FILE NO. EO-2011-0134

STAFF REPORT

AS ORDERED ON NOVEMBER 23, 2010

BY THE MISSOURI PUBLIC SERVICE COMMISSION

JANUARY 3, 2011

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Summary

The Missouri Public Service Commission (Commission) established on November 23, 2010 a case to investigate the Southwest Power Pool's (SPP) process for selecting projects including costs estimates and cost-benefit analysis, the issue of novations and what to do about construction cost overruns for new transmission projects. The Order establishing this case directed the Utility Services Division to work with Adam C. McKinnie of the Utility Operations Division, Commission consultant Michael S. Proctor, The Empire District Electric Company (EDE), Office of the Public Counsel (Public Counsel), SPP, and other persons necessary to prepare a report detailing the costs and benefits of SPP membership for EDE by December 31, 2010. The report is to include an estimate of the costs of new transmission payments and benefits to EDE as a result of the SPP's proposed Integrated Transmission Planning 20-Year Assessment as of December 15, 2010.

The order establishing this case also directed parties interested in the issue of construction cost overruns as well as the problems posed by novations and making recommendations as to how the problem should be addressed to file comments in this docket by December 31, 2010.

This Report will address these requirements in the following sections contained in this Report;

Section 1	EDE Costs/Benefits from SPP Membership – Staff Sponsor: Bob Schallenberg
Section 2	Impact of SPP's Proposed ITP 20 on EDE's Costs/Benefits Status of SPP Membership – Staff Consultant Sponsor: Michael S. Proctor
Section 3	Cost Overruns and Novations Problems and Recommendations – Staff Sponsor: Adam C. McKinnie
Section 4	Other Issues Raised – Staff Sponsors: Adam C. McKinnie and Bob Schallenberg

The last section is included to document those issues raised in addition to those issues specifically listed in the Commission Order to bring these matters to everyone's attention instead of allowing the issues to exist below the surface and develop as previously unrecognized issues in the future.

Section 1 EDE Costs/Benefits from SPP Membership

At this time there is general consensus that EDE's current membership in SPP is cost beneficial to EDE. This section will be supplemented with cost/benefit detail as the information is acquired from EDE and SPP and if there is any other information available under the circumstances.

Section 2 Impact of SPP's Proposed ITP 20 on EDE's Costs/Benefits Status of SPP Membership

Applying ITP 20

Background

This is the SPP's first attempt at doing a 20 year transmission planning study. Time was limited as the SPP staff had to develop several elements for the first time. In addition, the analysis of the Priority Projects carried over into the time frame where the SPP planning staff and the SPP stakeholders had planned to spend time on ITP 20; i.e., the last quarter of 2009 and first quarter of 2010. Several elements of a good long-term planning study had to be omitted. Key among these elements is the lack of sensitivity runs to determine the how Adjusted Production Costs Savings might vary with changes in key variables such as natural gas prices. In addition, the carbon futures did not include an analysis of a carbon cap; instead SPP only included a carbon tax, and sensitivities were not run by SPP on this hard to predict input. Given these restrictions, this section of the Staff report addresses the proper application of ITP 20 as SPP moves forward with ITP 10.

Application of a Specific ITP 20 Plan to ITP 10

What ITP 10 is designed to do is go out ten years and ask the same questions that were asked about 300 kV and higher upgrades for ITP 20, but with a 10-year horizon rather than a 20-year horizon. However, the choice of 300 kV and higher upgrades to be evaluated over the 10-year horizon are limited by the choice of a specific ITP 20 plan. In addition, the ITP 10 plan will evaluate lower voltage upgrades needed to support the higher voltage upgrades (i.e., lower voltage under-build) to be included in the10-year plan.

Step 1: Inputs to ITP 10

The first step in the ITP 10 analysis is to specify all the inputs to the 10-year plan including load forecasts, added generation requirements (what types of new units and where they are likely to be located), fuel prices, and the existing topology of the power grid, including generation and transmission. One difference is that all these inputs need to be specified on a year-to-year basis or at least on a current year, five years out and ten years out basis. This is because the timing of transmission upgrades it a critical component to the ITP 10 analysis.

Recommendation 1: The state commissions should take an active role in the SPP process for determining the inputs to the 10-year plan. Most importantly, the states should determine their most immediate needs for renewable resources (with and without a federal renewable energy standard (RES)) over the next 10 years and should have the Cost Allocation Working Group perform a survey to determine expected needs on a year-by-year basis.

Step 2: Determination of Higher Voltage Upgrades Needed Over the Next 10 Years

Once these inputs are specified, SPP planners must take the ITP 20 plan and evaluate which of these upgrades are needed in the 10-year plan. This means recalculating a cost-effective 10-year plan and a robust 10 year plan. The cost-effective plan will also include lower voltage upgrades needed to support the higher voltage system to cost effectively meet delivery of energy required over the 10-year period. Robustness analysis should include additional upgrades that provide incremental benefits in excess of incremental costs. SPP stakeholders will need to determine the specific analysis to be used in evaluating "delivery of energy required" for the cost-effective 10-year plan. The basic assumption here is that there is a best implementation strategy over the next 10 years and that not all of the higher voltage upgrades in the ITP 20 plan will be included in that strategy. The results of this step should include a cost-effective 10-year plan and may include additional robust plans to be evaluated regarding incremental costs and incremental benefits.

Recommendation 2: The state commissions should take an active role in the SPP process for determining the specific analysis used to determine "delivery of energy required."

a. Strongest ITP 20 Higher Voltage Candidates for ITP 10

One of the key components of the ITP 20 analysis is the determination of cost-effective plans for each of four futures. The SPP presentation of these four plans is found on pages 54 through 58 of the December 8, 2010 ITP 20 Report. On page 59, SPP presents what it calls the "Common Plan."

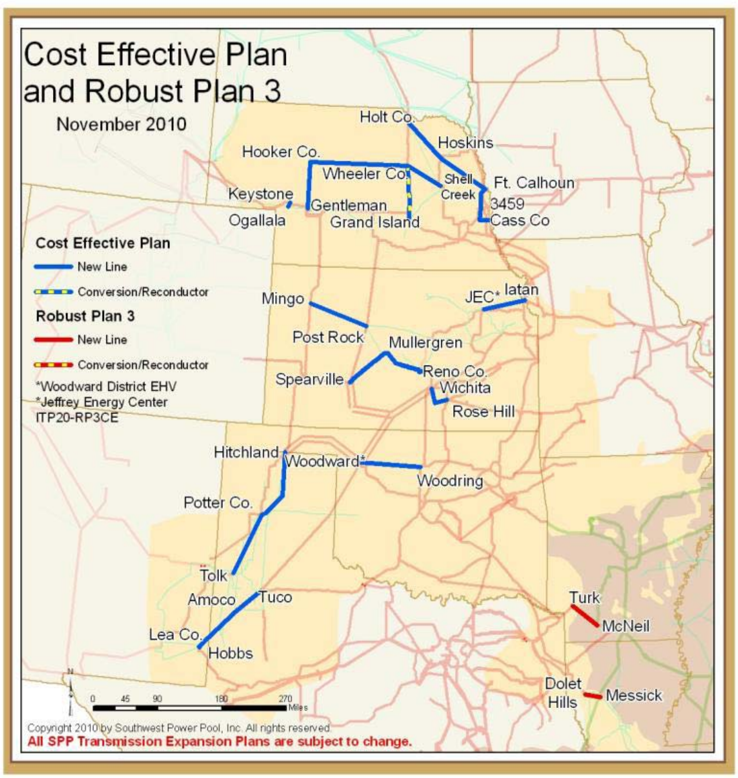
Common Plan Elements	kV	State
Iatan - Jeffrey Energy Center	345	Kansas
Wichita - Viola - Rose Hill	345	Kansas
Spearville - Mullergren - Circle – Reno	345	Kansas
Cass Co. - S.W. Omaha (Sub 3454)	345	Nebraska
Gentleman - Hooker Co. - Wheeler Co.	345	Nebraska
Tolk - Potter Co.	345	Texas
TX Grand Island - Wheeler Co. (Rebuild)	345	Nebraska
S3459-S1209 Transformer	345/161	Nebraska
Mullergren Transformer	345/230	Kansas
Circle Transformer	345/320	Kansas
KS Wheeler Co. Substation 345 NE	345	Nebraska

This plan includes elements that the cost-effective plans for all four futures have in common. What this Common Plan represents is that no matter which of the four futures occurs, it would be cost effective to build these upgrades. Therefore, they constitute the higher voltage upgrades that are needed for no matter which of the four futures occurs, and are therefore the strongest candidates to be included in ITP 10. According to the ITP 20 Report, the estimated costs for these upgrades are $883 million for 776 miles of 345 kV lines and three 345 kV step-down transformers.

Recommendation 3: The state commissions should recommend that the higher voltage upgrades in the Common Plan be given priority as candidates for in the ITP 10 plan.

b. Next Strongest Higher Voltage Candidates

SPP used these common elements as a basis to design what it called an overall Cost-Effective plan. However, it also looked at Robust plans, one of which (Robust Plan 3) has incremental Adjusted Production Cost (APC) benefits in excess of incremental costs compared to the Cost-Effective plan, making it superior to the Cost Effective Plan. Both of these plans are designed to meet a 20% federal RES, and therefore may or may not be needed over the next 10 years, depending on the futures chosen for ITP 10. The following shows the upgrades for the Cost Effective Plan and Robust Plan 3.



Projects Added in Cost-Effective Plan to the Common Plan		
Added Plan Elements	kV	State
Potter Co. - Tuco (Replaces Tolk-Potter in Common Plan)	345	Texas
Hitchland - Potter Co	345	Texas
Woodward District EHV - Woodring	345	Oklahoma
Mingo - Post Rock	345	Kansas
Holt - Hoskins - Ft. Calhoun	345	Nebraska
Ft. Calhoun - S3454	345	Nebraska
Tuco - Amoco - Lea Co. - Hobbs	345	Texas
Keystone - Ogallala	345	Nebraska
Wheeler Co. - Shell Creek	345	Nebraska
Projects Added in Robust Plan 3 to the Cost-Effective Plan		
Added Plan Elements	kV	State
Dolet Hills - Messick	345	Lousiana
Turk - McNeil	345	Arkansas
Messick Transformer	500/345	Lousiana

Robust Plan 3 has an estimated cost of $1,881 million, adding a billion dollars to the common plan, and includes 1,535 miles of transmission lines – more than double the mileage included in the Common Plan. It also replaces the Tolk to Potter 345 kV line with the Tuco to Potter 345 kV line.

Recommendation 4: If the Common Plan is not sufficient to provide delivery of generation, the state commissions should recommend that the upgrades included for evaluation in the ITP 10 plan be limited to those in Robust Plan 3. In any case, the SPP should evaluate substitution of the Tuco to Potter 345 kV line for the Tolk to Potter 345 kV line.

It should be pointed out that the SPP Staff recommended Robust Plan 1 over Robust Plan 3 even though it was not the most cost beneficial plan. Robust Plan 1 and Robust Plan 3 are identical with three additional lines and one additional transformer at an estimated cost of $2,454 million.

Projects Added in Robust Plan 1 to Robust Plan 3		
Added Plan Elements	kV	State
Post Rock - Elm Creek - Jeffrey Energy Center	345	Kansas
N.W. Texarkana - Ft. Smith	345	Arkansas
AR Ft. Smith - Chamber Springs	345	Arkansas
Elm Creek Transformer	345/230	Kansas

It is highly unlikely that any of these additional projects will be needed for delivery of energy over the next ten years, and because these projects add additional cost in excess of additional benefits that cannot be justified by the robustness metrics, they should not be considered in the ITP 10 analysis.

Step 3: Evaluation of Candidate 10-year Plans

The next step is to evaluate the candidate 10-year plans over a 20-year horizon by adding in the higher voltage upgrades from the ITP 20 plan that were not included in the candidate 10-year plans. The objective here is to determine which of the candidate plans does the best in reaching the longer-term plan.

Recommendation 5: For purposes of evaluating the candidate 10-year plans over a 20 year horizon, the state commissions should recommend using Robust Plan 3 for the twenty year out time frame.

Step 4: Issuing of Notices to Construct

The final step is the determination of upgrades needed for approval this year in order that they are in place by their specified time frame; i.e., the issuing of Notices to Construct (NTC). NTCs should only be granted to upgrades that if delayed to start by one year would result in not meeting their specified time to be on line. These recommendations will go to the SPP Board in the STEP 2010 report, with approval at the January Board meeting in 2012.

Approval of an ITP 20 Plan

Given the application of an ITP 20 plan in ITP 10, what does the approval of the ITP 20 plan in January 2011 mean? Clearly, it means that the higher voltage upgrades to be considered in ITP 10 will be limited by the choice of the ITP 20 plan. It also means that several of the higher voltage upgrades included in the final ITP 10 plan will come from the ITP 20 plan, and some of these higher voltage upgrades included in the ITP 10 plan could be issued a NTC in January 2012. It does not mean that any of the higher voltage upgrades in ITP 20 will be issued a NTC in January 2011. Moreover, ITP 20 did not include an analysis of timing and should therefore not include sufficient information to issue a NTC.

Recommendation 6: The state commissions should make clear that NTCs for higher voltage upgrades should not be issued until the results of ITP 10 are completed.

Analysis of ITP 20 Results

This analysis starts with the costs and benefits of the various portfolios of upgrades that were evaluated by SPP. These include seven plans:

0. Cost Effective Plan
1. Robust Plan 1
2. Robust Plan 2
3. Robust Plan 3
4. Robust Plan 4
5. Robust Plan 5
6. Robust Plan 6

The following table shows the basic cost benefit results for each of these plans in billions of dollars.

Table 1: Costs and Benefits

Plan	0	1	2	3	4	5	6
Cost	$1.76	$2.45	$3.22	$1.88	$6.88	$2.75	$3.48
B/C	1.82	1.53	1.18	1.92	0.51	1.37	1.07
Benefits	$3.20	$3.75	$3.80	$3.61	$3.51	$3.77	$3.72
Cost	$0.00	$0.69	$1.46	$0.12	$5.12	$0.99	$1.72

SPP's report on ITP 20 does not show dollar values for benefits, but does show costs and a benefit to cost ratio for each of these plans. Benefits are then calculated by multiplying the costs by the B/C ratio.

The next step is to compare the cost and benefit in table 1 to the Cost Effective Plan (Plan 0). The following table presents this comparison.

Table 2: Difference in Costs and Benefits from Cost Effective Plan

Plan		1	2	3	4	5	6
Δ Costs		$0.690	$1.460	$0.120	$5.120	$0.990	$1.720
Δ Benefits		$0.545	$0.596	$0.406	$0.306	$0.564	$0.520
Δ Net Benefits		-$0.145	-$0.864	$0.286	-$4.814	-$0.426	-$1.200
Rank		3	4	1	7	6	5

This comparison shows increase in costs and benefits for all the robust plans. However, the key question to ask is whether or not the increase in benefits exceeds the increase in costs. This Δ Net Benefits is shown in the fourth row of Table 2. A positive Δ Net Benefits compared to the Cost-Effective Plan only occurs for Robust Plan 3 (highlighted in Table 2). All other plans show negative Δ Net Benefits – difference in incremental benefits over incremental costs. The last row shows how the plans rank in terms of incremental benefits over costs, with Robust Plan 3 ranking number 1, the Cost Effective Plan ranking number 2 (not shown in Table 2 as its Δ Net Benefits compared to itself is $0) and the plan recommended by SPP staff (Robust Plan 1) ranking number 3.

The SPP staff performed additional analysis of eleven measures of robustness. Each of the robustness metrics are detailed in the ITP 20 report. The metric values for each along with the weights given each metric by votes taken from the Economic Studies Working Group (ESWG) of SPP are shown in Table 3. The metric values for the Cost-Effective Plan, Robust Plan 1 and Robust Plan 3 are highlighted, as these are the primary plans to be compared. Moreover, the key question to ask is whether the difference between the robust metrics from Robust Plan 1 and Robust Plan 3 are significant enough to justify the difference in the Δ Net Benefits between the two plans. This difference is $431 million dollars is calculated from Table 2 as $286 million Δ Net Benefits for Robust Plan 3 minus -$145 million Δ Net Benefits for Robust Plan 1.

Table 3: Robustness Metric Values

Metric No	Metric Desciption	Wgt	% Wgt	0	1	2	3	4	5	6
1.1 2	Value of Improved ATC's in the SPP Grid	202.3	20.23%	253%	255%	261%	254%	269%	257%	257%
2	Levelization of LMPs	133.33	13.33%	-$12	-$15	-$14	-$12	-$23	-$16	-$16
6	Limited Import/Export Improvements	112.5	11.25%	191%	198%	211%	192%	197%	192%	197%
14	Ability to Serve New Load	108	10.80%	218%	228%	228%	218%	230%	237%	238%
3	Improved Competition in SPP Markets	93 33	9.33%	-$9	-$12	-$9	-$8	-$20	-$12	-$12
1.6	Positive Impact on Losses Capacity	92	9.20%	-27	-38	-52	-29	-25	-21	-33
1.2	Enable Efficient Location of New Generation	81 83	8.18%	317	323	352	317	439	323	323
11.1	Existing ROW Utilization	58	5.80%	44%	39%	36%	45%	30%	39%	39%
13	Generation Resource Diversity	57	5.70%	$0.018	$0.011	$0.019	$0.029	$0.001	$0.011	$0.013
11 2	Sensitive ROW Utilization	32	3.20%	98%	96%	96%	98%	98%	96%	96%
10	Reduction of Emission Rates and Values	29.67	2.97%	35.43	39.48	40.06	39.83	40.20	39.50	39.50

Comparison of Robust Plan 1 and Robust Plan 3

To compare Robust Plan 1 and Robust Plan 3 a ratio of the metrics for the two plans was calculated. If a higher absolute value is better, the ratio calculated is the metric for Robust Plan 1 divided by the metric for Robust Plan 3. If a lower absolute value is better, the ratio is the metric for Robust Plan 3 divided by the metric for Robust Plan 1. Ratios greater than 100% show that the Robust Plan 1 metric is superior to the Robust Plan 3 metric. If there is less than 5% difference, the two metrics are deemed to be equivalent and a weighted average using the SPP's ESWG weights is calculated for this group of metrics.

Table 4: Robustness Metric Values Compared for Robust Plan 1 and Robust Plan 3

Metric No	Metric Desciption	% Wgt	1	3	Ratio		% Wgt	Ratio
1.1.2	Value of Improved ATC's in the SPP Grid	20.23%	255%	254%	100.39%		35.72%	35.86%
2	Levelization of LMPs	13.33%	-$15	-$12	125.00%			
6	Limited Import/Export Improvements	11.25%	198%	192%	103.13%		19.87%	20.49%
14	Ability to Serve New Load	10.80%	228%	218%	104.59%		19.07%	19.95%
3	Improved Competition in SPP Markets	9.33%	-$12	-$8	150.00%			
1.6	Positive Impact on Losses Capacity	9.20%	-38	-29	131.03%			
1.2	Enable Efficient Location of New Generation	8.18%	323	317	101.89%		14.45%	14.72%
11.1	Existing ROW Utilization	5.80%	39%	45%	115.38%			
13	Generation Resource Diversity	5.70%	$0.011	$0.029	263.64%			
11.2	Sensitive ROW Utilization	3.20%	96%	98%	97.96%		5.65%	5.54%
10	Reduction of Emission Rates and Values	2.97%	39.48	39.83	99.12%		5.24%	5.19%
							100.00%	101.75%

Table 4 shows that six of the eleven metrics fall within the 5% range of equivalence, and when the ESWG weights are applied to these six metrics the overall percentage difference between Robust Plan 1 and 3 is only 1.75%. The remaining 5 metrics will be analyzed along with Improved Available Transfer Capability (ATC) since it has the greatest weight.

Improved Available Transfer Capability (ATC)

The metrics are ranked in Table 3 according to the ESWG's weights. The metric given the highest value by ESWG is Improved ATC's in the SPP Grid. It is very clear from the results that there is very little difference between Robust Plan 1 and Robust Plan 3, and while almost one quarter of the weight is given to Improved ATC, the small difference in ATC improvement (less than one percent) for Robust Plan 1 compared to Robust Plan 3 cannot justify spending an additional $431 million.

Positive Impact on Losses Capacity

This metric compares losses at peak in each of the plans to the base case and multiplies the impact on reserves that these savings in losses would produce – similar to interruptible demand. The ESWG recommended multiplying by $750/kW to obtain savings in costs. This metric could be added to Adjusted Production Costs Savings as the dollars are comparable measures of savings to customers. Bottom line is that the difference between Robust Plan 1 and Robust Plan 3 is 9 MW per year. Multiplying by $750,000/ MW and a 12% capacity margin gives $810,000 per year in savings. Dividing by a fixed charge rate of 17% gives a present value of savings of approximately $5 million per year. This reduces the $431 million difference in Δ Net Benefits to $426 million. This metric should be added to the benefits calculations and removed from the list of robustness metrics. Bottom line is that this difference is insignificant in comparison to the size of overall Δ Net Benefits between Robust Plan 3 and Robust Plan 1.

Existing Right of Way (ROW) Utilization

This metric compares the "proportion of transmission expansion plan cost that *does not* effectively utilize existing ROW." Apparently, the additional transmission included in Robust Plan 1 compared to Robust Plan 3 has a greater proportion of these additional facilities planned to use existing ROW. However, the following table tells the whole story between Robust Plan 1 and Robust Plan 3:

Table 5: Total Miles Not Using Existing ROW

Robust Plan	1	3
Total Miles	2,078	1,574
% not Using Existing ROW	39%	45%
Miles not Using Existing ROW	810.42	708.3

Applying the percentages provided to the total miles of ROW for each plan, it turns out that Robust Plan 1 has in excess of 100 additional miles that is not using existing ROW compared to Robust Plan 3. Yet the manner in which the metrics are reported would indicate that Robust Plan 1 is superior to Robust Plan 3 since it has a lower percentage not using existing ROW. The use of a percentage not using existing ROW may be misleading as adding over

100 miles not using existing ROW poses a greater risk in terms of the time and cost of adding miles of transmission lines. Yet, this greater risk is not taken into account in the cost estimates being used. A better approach by SPP would be to adjust the cost estimates using higher costs per mile for new ROW as well as for environmentally sensitive ROW. In regard to environmentally sensitive ROW, the following table gives a comparison of the two plans.

Table 6: Miles of Environmentally Sensitive ROW

Robust Plan	1	3
Total Miles	2,078	1,574
Sensitive Miles	89	39
Non-Sensitive Miles	1,989	1,535
Percent of Non-Sensitive Miles	95.72%	97.52%

This table shows an additional 50 miles of environmentally sensitive ROW for Robust Plan 1. This should be reflected in higher costs than reported for this plan. With respect to comparing to the Δ net benefits between the two plans, these ROW metrics indicate that that gap is likely to widen rather than to narrow.

Generation Resource Diversity

While SPP reported this metric, it believed the differences were not statistically significant. For this round of ITP, this metric should be ignored.

Levelization of Locational Marginal Prices (LMPs)

Ranked second by the SPP's ESWG is the levelization of LMPs. The metric used to measure levelization of LMP is the standard deviation of LMPs for loads and generation across the SPP footprint. Unfortunately the ITP 20 report makes the mistake of comparing a lower standard deviation with a lower mean. This is not a true statement. Standard deviation calculates the difference between the LMP at a specific location compared to the average over the entire footprint, squares that difference, adds up the differences over all locations and takes the square root of the sum of squared differences. In essence it is a dollar measure of how the LMPs are spread out across the entire SPP region. This metric was run for a sample of hours (25% with the highest standard deviations), not for all hours. The metric measures the average reduction in standard deviation compared to the base plan over the hours being sampled. Comparing the results of Robust Plan 3 to Robust Plan 1, there is a $3/MWh difference in the decrease in the averaged standard deviations between the two plans, with Robust Plan 1 showing the greater reduction. What is the value of bringing LMPs closer together and is a $3 difference significant?

In my opinion the first question can never be answered because this metric is neither measuring a reduction in direct costs to market participants, nor is it measuring risk. Moreover, standard deviation across the footprint (how LMPs at each location vary from the overall average across all locations) does not measure differences related to price at generation compared to load (congestion costs to load) that is a direct cost to loads, and does not correspond to an overall lowering of LMPs across the region that can be a direct benefit to loads. With respect to risk, it can easily be shown that LMPs can be closer together but the standard deviation of the difference between the two LMPs (the correct measure of risk related to hedging) stays the same. This metric does not measure a decrease in market risk related to hedging market purchases and sales.

With respect to the second question of whether a $3 difference is significant, we can only do a comparative analysis. If we compare this $3 difference to the $11 difference shown by comparing Robust Plan 3 to Robust Plan 4, or the $8 difference from comparing Robust Plan 1 to Robust Plan 4, we find that the $3 difference is relatively small, but not insignificant.

Bottom line is that the answer to the second question is not relevant in light of not being able to answer the first question. The results of this metric should not be used and this metric should be changed in the next round of ITP 20. Improved competition, which is a similar metric to levelization of LMPs, should be looked at.

Improved Competition

This metric separates generation by type and calculates the average of standard deviations of LMPs for generator groups over the 25% of hours having the highest standard deviations. The standard deviations for each capacity type are then weighted by total generator capacity in each group to arrive at a single value. The metric then calculates the reduction in standard deviation compared to the base case.

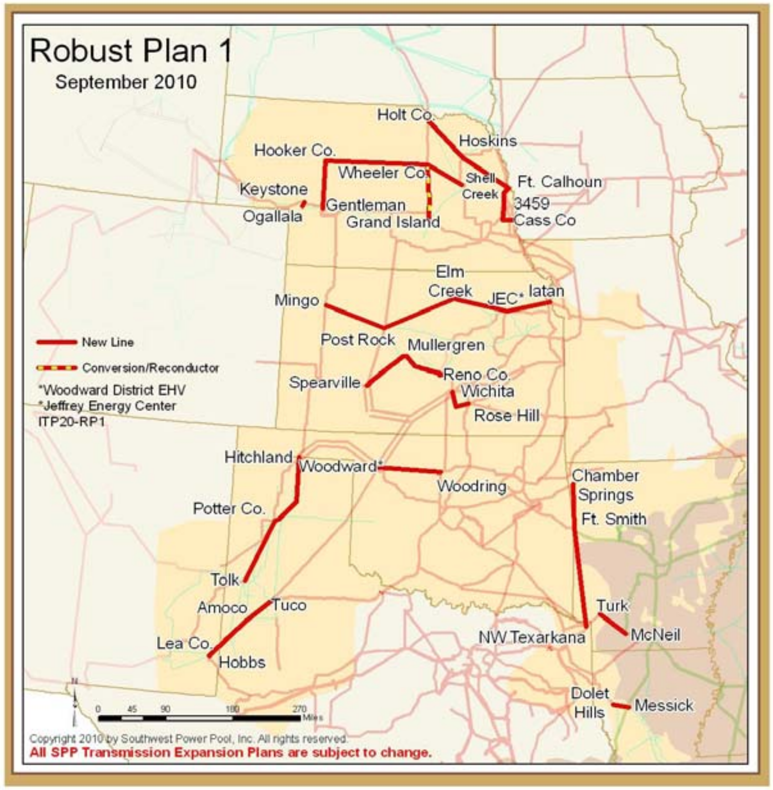
This metric measures how the upgrades in each plan are moving the prices that generators of the same type are receiving more closely together. The difference is $3/MWh between Robust Plan 1 and Robust Plan 3. Again comparing to Robust Plan 4 that has a decrease of $20/MWh, Robust Plan 1 is $8/MWh less and Robust Plan 3 is $11/MWh less. Thus, $3/MWh difference does not appear to be significant.

Conclusions

Robust Plan 1 and Robust Plan 3 are nearly the same on almost all the other metrics besides Levelization of LMP and Improved Competition. This leaves these two metrics to make up for a $426 million difference after accounting for added benefits for reduction in generation capacity from improved losses. This two are comparable metrics, with Improved Competition being the more meaningful. However, I find that Average Production Cost Savings is the most meaningful way to measure improved competition, and the metric used by SPP for Improved Competition is a duplicative, not additive measure. So even if this metric could be monetized, it is not clear how it would reduce the $426 million dollar deficit in Δ Net Benefits difference between

Robust Plan 1 and Robust Plan 3. Thus, it can only be concluded that of the plans presented by SPP in ITP 20, Robust Plan 3 is the best.

Graphics of the Cost Effective Plan, Robust Plan 1 and Robust Plan 3 are attached. These graphics are from the December 8, 2010 Draft ITP 20 Report. They show that Robust Plan 3 adds two 345 kV lines to the Cost Effective Plan: 1) Turk to McNeil; and 2) Dolet Hills to Messick. These lines appear to be cost beneficial additions to the Cost Effective Plan. In addition to these two lines, Robust Plan 1 adds two much longer 345 kV lines to connect Post Rock to Elm Creek to JEC, and Chamber Springs to NW Texarkana. While these two lines add a little to robustness, they do not add enough to justify their additional and significant costs; i.e., these are not cost beneficial additions. SPP should evaluate each of these separately to determine if either of these two lines can prove to be cost beneficial in comparison to Robust Plan 3.


Robust Plan 1
September 2010
Holt Co.
Hoskins
Hooker Co.
Wheeler Co.
Shell Creek
Ft. Calhoun
Keystone
Gentleman
3459
Ogallala
Grand Island
Cass Co
Elm Creek
JEC*
Iatan
Mingo
Post Rock
Mullergren
New Line
Conversion/Reconductor
*Woodward District EHV
*Jeffrey Energy Center
ITP20-RP1
Spearville
Reno Co.
Wichita
Rose Hill
Hitchland
Woodward*
Woodring
Chamber Springs
Ft. Smith
Potter Co.
Tolk
Amoco
Tuco
Turk
McNeil
NW Texarkana
Lea Co.
Hobbs
Dolet Hills
Messick
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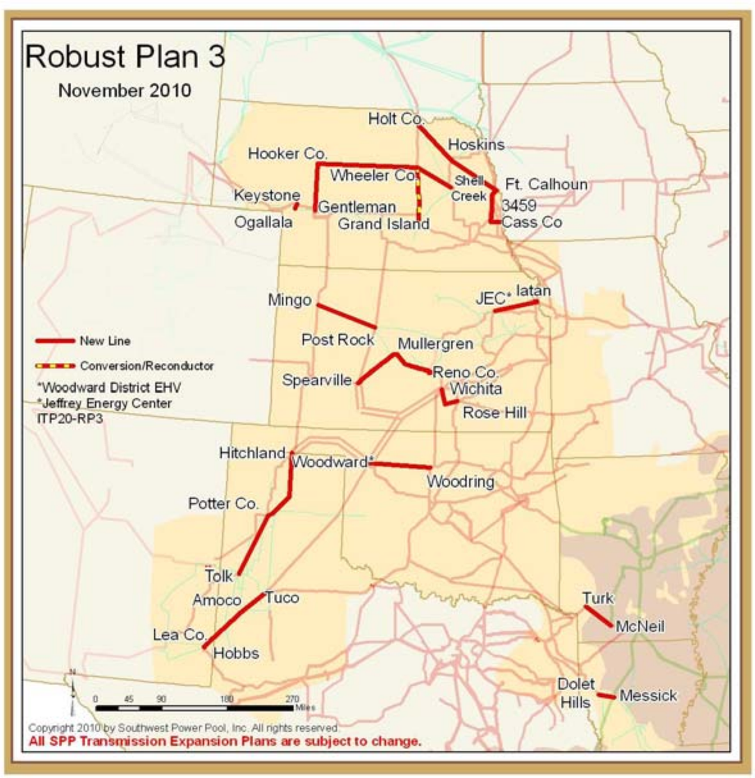
Robust Plan 3
November 2010
Holt Co.
Hoskins
Hooker Co.
Wheeler Co.
Shell Creek
Ft. Calhoun
Keystone
Gentleman
3459
Ogallala
Grand Island
Cass Co
JEC*
Iatan
Mingo
Post Rock
Mullergren
New Line
Conversion/Reconductor
*Woodward District EHV
*Jeffrey Energy Center
ITP20-RP3
Spearville
Reno Co.
Wichita
Rose Hill
Hitchland
Woodward*
Woodring
Potter Co.
Tolk
Amoco
Tuco
Turk
McNeil
Lea Co.
Hobbs
Dolet Hills
Messick
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Priority Project Benefits Calculated for EDE

Overall Methods

When SPP ran benefits for the Priority Projects, they did not assign any wind resources as designated resources to the various utilities. This results in the utilities having to make up the energy from wind either through additional purchases of energy in the market for those utilities which are purchasing energy in a given hour, or in the case of utilities that are selling power in a given hour, fewer sales. To compensate for these additional purchases or decreases in sales, SPP allocated the revenues that wind generation received from the market to the various utilities. This is a two part allocation developed by Regional State Committee consultant Michael S. Proctor, who also does some consulting for the Missouri Commission. First, revenues from wind resources under contract (a major portion of existing wind) were allocated to the utility that has that wind under contract. Second, revenues from wind resources not under contract (new wind resources and existing wind resources without a contract) was first allocated to states and then to utilities within the states. The allocation to states was based on the following allocation rules: First, wind generated within a state was allocated to the state in which the wind is located. This results in excess wind for Texas, Oklahoma, Kansas and Nebraska (in the state renewable energy target (RET) future), and a shortage of wind for Nebraska (in the federal RES future), Missouri and Arkansas. Second, the excess wind is then allocated from the excess states to the shortage states on the basis of a pro rata share of each state's shortage. Within the states, revenues were allocated to utilities based on a pro rata share of each utility's difference between its renewable energy needs and its renewable energy contracted for.

Results for EDE

The tables on the next page show the results of these calculations for all the zones within the SPP region. Two futures (7 gigawatts (GW = 1,000 MW) and 11 GW with existing wind resources at 3 GW) of total wind resources were run for two groups of priority projects (Group 1 and Group 2 – the alternative chosen). In all four cases, EDE's allocation of "benefits" (i.e., change in wind revenues before and after the addition of the priority projects) shows that wind revenues **decreased** for EDE. This means that by excluding wind revenues from the calculation of benefits by the Rate Impact Task Force, the net cost to EDE's customers is UNDERSTATED by the amount of three to five million dollars per year ($3 million for 7 GW and $5 million for 11 GW).

The existing wind resources for EDE accounts for almost all of the decrease in revenues. This occurs because of the decrease in prices paid to the two existing wind farms (Cloud County and Elk River) with whom EDE has contracts when the new transmission is added. The attached tables of modeling results show almost no change in energy but large decreases in prices. This decrease in prices likely occurs because of the addition of new wind resources which lowers the overall price levels in the footprint. While a decrease in prices is of benefit to EDE (a net purchaser of energy in the SPP market), the APC results not adjusted for wind revenues overstates this benefit because it overstates EDE's purchases, and therefore needs to be adjusted down for the change in wind revenues.

The much smaller decrease in revenues for new wind occurs because of a modeling issue with the wind located in Missouri (at the Fairport substation), and is not a reliable number. The energy from these wind farms in NE Missouri were injected into the power grid on an existing 345 kV line at Fairport, and in the runs with the new 345 kV line in the priority projects, SPP did not move the injection points to the new 345 kV line where the wind resource would more likely be located. The attached tables for modeling results show a relatively poor capacity factor for the Fairport wind on the existing 345 kV transmission system both before and after the upgrade indicating that the upgrade did not enhance the deliverability of the wind. This is unlikely to be the case. In the 7 GW case the prices slightly increase, while in the 11 GW case the prices show significant decreases at Fairport – again indicating an increase in competition from new wind resources resulting in lower prices.

Keep in mind that that purchased power costs for EDE are decreased in both the base and change cases. What the inclusion of wind revenues in the calculations indicates is that these purchased power costs are decreased more in the change case than in the base case by approximately $3 million to $5 million. Inclusion of wind revenues corrects for this difference.

7 GW Wind Benefits
Group 2 Results
Sign Convention: Benefits > 0 and Costs < 0

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

11 GW Wind Benefits
Group 2 Results
Sign Convention: Benefits > 0 and Costs < 0

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

7 GW Wind Benefits
Group 1 Results
Sign Convention: Benefits > 0 and Costs < 0

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

11 GW Wind Benefits
Group 1 Results
Sign Convention: Benefits > 0 and Costs < 0

Zone	Wind Capacity DR	Wind Capacity Non-DR	40 Year Levelized DR Wind Net Benefit	40 Year Levelized Non-DR Wind Net Benefit	40 Year Levelized Total Wind Net Benefit	NPV Total Wind Net Benefit
AEP	421	2,465	($12,380,833)	$54,546,230	$42,165,397	$502,806,055
EMDE	255	95	($4,378,753)	($190,488)	($4,569,241)	($54,486,433)
GMO	61	393	$1,192,192	($788,785)	$403,407	$4,810,473
GRDA	0	0	$0	$0	$0	$0
KCPL	125	815	$3,783,586	$22,861,984	$26,645,571	$317,738,127
LES	6	111	$38,294	$958,069	$996,363	$11,881,244
MIDW	49	121	$14,036	$6,473,502	$6,487,538	$77,361,387
MKEC	75	171	$1,003,597	$9,142,349	$10,145,946	$120,986,482
NPPD	100	498	$715,161	$4,304,935	$5,020,096	$59,862,704
OKGE	451	1,285	($19,154,131)	$26,881,573	$7,727,442	$92,146,754
OPPD	95	311	$558,919	$2,689,556	$3,248,475	$38,736,809
SPRM	50	28	$14,264	($55,471)	($41,207)	($491,380)
SUNC	50	159	$14,264	$8,508,646	$8,522,910	$101,632,407
SWPS	658	651	($15,821,703)	$17,218,827	$1,397,124	$16,660,158
WEFA	216	98	($4,427,976)	$2,041,750	($2,386,226)	($28,454,820)
WRI	295	1,248	$2,157,152	$66,704,319	$68,861,471	$821,146,411
TOTAL	2,907	8,449	($46,671,931)	$221,296,996	$174,625,065	$2,082,336,377
	11,356					

7 GW of Wind Group 2 Results

Model Results for Cloud County

MWh	2009	2014	2019
Change Case	366,464	377,546	378,949
Base Case	369,102	376,680	377,692
Difference	-2,639	866	1,257
Capacity Factors	**2009**	**2014**	**2019**
Change Case	20.84%	21.47%	21.55%
Base Case	20.99%	21.42%	21.48%
Difference	-0.15%	0.05%	0.07%
Revenues	**2009**	**2014**	**2019**
Change Case	$9,038,613	$14,702,293	$21,456,277
Base Case	$10,287,711	$15,670,513	$22,911,286
Difference	-$1,249,099	-$968,219	-$1,455,010
Avg Prices	**2009**	**2014**	**2019**
Change Case	$24.66	$38.94	$56.62
Base Case	$27.87	$41.60	$60.66
Difference	-$3.21	-$2.66	-$4.04

Model Results for Elk River

MWh	2009	2014	2019
Change Case	595,100	598,211	598,209
Base Case	596,355	598,212	598,208
Difference	-1,255	-1	1
Capacity Factors	**2009**	**2014**	**2019**
Change Case	45.34%	45.58%	45.58%
Base Case	45.44%	45.58%	45.58%
Difference	-0.10%	0.00%	0.00%
Revenues	**2009**	**2014**	**2019**
Change Case	$16,056,872	$21,516,020	$31,782,618
Base Case	$17,094,361	$22,893,721	$33,664,698
Difference	-$1,037,489	-$1,377,701	-$1,882,079
Avg Prices	**2009**	**2014**	**2019**
Change Case	$26.98	$35.97	$53.13
Base Case	$28.66	$38.27	$56.28
Difference	-$1.68	-$2.30	-$3.15

Model Results for Fairport

MWh	2009	2014	2019
Change Case	924,302	1,425,475	1,315,047
Base Case	870,161	1,370,579	1,321,321
Difference	54,141	54,895	-6,273
Capacity Factors	**2009**	**2014**	**2019**
Change Case	17.59%	27.12%	25.02%
Base Case	16.56%	26.08%	25.14%
Difference	1.03%	1.04%	-0.12%
Revenues	**2009**	**2014**	**2019**
Change Case	$24,368,604	$48,858,992	$65,252,871
Base Case	$22,263,108	$45,190,949	$62,086,906
Difference	$2,105,496	$3,668,044	$3,165,965
Prices	**2009**	**2014**	**2019**
Change Case	$26.36	$34.28	$49.62
Base Case	$25.59	$32.97	$46.99
Difference	$0.78	$1.30	$2.63

11 GW of Wind Group 2 Results

Model Results for Cloud County

MWh	2009	2014	2019
Change Case	363,568	370,119	371,573
Base Case	351,073	359,864	363,338
Difference	12,495	10,255	8,236
Capacity Factors	**2009**	**2014**	**2019**
Change Case	20.67%	21.04%	21.13%
Base Case	19.96%	20.46%	20.66%
Difference	0.71%	0.58%	0.47%
Revenues	**2009**	**2014**	**2019**
Change Case	$9,220,001	$12,547,932	$18,917,415
Base Case	$10,607,205	$14,409,866	$21,369,224
Difference	-$1,387,204	-$1,861,934	-$2,451,809
Avg Prices	**2009**	**2014**	**2019**
Change Case	$25.36	$33.90	$50.91
Base Case	$30.21	$40.04	$58.81
Difference	-$4.85	-$6.14	-$7.90

Model Results for Elk River

MWh	2009	2014	2019
Change Case	594,188	598,212	597,938
Base Case	595,143	598,210	598,179
Difference	-955	2	-240
Capacity Factors	**2009**	**2014**	**2019**
Change Case	45.27%	45.58%	45.56%
Base Case	45.34%	45.58%	45.58%
Difference	-0.07%	0.00%	-0.02%
Revenues	**2009**	**2014**	**2019**
Change Case	$15,394,253	$20,394,864	$30,558,922
Base Case	$17,041,471	$22,603,661	$33,352,252
Difference	-$1,647,218	-$2,208,796	-$2,793,330
Avg Prices	**2009**	**2014**	**2019**
Change Case	$25.91	$34.09	$51.11
Base Case	$28.63	$37.79	$55.76
Difference	-$2.73	-$3.69	-$4.65

Model Results for Fairport

MWh	2009	2014	2019
Change Case	579,948	1,014,898	1,040,062
Base Case	673,368	1,157,153	1,049,578
Difference	-93,419	-142,255	-9,516
Capacity Factors	**2009**	**2014**	**2019**
Change Case	11.03%	19.31%	19.79%
Base Case	12.81%	22.02%	19.97%
Difference	-1.78%	-2.71%	-0.18%
Revenues	**2009**	**2014**	**2019**
Change Case	$14,766,899	$31,480,271	$45,220,863
Base Case	$18,247,164	$39,446,108	$55,460,321
Difference	-$3,480,265	-$7,965,837	-$10,239,458
Prices	**2009**	**2014**	**2019**
Change Case	$25.46	$31.02	$43.48
Base Case	$27.10	$34.09	$52.84
Difference	-$1.64	-$3.07	-$9.36

Section 3 Cost Overruns and Novations Problems and Recommendations

Cost Overrun and Cost Estimation Issues

A critical portion of any transmission planning process is the estimation of transmission project costs. In order for there to be proper transmission project selection, there must be a degree of confidence regarding cost estimates.

Additionally, there must be a mechanism in place regarding transmission project cost overruns to give transmission building companies an additional incentive to (1) produce an accurate transmission project cost estimate in the transmission planning phase; and (2) keep transmission project costs prudently, reasonably, and efficiently low while still delivering a quality, appropriate transmission project.

Priority Project Cost Issues:

For the Priority Projects, SPP states in the final Priority Projects Report[1] that "The Engineering and Construction (E&C) cost estimates were provided by the Transmission Owners (TOs)."

These cost estimates are used throughout the Priority Projects Report as part of the analysis to show support for building this particular group of transmission projects, as they are the basis of any benefit-to-cost ratios.

The final approved group of Priority Projects is as follows:

1. Spearville – Comanche – Medicine Lodge – Wichita (345 kV double circuit) – projected cost of $356 million

2. Comanche – Woodward District EHV (345 kV double circuit) – projected cost of $108 million

3. Hitchland – Woodward District EHV (345 kV double circuit) – projected cost of $247 million

4. Valiant – NW Texarkana (345 kV) – projected cost of $131 million

5. Nebraska City – Maryville – Sibley (345 kV) – projected cost of $301 million

6. Riverside – Tulsa Reactor (138 kV) – projected cost of $840,000

After the Regional State Committee (RSC) and the SPP Board voted to accept the Priority Projects Report in April 2010, Notices to Construct (NTCs) were issued to Transmission Owners to construct the six Priority Projects listed above.

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[1] http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf

In the response to the NTCs, the estimated cost of the Priority Projects increased by 24%, as detailed in the following charts:

SOUTHWEST POWER POOL

Project Cost Summary

Project	PP Report Project Cost	NTC Response/Latest Update Project Cost	Cost Variance	% Increase /Decrease
NW Texarkana - Valliant	$131,451,250	$131,451,250	$0	0%
Tulsa Reactor	$842,847	$842,847	$0	0%
Nebraska City - Maryville - Sibley	$301,029,091	$403,740,000	$102,710,909	34%
Hitchland - Woodward	$247,005,793	$221,572,283	($25,433,510)	-10%
Woodward - Comanche County/Medicine Lodge	$108,227,500	$201,940,759	$93,713,259	87%
Spearville - Comanche County - Medicine Lodge - Wichita	$356,300,000	$456,723,000	$100,423,000	28%
Total Projects	**$1,144,856,481**	**$1,416,270,139**	**$271,413,658**	**24%**

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SOUTHWEST POWER POOL

Transmission Owner Cost Changes

Project	Transmission Owner	Transmission Owner Cost Variance	Cost Variance Reason
Nebraska City - Maryville - Sibley	KCPL GMO OPPD	$95,000,000 $7,500,000	KCPL GMO- Forecasted contingency; reactive support OPPD- ROW/rerouting; reactive support
Hitchland - Woodward	SPS OGE	($25,000,000)	Ownership change; current estimate lower than original
Woodward - Comanche County/Medicine Lodge	ITC Great Plains Prairie Wind OGE	$6,000,000 $50,000,000 $37,000,000	Rerouting; increase in line length
Spearville - Comanche County - Medicine Lodge - Wichita	ITC Great Plains Prairie Wind	$88,000,000 $12,500,000	ITC GP- Reactive support and compensation Prairie Wind- New substation; rerouting
Total Projects		**$271,000,000**	

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Note that Staff has received information regarding the increase in cost estimates from KCPL / GMO for the Nebraska City – Maryville – Sibley transmission project. This information is attached as Appendix 1.

Novations:

In the Priority Projects, there were proposed novations, where Westar Energy, Mid-Kansas Electric Co., and Sunflower Electric Power Corp. proposed a novation to Prairie Wind and ITC Great Plains.

What is a Novation?

To quote the Order opening this case:

> An additional factor complicating analysis utilizing the estimated cost of a transmission project is the issue of novation. Under the current SPP process, a transmission owner may transfer its right to construct a transmission project assigned by the SPP Board to another company, possibly for a monetary consideration. This process is called a novation. It is entirely possible, and has occurred recently in SPP, that the company newly assigned to construct an assigned transmission project has an entirely different cost estimate for the new transmission project.

Impact of Novations:

The impact of novations was raised in a letter signed by employees of The Empire District Electric Company (EDE), Lincoln Electric System, and Omaha Public Power District, included in the RSC materials for its October 2010 meeting[2]:

> Fourth, the costs to customers of the Priority Projects and ITP-20 Projects are affected by the "novation" process – that is, the process by which certain SPP transmission owners will transfer their construction responsibilities to other entities (such as affiliates of the transmission owners or parties selected through a negotiated settlement process) who then will fund completion of the projects. The entities that take on the funding and completion responsibilities through "novation" typically have higher fixed charge rates than the transferring transmission owners. As new entities, they may have higher costs of capital than the transmission owners, or they may have been granted various incentives by FERC that increase their carrying charges. In such instances, the costs that customers ultimately will bear are likely to be higher than the costs that the Board originally considered in approving the projects. Consideration of the additional costs resulting from novation would further erode the net benefits of the relevant projects.

The RSC issued a motion regarding novations in its October 2010 meeting:

> Motion 2: RSC Recommends that SPP review the Novation Process and report to the RSC by April 2011.

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[2] http://www.spp.org/publications/RSC102510.pdf (page 78 of 124)

SPP Staff created a draft response to this motion, and presented it at the December 3, 2010 meeting of the SPP Strategic Planning Committee. The full draft response is attached as Appendix 2, SPP Response to RSC Motion #2.

The "Conclusion" of the SPP Staff draft response is as follows:

> **Conclusion**
> In an effort to address the concerns raised by the Motions from the RSC, SPP Staff suggests the solution is multi-faceted. Staff believes increased transparency through the regional planning and cost allocation processes is beneficial, so proposes the following:
>
> (1) SPP will provide proposed Novations and supporting analysis to the RSC for review and discussion prior to submission to the MOPC and Board of Directors/Members Committee for approval for filing with FERC.
>
> (2) Staff will increase efforts to communicate with state commissions and state commission staff members about how the regional planning and cost allocation processes work, and more specifically how and when estimates for transmission projects are requested by SPP and provided by Transmission Owners to SPP, including opportunities for adjustments.
>
> SPP also suggests increased communication between jurisdictional transmission owners and state commissions might result in a better understanding of the Transmission Owners' processes for development of cost estimates and causes for variances in cost estimates.

Additionally, SPP Staff has put out a "Recently Asked Questions" document regarding "Regional Planning"[3], which included this Question and Answer regarding novations:

> **What does novation mean?**
> Under the SPP Tariff, Transmission Owners whose substations connect to the beginning or end of the lines have the right of first obligation to build the projects. We issue NTCs to these entities, and they can accept or decline to accept the NTC. Even if the Transmission Owner accepts the NTC they may choose to novate the project to an existing Transmission Owner or to an entity willing to become a Transmission Owner. If a project is novated, the original Transmission Owner transfers all legal and financial obligations of the project to the novate entity. If the Transmission Owner declines to accept the NTC, SPP has the responsibility to find a Transmission Owner that is willing to build the project as specified.

[3] http://www.spp.org/publications/Regional%20Planning%20Recently%20Asked%20Questions.pdf

Three Transmission Owners - Westar Energy, Mid-Kansas Electric Co., and Sunflower Electric Power Corporation – are proposing to novate projects listed in the Priority Project NTCs to Prairie Wind and ITC Great Plains, although no novations have been finalized.

The following is a list of the three prior SPP novations, and links to their filings at FERC:

FERC Docket No. ER09-1130 – ITC Great Plains-WFEC (Western Farmers) Novation

http://www.spp.org/publications/2009-05-12_SPP-WFEC-ITC%20Designee%20Qualification%20and%20Novation%20-%20SA%201814_ER09-1130.pdf

FERC Docket No. ER10-364 – ITC Great Plains – MidwestEnergy Novation

http://www.spp.org/publications/2009-12-01_ITC-Midwest%20Novation%20-%20SA%201873_ER10-364.pdf

FERC Docket No. ER10-365 – ITC Great Plains – Sunflower Novation

http://www.spp.org/publications/2009-12-01_ITC-Sunflower%20Novation%20-%20SA%201872_ER10-365.pdf

Recommendations for Section 3 – Issues - Cost Overruns and Novations

<u>Cost issues:</u>

- The Commission's RSC representative should not vote in favor of recommending the SPP Board issue any additional NTCs without the NTCs being the result of a more thorough cost estimation process
- The Commission's RSC representative should recommend and vote in favor of a stricter cost estimation process, with no NTCs issued until a more thorough cost estimate has been produced and put in place
- The Commission's RSC representative should recommend and vote in favor of SPP not selling transmission service over a project until an NTC based on a more thorough cost estimation process than is currently in place has been returned with a firm cost estimate.
- The Commission's RSC representative should recommend and vote in favor of a proposal where SPP develops construction standards for cost estimation, as recommended in RSC Motion 3.
- The Commission's RSC representative should recommend and vote in favor of a proposal where SPP should: (1) establish who has audit rights regarding costs of transmission projects where the SPP Board has issued an NTC; (2) create an obligation of entities constructing transmission projects where the SPP Board has issued an NTC to furnish information requested by an entity who has such audit rights. The goal of this

recommendation is to prevented unaudited transmission project costs from going into customer rates

Novations:

- The Commission's RSC representative should recommend and vote in favor of: If a novation occurs during the NTC process, or after the NTC is returned, a new cost estimate developed based on the new construction company's cost estimate and rate of return
- The Commission's RSC representative should recommend and vote in favor of a process where when a novation is proposed, the estimated financial impact of that novation must be presented to stakeholders
- The Commission's RSC representative should recommend and vote in favor of a proposal regarding payments made for novations not being added to the cost a transmission project that is ultimately passed on to customers. To enforce this proposal, action may need to be taken at FERC.
- The Commission's RSC representative should recommend and vote in favor of a proposal where all novation payments amounts are released to the public
- The SPP proposal is to bring proposed novations before the RSC prior to when they are brought before the SPP Board. A concern is that novations can occur before and after NTCs are returned by transmission owners. Thus, the Commission's RSC representative should recommend and vote in favor of a proposal where (1) transmission project costs estimates are newly generated whenever a novation takes place; and (2) NTCs are reevaluated based on those updated cost estimates whenever a novation takes place.

Section 4 Other Issues Raised

This section is intended to address other issues raised in the Staff's investigation of the issues raised in the Order opening this file.

ITP20 Fuel Price Sensitivity:

Page 1343 of the SPP Open Access Transmission Tariff (OATT) reads:

> 8) Process to Analyze Transmission Alternatives for each Assessment
> The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year Assessment, 10-Year Assessment and Near Term Assessment studies:
> ⋮
> iv) The analysis scope shall include different scenarios to analyze sensitivities to load forecasts, wind generation levels, fuel prices, environmental costs, and other relevant factors. The Transmission Provider shall consult the stakeholders to guide the development of these scenarios.

A concern has been brought up that the draft ITP20 report, scheduled to be presented to the RSC and the SPP Board in the January 2011 cycle of meetings, does not contain sensitivities to fuel prices across different scenarios. The following is the portion of the draft ITP20 report regarding fuel prices:

Fuel Cost and Emissions Charge

The ESWG selected fuel costs for uranium, natural gas, and coal in study year dollars based upon current market prices and industry forecasts. The costs of each fuel were used as inputs in the market simulations and contribute to the price per MWh at each generator in the study.

An additional charge for CO_2 emissions of $73/ton, 2030 nominal dollars, was also selected by the ESWG and applied to the futures as appropriate. The decision to use this figure was made after reviewing the latest EPA report of the calculated cost of tradable carbon emission allowances. The EPA calculations took into account pending legislation from the United States Congress.

	Future 1	Future 2	Future 3	Future 4
SO_2 Emissions ($/ton)	533.83	533.83	533.83	533.83
NO_X Emissions ($/ton)	1,888.08	1,888.08	1,888.08	1,888.08
CO_2 Emissions ($/ton)	0.00	0.00	73.00	73.00
Uranium ($/MMBTu)	2.52	2.52	2.52	2.52
Natural Gas ($/MMBTu)	15.68	15.68	15.68	15.68
Coal ($/MMBTu)	1.78	1.78	1.78	1.78

Table 8.1: Fuel Cost and Emissions Charge Assumptions (2030 nominal dollars)

Staff recommends this question be posed to SPP regarding the above tariff language and the Table 8.1 pasted in above.

<u>ITP20 Investigation Issues:</u>

Staff also recommends that SPP be required to present a list of issues that either SPP or SPP stakeholders decided not to study in the current ITP20 due to a lack of time.

<u>NTCs versus ATPs:</u>

While previously the SPP Board has only issued "Notices to Construct", or NTCs, for projects that have received SPP Board approval, the new ITP draft manual has introduced the concept of "Authorizations to Plan", or ATPs.

An ATP is defined as follows in the ITP20 Draft Manual:

> 1. ATP – Authorization to Plan: The ATP is a status given to a project which indicates that the BOD [Board of Directors] has approved the project in the SPP ITP and it has not yet been issued an NTC because it is outside of the NTC financial commitment window.

The draft ITP manual[4] contains the following section on NTCs and ATPs, regarding when each will be issued:

> **Issuance of NTCs and ATPs**
>
> Once the ITP is reviewed by the MOPC and approved by the BOD, staff will issue NTC letters for approved projects in the 20-Year, 10-Year, and Near-Term Assessments which are within the financial window as approved by the BOD. The NTC is sent to the incumbent Transmission Owner(s) for the project. All other projects approved by the BOD in the ITP will receive an Authorization to Plan (ATP). All of the projects for which an ATP is issued will be posted on the SPP website. ATPS will be included in all future Aggregate Study and Generation Interconnection study models.

Staff is concerned regarding the inclusion of transmission projects that have only received an ATP, but not an NTC, "in all future Aggregate Study and Generation Interconnection study models." In short, Staff is concerned that transmission service could and will be sold over these transmission projects with only an ATP, making it difficult to unwind or rescind the ATP.

SPP Staff has consistently stated they are fine with a lesser level of cost estimation exactness for an ATP versus an NTC. Staff recommends that if a transmission project is going to have transmission service sold over it, it should have, for lack of a better term, NTC level cost estimation precision, as described in the following Staff recommendations:

- The Commission's RSC representative should recommend and vote in favor of SPP installing a process of review of changes in cost estimation / cost overrun that would allow a re-evaluation of a project, including possible revocations of ATPs and / or NTCs, after new cost information has been received.
- The Commission's RSC representative should recommend and vote in favor of SPP not selling any transmission service over transmission projects that have received an ATP without a more thorough cost estimate having been performed in the project selection process.

<u>Future Impacts of ITP20 Projects:</u>

Regarding issues such as those related to Section 2 of this Report regarding the impact of ITP20 projects on EDE's Cost/Benefit Status of SPP Membership, this issue has arisen regarding a future "unintended consequences" analysis.

During the SPP stakeholder discussions regarding the implementation of the "Highway Byway" cost methodology, concerns were raised by multiple parties regarding how any series or multiple

[4] http://www.spp.org/publications/Draft%20Integrated%20Transmission%20Planning%20Manual.doc

series of projects could benefit some portions of the SPP region more than others, and the possibility that some regions may not benefit at all.

In order to attempt to address the above issue, language was inserted into the tariff filing to create an ‘unintended consequences’ analysis and review. This review, and any actions taken in response to a review, would attempt to address an inequity between / among different portions of SPP.

SPP Staff have repeatedly pointed towards a possible future “unintended consequences” review as a solution to problems regarding a deficit in a utility’s costs versus benefits of any round of projects.

The ‘unintended consequences’ section of the SPP OATT is posted below:

> **D. Review of Base Plan Allocation Methodology**
>
> 1. The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years in accordance with this Section III.D. The Transmission Provider and/or the Regional State Committee may initiate such review at any time. Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.
>
> 2. For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts utilizing the analysis specified in Section III.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J.
>
> 3. The Transmission Provider shall review the results of the cost allocation analysis with SPP’s Regional Tariff Working Group, Markets and Operations Policy Committee, and the Regional State Committee. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.
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> 4. The Transmission Provider shall request the Regional State Committee provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.

However, the requirement of III.D.2 above is to only look at the "cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region."

Thus, Staff is confused regarding how the impact of any transmission projects that have received an ATP, but not an NTC, would be considered in this analysis. If a transmission project without only an ATP is allowed to be included "in all future Aggregate Study and Generation Interconnection study models" and thus have transmission service sold over it, Staff would recommend its inclusion in the unintended consequences analysis. This may require a change to the SPP OATT.

Furthermore, Staff recommends that the Commission take notice of the impact of any transmission projects that have received an ATP, but not an NTC, that are "in all future Aggregate Study and Generation Interconnection study models," when the Commission considers the costs and benefits of EDE remaining in SPP.

Additional Recommendations:

- The Commission's RSC representative should recommend and vote in favor of a proposal where: SPP considers a process where transmission owner (TO) members are allowed to not "participate" in projects the TO believes are not cost effective to their utility customers that will ultimately pay for the projects. This process could include the TO paying point-to-point service costs (instead of network service costs) for future utilization of the transmission project or paying a different price in a future "Day 2" market for resources that utilize such facilities.
- The Commission's RSC representative should recommend and vote in favor of a proposal where: SPP considers a process where TO utilities have the right to contribute their regional share of a transmission projects cost in an up front payment in lieu of paying fixed carrying charges related to the project's cost over time.

Materials Provided By Other Parties:

EDE provided questions that EDE believes should be asked in this docket. Schedule 1 to this Report is a list of those questions. Also SPP provided questions and comments regarding the scope of this investigation. This material is contained in Schedule 2 to this Report. Staff was also provided comments and questions from the Omaha Public Power District (OPPD). This material is contained on Schedule 3 to the Report.

APPENDIX 1

HAS BEEN DEEMED

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IN ITS ENTIRETY

RSC Motion 2: The Novation Process

Both the SPP Membership Agreement and Attachment O to SPP's OATT provide a designated Transmission Owner the unfettered right to assign the construction and ownership of a transmission project to a third party. Section 3.3(c) of the SPP Membership Agreement provides in part:

> A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place. If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

Section VI(6) of Attachment O of SPP's OATT provides, in relevant part:

> A Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the [entity having the following] qualifications . . . .
>
> i) Entities that have obtained all state regulatory authority necessary to construct, own and operate transmission facilities within the state(s) where the project is located,
>
> ii) Entities that meet the creditworthiness requirements of the Transmission Provider,
>
> iii) Entities that have signed or are capable and willing to sign the SPP Membership Agreement as a Transmission Owner upon the selection of its proposal to construct and own the project, and
>
> iv) Entities that meet such other technical, financial and managerial qualifications as are specified in the Transmission Provider's business practices.

For purposes of understanding roles and responsibilities related to the construction and ownership of transmission facilities, it is important to understand the distinction between assignment of a project and novation of a project. If a designated Transmission Owner cannot or does not want to construct a transmission project, there are two options available: assignment and novation. An assignment allows the designated Transmission Owner to transfer responsibility for construction of the project, but does not relieve the designated Transmission Owner of the financial or legal obligation to construct the project. SPP will continue to hold the designated Transmission Owner financially and legally responsible for timely construction of the project in accordance with the NTC. In contrast, a novation allows the designated Transmission Owner to transfer all legal and financial responsibility for the timely construction of the project to an existing Transmission Owner or an entity who will become qualified under SPP's process and become a Transmission Owner under SPP's OATT and Membership Agreement. SPP, through its stakeholder process, developed and documented a process for determining if an entity not currently an SPP Transmission Owner is qualified to become a Transmission Owner in SPP. That document is attached as an exhibit to this strawman. This process document is final in its form, but it is going to continually evolve as SPP develops more experience in using the process and addressing any issues or concerns that may arise from the process.

FERC accepted this process and the corresponding form of agreement, finding it was consistent with the SPP Membership Agreement, SPP's OATT and the filed rate doctrine, and would encourage third-party participation in SPP's transmission planning and construction and facilitate timely construction of needed transmission upgrades.

Reasons for assignment or novation

Numerous factors can result in a decision by a designated Transmission Owner to assign or novate a transmission project. These can include, but are not limited to, funding or financing limitations, increased costs of financing, and inability to timely construct the project.

SPP has issued NTCs for assigned a number of large 345 kV projects to smaller Transmission Owners, several of which happen to be RUS borrowers. As a general matter, the RUS denies loans that comprise an undue risk to a borrowing cooperative, i.e., loans that are unusually large or that are for purposes that are not normally undertaken by the cooperative for its own power supply purposes. The availability of a loan also depends upon congressional appropriations that are sufficient to meet RUS' funding plans. Consequently, the availability of an RUS loan may not be known for a year or more after a request is made and the loan may not actually be funded for two years or more after the request. These factors make the availability of RUS funding highly uncertain for large regional transmission projects. As an alternative to RUS borrowing, cooperatives are able to finance projects with private capital. RUS borrowers have typically mortgaged all of their facilities to the RUS to securitize their RUS loans. In order to fund a new project with private capital, RUS borrowers must implement a lien accommodation with the RUS to exempt the privately financed facilities from the RUS lien. This accommodation, if successfully achieved, typically takes a number of months to achieve. Private financing can be expected to cost at least two to three hundred basis points more than a RUS loan. Accordingly, the expectations that SPP's smaller Transmission Owners can make timely commitments to construct projects directed to them for construction at a cost reflecting their historic carrying charge rates have not proven to be realistic.

FERC Incentives

In response to the Energy Policy Act of 2005, FERC issued Order No. 679[1] implementing new policies regarding Transmission Owners' cost of service. FERC explained its rationale for providing incentives to Transmission Owners in setting rates:

> 25. These challenges and risks [associated with siting large new transmission projects] are underscored by the fact that, in many instances, new transmission projects will not be financed and constructed in the traditional manner. New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (e.g., proximity to wind currents), not simply on a "local" basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be "obligated" to build such facilities. Indeed, many of these projects may be too large for a single load serving entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability. Our policies also must encourage all other needed transmission investments, whether they are regional or local, designed to improve reliability or to lower the delivered cost of power.
>
> 26. To address the substantial challenges and risks in constructing new transmission, the Final Rule identifies instances where our regulatory policies may no longer strike the appropriate balance in encouraging new investment. The Final Rule identifies several policies that should be adjusted, where appropriate on the facts of a particular case, to encourage new transmission investment or otherwise remove impediments to such investment. Although each reform adopted by the Final Rule constitutes an "incentive" as that term is used by section 219, this label has caused some confusion in the comments. It is true that our reforms adopted in the Final Rule provide "incentives" to construct new transmission, but they do not constitute an "incentive" in the sense of a "bonus" for good behavior. Rather, as we explain below, each will be applied in a manner that is rationally tailored to the risks and challenges faced in constructing new transmission. Not every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. Our reforms therefore continue to meet the just and reasonable standard by achieving the proper balance between consumer and investor interests on the facts of a particular case and

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[1] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 2006 2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,222, *order on reh'g*, Order No. 679 A, 2006 2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,236 (2006), *order on reh'g*, Order No. 679 B, 119 FERC ¶ 61,062 (2007).

> considering the fact that our traditional policies have not adequately encouraged the construction of new transmission.[2]

Among other things, FERC Order No. 679 allowed Transmission Owners to propose to include 100% of prudently-incurred Construction Work in Progress (CWIP) in rate base, thereby permitting Transmission Owners to avoid accounting for and collecting a return on and a return of Allowances for Funds Used During Construction (AFUDC), to permit higher returns on equity which in turn affects the Net Plant Carrying Charge (NPCC), and to permit a hypothetical capital structure.

FERC explained that it adopted the CWIP incentive because recovery of 100% of CWIP in rate base relieves "pressures on [utility] finances caused by transmission development programs" and provides "up-front regulatory certainty" and "improved cash flow[s]" for utilities and rate stability for customers.[3] FERC also stressed that CWIP recovery provides utilities "a higher credit rating and lower cost of capital, thus benefiting customers."[4] A higher credit rating and lower cost of capital makes it cheaper and easier for a utility to attract capital investment and borrow money to construct facilities, which benefits customers because the utility has fewer costs to recover from customers for new facilities.[5] Pursuant to Order No. 679, FERC has approved CWIP in rate base because it helps transmission projects stay on schedule, it offers a prompt return on investment, it improves utility cash flow, it enhances the utilities' credit quality and debt ratings,[6] and it results in better rate stability for customers.[7] FERC found that including CWIP in rate base passes on costs to customers during the construction period, which raises prices to customers earlier. The rise in prices results in reduction in customer demand, which allows the utility to avoid investing in unnecessary capacity expansion. Based on this logic, FERC found that "CWIP will generally allow utilities to pursue least *total* cost strategies to meeting their customers' electric power demands,"[8] which results in cost savings for customers.

FERC incentives are available to those jurisdictional utilities that seek permission for and justify the need for the incentive. Furthermore, because FERC required utilities seeking CWIP recovery to submit additional information about their construction programs, the recovery of CWIP allows FERC the "opportunity to review and judge the prudence of costs as those costs are incurred and claimed in rate

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[2] Order No. 679 at PP 25, 26.

[3] Order No. 679 at P 115.

[4] *Id*. In the comments supporting FERC's notice of proposed rulemaking prior to Order No. 679, parties stated that the CWIP incentive allows the utility to balance the short and long term impact on rates, and avoid rate shock on customers. *See e.g.*, Comments of San Diego Gas & Electric Company, Docket No. RM06 4 000, at 15 (Jan 11, 2006) ("Including CWIP in rate base instead of accruing allowance for funds used during construction will increase short term rates during the construction period but reduce long term rates once the project goes into commercial service.").

[5] *See* Order No. 679 at 115.

[6] *PPL Elec. Utils. Corp.,* 123 FERC ¶ 61,068, at P 6 (2008); *see also id.* at P 42 (FERC approved PPL's request to recover 100% of CWIP in rate base because FERC found that the incentive " enhance[s] [PPL's] cash flow, reduce[s] interest expense, assist[s] Petitioners with financing, and improve[s] Petitioners' coverage ratios used by rating agencies to determine credit quality by replacing non cash AFUDC with cash earnings…[t]his, in turn, will reduce the risk of a down grade in Petitioners' debt ratings."); *see also ITC Great Plains, LLC,* 126 FERC ¶ 61,223, at PP 80 82 (2009); *Otter Tail Power Co.*, 129 FERC ¶ 61,287, at PP 32 33 (2009); *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284, at PP 57 61 (2007).

[7] *See Green Power Express LP,* 127 FERC ¶ 61,031, at P 67 (2009); *Potomac Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 42 (2008) ("By allowing CWIP for the Project, the rate impact of the Project can be spread over the entire construction period and will help consumers avoid a return on and of capitalized AFUDC.").

[8] *Id*. at 24,331.

base, rather than at a later point in time when a project is completed or abandoned and a potentially unwise investment has already been made."[9] Therefore, another benefit of CWIP is a regulatory agency's ability to review CWIP expenses to determine the prudence of the utilities' investments as they are incurred, which protects customers from imprudent costs

To date within SPP, FERC has approved rates including CWIP only for transcos, i.e., ITC-Great Plains, Prairie Wind, and Tall Grass. SPP's analysis of the projects novated to ITC-Great Plains and proposed to be novated to Prairie Wind has demonstrated that, for the same cost of capital, the cost of CWIP and AFUDC are essentially the same over time. The primary benefit of CWIP to the builder is that capital markets perceive less risk in funding projects receiving CWIP treatment in rates and consequently should fund projects eligible for CWIP at a lower cost of capital than an AFUDC only project. SPP has not analyzed the effect of CWIP treatment on a project's cost of capital. While holding cost of capital equivalent, SPP has analyzed the effect of CWIP's increased short-term rate impact versus AFUDC's increased long-term rate impact and has found them to be approximately rate neutral when viewed from the perspective of the present value to the transmission customer. To the extent that CWIP rate treatment of a project does result in a lower cost of capital than AFUDC would, SPP believes that CWIP will provide benefit to customers based on SPP's conclusion that the CWIP is otherwise equivalent to AFUDC.

Creating a definitive side-by-side comparison of the impacts of rate-making factors such as NPCC, CWIP, and AFUDC would be challenging for several reasons:

1. There is no adequate baseline for a comparison, as it may not be financially feasible for the original designated Transmission Owner to build the project, at least not at its traditional cost of service. The original designated Transmission Owner that decides to assign or novate a project may not deem it necessary to estimate the project cost.
2. The various cost components are interrelated. Neither SPP, the original designated Transmission Owner, nor a third-party builder, is able to precisely determine its financing costs in the project estimation phase.
3. The final rate is dependent on a FERC determination regarding the justness and reasonableness of the appropriate incentives.
4. The rate impact will depend on the Transmission Owner to which the project is assigned.

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Conclusion

In an effort to address the concerns raised by the Motions from the RSC, SPP Staff suggests the solution is multi-faceted. Staff believes increased transparency through the regional planning and cost allocation processes is beneficial, so proposes the following:

(1) SPP will provide proposed Novations and supporting analysis to the RSC for review and discussion prior to submission to the MOPC and Board of Directors/Members Committee for approval for filing with FERC.

(2) Staff will increase efforts to communicate with state commissions and state commission staff members about how the regional planning and cost allocation processes work, and more specifically

[9] Order No. 298 at 30,515.

how and when estimates for transmission projects are requested by SPP and provided by Transmission Owners to SPP, including opportunities for adjustments.

SPP also suggests increased communication between jurisdictional transmission owners and state commissions might result in a better understanding of the Transmission Owners' processes for development of cost estimates and causes for variances in cost estimates.