2.00	120	$240.00	$65,000.00	$247.80
Spearville	Holcomb	765	$2.00	66	$132.00	$65,000.00	$136.29
LaCygne	Neosho	765	$2.00	55	$110.00	$65,000.00	$113.58
Neosho	Flint_Creek	765	$2.00	60	$120.00	$65,000.00	$123.90
Spearville	Mooreland	765	$2.00	80	$160.00	$65,000.00	$165.20
Mooreland	OKU	765	$2.00	125	$250.00	$65,000.00	$258.13
OKU	Pittsburg	765	$2.00	180	$360.00	$65,000.00	$371.70
Pittsburg	Ft. Smith	765	$2.00	140	$280.00	$65,000.00	$289.10
Pittsburg	Texarkana	765	$2.00	130	$260.00	$65,000.00	$268.45
Wichita	Spearville	765	$2.00	125	$250.00	$65,000.00	$258.13
Mooreland	Northwest	765	$2.00	100	$200.00	$65,000.00	$206.50
Northwest	Tulsa North	765	$2.00	100	$200.00	$65,000.00	$206.50
Tulsa North	Flint_Creek	765	$2.00	80	$160.00	$65,000.00	$165.20
Tuco	OKU	765	$2.00	150	$300.00	$65,000.00	$309.75
Mooreland	Harrington	765	$2.00	140	$280.00	$65,000.00	$289.10
Tuco	Harrington	765	$2.00	75	$150.00	$65,000.00	$154.88
Holcomb	Harrington	765	$2.00	150	$300.00	$65,000.00	$309.75

Ozark 500 kV Loop - Line Costs							
From	To	Voltage (kV)	Cost/Mile in MM	Miles	Total Cost in MM	Transmission ROW Estimate/mile	Transmission Line Cost with ROW in MM
LACYGNE	BRKLINE	500	$1.75	115	$201.25	$65,000.00	$208.73
BRKLINE	TABLE-ROCK	500	$1.75	55	$96.25	$65,000.00	$99.83
TABLE-ROCK	ISES	500	$1.75	144	$252.00	$65,000.00	$261.36
TABLE-ROCK	FL-CRK	500	$1.75	84	$147.00	$65,000.00	$152.46
FL-CRK	FT-SMITH	500	$1.75	72	$126.00	$65,000.00	$130.68
FT-SMITH	NW-TEXARKAN	500	$1.75	140	$245.00	$65,000.00	$254.10

		Substation Cost 765 kV	Substation Cost 500 kV
Total Line Costs	$6,451.37	$21,576,000.00	$17,644,000.00
765 kV Transformers	$409.94		
500 kV Transformers	$176.44		

Total Costs in Millions	**$7,037.75**		

ALTERNATIVE 5 COSTS:

Alternative 5 Costs:

From	To	Voltage (kV)	Cost/Mile in MM	Miles	Total Cost in MM	Transmission ROW Estimate/mile	Transmission Line Cost with ROW in MM
Labadie	Collins	765	$2.00	250	$500.00	$65,000.00	$516.25
Lacygne	Labadie	765	$2.00	270	$540.00	$65,000.00	$557.55
Wolf_Creek	Wichita	765	$2.00	120	$240.00	$65,000.00	$247.80
Wichita	Mooreland	765	$2.00	150	$300.00	$65,000.00	$309.75
Mooreland	OKU	765	$2.00	150	$300.00	$65,000.00	$309.75
OKU	Seminole	765	$2.00	220	$440.00	$65,000.00	$454.30
Seminole	Muskogee	765	$2.00	85	$170.00	$65,000.00	$175.53
Muskogee	Wolf_Creek	765	$2.00	170	$340.00	$65,000.00	$351.05
Mooreland	Harrington	500	$1.75	140	$245.00	$65,000.00	$254.10
Harrington	Tuco	500	$1.75	70	$122.50	$65,000.00	$127.05

From	To	Voltage (kV)	Cost/Mile in MM	Miles	Total Cost in MM	Transmission ROW Estimate/mile	Transmission Line Cost with ROW in MM
LACYGNE	BRKLINE	500	$1.75	115	$201.25	$65,000.00	$208.73
BRKLINE	TABLE-ROCK	500	$1.75	55	$96.25	$65,000.00	$99.83
TABLE-ROCK	ISES	500	$1.75	144	$252.00	$65,000.00	$261.36
TABLE-ROCK	FL-CRK	500	$1.75	84	$147.00	$65,000.00	$152.46
FL-CRK	FT-SMITH	500	$1.75	72	$126.00	$65,000.00	$130.68
FT-SMITH	NW-TEXARKAN	500	$1.75	140	$245.00	$65,000.00	$254.10
NW-TEXARKAN	MCNEIL	500	$1.75	70	$122.50	$65,000.00	$127.05

		Substation Cost 765 kV	Substation Cost 500 kV
Total Line Costs	$4,537.33	$21,576,000.00	$17,644,000.00
765 kV Transformers	$172.61		
500 kV Transformers	$194.08		
Total Costs in Millions	**$4,904.02**		

ALTERNATIVE 6 COSTS:

Alternative 6 Costs:					

From	To	Voltage (kV)	Cost/Mile in MM	Miles	Total Cost in MM	Transmission ROW Estimate/mile	Transmission Line Cost with ROW in MM
Labadie	Collins	500	$1.75	250	$437.50	$65,000.00	$453.75
Wolf_Creek	Labadie	500	$1.75	270	$472.50	$65,000.00	$490.05
Wolf_Creek	Wichita	500	$1.75	120	$210.00	$65,000.00	$217.80
Wichita	Mooreland	500	$1.75	150	$262.50	$65,000.00	$272.25
Mooreland	OKU	500	$1.75	150	$262.50	$65,000.00	$272.25
OKU	Seminole	500	$1.75	220	$385.00	$65,000.00	$399.30
Seminole	Muskogee	500	$1.75	85	$148.75	$65,000.00	$154.28
Wolf_Creek	Collins	500	$1.75	270	$472.50	$65,000.00	$490.05
Mooreland	Harrington	500	$1.75	140	$245.00	$65,000.00	$254.10
Harrington	Tuco	500	$1.75	70	$122.50	$65,000.00	$127.05
Ozark Line Costs - 500 kV Loop							
From	**To**	**Voltage (kV)**	**Cost/Mile in MM**	**Miles**	**Total Cost in MM**	**Transmission ROW Estimate/mile**	**Transmission Line Cost with ROW in MM**
LACYGNE	BRKLINE	500	$1.75	115	$201.25	$65,000.00	$208.73
BRKLINE	TABLE-ROCK	500	$1.75	55	$96.25	$65,000.00	$99.83
TABLE-ROCK	ISES	500	$1.75	144	$252.00	$65,000.00	$261.36
TABLE-ROCK	FL-CRK	500	$1.75	84	$147.00	$65,000.00	$152.46
FL-CRK	FT-SMITH	500	$1.75	72	$126.00	$65,000.00	$130.68
FT-SMITH	NW-TEXARKAN	500	$1.75	140	$245.00	$65,000.00	$254.10
NW-TEXARKAN	MCNEIL	500	$1.75	70	$122.50	$65,000.00	$187.50

		Substation Cost 765 kV	Substation Cost 500 kV
Total Line Costs	$4,425.53	$21,576,000.00	$17,644,000.00
500 kV Transformers	$158.80		
500 kV Transformers	$123.51		
Total Costs in Millions	**$4,707.83**		

765 kV SUBSTATION COSTS:

	ENGINEERING

	Base Cost	Unit Cost	Number of Units	Sub-Total	Percent Adjustment	TOTAL	BID TOTALS
						Inflation Factor:	**0.00%**
Civil Package (Note 1)							
Site (per station)	$126,000		1	$126,000		$126,000	
Permitting (per station)	$20,000		1	$20,000		$20,000	
Environmental (per station)	$20,000		1	$20,000		$20,000	
Surveying (per line)	$6,000	$2,000		$0		$0	
Soil Boring (per line)	$4,000	$1,000		$0		$0	
						$166,000	**$166,000**
Electrical Package - Physical							
500kV Terminals (Double Breaker Double Bus)	$96,000	$24,000		$0		$0	
Transformers	$21,000	$21,000	1	$21,000		$21,000	
765kV Terminals (Double Breaker Double Bus)	$110,000	$30,000	3	$170,000		$170,000	
345 kV Terminals (Breaker and Half)	$85,000	$20,000	1	$85,000		$85,000	
						$276,000	**$276,000**
Electrical Package - Controls							
500kV Terminals	$360,000	$90,000		$0		$0	
Transformers	$63,000	$63,000	1.0	$63,000		$63,000	
765kV Terminals	$400,000	$100,000	3.0	$600,000		$600,000	
345 kV Terminals	$280,000	$75,000	1.0	$280,000		$280,000	
						$943,000	**$943,000**
Control House							
Each (1 per site)	$120,000		1	$120,000		$120,000	
						$120,000	**$120,000**
Total Project Engineering Cost							**$1,505,000**

	Construction						
	Material Cost	Labor Cost	Number of Units	Sub-Total	Percent Adjustment	TOTAL	**BID TOTALS**
Civil Package (1 per station)	$ 43,000	$ 59,000	1	$102,000		$102,000	
500 kV Line Termination (Note 3)	$1,868,000	$ 1,200,000	0	$0		$0	

345 kV Line Termination (Note 2)	$ 900,000	$ 750,000	1	$1,650,000		$1,650,000	
765 kV Line Termination (Note 4)	$2,250,000	$ 1,500,000	3	$11,250,000		$11,250,000	
Transformer (Note 5)	$5,800,000	$ 487,000	1	$6,287,000		$6,287,000	
Control House (includes SCADA)	$ 447,000	$ 85,000	1	$532,000		$532,000	
Commissioning & Testing (per element) (Note 6)		$ 50,000	5	$250,000		$250,000	
Total Project Material & Labor Cost							**$20,071,000**
Total Project Cost							**$21,576,000**

Notes

1) Site cut and fill not included
2) 345 kv breaker cost of $ 200,000 ea included
3) 500 kv breaker cost of $ 500,000 ea included
4) 765 kv breaker cost of $ 750,000 ea included
5) Transformer cost of $ 5,800,000 per 3 phase included
6) Transformer testing not included

500 kV SUBSTATION COSTS:

	ENGINEERING

	Base Cost	Unit Cost	Number of Units	Sub-Total	Percent Adjustment	TOTAL	**BID TOTALS**
						Inflation Factor:	**0.00%**
Civil Package (Note 1)							
Site (per station)	$126,000		1	$126,000		$126,000	
Permitting (per station)	$20,000		1	$20,000		$20,000	
Environmental (per station)	$20,000		1	$20,000		$20,000	
Surveying (per line)	$6,000	$2,000		$0		$0	
Soil Boring (per line)	$4,000	$1,000		$0		$0	
						$166,000	**$166,000**
Electrical Package - Physical							
500kV Terminals (Double Breaker Double Bus)	$96,000	$24,000	3	$144,000		$144,000	
Transformers	$21,000	$21,000	1	$21,000		$21,000	
765kV Terminals (Double Breaker Double Bus)	$110,000	$30,000	0	$0		$0	
345 kV Terminals (Breaker and Half)	$85,000	$20,000	1	$85,000		$85,000	
						$250,000	**$250,000**
Electrical Package - Controls							
500kV Terminals	$360,000	$90,000	3.0	$540,000		$540,000	
Transformers	$63,000	$63,000	1.0	$63,000		$63,000	
765kV Terminals	$400,000	$100,000	0.0	$0		$0	
345 kV Terminals	$280,000	$75,000	1.0	$280,000		$280,000	
						$883,000	**$883,000**
Control House							
Each (1 per site)	$120,000		1	$120,000		$120,000	
						$120,000	**$120,000**
Total Project Engineering Cost							**$1,419,000**
	Construction						
	Material Cost	Labor Cost	Number of Units	Sub-Total	Percent Adjustment	TOTAL	**BID TOTALS**
Civil Package (1 per station)	$ 43,000	$ 59,000	1	$102,000		$102,000	

500 kV Line Termination (Note 3)	$ 1,868,000	$ 1,200,000	3	$9,204,000		$9,204,000	
345 kV Line Termination (Note 2)	$ 900,000	$ 750,000	1	$1,650,000		$1,650,000	
765 kV Line Termination (Note 4)	$ 2,250,000	$ 1,500,000	0	$0		$0	
Transformer (Note 5)	$ 4,000,000	$ 487,000	1	$4,487,000		$4,487,000	
Control House (includes SCADA)	$ 447,000	$ 85,000	1	$532,000		$532,000	
Commissioning & Testing (per element) (Note 6)		$ 50,000	5	$250,000		$250,000	
Total Project Material & Labor Cost							**$16,225,000**
Total Project Cost							**$17,644,000**

Notes

1) Site cut and fill not included

2) 345 kv breaker cost of $ 200,000 ea included

3) 500 kv breaker cost of $ 500,000 ea included

4) 765 kv breaker cost of $ 750,000 ea included

5) Transformer cost of $ 4,000,000 per 3 phase included

6) Transformer testing not included

Appendix F: Alternative 5 EHV Contingency Results

Contingency simulation of Alternative 5 - 400kV and above

ContingencyViolationTableRow Contingency	LP-HOLL2 (50520) TO LP-HOLL6 (50521) CKT 1	FTSMTHE5 (55300) TO FTSMTSTR (2000558) CKT 3	FTSMTHW5 (55301) TO FTSMTSTR (2000560) CKT 5
L_55305FTSMITH8-994868ANO50C1	107.99		
T_55305FTSMITH8-2000558FTSMTSTRC3	107.99		125.5
T_55305FTSMITH8-2000559FTSMTSTRC4	107.99	105.81	
T_55305FTSMITH8-2000561FTSMISTRC1	107.99	124.67	
L_5053140FlintCRK8-55305FTSMITH8C1	107.99	110.96	
L_55305FTSMITH8-5330110NWTXARK8C1	107.99		
L_5330110NWTXARK8-993098MCNEILC1	107.99	103.61	
L_5052672TableRoc8-998188ISES5C1	107.99	105.4	
L_5679711WOLfCRK9-3088611LABADIE9C1	107.98	100.57	
L_5052672TableRoc8-5053140FlintCRK8C1	107.99	103.45	
L_5059984BRKLINE8-5052672TableRoc8C1	107.99	104.33	
L_5057981LACYGNE8-5059984BRKLINE8C1	107.99	104.06	
L_5090710HARRNG8-5153410TUCO8C1	108.32	106.01	
L_5581910MOORLND8-5090710HARRNG8C1	108	105.82	
L_5581910MOORLND8-5153410TUCO8C1	107.99	105.81	
L_5403310PITTSB-8-5330110NWTXARK8C1	107.99	105.81	
T_5403310PITTSB-8-5403311PITTSB-9C1	107.99	105.81	
L_5411911O.K.U.-9-5403311PITTSB-9C1	107.99	105.81	
L_5403311PITTSB-9-5522411MUSKOGE9C1	107.99	105.81	
L_5411911O.K.U.-9-5504511Seminole9C1	107.99	105.83	
L_5581911MOORLND9-5411911O.K.U.-9C1	108.06	107.48	
L_5522411MUSKOGE9-5504511Seminole9C1	108	105.58	
L_5522411MUSKOGE9-5679711WOLfCRK9C1	108	108.32	
T_5581910MOORLND8-5581911MOORLND9C1	108	105.82	
L_5679611WICHITA9-5581911MOORLND9C1	107.99	105.54	
L_5679711WOLfCRK9-5679611WICHITA9C1	107.99	105.89	

ContingencyViolationTableRow Contingency	FTSMITH7 (55302) TO FTSMTSTR (2000560) CKT 5	FTSMITH8 (55305) TO FTSMTSTR (2000558) CKT 3	BRKLNE 7 (59984) TO BRKLNSTR (2000779) CKT 1
L_55305FTSMITH8-994868ANO50C1			
T_55305FTSMITH8-2000558FTSMTSTRC3	136.7		
T_55305FTSMITH8-2000559FTSMTSTRC4		114.57	
T_55305FTSMITH8-2000561FTSMISTRC1		135.31	
L_5053140FlintCRK8-55305FTSMITH8C1		119.68	
L_55305FTSMITH8-5330110NWTXARK8C1		107.61	
L_5330110NWTXARK8-993098MCNEILC1		112.09	
L_5052672TableRoc8-998188ISES5C1		113.97	
L_5679711WOLfCRK9-3088611LABADIE9C1		109.04	
L_5052672TableRoc8-5053140FlintCRK8C1		111.67	
L_5059984BRKLINE8-5052672TableRoc8C1		113.03	105.26
L_5057981LACYGNE8-5059984BRKLINE8C1		112.64	
L_5090710HARRNG8-5153410TUCO8C1		114.78	
L_5581910MOORLND8-5090710HARRNG8C1		114.58	
L_5581910MOORLND8-5153410TUCO8C1		114.57	
L_5403310PITTSB-8-5330110NWTXARK8C1		114.57	
T_5403310PITTSB-8-5403311PITTSB-9C1		114.57	
L_5411911O.K.U.-9-5403311PITTSB-9C1		114.57	
L_5403311PITTSB-9-5522411MUSKOGE9C1		114.57	
L_5411911O.K.U.-9-5504511Seminole9C1		114.59	
L_5581911MOORLND9-5411911O.K.U.-9C1		116.34	
L_5522411MUSKOGE9-5504511Seminole9C1		114.33	
L_5522411MUSKOGE9-5679711WOLfCRK9C1		117.22	
T_5581910MOORLND8-5581911MOORLND9C1		114.58	
L_5679611WICHITA9-5581911MOORLND9C1		114.29	
L_5679711WOLfCRK9-5679611WICHITA9C1		114.65	

ContingencyViolationTableRow	BRKLNE 7 (59984) TO
Contingency	BRKLNSTR (2000780) CKT 2
L_55305FTSMITH8-994868ANO50C1	
T_55305FTSMITH8-2000558FTSMTSTRC3	
T_55305FTSMITH8-2000559FTSMTSTRC4	
T_55305FTSMITH8-2000561FTSMISTRC1	
L_5053140FlintCRK8-55305FTSMITH8C1	
L_55305FTSMITH8-5330110NWTXARK8C1	
L_5330110NWTXARK8-993098MCNEILC1	
L_5052672TableRoc8-998188ISES5C1	
L_5679711WOLfCRK9-3088611LABADIE9C1	
L_5052672TableRoc8-5053140FlintCRK8C1	
L_5059984BRKLINE8-5052672TableRoc8C1	104.35
L_5057981LACYGNE8-5059984BRKLINE8C1	
L_5090710HARRNG8-5153410TUCO8C1	
L_5581910MOORLND8-5090710HARRNG8C1	
L_5581910MOORLND8-5153410TUCO8C1	
L_5403310PITTSB-8-5330110NWTXARK8C1	
T_5403310PITTSB-8-5403311PITTSB-9C1	
L_5411911O.K.U.-9-5403311PITTSB-9C1	
L_5403311PITTSB-9-5522411MUSKOGE9C1	
L_5411911O.K.U.-9-5504511Seminole9C1	
L_5581911MOORLND9-5411911O.K.U.-9C1	
L_5522411MUSKOGE9-5504511Seminole9C1	
L_5522411MUSKOGE9-5679711WOLfCRK9C1	
T_5581910MOORLND8-5581911MOORLND9C1	
L_5679611WICHITA9-5581911MOORLND9C1	
L_5679711WOLfCRK9-5679611WICHITA9C1	

Appendix G: Alternative 5 Contingency Results for 345kV Transformers and Above

Contingency simulation of Alternative 5

ContingencyViolationTableRow

Contingency	LP-HOLL2 (50520) TO LP-HOLL6 (50521) CKT 1	TUCO3 (51532) TO TUCO7 (51534) CKT 1	CARLISL3 (51646) TO CARLISL6 (51647) CKT 1	FLINTCR5 (53139) TO FLINTSTR (2000320) CKT 1
T_50888POTTRC7-2000279POTTRSTRC1	108.01			
T_50888POTTRC7-2000280POTTRSTRC2	108.01			
T_51440TOLK7-2000281TOLK7STRC1	108.09		103.54	
T_51534TUCO7-2000282TUCO7STRC1	108.42	113		
T_51534TUCO7-5153410TUCO8C1	108.15			
T_51534TUCO7-5153410TUCO8C2	108.15			
T_52186EDDYCO7-2000283EDDYCSTRC1	108.83		105.39	
T_53140FLINTCR7-2000320FLINTSTRC1	107.99			
T_53140FLINTCR7-2000321FLINTSTRC2	107.99			107.41
T_5053140FlintCRK8-53140FLINTCR7C1	107.99			
T_53155CHAMSPR7-2000324CHAMSSTRC1	107.99			
T_53176TONTITN7-2000326TONTISTRC1	107.99			
T_53301NWTXARK7-2000343NWTXASTRC1	107.99			
T_53301NWTXARK7-2000344NWTXASTRC2	107.99			
T_53301NWTXARK7-5330110NWTXARK8C1	107.99			
T_53424LONGWD7-2000365LONGWSTRC1	107.99			
T_53454SWSHV7-2000371SWSHSTRC1	107.99			
T_53454SWSHV7-2000372SWSHSTRC2	107.99			
T_53526CROCKET7-2000374CROCKSTRC1	107.99			
T_53528DIANA7-2000375DIANASTRC1	107.99			
T_53528DIANA7-2000376DIANASTRC2	107.99			
T_53528DIANA7-2000377DIANASTRC3	107.99			
T_53593PIRKEY7-2000388PIRKESTRC1	107.99			
T_53593PIRKEY7-2000389PIRKESTRC2	107.99			
T_53620WILKES7-2000394WILKESTRC1	107.99			
T_53767WEKIWA-7-2000397WEKIWSTRC1	107.99			
T_53794R.S.S.-7-2000398RSSTSTRC1	107.99			
T_53794R.S.S.-7-2000412RSSTSTRC1	107.99			
T_53819ONETA--7-2000405ONETASTRC1	107.99			
T_53819ONETA--7-2000406ONETASTRC2	107.99			
T_53819ONETA--7-2000407ONETASTRC3	107.99			
T_53848COGENT7-2000449COGENSTRC1	107.99			
T_53848COGENT7-2000450COGENSTRC1	107.99			
T_53848COGENT7-2000451COGENSTRC1	107.99			
T_53866T.NO.--7-2000409T.NO.STRC1	107.99			
T_53885SAPLPRD7-2000411SAPLPSTRC1	107.99			
T_53929DELWARE7-2000413DELWASTRC1	107.99			
T_54033PITTSB-7-5403310PITTSB-8C1	107.99			
T_54033PITTSB-7-5403311PITTSB-9C1	107.99			
T_54037VALIANT7-2000427VALIASTRC2	107.99			
T_54037VALIANT7-2000428VALIASTRC1	107.99			

ContingencyViolationTableRow

Contingency	LP-HOLL2 (50520) TO LP-HOLL6 (50521) CKT 1	TUCO3 (51532) TO TUCO7 (51534) CKT 1	CARLISL3 (51646) TO CARLISL6 (51647) CKT 1	FLINTCR5 (53139) TO FLINTSTR (2000320) CKT 1
T_54119O.K.U.-7-5411911O.K.U.-9C1	108.13			
T_54131L.E.S.-7-2000437L.E.SSTRC1	107.99			
T_54131L.E.S.-7-2000438L.E.SSTRC2	107.99			
T_54450GRDA17-2000469GRDA1STRC1	107.99			
T_54450GRDA17-2000470GRDA1STRC2	107.99			
T_54715WOODRNG7-2000492WOODRSTRC1	107.99			
T_54803SOONER7-2000502SOONESTRC1	107.99			
T_54803SOONER7-2000503SOONESTRC2	107.99			
T_54880NORTWST7-2000508NORTWSTRC1	107.99			
T_54880NORTWST7-2000509NORTWSTRC1	107.99			
T_54901CIMARON7-2000511CIMARSTRC1	107.99			
T_54901CIMARON7-2000512CIMARSTRC1	107.99			
T_54908ARCADIA7-2000513ARCADSTRC1	107.99			
T_54908ARCADIA7-2000514ARCADSTRC1	107.99			
T_54934DRAPER7-2000521DRAPESTRC1	107.99			
T_54934DRAPER7-2000522DRAPESTRC1	107.99			
T_54934DRAPER7-2000523DRAPESTRC1	107.99			
T_55045SEMINOL7-2000529SEMINSTRC1	107.99			
T_55045SEMINOL7-2000530SEMINSTRC1	107.99			
T_55045SEMINOL7-5504511Seminole9C1	107.99			
T_55136SUNNYSD7-2000539SUNNYSTRC1	107.99			
T_55224MUSKOGE7-5522411MUSKOGE9C1	107.99			
T_55235PECANCK7-2000552PECANSTRC2	107.99			
T_55235PECANCK7-2000553PECANSTRC1	107.99			
T_55302FTSMITH7-2000560FTSMTSTRC5	107.99			
T_55302FTSMITH7-2000561FTSMISTRC1	107.99			
T_55305FTSMITH8-2000558FTSMTSTRC3	107.99			
T_55305FTSMITH8-2000559FTSMTSTRC4	107.99			
T_55305FTSMITH8-2000561FTSMISTRC1	107.99			
T_55819MOORLND-5581911MOORLND9C1	107.99			
T_55819MOORLND-5581911MOORLND9C2	107.99			
T_56449HOLCOMB7-2000588HOLCOSTRC1	107.99			
T_56451MINGO7-2000586MINGOSTRC1	107.99			
T_56465SETAB7-2000589SETABSTRC1	107.99			
T_56469SPERVIL7-2000699SPEARSTRC1	107.99			
T_56469SPERVIL7-2000700SPEARSTRC2	107.99			
T_56765HOYT7-2000591HOYTSTRC1	107.99			
T_56766JECN7-2000592JECNSTRC1	107.99			
T_56766JECN7-2000593JECNSTRC1	107.99			
T_56769LANG7-2000594LANGSTRC1	107.99			
T_56770MORRIS7-2000595MORRISTRC1	107.99			
T_56771RENO-2000596RENOSTRC1	107.99			
T_56771RENO-2000597RENOSTRC1	107.99			
T_56772STRANGR7-2000598STRANSTRC1	107.99			

ContingencyViolationTableRow

Contingency	LP-HOLL2 (50520) TO LP-HOLL6 (50521) CKT 1	TUCO3 (51532) TO TUCO7 (51534) CKT 1	CARLISL3 (51646) TO CARLISL6 (51647) CKT 1	FLINTCR5 (53139) TO FLINTSTR (2000320) CKT 1
T_56774SWISVAL7-2000602SWISVSTRC1	107.99			
T_56796WICHITA7-2000603WICHISTRC1	107.99			
T_56796WICHITA7-2000604WICHISTRC1	107.99			
T_56796WICHITA7-5679611WICHITA9C1	107.99			
T_56796WICHITA7-5679611WICHITA9C2	107.99			
T_56797WOLFCRK7-5679711WOLfCRK9C1	107.99			
T_56797WOLFCRK7-5679711WOLfCRK9C2	107.99			
T_56797WOLFCRK7-5679711WOLfCRK9C3	107.99			
T_5057981LACYGNE8-57981LACYGNE7C1	107.99			
T_59199STJOE3-2000743STJOSTRC1	107.99			
T_59199STJOE3-2000744STJOSTRC2	107.99			
T_59200PHILL7-2000742PHILLSTRC1	107.99			
T_5059984BRKLINE8-59984BRKLNE7C1	107.99			
T_5403310PITTSB-8-5403311PITTSB-9C1	107.99			
T_5581910MOORLND8-5581911MOORLND9C1	108			

ContingencyViolationTableRow

Contingency	FLINTCR5 (53139) TO FLINTSTR (2000321) CKT 2	FLINTCR7 (53140) TO FLINTSTR (2000320) CKT 1	FLINTCR7 (53140) TO FLINTSTR (2000321) CKT 2	SW SHV 4 (53453) TO SW SHSTR (2000371) CKT 1
T_50888POTTRC7-2000279POTTRSTRC1				
T_50888POTTRC7-2000280POTTRSTRC2				
T_51440TOLK7-2000281TOLK7STRC1				
T_51534TUCO7-2000282TUCO7STRC1				
T_51534TUCO7-5153410TUCO8C1				
T_51534TUCO7-5153410TUCO8C2				
T_52186EDDYCO7-2000283EDDYCSTRC1				
T_53140FLINTCR7-2000320FLINTSTRC1	107.24		107.46	
T_53140FLINTCR7-2000321FLINTSTRC2		107.59		
T_5053140FlintCRK8-53140FLINTCR7C1				
T_53155CHAMSPR7-2000324CHAMSSTRC1				
T_53176TONTITN7-2000326TONTISTRC1				
T_53301NWTXARK7-2000343NWTXASTRC1				
T_53301NWTXARK7-2000344NWTXASTRC2				
T_53301NWTXARK7-5330110NWTXARK8C1				
T_53424LONGWD7-2000365LONGWSTRC1				
T_53454SWSHV7-2000371SWSHSTRC1				
T_53454SWSHV7-2000372SWSHSTRC2				118.29
T_53526CROCKET7-2000374CROCKSTRC1				
T_53528DIANA7-2000375DIANASTRC1				
T_53528DIANA7-2000376DIANASTRC2				
T_53528DIANA7-2000377DIANASTRC3				
T_53593PIRKEY7-2000388PIRKESTRC1				
T_53593PIRKEY7-2000389PIRKESTRC2				
T_53620WILKES7-2000394WILKESTRC1				
T_53767WEKIWA-7-2000397WEKIWSTRC1				
T_53794R.S.S.-7-2000398RSSTSTRC1				
T_53794R.S.S.-7-2000412RSSTSTRC1				
T_53819ONETA--7-2000405ONETASTRC1				
T_53819ONETA--7-2000406ONETASTRC2				
T_53819ONETA--7-2000407ONETASTRC3				
T_53848COGENT7-2000449COGENSTRC1				
T_53848COGENT7-2000450COGENSTRC1				
T_53848COGENT7-2000451COGENSTRC1				
T_53866T.NO.--7-2000409T.NO.STRC1				
T_53885SAPLPRD7-2000411SAPLPSTRC1				
T_53929DELWARE7-2000413DELWASTRC1				
T_54033PITTSB-7-5403310PITTSB-8C1				
T_54033PITTSB-7-5403311PITTSB-9C1				
T_54037VALIANT7-2000427VALIASTRC2				
T_54037VALIANT7-2000428VALIASTRC1				

ContingencyViolationTableRow

Contingency	FLINTCR5 (53139) TO FLINTSTR (2000321) CKT 2	FLINTCR7 (53140) TO FLINTSTR (2000320) CKT 1	FLINTCR7 (53140) TO FLINTSTR (2000321) CKT 2	SW SHV 4 (53453) TO SW SHSTR (2000371) CKT 1
T_54119O.K.U.-7-541191O.K.U.-9C1				
T_54131L.E.S.-7-2000437L.E.SSTRC1				
T_54131L.E.S.-7-2000438L.E.SSTRC2				
T_54450GRDA17-2000469GRDA1STRC1				
T_54450GRDA17-2000470GRDA1STRC2				
T_54715WOODRNG7-2000492WOODRSTRC1				
T_54803SOONER7-2000502SOONESTRC1				
T_54803SOONER7-2000503SOONESTRC2				
T_54880NORTWST7-2000508NORTWSTRC1				
T_54880NORTWST7-2000509NORTWSTRC1				
T_54901CIMARON7-2000511CIMARSTRC1				
T_54901CIMARON7-2000512CIMARSTRC1				
T_54908ARCADIA7-2000513ARCADSTRC1				
T_54908ARCADIA7-2000514ARCADSTRC1				
T_54934DRAPER7-2000521DRAPESTRC1				
T_54934DRAPER7-2000522DRAPESTRC1				
T_54934DRAPER7-2000523DRAPESTRC1				
T_55045SEMINOL7-2000529SEMINSTRC1				
T_55045SEMINOL7-2000530SEMINSTRC1				
T_55045SEMINOL7-5504511Seminole9C1				
T_55136SUNNYSD7-2000539SUNNYSTRC1				
T_55224MUSKOGE7-5522411MUSKOGE9C1				
T_55235PECANCK7-2000552PECANSTRC2				
T_55235PECANCK7-2000553PECANSTRC1				
T_55302FTSMITH7-2000560FTSMTSTRC5				
T_55302FTSMITH7-2000561FTSMISTRC1				
T_55305FTSMITH8-2000558FTSMTSTRC3				
T_55305FTSMITH8-2000559FTSMTSTRC4				
T_55305FTSMITH8-2000561FTSMISTRC1				
T_55819MOORLND-5581911MOORLND9C1				
T_55819MOORLND-5581911MOORLND9C2				
T_56449HOLCOMB7-2000588HOLCOSTRC1				
T_56451MINGO7-2000586MINGOSTRC1				
T_56465SETAB7-2000589SETABSTRC1				
T_56469SPERVIL7-2000699SPEARSTRC1				
T_56469SPERVIL7-2000700SPEARSTRC2				
T_56765HOYT7-2000591HOYTSTRC1				
T_56766JECN7-2000592JECNSTRC1				
T_56766JECN7-2000593JECNSTRC1				
T_56769LANG7-2000594LANGSTRC1				
T_56770MORRIS7-2000595MORRISTRC1				
T_56771RENO-2000596RENOSTRC1				
T_56771RENO-2000597RENOSTRC1				
T_56772STRANGR7-2000598STRANSTRC1				

ContingencyViolationTableRow

Contingency	FLINTCR5 (53139) TO FLINTSTR (2000321) CKT 2	FLINTCR7 (53140) TO FLINTSTR (2000320) CKT 1	FLINTCR7 (53140) TO FLINTSTR (2000321) CKT 2	SW SHV 4 (53453) TO SW SHSTR (2000371) CKT 1
T_56774SWISVAL7-2000602SWISVSTRC1				
T_56796WICHITA7-2000603WICHISTRC1				
T_56796WICHITA7-2000604WICHISTRC1				
T_56796WICHITA7-5679611WICHITA9C1				
T_56796WICHITA7-5679611WICHITA9C2				
T_56797WOLFCRK7-5679711WOLfCRK9C1				
T_56797WOLFCRK7-5679711WOLfCRK9C2				
T_56797WOLFCRK7-5679711WOLfCRK9C3				
T_5057981LACYGNE8-57981LACYGNE7C1				
T_59199STJOE3-2000743STJOSTRC1				
T_59199STJOE3-2000744STJOSTRC2				
T_59200PHILL7-2000742PHILLSTRC1				
T_5059984BRKLINE8-59984BRKLNE7C1				
T_5403310PITTSB-8-5403311PITTSB-9C1				
T_5581910MOORLND8-5581911MOORLND9C1				

ContingencyViolationTableRow

Contingency	SW SHV 4 (53453) TO SW SHSTR (2000372) CKT 2	SW SHV 7 (53454) TO SW SHSTR (2000371) CKT 1	SW SHV 7 (53454) TO SW SHSTR (2000372) CKT 2	NORTWST 4 (54879) TO NORTWST R (2000508) CKT 1
T_50888POTTRC7-2000279POTTRSTRC1				
T_50888POTTRC7-2000280POTTRSTRC2				
T_51440TOLK7-2000281TOLK7STRC1				
T_51534TUCO7-2000282TUCO7STRC1				
T_51534TUCO7-5153410TUCO8C1				
T_51534TUCO7-5153410TUCO8C2				
T_52186EDDYCO7-2000283EDDYCSTRC1				
T_53140FLINTCR7-2000320FLINTSTRC1				
T_53140FLINTCR7-2000321FLINTSTRC2				
T_5053140FlintCRK8-53140FLINTCR7C1				
T_53155CHAMSPR7-2000324CHAMSSTRC1				
T_53176TONTITN7-2000326TONTISTRC1				
T_53301NWTXARK7-2000343NWTXASTRC1				
T_53301NWTXARK7-2000344NWTXASTRC2				
T_53301NWTXARK7-5330110NWTXARK8C1				
T_53424LONGWD7-2000365LONGWSTRC1				
T_53454SWSHV7-2000371SWSHSTRC1	115.32		118.74	
T_53454SWSHV7-2000372SWSHSTRC2		120.87		
T_53526CROCKET7-2000374CROCKSTRC1				
T_53528DIANA7-2000375DIANASTRC1				
T_53528DIANA7-2000376DIANASTRC2				
T_53528DIANA7-2000377DIANASTRC3				
T_53593PIRKEY7-2000388PIRKESTRC1				
T_53593PIRKEY7-2000389PIRKESTRC2				
T_53620WILKES7-2000394WILKESTRC1				
T_53767WEKIWA-7-2000397WEKIWSTRC1				
T_53794R.S.S.-7-2000398RSSTSTRC1				
T_53794R.S.S.-7-2000412RSSTSTRC1				
T_53819ONETA--7-2000405ONETASTRC1				
T_53819ONETA--7-2000406ONETASTRC2				
T_53819ONETA--7-2000407ONETASTRC3				
T_53848COGENT7-2000449COGENSTRC1				
T_53848COGENT7-2000450COGENSTRC1				
T_53848COGENT7-2000451COGENSTRC1				
T_53866T.NO.--7-2000409T.NO.STRC1				
T_53885SAPLPRD7-2000411SAPLPSTRC1				
T_53929DELWARE7-2000413DELWASTRC1				
T_54033PITTSB-7-5403310PITTSB-8C1				
T_54033PITTSB-7-5403311PITTSB-9C1				
T_54037VALIANT7-2000427VALIASTRC2				
T_54037VALIANT7-2000428VALIASTRC1				

ContingencyViolationTableRow

Contingency	SW SHV 4 (53453) TO SW SHSTR (2000372) CKT 2	SW SHV 7 (53454) TO SW SHSTR (2000371) CKT 1	SW SHV 7 (53454) TO SW SHSTR (2000372) CKT 2	NORTWST 4 (54879) TO NORTWST R (2000508) CKT 1
T_54119O.K.U.-7-5411911O.K.U.-9C1				
T_54131L.E.S.-7-2000437L.E.SSTRC1				
T_54131L.E.S.-7-2000438L.E.SSTRC2				
T_54450GRDA17-2000469GRDA1STRC1				
T_54450GRDA17-2000470GRDA1STRC2				
T_54715WOODRNG7-2000492WOODRSTRC1				
T_54803SOONER7-2000502SOONESTRC1				
T_54803SOONER7-2000503SOONESTRC2				
T_54880NORTWST7-2000508NORTWSTRC1				
T_54880NORTWST7-2000509NORTWSTRC1				109.81
T_54901CIMARON7-2000511CIMARSTRC1				
T_54901CIMARON7-2000512CIMARSTRC1				
T_54908ARCADIA7-2000513ARCADSTRC1				
T_54908ARCADIA7-2000514ARCADSTRC1				
T_54934DRAPER7-2000521DRAPESTRC1				
T_54934DRAPER7-2000522DRAPESTRC1				
T_54934DRAPER7-2000523DRAPESTRC1				
T_55045SEMINOL7-2000529SEMINSTRC1				
T_55045SEMINOL7-2000530SEMINSTRC1				
T_55045SEMINOL7-5504511Seminole9C1				
T_55136SUNNYSD7-2000539SUNNYSTRC1				
T_55224MUSKOGE7-5522411MUSKOGE9C1				
T_55235PECANCK7-2000552PECANSTRC2				
T_55235PECANCK7-2000553PECANSTRC1				
T_55302FTSMITH7-2000560FTSMTSTRC5				
T_55302FTSMITH7-2000561FTSMISTRC1				
T_55305FTSMITH8-2000558FTSMTSTRC3				
T_55305FTSMITH8-2000559FTSMTSTRC4				
T_55305FTSMITH8-2000561FTSMISTRC1				
T_55819MOORLND-5581911MOORLND9C1				
T_55819MOORLND-5581911MOORLND9C2				
T_56449HOLCOMB7-2000588HOLCOSTRC1				
T_56451MINGO7-2000586MINGOSTRC1				
T_56465SETAB7-2000589SETABSTRC1				
T_56469SPERVIL7-2000699SPEARSTRC1				
T_56469SPERVIL7-2000700SPEARSTRC2				
T_56765HOYT7-2000591HOYTSTRC1				
T_56766JECN7-2000592JECNSTRC1				
T_56766JECN7-2000593JECNSTRC1				
T_56769LANG7-2000594LANGSTRC1				
T_56770MORRIS7-2000595MORRISTRC1				
T_56771RENO-2000596RENOSTRC1				
T_56771RENO-2000597RENOSTRC1				
T_56772STRANGR7-2000598STRANSTRC1				

ContingencyViolationTableRow

Contingency	SW SHV 4 (53453) TO SW SHSTR (2000372) CKT 2	SW SHV 7 (53454) TO SW SHSTR (2000371) CKT 1	SW SHV 7 (53454) TO SW SHSTR (2000372) CKT 2	NORTWST 4 (54879) TO NORTWST R (2000508) CKT 1
T_56774SWISVAL7-2000602SWISVSTRC1				
T_56796WICHITA7-2000603WICHISTRC1				
T_56796WICHITA7-2000604WICHISTRC1				
T_56796WICHITA7-5679611WICHITA9C1				
T_56796WICHITA7-5679611WICHITA9C2				
T_56797WOLFCRK7-5679711WOLfCRK9C1				
T_56797WOLFCRK7-5679711WOLfCRK9C2				
T_56797WOLFCRK7-5679711WOLfCRK9C3				
T_5057981LACYGNE8-57981LACYGNE7C1				
T_59199STJOE3-2000743STJOSTRC1				
T_59199STJOE3-2000744STJOSTRC2				
T_59200PHILL7-2000742PHILLSTRC1				
T_5059984BRKLINE8-59984BRKLNE7C1				
T_5403310PITTSB-8-5403311PITTSB-9C1				
T_5581910MOORLND8-5581911MOORLND9C1				

ContingencyViolationTableRow

Contingency	NORTWST 4 (54879) TO NORTWST R (2000509) CKT 1	NORTWST 7 (54880) TO NORTWST R (2000508) CKT 1	NORTWST 7 (54880) TO NORTWST R (2000509) CKT 1	FTSMTHE5 (55300) TO FTSMTSTR (2000558) CKT 3
T_50888POTTRC7-2000279POTTRSTRC1				105.82
T_50888POTTRC7-2000280POTTRSTRC2				105.82
T_51440TOLK7-2000281TOLK7STRC1				106.2
T_51534TUCO7-2000282TUCO7STRC1				105.95
T_51534TUCO7-5153410TUCO8C1				105.91
T_51534TUCO7-5153410TUCO8C2				105.91
T_52186EDDYCO7-2000283EDDYCSTRC1				106.25
T_53140FLINTCR7-2000320FLINTSTRC1				106.4
T_53140FLINTCR7-2000321FLINTSTRC2				106.37
T_5053140FlintCRK8-53140FLINTCR7C1				114.87
T_53155CHAMSPR7-2000324CHAMSSTRC1				105.51
T_53176TONTITN7-2000326TONTISTRC1				105.35
T_53301NWTXARK7-2000343NWTXASTRC1				105.98
T_53301NWTXARK7-2000344NWTXASTRC2				105.97
T_53301NWTXARK7-5330110NWTXARK8C1				108.23
T_53424LONGWD7-2000365LONGWSTRC1				105.8
T_53454SWSHV7-2000371SWSHSTRC1				105.79
T_53454SWSHV7-2000372SWSHSTRC2				105.79
T_53526CROCKET7-2000374CROCKSTRC1				105.79
T_53528DIANA7-2000375DIANASTRC1				105.8
T_53528DIANA7-2000376DIANASTRC2				105.8
T_53528DIANA7-2000377DIANASTRC3				105.8
T_53593PIRKEY7-2000388PIRKESTRC1				105.81
T_53593PIRKEY7-2000389PIRKESTRC2				105.81
T_53620WILKES7-2000394WILKESTRC1				105.74
T_53767WEKIWA-7-2000397WEKIWSTRC1				106
T_53794R.S.S.-7-2000398RSSTSTRC1				105.92
T_53794R.S.S.-7-2000412RSSTSTRC1				105.92
T_53819ONETA--7-2000405ONETASTRC1				105.84
T_53819ONETA--7-2000406ONETASTRC2				105.84
T_53819ONETA--7-2000407ONETASTRC3				105.84
T_53848COGENT7-2000449COGENSTRC1				107.25
T_53848COGENT7-2000450COGENSTRC1				105.81
T_53848COGENT7-2000451COGENSTRC1				105.81
T_53866T.NO.--7-2000409T.NO.STRC1				105.89
T_53885SAPLPRD7-2000411SAPLPSTRC1				105.88
T_53929DELWARE7-2000413DELWASTRC1				105.92
T_54033PITTSB-7-5403310PITTSB-8C1				105.81
T_54033PITTSB-7-5403311PITTSB-9C1				105.81
T_54037VALIANT7-2000427VALIASTRC2				105.83
T_54037VALIANT7-2000428VALIASTRC1				105.83

ContingencyViolationTableRow

Contingency	NORTWST 4 (54879) TO NORTWST R (2000509) CKT 1	NORTWST 7 (54880) TO NORTWST R (2000508) CKT 1	NORTWST 7 (54880) TO NORTWST R (2000509) CKT 1	FTSMTHE5 (55300) TO FTSMTSTR (2000558) CKT 3
T_54119O.K.U.-7-5411911O.K.U.-9C1				106.51
T_54131L.E.S.-7-2000437L.E.SSTRC1				105.83
T_54131L.E.S.-7-2000438L.E.SSTRC2				105.85
T_54450GRDA17-2000469GRDA1STRC1				105.69
T_54450GRDA17-2000470GRDA1STRC2				105.69
T_54715WOODRNG7-2000492WOODRSTRC1				105.9
T_54803SOONER7-2000502SOONESTRC1				105.81
T_54803SOONER7-2000503SOONESTRC2				105.81
T_54880NORTWST7-2000508NORTWSTRC1	100.11		103.07	105.89
T_54880NORTWST7-2000509NORTWSTRC1		112.33		105.87
T_54901CIMARON7-2000511CIMARSTRC1				105.87
T_54901CIMARON7-2000512CIMARSTRC1				105.87
T_54908ARCADIA7-2000513ARCADSTRC1				105.82
T_54908ARCADIA7-2000514ARCADSTRC1				105.82
T_54934DRAPER7-2000521DRAPESTRC1				105.89
T_54934DRAPER7-2000522DRAPESTRC1				105.9
T_54934DRAPER7-2000523DRAPESTRC1				105.9
T_55045SEMINOL7-2000529SEMINSTRC1				105.93
T_55045SEMINOL7-2000530SEMINSTRC1				105.93
T_55045SEMINOL7-5504511Seminole9C1				106.11
T_55136SUNNYSD7-2000539SUNNYSTRC1				106.86
T_55224MUSKOGE7-5522411MUSKOGE9C1				106.18
T_55235PECANCK7-2000552PECANSTRC2				107.03
T_55235PECANCK7-2000553PECANSTRC1				107.03
T_55302FTSMITH7-2000560FTSMTSTRC5				153.68
T_55302FTSMITH7-2000561FTSMISTRC1				124.65
T_55305FTSMITH8-2000558FTSMTSTRC3				
T_55305FTSMITH8-2000559FTSMTSTRC4				105.81
T_55305FTSMITH8-2000561FTSMISTRC1				124.67
T_55819MOORLND-5581911MOORLND9C1				105.84
T_55819MOORLND-5581911MOORLND9C2				105.84
T_56449HOLCOMB7-2000588HOLCOSTRC1				105.84
T_56451MINGO7-2000586MINGOSTRC1				105.93
T_56465SETAB7-2000589SETABSTRC1				105.82
T_56469SPERVIL7-2000699SPEARSTRC1				105.8
T_56469SPERVIL7-2000700SPEARSTRC2				105.8
T_56765HOYT7-2000591HOYTSTRC1				105.9
T_56766JECN7-2000592JECNSTRC1				105.81
T_56766JECN7-2000593JECNSTRC1				105.81
T_56769LANG7-2000594LANGSTRC1				105.84
T_56770MORRIS7-2000595MORRISTRC1				105.83
T_56771RENO-2000596RENOSTRC1				105.8
T_56771RENO-2000597RENOSTRC1				105.8
T_56772STRANGR7-2000598STRANSTRC1				105.8

ContingencyViolationTableRow

Contingency	NORTWST 4 (54879) TO NORTWST R (2000509) CKT 1	NORTWST 7 (54880) TO NORTWST R (2000508) CKT 1	NORTWST 7 (54880) TO NORTWST R (2000509) CKT 1	FTSMTHE5 (55300) TO FTSMTSTR (2000558) CKT 3
T_56774SWISVAL7-2000602SWISVSTRC1				105.81
T_56796WICHITA7-2000603WICHISTRC1				105.8
T_56796WICHITA7-2000604WICHISTRC1				105.79
T_56796WICHITA7-5679611WICHITA9C1				105.77
T_56796WICHITA7-5679611WICHITA9C2				105.77
T_56797WOLFCRK7-5679711WOLfCRK9C1				105.98
T_56797WOLFCRK7-5679711WOLfCRK9C2				105.98
T_56797WOLFCRK7-5679711WOLfCRK9C3				105.98
T_5057981LACYGNE8-57981LACYGNE7C1				104.4
T_59199STJOE3-2000743STJOSTRC1				105.8
T_59199STJOE3-2000744STJOSTRC2				105.8
T_59200PHILL7-2000742PHILLSTRC1				105.8
T_5059984BRKLINE8-59984BRKLNE7C1				106.62
T_5403310PITTSB-8-5403311PITTSB-9C1				105.81
T_5581910MOORLND8-5581911MOORLND9C1				105.82

ContingencyViolationTableRow

Contingency	FTSMTHW5 (55301) TO FTSMTSTR (2000560) CKT 5	FTSMITH7 (55302) TO FTSMTSTR (2000560) CKT 5	FTSMITH8 (55305) TO FTSMTSTR (2000558) CKT 3	NEOSHO 7 (56793) TO NEOSHSTR (2000638) CKT 1
T_50888POTTRC7-2000279POTTRSTRC1			114.58	
T_50888POTTRC7-2000280POTTRSTRC2			114.58	
T_51440TOLK7-2000281TOLK7STRC1			114.97	
T_51534TUCO7-2000282TUCO7STRC1			114.72	
T_51534TUCO7-5153410TUCO8C1			114.67	
T_51534TUCO7-5153410TUCO8C2			114.67	
T_52186EDDYCO7-2000283EDDYCSTRC1			115.02	
T_53140FLINTCR7-2000320FLINTSTRC1			115.22	
T_53140FLINTCR7-2000321FLINTSTRC2			115.19	
T_5053140FlintCRK8-53140FLINTCR7C1			124.96	
T_53155CHAMSPR7-2000324CHAMSSTRC1			114.24	
T_53176TONTITN7-2000326TONTISTRC1			114.05	
T_53301NWTXARK7-2000343NWTXASTRC1			114.74	
T_53301NWTXARK7-2000344NWTXASTRC2			114.73	
T_53301NWTXARK7-5330110NWTXARK8C1			117.36	
T_53424LONGWD7-2000365LONGWSTRC1			114.56	
T_53454SWSHV7-2000371SWSHSTRC1			114.55	
T_53454SWSHV7-2000372SWSHSTRC2			114.55	
T_53526CROCKET7-2000374CROCKSTRC1			114.54	
T_53528DIANA7-2000375DIANASTRC1			114.56	
T_53528DIANA7-2000376DIANASTRC2			114.56	
T_53528DIANA7-2000377DIANASTRC3			114.56	
T_53593PIRKEY7-2000388PIRKESTRC1			114.57	
T_53593PIRKEY7-2000389PIRKESTRC2			114.57	
T_53620WILKES7-2000394WILKESTRC1			114.48	
T_53767WEKIWA-7-2000397WEKIWSTRC1			114.77	
T_53794R.S.S.-7-2000398RSSTSTRC1			114.69	
T_53794R.S.S.-7-2000412RSSTSTRC1			114.69	
T_53819ONETA--7-2000405ONETASTRC1			114.6	
T_53819ONETA--7-2000406ONETASTRC2			114.6	
T_53819ONETA--7-2000407ONETASTRC3			114.6	
T_53848COGENT7-2000449COGENSTRC1			116.08	
T_53848COGENT7-2000450COGENSTRC1			114.57	
T_53848COGENT7-2000451COGENSTRC1			114.57	
T_53866T.NO.--7-2000409T.NO.STRC1			114.65	
T_53885SAPLPRD7-2000411SAPLPSTRC1			114.64	
T_53929DELWARE7-2000413DELWASTRC1			114.68	110.01
T_54033PITTSB-7-5403310PITTSB-8C1			114.57	
T_54033PITTSB-7-5403311PITTSB-9C1			114.57	
T_54037VALIANT7-2000427VALIASTRC2			114.59	
T_54037VALIANT7-2000428VALIASTRC1			114.59	

ContingencyViolationTableRow

Contingency	FTSMTHW5 (55301) TO FTSMTSTR (2000560) CKT 5	FTSMITH7 (55302) TO FTSMTSTR (2000560) CKT 5	FTSMITH8 (55305) TO FTSMTSTR (2000558) CKT 3	NEOSHO 7 (56793) TO NEOSHSTR (2000638) CKT 1
T_54119O.K.U.-7-5411911O.K.U.-9C1			115.31	
T_54131L.E.S.-7-2000437L.E.SSTRC1			114.59	
T_54131L.E.S.-7-2000438L.E.SSTRC2			114.61	
T_54450GRDA17-2000469GRDA1STRC1			114.44	
T_54450GRDA17-2000470GRDA1STRC2			114.44	
T_54715WOODRNG7-2000492WOODRSTRC1			114.66	
T_54803SOONER7-2000502SOONESTRC1			114.57	
T_54803SOONER7-2000503SOONESTRC2			114.57	
T_54880NORTWST7-2000508NORTWSTRC1			114.65	
T_54880NORTWST7-2000509NORTWSTRC1			114.63	
T_54901CIMARON7-2000511CIMARSTRC1			114.63	
T_54901CIMARON7-2000512CIMARSTRC1			114.63	
T_54908ARCADIA7-2000513ARCADSTRC1			114.58	
T_54908ARCADIA7-2000514ARCADSTRC1			114.58	
T_54934DRAPER7-2000521DRAPESTRC1			114.66	
T_54934DRAPER7-2000522DRAPESTRC1			114.67	
T_54934DRAPER7-2000523DRAPESTRC1			114.67	
T_55045SEMINOL7-2000529SEMINSTRC1			114.7	
T_55045SEMINOL7-2000530SEMINSTRC1			114.7	
T_55045SEMINOL7-5504511Seminole9C1			114.9	
T_55136SUNNYSD7-2000539SUNNYSTRC1			115.71	
T_55224MUSKOGE7-5522411MUSKOGE9C1			114.96	
T_55235PECANCK7-2000552PECANSTRC2			115.89	
T_55235PECANCK7-2000553PECANSTRC1			115.89	
T_55302FTSMITH7-2000560FTSMTSTRC5			166.81	
T_55302FTSMITH7-2000561FTSMISTRC1			135.28	
T_55305FTSMITH8-2000558FTSMTSTRC3	125.5	136.7		
T_55305FTSMITH8-2000559FTSMTSTRC4			114.57	
T_55305FTSMITH8-2000561FTSMISTRC1			135.31	
T_55819MOORLND-5581911MOORLND9C1			114.6	
T_55819MOORLND-5581911MOORLND9C2			114.6	
T_56449HOLCOMB7-2000588HOLCOSTRC1			114.6	
T_56451MINGO7-2000586MINGOSTRC1			114.7	
T_56465SETAB7-2000589SETABSTRC1			114.58	
T_56469SPERVIL7-2000699SPEARSTRC1			114.56	
T_56469SPERVIL7-2000700SPEARSTRC2			114.56	
T_56765HOYT7-2000591HOYTSTRC1			114.66	
T_56766JECN7-2000592JECNSTRC1			114.56	
T_56766JECN7-2000593JECNSTRC1			114.56	
T_56769LANG7-2000594LANGSTRC1			114.6	
T_56770MORRIS7-2000595MORRISTRC1			114.59	
T_56771RENO-2000596RENOSTRC1			114.56	
T_56771RENO-2000597RENOSTRC1			114.56	
T_56772STRANGR7-2000598STRANSTRC1			114.56	

ContingencyViolationTableRow

Contingency	FTSMTHW5 (55301) TO FTSMTSTR (2000560) CKT 5	FTSMITH7 (55302) TO FTSMTSTR (2000560) CKT 5	FTSMITH8 (55305) TO FTSMTSTR (2000558) CKT 3	NEOSHO 7 (56793) TO NEOSHSTR (2000638) CKT 1
T_56774SWISVAL7-2000602SWISVSTRC1			114.57	
T_56796WICHITA7-2000603WICHISTRC1			114.55	
T_56796WICHITA7-2000604WICHISTRC1			114.55	
T_56796WICHITA7-5679611WICHITA9C1			114.52	
T_56796WICHITA7-5679611WICHITA9C2			114.52	
T_56797WOLFCRK7-5679711WOLfCRK9C1			114.75	
T_56797WOLFCRK7-5679711WOLfCRK9C2			114.75	
T_56797WOLFCRK7-5679711WOLfCRK9C3			114.75	
T_5057981LACYGNE8-57981LACYGNE7C1			113.11	
T_59199STJOE3-2000743STJOSTRC1			114.55	
T_59199STJOE3-2000744STJOSTRC2			114.55	
T_59200PHILL7-2000742PHILLSTRC1			114.56	
T_5059984BRKLINE8-59984BRKLNE7C1			115.63	
T_5403310PITTSB-8-5403311PITTSB-9C1			114.57	
T_5581910MOORLND8-5581911MOORLND9C1			114.58	

ContingencyViolationTableRow

Contingency	AUBURN 6 (56851) TO AUBURSTR (2000605) CKT 1	AUBURN 3 (57151) TO AUBURSTR (2000605) CKT 1	ST JOE 3 (59199) TO ST JOSTR (2000743) CKT 1	ST JOE 5 (59253) TO ST JOSTR (2000743) CKT 1
T_50888POTTRC7-2000279POTTRSTRC1				
T_50888POTTRC7-2000280POTTRSTRC2				
T_51440TOLK7-2000281TOLK7STRC1				
T_51534TUCO7-2000282TUCO7STRC1				
T_51534TUCO7-5153410TUCO8C1				
T_51534TUCO7-5153410TUCO8C2				
T_52186EDDYCO7-2000283EDDYCSTRC1				
T_53140FLINTCR7-2000320FLINTSTRC1				
T_53140FLINTCR7-2000321FLINTSTRC2				
T_5053140FlintCRK8-53140FLINTCR7C1				
T_53155CHAMSPR7-2000324CHAMSSTRC1				
T_53176TONTITN7-2000326TONTISTRC1				
T_53301NWTXARK7-2000343NWTXASTRC1				
T_53301NWTXARK7-2000344NWTXASTRC2				
T_53301NWTXARK7-5330110NWTXARK8C1				
T_53424LONGWD7-2000365LONGWSTRC1				
T_53454SWSHV7-2000371SWSHSTRC1				
T_53454SWSHV7-2000372SWSHSTRC2				
T_53526CROCKET7-2000374CROCKSTRC1				
T_53528DIANA7-2000375DIANASTRC1				
T_53528DIANA7-2000376DIANASTRC2				
T_53528DIANA7-2000377DIANASTRC3				
T_53593PIRKEY7-2000388PIRKESTRC1				
T_53593PIRKEY7-2000389PIRKESTRC2				
T_53620WILKES7-2000394WILKESTRC1				
T_53767WEKIWA-7-2000397WEKIWSTRC1				
T_53794R.S.S.-7-2000398RSSTSTRC1				
T_53794R.S.S.-7-2000412RSSTSTRC1				
T_53819ONETA--7-2000405ONETASTRC1				
T_53819ONETA--7-2000406ONETASTRC2				
T_53819ONETA--7-2000407ONETASTRC3				
T_53848COGENT7-2000449COGENSTRC1				
T_53848COGENT7-2000450COGENSTRC1				
T_53848COGENT7-2000451COGENSTRC1				
T_53866T.NO.--7-2000409T.NO.STRC1				
T_53885SAPLPRD7-2000411SAPLPSTRC1				
T_53929DELWARE7-2000413DELWASTRC1				
T_54033PITTSB-7-5403310PITTSB-8C1				
T_54033PITTSB-7-5403311PITTSB-9C1				
T_54037VALIANT7-2000427VALIASTRC2				
T_54037VALIANT7-2000428VALIASTRC1				

ContingencyViolationTableRow

Contingency	AUBURN 6 (56851) TO AUBURSTR (2000605) CKT 1	AUBURN 3 (57151) TO AUBURSTR (2000605) CKT 1	ST JOE 3 (59199) TO ST JOSTR (2000743) CKT 1	ST JOE 5 (59253) TO ST JOSTR (2000743) CKT 1
T_54119O.K.U.-7-5411911O.K.U.-9C1				
T_54131L.E.S.-7-2000437L.E.SSTRC1				
T_54131L.E.S.-7-2000438L.E.SSTRC2				
T_54450GRDA17-2000469GRDA1STRC1				
T_54450GRDA17-2000470GRDA1STRC2				
T_54715WOODRNG7-2000492WOODRSTRC1				
T_54803SOONER7-2000502SOONESTRC1				
T_54803SOONER7-2000503SOONESTRC2				
T_54880NORTWST7-2000508NORTWSTRC1				
T_54880NORTWST7-2000509NORTWSTRC1				
T_54901CIMARON7-2000511CIMARSTRC1				
T_54901CIMARON7-2000512CIMARSTRC1				
T_54908ARCADIA7-2000513ARCADSTRC1				
T_54908ARCADIA7-2000514ARCADSTRC1				
T_54934DRAPER7-2000521DRAPESTRC1				
T_54934DRAPER7-2000522DRAPESTRC1				
T_54934DRAPER7-2000523DRAPESTRC1				
T_55045SEMINOL7-2000529SEMINSTRC1				
T_55045SEMINOL7-2000530SEMINSTRC1				
T_55045SEMINOL7-5504511Seminole9C1				
T_55136SUNNYSD7-2000539SUNNYSTRC1				
T_55224MUSKOGE7-5522411MUSKOGE9C1				
T_55235PECANCK7-2000552PECANSTRC2				
T_55235PECANCK7-2000553PECANSTRC1				
T_55302FTSMITH7-2000560FTSMTSTRC5				
T_55302FTSMITH7-2000561FTSMISTRC1				
T_55305FTSMITH8-2000558FTSMTSTRC3				
T_55305FTSMITH8-2000559FTSMTSTRC4				
T_55305FTSMITH8-2000561FTSMISTRC1				
T_55819MOORLND-5581911MOORLND9C1				
T_55819MOORLND-5581911MOORLND9C2				
T_56449HOLCOMB7-2000588HOLCOSTRC1				
T_56451MINGO7-2000586MINGOSTRC1				
T_56465SETAB7-2000589SETABSTRC1				
T_56469SPERVIL7-2000699SPEARSTRC1				
T_56469SPERVIL7-2000700SPEARSTRC2				
T_56765HOYT7-2000591HOYTSTRC1	130.3	127.55		
T_56766JECN7-2000592JECNSTRC1				
T_56766JECN7-2000593JECNSTRC1				
T_56769LANG7-2000594LANGSTRC1				
T_56770MORRIS7-2000595MORRISTRC1				
T_56771RENO-2000596RENOSTRC1				
T_56771RENO-2000597RENOSTRC1				
T_56772STRANGR7-2000598STRANSTRC1				

ContingencyViolationTableRow

Contingency	AUBURN 6 (56851) TO AUBURSTR (2000605) CKT 1	AUBURN 3 (57151) TO AUBURSTR (2000605) CKT 1	ST JOE 3 (59199) TO ST JOSTR (2000743) CKT 1	ST JOE 5 (59253) TO ST JOSTR (2000743) CKT 1
T_56774SWISVAL7-2000602SWISVSTRC1				
T_56796WICHITA7-2000603WICHISTRC1				
T_56796WICHITA7-2000604WICHISTRC1				
T_56796WICHITA7-5679611WICHITA9C1				
T_56796WICHITA7-5679611WICHITA9C2				
T_56797WOLFCRK7-5679711WOLfCRK9C1				
T_56797WOLFCRK7-5679711WOLfCRK9C2				
T_56797WOLFCRK7-5679711WOLfCRK9C3				
T_5057981LACYGNE8-57981LACYGNE7C1				
T_59199STJOE3-2000743STJOSTRC1				
T_59199STJOE3-2000744STJOSTRC2			108.19	106.03
T_59200PHILL7-2000742PHILLSTRC1				
T_5059984BRKLINE8-59984BRKLNE7C1				
T_5403310PITTSB-8-5403311PITTSB-9C1				
T_5581910MOORLND8-5581911MOORLND9C1				

ContingencyViolationTableRow

Contingency	ST JOE 5 (59253) TO ST JOSTR (2000744) CKT 2
T_50888POTTRC7-2000279POTTRSTRC1	
T_50888POTTRC7-2000280POTTRSTRC2	
T_51440TOLK7-2000281TOLK7STRC1	
T_51534TUCO7-2000282TUCO7STRC1	
T_51534TUCO7-5153410TUCO8C1	
T_51534TUCO7-5153410TUCO8C2	
T_52186EDDYCO7-2000283EDDYCSTRC1	
T_53140FLINTCR7-2000320FLINTSTRC1	
T_53140FLINTCR7-2000321FLINTSTRC2	
T_5053140FlintCRK8-53140FLINTCR7C1	
T_53155CHAMSPR7-2000324CHAMSSTRC1	
T_53176TONTITN7-2000326TONTISTRC1	
T_53301NWTXARK7-2000343NWTXASTRC1	
T_53301NWTXARK7-2000344NWTXASTRC2	
T_53301NWTXARK7-5330110NWTXARK8C1	
T_53424LONGWD7-2000365LONGWSTRC1	
T_53454SWSHV7-2000371SWSHSTRC1	
T_53454SWSHV7-2000372SWSHSTRC2	
T_53526CROCKET7-2000374CROCKSTRC1	
T_53528DIANA7-2000375DIANASTRC1	
T_53528DIANA7-2000376DIANASTRC2	
T_53528DIANA7-2000377DIANASTRC3	
T_53593PIRKEY7-2000388PIRKESTRC1	
T_53593PIRKEY7-2000389PIRKESTRC2	
T_53620WILKES7-2000394WILKESTRC1	
T_53767WEKIWA-7-2000397WEKIWSTRC1	
T_53794R.S.S.-7-2000398RSSTSTRC1	
T_53794R.S.S.-7-2000412RSSTSTRC1	
T_53819ONETA--7-2000405ONETASTRC1	
T_53819ONETA--7-2000406ONETASTRC2	
T_53819ONETA--7-2000407ONETASTRC3	
T_53848COGENT7-2000449COGENSTRC1	
T_53848COGENT7-2000450COGENSTRC1	
T_53848COGENT7-2000451COGENSTRC1	
T_53866T.NO.--7-2000409T.NO.STRC1	
T_53885SAPLPRD7-2000411SAPLPSTRC1	
T_53929DELWARE7-2000413DELWASTRC1	
T_54033PITTSB-7-5403310PITTSB-8C1	
T_54033PITTSB-7-5403311PITTSB-9C1	
T_54037VALIANT7-2000427VALIASTRC2	
T_54037VALIANT7-2000428VALIASTRC1	

ContingencyViolationTableRow	ST JOE 5 (59253) TO ST JOSTR (2000744) CKT 2
Contingency	
T_54119O.K.U.-7-5411911O.K.U.-9C1	
T_54131L.E.S.-7-2000437L.E.SSTRC1	
T_54131L.E.S.-7-2000438L.E.SSTRC2	
T_54450GRDA17-2000469GRDA1STRC1	
T_54450GRDA17-2000470GRDA1STRC2	
T_54715WOODRNG7-2000492WOODRSTRC1	
T_54803SOONER7-2000502SOONESTRC1	
T_54803SOONER7-2000503SOONESTRC2	
T_54880NORTWST7-2000508NORTWSTRC1	
T_54880NORTWST7-2000509NORTWSTRC1	
T_54901CIMARON7-2000511CIMARSTRC1	
T_54901CIMARON7-2000512CIMARSTRC1	
T_54908ARCADIA7-2000513ARCADSTRC1	
T_54908ARCADIA7-2000514ARCADSTRC1	
T_54934DRAPER7-2000521DRAPESTRC1	
T_54934DRAPER7-2000522DRAPESTRC1	
T_54934DRAPER7-2000523DRAPESTRC1	
T_55045SEMINOL7-2000529SEMINSTRC1	
T_55045SEMINOL7-2000530SEMINSTRC1	
T_55045SEMINOL7-5504511Seminole9C1	
T_55136SUNNYSD7-2000539SUNNYSTRC1	
T_55224MUSKOGE7-5522411MUSKOGE9C1	
T_55235PECANCK7-2000552PECANSTRC2	
T_55235PECANCK7-2000553PECANSTRC1	
T_55302FTSMITH7-2000560FTSMTSTRC5	
T_55302FTSMITH7-2000561FTSMISTRC1	
T_55305FTSMITH8-2000558FTSMTSTRC3	
T_55305FTSMITH8-2000559FTSMTSTRC4	
T_55305FTSMITH8-2000561FTSMISTRC1	
T_55819MOORLND-5581911MOORLND9C1	
T_55819MOORLND-5581911MOORLND9C2	
T_56449HOLCOMB7-2000588HOLCOSTRC1	
T_56451MINGO7-2000586MINGOSTRC1	
T_56465SETAB7-2000589SETABSTRC1	
T_56469SPERVIL7-2000699SPEARSTRC1	
T_56469SPERVIL7-2000700SPEARSTRC2	
T_56765HOYT7-2000591HOYTSTRC1	
T_56766JECN7-2000592JECNSTRC1	
T_56766JECN7-2000593JECNSTRC1	
T_56769LANG7-2000594LANGSTRC1	
T_56770MORRIS7-2000595MORRISTRC1	
T_56771RENO-2000596RENOSTRC1	
T_56771RENO-2000597RENOSTRC1	
T_56772STRANGR7-2000598STRANSTRC1	

ContingencyViolationTableRow

Contingency	ST JOE 5 (59253) TO ST JOSTR (2000744) CKT 2
T_56774SWISVAL7-2000602SWISVSTRC1	
T_56796WICHITA7-2000603WICHISTRC1	
T_56796WICHITA7-2000604WICHISTRC1	
T_56796WICHITA7-5679611WICHITA9C1	
T_56796WICHITA7-5679611WICHITA9C2	
T_56797WOLFCRK7-5679711WOLfCRK9C1	
T_56797WOLFCRK7-5679711WOLfCRK9C2	
T_56797WOLFCRK7-5679711WOLfCRK9C3	
T_5057981LACYGNE8-57981LACYGNE7C1	
T_59199STJOE3-2000743STJOSTRC1	105.98
T_59199STJOE3-2000744STJOSTRC2	
T_59200PHILL7-2000742PHILLSTRC1	
T_5059984BRKLINE8-59984BRKLNE7C1	
T_5403310PITTSB-8-5403311PITTSB-9C1	
T_5581910MOORLND8-5581911MOORLND9C1	