BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas Power Pool for a Certificate of Convenience and Authority to Transact the Business of an Electric Public Utility in the State of Kansas for Transmission Rights Only in Cross Service Territory of Southern Pioneer Electric Company and Ninnescah Rural Electric Company.	))))	Docket No. 18-KPPE-343-COC

DIRECT TESTIMONY OF

H. DAVIS ROONEY
VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

ON BEHALF OF

MID-KANSAS ELECTRIC COMPANY, INC.

JULY 9, 2018

Q. Please state your name.

A. My name is H. Davis Rooney.

Q. Are you an officer of Mid-Kansas Electric Company, Inc. ("Mid-Kansas")?

A. Yes. I am Vice President and Chief Financial Officer of Mid-Kansas and have been since November 21, 2008.

Q. By who are you employed and what is your business address?

A. I am employed by Sunflower Electric Power Corporation ("Sunflower"). My business address is 301 W. 13th Street, Hays, Kansas.

Q. What is your present position at Sunflower, how long have you held the position and other positions at Sunflower?

A. I am Vice President and Chief Financial Officer. I assumed this position on October 22, 2008. Although Mid-Kansas has no employees, I also hold the same position in Mid-Kansas.

Q. What prior positions have you held?

A. Prior to joining Sunflower, I held positions at Kansas City Power & Light Company ("KCP&L"); Aquila, Inc. ("Aquila"); and Arthur Andersen.

Q. Please describe your education, experience and employment history.

A. I graduated from the University of Kansas. I received a B.A., with distinction, in Mathematics (1982), and a B.S., with distinction, in Business (1983), with majors in Accounting and Business Administration and a concentration in Computer Science. I obtained my Certified Public Accountant certificate in 1983 and practiced in public accounting from 1983 to 1992. In 1992, I joined Aquila, Inc. as Controller of its WestPlains Energy division and held several positions focused on financial management and analysis including Director of Accounting and Finance for the Missouri Electric divisions of Aquila Networks. My last position at Aquila was as Director of Resource Planning and Commodity Analysis. At KCP&L I held the position of Manager, CEP Business Operations. My responsibilities included business planning and analysis concerning infrastructure investment projects for KCP&L and Aquila (d/b/a KCP&L Greater Missouri Operations Company).

Q. What is Sunflower's relationship with Mid-Kansas?

A. Sunflower provides contract services to Mid-Kansas for all the generation and transmission activities of Mid-Kansas. Mid-Kansas has no employees, so Sunflower operates Mid-Kansas under a contract approved by the Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to testimony of Mr. Larry Holloway, and in particular, his financial analysis of the transmission project proposed by KPP.

Q. What are the important considerations for the Commission to understand regarding the financial analysis?

A. The following are the key considerations:

- The KPP proposal is more expensive to the public than an alternative electrically equivalent SemCrude Substation Upgrade that was the result of the Commission approved local planning process. Granting of a certificate of convenience to KPP will not result in the selection of the least cost option and will raise the total costs paid by public.
- KPP's financial analysis addresses only the impact on the applicant and not the impact on the public. I prepare an analysis of the public costs and the public

benefits. Additionally, much of Mr. Holloway's financial analysis is incomplete, incorrect and misleading. A proper financial analysis of the costs and benefits to the public focuses on capital cost (investment outlay), incremental annual operating costs to the public (excluding financing costs), incremental benefits to the public, and a proper discount rate. Mr. Holloway's analysis does none of these.

- KPP is embracing a new business model that is aimed only at its self-interest and should be rejected by the Commission. That model strategically builds transmission projects that will be paid for by others. The benefits of the project are substantially from the ability to make others pay for those projects. The higher cost of the Kingman Direct Connection will not be recovered solely, or even mostly, from KPP customers but from other customers in western Kansas.

<u>**Projects Under Consideration**</u>

Q. What is the project in the application and what is the least cost project identified by the local planning process?

A. The first project called the Kingman Direct Connection and proposed by the Kansas Power Pool (KPP) in its application, involves building an additional substation near the existing Southern Pioneer Electric Company (SPEC) 115/34.5 kV SemCrude Substation and building approximately 5 miles of line to connect to an existing 34.5 kV line owned by the City of Kingman. The second project, identified as the least cost option in the Mid-Kansas local planning process, is called the SemCrude Substation Upgrade which would upgrade the existing SemCrude substation and require building approximately 3.2 miles of line to connect to the existing 34.5 kV line owned by the City of Kingman.

Project Costs and Who is Paying

Q. Please explain why you state that the Kingman Direct Connection is more expensive to the public than an alternative electrically equivalent SemCrude Substation Upgrade.

A. I performed a benefit to cost analysis and reached a conclusion that the cost of the Kingman Direct Connection was more than twice the cost to the public than the SemCrude Substation Upgrade, which was the least cost option resulting from the local planning process, as testified to by Dr. Tamimi.

Q. Can you summarize your benefit to cost analysis?

A. My analysis can be summarized in the following table:

Table 1

Item	**NPV Cost/(Benefit) Kingman Direct Connection**	**NPV Cost/(Benefit) SemCrude Substation Upgrade**
Investment Outlay	$3,021,106	$1,754,840
O&M Costs	$2,057,955	$1,195,384
Total NPV of Costs	$5,079,061	$2,950,224
Kingman Generation Savings	$(1,375,038)	$(1,375,038)
Area Loss Savings	$(321,056)	$(261,617)
Total NPV of Public Benefits	$(1,696,094)	$(1,636,655)
Net Public Cost/(Benefit)	**$3,382,967**	**$1,313,569**

The net cost to the public of the Kingman Direct Connection is more than twice the net cost to the public of the SemCrude Substation Upgrade.

Q. What types of costs are there for the proposed projects?

A. There are investment outlays (capital costs) and operating and maintenance (O&M) costs.

Q. What are the capital costs of the proposed projects?

A. Below is a table comparing the project capital costs:

Table 2		
	Kingman Direct Connection	SemCrude Substation Upgrade
Total Capital Cost	$3.0mm	$1.8mm

Q. Are there other capital costs not included above that may be required to complete the projects?

A. Yes. Neither project would be possible, but for the acquisition of the Ninnescah 115 kV line by Mid-Kansas in 2014 for $950,000. Although this cost is now a sunk cost and does not impact the public cost analysis today, it is important to recognize the financial commitment and efforts SPEC and the members of Mid-Kansas have made to help Kingman achieve full import capabilities.[1] Upgrades are required at the Kingman Substation. Exhibit LWH-3 attached to Mr. Holloway's testimony includes a letter from Olsson Associates that identifies a probable construction cost of $555,000 to replace the 7/10 MVA transformer with a 15/28 MVA transformer. The loss study performed under Dr. Tamimi's supervision identifies the potential need for a 6 MVAR Capacitor (approximately $250,000) at the Kingman Substation. These costs, if needed, would be required for either project. Additionally, the testimony of Mr. Sonju states that the Kingman Direct Connection project will cost over $1 million more than the $3.0 million KPP has presented. These capital costs, if incurred, will also require increased O&M costs.

Q. What would the public costs and benefits look like if these additional costs are considered?

[1] Additional discussion of the project development history can be found in the testimony of Randy Magnison.

A. The following table summarizes the public costs and benefits if the additional capital costs (Kingman city substation and costs identified by Mr. Sonju) and associated O&M costs were included for both projects:

Table 3

Item	**NPV Cost/(Benefit) Kingman Direct Connection**	**NPV Cost/(Benefit) SemCrude Substation Upgrade**
Investment Outlay	$4,884,814	$2,559,840
O&M Costs	$3,327,499	$1,743,744
Total NPV of Costs	$8,212,313	$4,303,584
Kingman Generation Savings	$(1,375,038)	$(1,375,038)
Area Loss Savings	$(321,056)	$(261,617)
Total NPV of Public Benefits	$(1,696,094)	$(1,636,655)
Net Public Cost/(Benefit)	**$6,516,219**	**$2,666,929**

The difference between to the two projects increases from $2.1 million to $3.8mm. This table was added for information only. The remainder of my testimony relates to Table 1.

Q. What are the annual O&M costs of the proposed projects?

A Below is a table comparing the 20-year NPV of each project's annual O&M costs. Included are operations, maintenance, administrative and general, and property taxes (or an allowance for city services) calculated as described later in my testimony:

Table 4		
	Kingman Direct Connection	SemCrude Substation Upgrade
NPV O&M costs	$2.1mm	$1.2mm

Q. What is the source of the information you used for these costs?

A. The KPP capital cost was obtained from Exhibit LWH-3 page 5 attached to Mr. Holloway's Direct Testimony. The SPEC capital cost was obtained from the PSE estimate in Mr.

Sonju's Direct Testimony. The O&M costs are calculated as described later in my testimony.

Q. Why is the capital cost of the project the key financial consideration?

A. Because the two projects are electrically equivalent, as confirmed by Dr. Tamimi's Direct testimony in this docket, both projects provide the same physical transmission service and benefits. The key financial consideration for the Commission is whether the KPP requested project puts higher or lower costs on the public than other alternatives. Most other annual costs of the project (operations, maintenance, overheads, etc.) are presumed to be proportional to the project cost. Variations in those other costs, will generally be dwarfed by the cost of the project itself. Although cost allocations need to be addressed, the primary financial issue to the rate paying public is whether to allow a high cost project when an electrically equivalent lower cost project is available.

<u>Cost Benefit and Economic Analysis</u>

Q. In Table 2 and Table 3 of his Direct Testimony and Table 12 of Exhibit LWH-3, Mr. Holloway presents recaps of the costs and benefits of his scenarios. Do you agree with his analysis?

A. No. Mr. Holloway makes a number of significant errors in his analysis. Below is a summary of my testimony on this topic:

a. <u>Public as a Whole</u>. His analysis is deficient because he does not analyze the economic impact on the public as a whole; only the impact to his utility (KPP) and his member (Kingman). [2]

[2] *Kansas Gas & Electric Co. v. Public Service Comm 'n*, 122 Kan. 462 (1927) – "In determining whether such certificate of convenience should be granted, the public convenience ought to be the commission's primary concern,

b. Costs vs. Cost Allocations. Costs and benefits are not the same as cost allocations. Many of the "benefits" to KPP and Kingman are cost shifts from KPP ratepayers to non-KPP ratepayers and therefore not public "benefits", especially for those ratepayers paying the cost of these "benefits" to KPP. Mr. Holloway's testimony does not distinguish between "costs" and "cost allocations". This causes confusion over the true costs and benefits of the Kingman Direct Connection to the public

c. Capacity Sale Benefit, Mr. Holloway inappropriately includes as a benefit of the project the potential sale of generation capacity. KPP can sell all its available 20-year excess capacity today, without this project. Additionally, Mr. Holloway vastly over states the potential benefit of generation capacity sales.

d. Improper Analysis. His analysis is neither a proper project analysis nor a proper analysis of revenue requirements. As discussed below, he includes items that should not be included and excludes items that should be included. Additionally, as discussed below he uses an improper discount rate.

e. Incremental vs. Total Costs and Benefits. Rather than properly analyzing the incremental costs and benefits, Mr. Holloway presents a mix of total and incremental costs, but only incremental benefits. He fails to present the total benefits when including total costs; or more properly, including only incremental costs and incremental benefits.

the interest of public utility companies already serving the territory secondary, and the desires and solicitations of the applicant a relatively minor consideration."

f. Inappropriate O&M Calculation. Mr. Holloway uses an inappropriate comparison group to estimate his O&M charge rate, and then applies it to less than the full project cost, understating his O&M cost estimate.

g. Inappropriate Loss Benefit Calculation. Mr. Holloway does not quantify the incremental change in losses that will occur from either project. Instead, he quantifies the amount of losses KPP will not be billed by SPEC if the Kingman Direct Connection is built instead of the electrically equivalent SemCrude Substation Upgrade.

h. Other Items. Mr. Holloway inappropriately presents costs and benefits in his scenarios.

a. Public as A Whole

Q. What problems did you find with the cost and benefit analysis prepared by Mr. Holloway?

A. First, and most importantly, although his analysis and testimony is that up to 97%[3] of the costs of the project, plus $9.4mm of local access charges currently paid by KPP plus the cost of the existing Kingman 34.5 kV line, will be paid by the non-KPP ratepaying public, he provides no testimony as to how this facilitates the public's convenience and necessity other than for KPP/Kingman. Frankly, I do not see how he could justify the project under such a public interest standard since KPP's approach is to build a more expensive project than the least cost electrically equivalent project and make others pay for it. KPP's failure to address the impact of its project on the public as a whole is a material deficiency. Obtaining the Commission's support for building more expensive projects that impose cost recovery on those who neither need it nor benefit from it, will accelerate the growth of

[3] Holloway Direct Testimony, p.24, footnote 28. Winfield cost allocation was based on zone load ratio share. KPP is 2.69% of the Mid-Kansas zone.

transmission costs well beyond the benefits they provide. Kansas is already struggling to contain the growth of utility costs. Transmission related costs are a contributor to that cost growth. In my opinion, it is imprudent to facilitate a more expensive project when a less expensive one will do. It is wasteful of materials and contributes to higher costs in serving the public.

b. <u>Costs vs. Cost Allocations</u>

Q. You state that costs are not the same as cost allocations and Mr. Holloway does not distinguish between the two. Can you elaborate?

A. Yes. Allocations are costs that do not go away but are simply shifted from one ratepayer to another. From a public cost point of view, it is not appropriate to claim a public benefit when one has merely reduced the cost to one group of ratepayers and increased the cost by the same amount to another group of ratepayers.

Q. What costs benefits does KPP claim that are cost allocations?

A. In Mr. Holloway's Exhibit LWH-3 on page 14 of 17 in Table 11, he lists most of the costs and benefits that appear in his analysis. Notably, KPP omits the following important items from his analysis, some of which I will discuss later:

- The actual capital costs (investment outlay) of the two projects;
- The O&M cost of the SemCrude Substation Upgrade, which is the relevant incremental cost to the public, not the local access delivery service (LADS) charges (sometimes referred to as local access charge (LAC)).
- The substantial benefits of the existing 6MW connection;
- The cost shift of the existing Kingman 34.5 kV line to the Mid-Kansas pricing zone when he places it under the Southwest Power Pool (SPP) Open Access Transmission

Tariff (OATT) as described in Mr. Holloway's direct testimony (Holloway Direct p.24 lines 1-3 and footnote 28);

Below is a reproduction of Mr. Holloway's Table 11 in his Direct Testimony identifying those costs that are allocations.

Table 5

Item	Total 2019 NPV	Categorization
SPEC Project Bond Payments	$2,302,492	Not Relevant
Kingman Direct Connection Bond Costs	$4,365,099	Not Relevant
O&M Costs (Kingman Direct Connection)	$1,424,180	Cost
LAC Charges with 6 MW limit	$9,395,727	Allocation
LAC Charges with No Limit	$11,624,627	Allocation
Increase in Capacity Payments	$2,186,469	Allocation
Kingman Loss Savings	$1,292,015	Benefits Both Proj
Kingman Generation Savings	$2,374,793	Benefits Both Proj.
Kingman Capacity Sale Revenue	$7,529,412	Not Relevant

Q. Why are some items categorized as "Not Relevant"?

A The first two items are not items that are properly included in a project financial cost benefit analysis, and therefore are not relevant to the analysis. I will discuss these two items in more detail later. Although the capacity sale revenue has been vastly overstated, as discussed later, KPP is able achieve the sale of all its excess generation capacity today. As such, it is not an incremental benefit of this project, and therefore, is not relevant.

Q. Can you explain further the items categorized as public benefits to both projects.

A. The generation savings is the easiest to explain. Kingman runs its generation when its loads are high because of import constraints at its current delivery point. Both projects will remove that import constraint, reducing the need for Kingman to run its generation. The

Kingman Direct Connection and the SemCrude Substation Upgrade are electrically equivalent, as discussed by Dr. Tamimi.

The loss savings is next. Kingman incurs electrical losses on the 34.5kV line from Pratt to Cunningham. These losses will be replaced by lower losses on the Ninnescah line but higher losses from increasing the imports to Kingman. Both projects will have the same losses on the Ninnescah line. Both projects will also have similar losses across a 115/34.5kV transformer. Again, this is true because the two projects are electrically equivalent.

Q. Are the LAC charges really allocations and not costs savings?

A. Yes. Neither project will change the amount of existing costs to be recovered by Southern Pioneer from the public in its LAC cost-based rates. Mr. Holloway proposes only to shift recovery of those costs from KPP to other customers in western Kansas. Therefore, the LAC charges are really allocations between groups of ratepayers and not savings to the public.

Q. **Are the Kingman Capacity Payments to KPP really allocations and not costs savings?**

A. Yes. The capacity payment between KPP and Kingman is an allocation of costs between KPP and its members. This can be seen in Table 12 of Exhibit LWH-3 where KPP lists a benefit to KPP, and Kingman (KPP's member) shows an equivalent expense. Clearly costs are being shifted from all the members of KPP to Kingman. As KPP is self-regulated as to its rates with its members, this amount can be as large or as small as the KPP board members decide. They are allocations among ratepayers, not costs or benefits to the public as a whole.

Q. What impact should these allocations have on the Commission's decision making?

A. The Commission's concern is with the public interest. As such, it should consider whether it is in the public interest to approve a $5.0mm (capital and O&M cost) for the Kingman Direct Connection project when an electrically equivalent option in the SemCrude Substation Upgrade that only costs $3.0mm is available.

c. <u>Capacity Sale Benefit</u>

Q. Why do you believe Mr. Holloway has made such a significant issue of the generation in his testimony?

A. Mr. Holloway assigns a $7.5mm value to selling all 16MW of Kingman capacity in the market for the next 20 years. Without this "value" there are insufficient public benefits under his analysis to justify his project.

Q. Do you agree with KPP's valuation of KPP's excess generation?

A. No. It is a clear over-statement by Mr. Holloway designed to justify his higher cost project. Without this "benefit" the project produces only increased costs to the public.

Q. Why do you disagree with KPP's valuation?

A. I disagree for the following reasons:

- As stated in the testimony of Mr. Linville and Dr. Tamimi there is currently no SPP or Mid-Kansas transmission or economic limitation on KPP's ability to deliver the Kingman generation to serve KPP's load in SPP. Building a new interconnection does not change this and therefore it does not produce a public benefit.
- KPP does not have 20 years of excess capacity to sell. KPP is capacity deficient after 2022. You can't sell what you don't have.[4]

[4] See Table 1 in Mr. Linville's direct testimony.

- To have excess capacity to sell, KPP would have to acquire it at a cost. KPP has omitted the cost of acquiring that excess capacity in its calculation. Acquiring capacity at a market cost, and then selling it at market, would greatly reduce, if not eliminate the benefit completely.

Q. What do you conclude regarding the valuation of KPP's excess generation?

A. As described in the testimony of Mr. Linville and Dr. Tamimi, KPP has vastly overstated the value of selling its excess capacity. In any event, KPP currently can obtain value from all the pooled excess capacity currently available to it. As such, this is not a valid incremental benefit of the Kingman Direct Connection project.

Q. Are there other generation issues?

A. Yes. At page 14 of Exhibit LWH-3 attached to Mr. Holloway's direct testimony, he discusses the allocation of certain SPP resource adequacy revenues. He states, "Because Kingman generation cannot be delivered economically over the SPEC 34.5 kV system it would not be available for these revenues." This statement is not accurate.

In March, SPP filed its proposed tariff with FERC for approval. I reviewed the proposed tariff and noted no economic test that determines eligibility for the revenue allocation. Further, and more the point, it specifically provides that excess capacity for purposes of revenue allocation includes all firm resources.[5] As Mr. Holloway testifies on page 15 line 21, "Today, all 5 of these (Kingman) generators are considered designated network resources under KPP's SPP NITSA." Designated network resources are considered firm. This is supported by KPP response to Staff DR 18 in which the supplied

[5] From section 14.1 of the proposed tariff. "LRE Excess Capacity: Deliverable Capacity and Firm Capacity less Resource Adequacy Requirement, or zero if the Deliverable Capacity and Firm Capacity is less than or equal to the Resource Adequacy Requirement". In this context "and" means "plus".

Resource Adequacy Workbook shows the Kingman generators as firm resources (See **Exhibit HDR-6**).

d. **<u>Improper Analysis</u>**

Q. In your opinion is Mr. Holloway's cost benefit analysis appropriately prepared?

A. No. I have spent a significant portion of my career performing project analysis and cost benefit analyses. Mr. Holloway makes several fundamental errors. First, he includes financing cash flows in his analysis in the form of Bond Issue Payments and Bond Reserve Refunds. These are not appropriate for a proper NPV project cost benefit analysis. Additionally, he has selected an inappropriate discount rate. Proper project analysis requires the discount rate be appropriate to the project Mr. Holloway instead uses a 2% inflation assumption as the basis for his discount rate (Holloway Direct Appendix F, page 2 of 3) rather than a project appropriate discount rate, significantly distorting the NPV calculations.

Q. What support do you have for your conclusion that inclusion of financing costs and the discount rate are inappropriate?

A. Contrary to the fundamentals of NPV analysis, Mr. Holloway has a) included financing costs; b) not included the total investment outlay; c) included a mix of current cash flows and incremental cash flows instead of just incremental cash flows; and d) has not used a discount rate that is either KPP's weighted average cost of capital (WACC) or a project based discount rate. Although some financing costs enter into a net present value of revenue requirements analysis through the return calculations, Mr. Holloway has not prepared such an analysis since he has omitted the cost of his debt service coverage requirements. I refer to an authoritative article addressing these issues titled "Financing

Costs and NPV Analysis in Finance and Real Estate." By: Delaney, Charles J.; Rich, Steven P.; Rose, John T. Journal of Real Estate Portfolio Management. Jan-Mar2008, Vol. 14, Issue 1, p. 35-39. Excerpts from that article succinctly describe certain principles of NPV analysis including the irrelevance of financing costs and the appropriate discount rate as follows (emphasis added):

> "A review of eight finance principles texts, which (in their full-length or abbreviated edition) account for nearly 80% of the introductory finance textbook market, revealed that only four books—Brealey, Myers, and Marcus (2004), Keown, Martin, Petty, and Scott (2006), Moyer, McGuigan, and Kretlow (2006), and Ross, Westerfield, and Jordan (2007)—specifically mention financing costs in discussing NPV analysis. <u>But all four books are consistent in arguing (1) that NPV analysis should focus on the total investment outlay to purchase the assets of a project without any adjustment for how the assets will be financed, and (2) that financing costs should not be considered in calculating the cash flows expected from the project.</u> Likewise, the remaining four textbooks can be viewed as implicitly arguing for the irrelevance of financing costs in NPV analysis since these books ignore such costs in their capital investment examples…"
>
> "First, finance theory teaches that in evaluating new projects, <u>the focus should be on the incremental cash flows</u> generated by the assets of the project, which are unaffected by the manner in which the assets are financed. Second, as Keown et al. (2006, p. 298) note, "(w)hen we discount the incremental cash flows back to the present at the required return, we are implicitly accounting for the cost of raising funds to finance the new project. In essence, the required rate of return reflects the cost of the funds needed to support the project…"
>
> "Moreover, in the finance approach to NPV analysis the relevant "cost of funds" <u>for a project of the same risk as the firm's existing assets</u> should be the firm's weighted average cost of capital (WACC) as calculated using weights from the firm's market-value target capital structure…"
>
> "In addition, <u>finance texts typically argue that firms should use a consistent cost of funds for all projects of the same risk, even if different projects are actually funded by different mixes of debt and equity</u>, say, at different points in time. Otherwise, a firm might discount two projects of the same risk by different required rates of return if the firm focused on the specific manner of financing, which would distort the calculated NPV's of the two projects [e.g., the discussions in Keown et al. (2006, p. 340) and Moyer et al. (2006, p. 409)]."

Q. What would be an appropriate discount rate?

A. As noted in the article above, the Company's weighted average cost of capital would be appropriate "for a project of the same risk as the firm's existing assets…"

Q. What is KPP's weighted average cost of capital (WACC)?

A. In response to Mid-Kansas data request 11, (see DR attached as **Exhibit HDR-7**) KPP replied "The KPP is not required to calculate a weighted average cost of capital." KPP was unable to provide its WACC.

Q. Were you able to estimate KPP's WACC?

A. Yes. Using other data request responses, I was able to estimate KPP's WACC for this project as approximately 9.10%. I also was able to estimate a probable range for KPP's WACC as 8.36% to 12.12%.

Q. Are KPP's existing assets the same risk as the proposed project?

A. No. KPP has only one major utility asset representing nearly 100% of their utility assets but only approximately 50% of their total assets. That one asset is KPP's fractional ownership interest in the Dogwood natural gas combined cycle generating facility. As of the end of 2016, I saw no ownership by KPP of transmission or distribution assets.

Q. What discount rate do you recommend?

A. The above article goes on to say "…finance texts typically argue that firms should use a consistent cost of funds for all projects of the same risk, even if different projects are actually funded by different mixes of debt and equity…" SPP adopted a net present value of revenue requirements template to aid in analyzing transmission project alternatives in their competitive bidding process. That model was reviewed by internal and outside consultants as well as SPP member representatives. I performed the review and provided input to the template on behalf of Sunflower. In that model, SPP adopted a standard 8% discount rate as the appropriate transmission project based discount rate. I recommend using an 8% discount rate consistent with the conclusions of SPP and its membership.

e. <u>Incremental Costs vs. Total Costs</u>

Q. Does Mr. Holloway's analysis properly focus on incremental cash flows?

A. No. The analysis includes a mix of existing and incremental flows. As noted in the article above, a proper analysis focuses on <u>total investment outlay</u> and <u>incremental cash flows</u>. By including an unbalanced mix of current and incremental costs and benefits, the analysis confuses the cost of the status quo with the costs and benefits of the project at issue.

Q. Can you give an example?

A. Yes. Mr. Holloway includes the results of his NPV analysis as Table 2 on page 19 of his direct testimony. In the "Do Nothing" scenario, KPP presents the NPV cost of LAC charges of $9.4mm. This is a current cost not an incremental cost. In the "SPEC Project" scenario, KPP presents the NPV cost of LAC charges of $11.6mm. This is both the current cost ($9.4mm) and the incremental cost ($2.2mm) of LAC charges. In the SPEC Project scenario, he presents the benefit of Kingman Generation Savings of $2.2mm. This is only the incremental benefit of obtaining import service beyond the current 6MW limit. However, the analysis inexplicably omits the benefit of the $9.4mm of LAC charges. Just as access to import service above 6MW produces a benefit, so does the access to the first 6 MW. KPP presents an unbalanced mix of current and incremental costs and benefits, the analysis confuses the cost of the status quo with the costs and benefits of the project at issue.

Q. Did you estimate the savings created by access to the first 6 MW of import service?

A. Yes. The existing 6MW allows Kingman to replace over 95% of its self-generation with market energy. Had KPP estimated the NPV of generation savings for the first 6MW in the same manner as they did for the incremental reduction in generation, the comparable savings number is nearly $40mm. The current generation savings KPP is achieving from its 6 MW access to market power at Cunningham (see **Exhibit HDR-5**) are over 4 times the cost of the LADS charges they pay SPEC.

Q. Are these numbers relevant to the project analysis at hand?

A. No, although they do provide some context as to the degree of imbalance in KPP's analysis, as well as why the initial 6MW project was so much more attractive than the follow-on project to remove the 6MW limit. Only the incremental costs and benefits to the public are relevant to the project analysis of the public impact.

Q. Which costs and benefits are relevant to the project analysis?

A. The incremental costs and benefits of "Do Nothing" are all zero. No change, no incremental costs or benefits. The incremental costs and benefits to the public are the following:

- The cost of the total investment outlay (capital costs) for each scenario
- The cost of incremental O&M costs
- The benefit of Kingman generation savings
- The benefit of loss savings from the 34.5kv system

f. <u>Inappropriate O&M Calculations</u>

Q. How did Mr. Holloway estimate operations, maintenance, and administrative and general (O&M) expenses?

A. He developed a comparison group from several transmission formula rates and developed an O&M rate per dollar of net plant. He then applied that rate only to the KPP portion of the project costs.

Q. Does this approach result in a reasonable estimate of O&M costs?

A. No. I believe his estimate is understated by more than half a reasonable estimate.

Q. Please explain.

A First the impact to the public is not the O&M on the KPP portion of the project, but rather the O&M on the entire project. KPP's O&M estimate is based on $2.4mm of the $3.0mm total project. Therefore, KPP's estimate is only 80% of the O&M for the full project. Secondly, the comparison group is not representative of costs on 34.5 kV systems. Lastly, the comparison group was limited to only companies with very new construction.

Q. Why is the comparison group not representative of costs on 34.5 kV systems?

A. KPP chose only comparison companies that own 345 kV, not 34.5 kV transmission plant. As a rule of thumb 345 kV plant is about 9 times the cost of 34.5 kV plant to construct per mile. Additionally, higher voltage transmission is built to a more robust standard than lower voltage plant. They are generally built with steel, not wood, structures that can withstand environmental risks of weather and deterioration better and thus require less maintenance. Additionally, many of the maintenance and operations costs, such as line patrols and vegetation management, do not have a significantly higher cost to perform for 345 kV as compared to 34.5 kV. The result is that 345 kV plant O&M costs as a percent of plant investment are much lower than lower voltage construction.

Q. Why is the age of the net plant important?

A. The O&M cost is lowest in the first few years. For example, routine vegetation management and pole inspections may not be needed for several years after construction. The O&M cost of new plant will be lowest in the first years, before age and conditions require any maintenance. This approach fails to recognize that O&M costs will grow faster than inflation over time as age and condition drive higher costs. KPP only grows its O&M by inflation.

Q. Can you suggest a better reference?

A. Yes. Since KPP has testified that they are following the approach they did in Winfield, I looked to that docket. In Docket No. 12-KPPE-630-MIS, the costs for O&M, A&G, rate case, and city services (property taxes) amounted to 6.21% of transmission net plant. This is comparable to the 6.13% rate for similar costs in SPEC's 34.5 kV formula rate it recently filed in Docket No. 18-SPEE-477-RTS. Both dockets reflect the costs of operating and maintaining lower voltage systems in Kansas. Additionally, the average age of the SPEC plant is approximately 10 years. This is right in the middle of the 20-year forecast period used by KPP, but also in the first 25% of the total expected life. As such it includes at least some of the increased costs in excess of inflation that come from age and conditions. I recommend using a 6% rate instead of the 3% rate proposed by KPP. See **Exhibit HDR-2**.

Q. Should the incremental O&M cost as a percent of net plant be different for KPP and SPEC?

A. Based on the extent of my review, no, not significantly. While there may be variations, both companies will need to follow similar good utility practices in maintaining their projects.

Q. Should the total dollars of O&M cost be different for KPP and SPEC?

A. Yes. SPEC's total incremental O&M costs should be lower. SPEC is already maintaining one transformer and so its incremental cost to maintain one larger transformer will be less than KPP's cost to maintain its own additional transformer. The SemCrude Substation Upgrade has fewer miles of line than the KPP project, so those costs will also be less. This cost difference is substantially captured by applying the same O&M rate to the different capital costs of the two projects. My calculations of the O&M costs are included as **Exhibit HDR-1**.

g. <u>Inappropriate Loss Benefit Calculation</u>

Q. Did KPP present a loss study in its direct testimony to determine the change in losses between its various options?

A. No.

Q. How did KPP estimate the quantity of losses used in its benefit calculation?

A. Mr. Holloway describes how his loss benefit is determined at page 11 of his Exhibit LWH-3 attached to his direct testimony. Essentially, he describes how KPP is billed 1.86% for system average losses by SPEC, not the actual losses. His testimony states "With the Kingman Direct Connection, the SPEC loss component of 1.86% will no longer be charged." KPP is describing how KPP is billed for losses, not how actual losses will change. He is describing how the applicant is impacted, not the public. The impact on the public is the incremental losses of the projects, not how KPP is or isn't billed for those losses.

Q. How did KPP value the losses used in its benefit calculation?

A. KPP used its total embedded costs of capacity and energy to value its losses, $20.83/kW-mo. and $29.63/MWh, respectively, in 2020 (Exhibit LWH-3 page 10, Table 7 and KPP response to Staff DR 8).

Q. Are these appropriate values to use?

A. No. If KPP needed to provide additional energy or capacity for a shortfall due to losses, it could acquire that energy or capacity at market rates. If KPP could "free up" energy or capacity by reducing its losses, it would buy less market energy or have additional excess capacity to sell. As Mr. Holloway testifies on page 16 line 12 of his direct testimony, "The current value for excess generation capacity in the SPP market is over $2.00/kW-mo." This is much less than the $20 for KPP's embedded capacity costs. The market value of the capacity and energy is not KPP's embedded costs since embedded costs include sunk costs that will not change by a change in the amount of losses.

Q. Did Mid-Kansas perform a loss study?

A. Yes. Mid-Kansas staff, under the supervision of Dr. Tamimi, quantified the area peak kW losses in each scenario using the KPP projected loads included with KPP's AQ request to SPP. The results are attached as **Exhibit HDR-3.**

Q. Did you assign a valuation to the losses identified in the Loss Study?

A. Yes. The calculations are attached as **Exhibit HDR-4** and the incremental 20-year NPV cost or benefits from the changes in losses produced by each project are summarized below:

Table 6

Item	NPV Cost/(Benefit) Kingman Direct Connection	NPV Cost/(Benefit) SemCrude Substation Upgrade
Area Loss Savings	$(321,056)	$(261,617)

h. Other Items.

Q. Are there other items inappropriately evaluated in Mr. Holloway's analysis?

A. Yes. Mr. Holloway inappropriately presents the costs and benefits in his scenarios. In doing so, he double counts the benefits to Kingman of the generation savings. He counts it both as a "cost" in his Do Nothing Scenario and as a benefit in the two project scenarios. This leads the reader to the incorrect conclusion that going from the Do Nothing to the project scenarios creates twice as much benefit from the generation savings as is appropriate.

Summary Economic Analysis

Q. Based on your review have you developed a financial analysis of the projects?

A. Yes. Using a conventional finance approach to NPV, and based on an 8% discount rate the following table summarizes the costs and benefits to the public of the SPEC Project and the KPP Kingman Direct Connection Project:

Table 7

Item	**NPV Cost/(Benefit) Kingman Direct Connection**	**NPV Cost/(Benefit) SemCrude Substation Upgrade**
Investment Outlay	$3,021,106	$1,754,840
O&M Costs	$2,057,955	$1,195,384
Total NPV of Costs	$5,079,061	$2,950,224
Kingman Generation Savings	$(1,375,038)	$(1,375,038)
Area Loss Savings	$(321,056)	$(261,617)
Total NPV of Public Benefits	$(1,696,094)	$(1,636,655)
Net Public Cost/(Benefit)	**$3,382,967**	**$1,313,569**

The net cost to the public of the Kingman Direct Connection is more than twice the net cost to the public of the SemCrude Substation Upgrade.

Q. What are the differences between your analysis and KPP's?

A. As described in my testimony above:

- I replaced the bond payments and bond reserve financing costs with the investment outlay, as is appropriate for a financing net present value analysis.
- I adjusted the O&M rate from 3% to 6% to be more representative of lower voltage operation and maintenance costs. I also included O&M costs for the SemCrude Substation Upgrade where KPP had omitted them.
- I used the same annual generation savings as proposed by KPP.
- I replaced KPP's billing-based loss benefit with the incremental public loss benefit or cost calculated from an area loss study.
- I removed the Capacity Sale because it is not an incremental benefit of the Kingman Direct Connection project.
- I removed the LADS charges shifted from KPP customers to SPEC customers and the KPP Capacity Charges between Kingman and KPP because they are reallocations of costs among members of the public, not incremental cost reductions benefiting the public as a whole.
- I replaced KPP's inflation based discount rate of 2% with the standard transmission project discount rate of 8% used by SPP, as is appropriate for a financing net present value analysis.

<u>**Present Value of Revenue Requirements**</u>

Q. Did you perform a net present value of revenue requirements (PVRR) analysis?

A. Yes. I used the PVRR template that was developed by SPP for competitive transmission projects to calculate the PVRR for the two scenarios. The PVRR template was adopted to standardize assumptions and project analysis presentations to make review and comparisons easier. The template was developed in a stakeholder driven process that included internal (SPP and stakeholders) and external (third party) expert reviews. I prepared a calculation using the template for the Kingman Direct Connection. I also prepared a calculation for the SemCrude Substation Upgrade. Because the SemCrude Substation Upgrade calls for part of the project to be funded by KPP, I split the SemCrude Substation Upgrade into two parts, a KPP portion and an SPEC portion. I calculated the PVRR of the two parts and added them together to get the total PVRR for the SemCrude Substation Upgrade.

Q. Did you make any modifications to the template or to the results?

A. Yes, I made two modifications. First, I changed the standard 2.5% inflation assumption in the template to match the 2.0% assumption used by KPP. Second, I made a modification to the results. The template assumes a 4-year construction cycle and discounts all costs back to 4-years before the in-service year. To be consistent with KPP's presentation of NPV as of the in-service year, I adjusted the template result to reflect the NPV as of the in-service year, not 4-years before the in-service year.

Q. **Did you identify any limitations to the template?**

A. Yes. It is my understanding that SPEC does not recover income taxes on a normalization basis. Instead it collects income taxes when paid (flow-through basis). The template reflects taxes on a normalization basis. If properly reflected, I believe the impact would be to make the SPEC PVRR lower (better in comparison to KPP).

Q. What were the assumptions made for the PVRR analysis?

A. The following table captures the key assumptions:

Table 8

Item	KPP Assumptions	SPEC Assumptions
Capital Cost	$3,021,106	$1,754,840
O&M Rate	6.0%	6.0%
Interest Rate	5.361%[6]	5.26
Percent of Project Initially financed	100%	85%[7]
DSC Requirement	1.30[8]	1.75
Loan Type	Mortgage	Mortgage
Loan Term	20 years	30 years
Income Tax Rate	0.00%	26.53%
Inflation Escalator	2.0%	2.0%

Q. What were the results?

A. The PVRR for the SemCrude Substation Upgrade was $4.0mm and for the KPP project it was $6.7mm. Like the finance approach the KPP project is higher cost to the public than the SemCrude Substation Upgrade. This is primarily because of the higher cost of investment and the higher projected incremental O&M costs. The table below summarizes the results shown in **Exhibit HDR-8.**

Table 9

	Kingman Direct Connection	SemCrude Substation Upgrade
Present Value of Revenue Requirements (PVRR)	6,017,146	3,569,399

[6] The KPP interest rate of 4.5% used by Mr. Holloway was adjusted to an effective interest rate to reflect his 3% bond issuance costs and his 10% bond reserve requirement.
[7] This is SPEC's debt to capitalization ratio, although the debt required for $23mm of capex over the last three years was only about 10% of the projects, as reported in their audited financial statement.
[8] This is KPP's reported target DSC, although the 3-year average of the DSC ratios reported in KPP audited financial statements 2015-2017 is 1.57 and would significantly increase the PVRR.

Economic Benefits Projected by Mr. Kriz

Q. Did KPP provide an economic benefit analysis in its testimony in this docket?

A. No, it did not. Mr. Holloway referenced some testimony filed in the 17-092 Docket by Mr. Kriz[9], but no such testimony is part of this case. As such, KPP has not presented any evidence upon which the Commission could find that the Kingman Direct Connection will provide economic benefits to the Kingman local economy. However, I will respond to the Kriz testimony in case the Commission decides to somehow consider it in this case.

Q. Does the Kriz report address benefits to the public?

A. No.

Q. Please explain.

A. First, the testimony of Mr. Kriz from the 17-092 docket to which Mr. Holloway refers in this case considers only how the numbers provided by Mr. Holloway impact the City of Kingman. It does not consider how Mr. Holloway's proposal impacts the larger public which includes the City of Kingman, the customers of Southern Pioneer and the customers of Mid-Kansas. As noted above, up to 97% of the Kingman Direct Connection project will be paid by customers other than KPP or Kingman. Additionally, the Local Access Charge costs will be shifted from Kingman to other customers. Any economic benefits to Kingman from these cost shifts, will be more than offset by economic detriments to the rest of the public.

Secondly, the entirety of Mr. Kriz testimony is predicated on assumptions provided by Mr. Holloway but apparently not vetted by Mr. Kriz. Neither Mr. Holloway, nor Mr. Kriz describe how those assumptions were developed.

[9] Holloway Direct, p. 20, footnote 23.

Third, the impact, though touted as impressive, is small relative to Kingman's economy.

Q. To the extent the Commission considers Mr. Kriz' analysis, can you respond to his economic analysis and conclusion that the KPP project would provide significant economic benefits to Kingman and should be allowed to proceed?

A. Yes. I have three comments regarding Mr. Kriz' analysis and conclusion.

First, and most importantly, like Mr. Holloway, Mr. Kriz' analysis focuses only on the impact of the project on Kingman; it does not consider the public interest. My understanding of the issue before the Commission is to determine what is in the public interest for Kansas and all customers impacted by the KPP project if it were to go forward. This includes the customers of Southern Pioneer as well as other customers in the region who will pay for the Kingman Direct Connection by virtue of the SPP OATT. Presumably, one of the benefits to the City of Kingman is the avoidance of its local access delivery charge. Since, these costs will still need to be recovered from someone, the City is simply shifting that cost to others. Obviously, assuming there is a positive economic impact to Kingman from shifting costs away from Kingman, there is going to be an off-setting negative economic impact in the area to which those costs are shifted. As a public utility regulated by the Commission, KPP is aware of the overall public interest standard applicable to this situation but chose to limit their retention of Mr. Kriz' service and testimony to an evaluation that only considers whether "the KPP project makes economic sense *for the City*".[10]

[10] Kriz Direct in 17-092, p. 12, emphasis added.

Second, the analysis is highly subjective and its results should not be viewed as very reliable. Since there is no data specifically evaluating the impact of utility rate reductions on business attraction, retention and expansion, Mr. Kriz uses tax rate data for this factor and assumes utility rate reductions would have approximately one-fourth the impact of tax reductions.[11] This assumption is not supported. Mr. Kriz also assumes that the reduction in cost for utility service will be equally distributed among all income groups in Kingman. Unless usage habits among various income groups are identical, in practice and reality this distribution of the reduction will not happen.

Additionally, Mr. Kriz uses data obtained from KPP on estimated growth rates and the value of cost savings Kingman will realize because of the project.[12] Such data cannot be assumed to be independent and unbiased.

Finally, even if we accept Mr. Kriz' results, the amount of the benefits he calculates are miniscule in comparison to the overall numbers for Kingman. For example, total personal income in Kingman in 2014 was $228 million, compared to the $130,729 annual increase in labor income he attributes to the KPP project (Kriz Exhibit 1, Table 1 and Table 3).[13] The very small amounts he calculates as benefits when considered in the overall scheme of the economic environment in Kingman undermine the credibility of his conclusion that the impact will directly cause additional jobs or businesses to locate or expand in Kingman.

Q. What about the offsetting negative impact of the KPP project on other Kansas citizens, such as the customers of Southern Pioneer and Mid-Kansas?

[11] Kriz Direct in 17-092, pp. 2-3; Kriz Exhibit 1, p. 4.
[12] Kriz Direct in 17-092, Exhibit 1, pp. 3-4.
[13] Kriz Direct in 17-092, Exhibit 1, pp. 4, 6.

A. One must assume that the negative impact of costs shifts at least fully offsets the positive impacts. If this were not true, economic development projects across Kansas would be able to produce infinite growth through an endless cycle of cost shifts. Again, Mr. Kriz does not factor the negative impacts of cost shifts to other ratepayers into his analysis.

The New Transmission Business Model

Q. What are the key aspects of this new transmission business model?

A. The new model strategically builds transmission projects that are paid for by others. The benefits of the project are substantially from the ability to make others pay for those projects.

Q. How has this new business model developed?

A. FERC has radically changed the landscape for transmission development. FERC's focus in transmission policy, has become a) increased reliability, b) greater socialization of costs; and c) reduced, if any, consideration of costs. Whether they intended to or not, FERC has reduced many of the old constraints of least cost planning and cost/benefit prudency in favor of a "more transmission" policy. Although open, transparent, and coordinated centralized planning at the RTO (SPP) level and coordinated local planning at the TO level are intended to provide the benefits of holistic least cost planning and prudency, there have been gaps and mixed levels of compliance. In the sparsely populated areas of western Kansas, the cost implications from the new concepts are magnified by the limited number of ratepayers. Even seemingly small cost shifts can compound to significantly impact rate payors. Sunflower and Mid-Kansas have been aggressively pushing back on these policies to limit the rate impacts on Kansas customers.

Q. Can you give an example of this push back?

A. Yes, since 2012, Mid-Kansas and Sunflower have been instrumental in restudying, redesigning or reconsidering SPP's western Kansas projects, resulting in the reduction, deferral, or withdrawal of nearly $190M of transmission projects on the Bulk Electric System. Considering Sunflower and Mid-Kansas together had transmission net utility plant of only $115M in 2011, this is a significant savings for our customers. While we have been partially successful in constraining unnecessary costs at the Bulk Electric System level, Sunflower/Mid-Kansas transmission net utility plant still more than doubled to $286M by 2017. The new project development battle ground is in local planning (sub-transmission and distribution) projects such as this one.

Q. Why do you believe this is the new battle ground?

A. Sunflower and Mid-Kansas are aware of projects (including this one) where the cost of the initial proposed project design is significantly greater than the least cost solution and/or is designed at a higher voltage to enhance the chances of getting someone else to pay for it. This approach is being actively marketed to municipals and cooperatives by industry consultants and at least one independent transmission company. [14]

Q. What do these consultants advise?

A. Below are some quotes from a recent "info-mercial" mailed out by MCR Performance Solutions[15] (emphasis added):

[14] See testimony of Stephen J. Epperson in Docket 17-KPPE-092-COM.
[15] "Transmission Spending in SPP: Are You Obtaining Your Share of Transmission Investment?" April 2018 MCR Performance Solutions, LLC.

- Each entity "should analyze its current distribution and sub-transmission assets to determine if there are investments that can be made <u>to make existing assets eligible for transmission revenue recovery</u>."
- "The lower the percentage of load a company has of the entire load in the joint pricing zone, the more attractive their investment is, <u>because other customers will pay a portion of the costs</u>."
- "<u>The larger the investment, the larger the dollar margin</u>."
- "Upgrading an aging transmission system and <u>obtaining a rightful share of new transmission</u> has become imperative as industry factors continue to drive increases in transmission rates and transmission costs become a more significant portion of the customer's total bill."

Note the point about small load ratio share entities in a zone. If a project owner has a larger load ratio share of the zone, expensive projects cause increased rates to the project owner. The owner's desire to keep rates low is in alignment with the owner's desire to keep project costs low. However, if a project owner has a small load ratio share, projects with high costs can result in reduced rates to the project owner and higher rates to everyone else in the zone. The profits and cost shift benefits for the owner from the project are larger than the project owner's share of the cost of the project. This is a perverse incentive. Projects are no longer driven by sound economics and sufficient overall benefits, but by pursuing shifts in allocated costs to other customers. Potential project owners will seek to justify transmission investments by making claims of inadequate reliability and poor service. Rarely are these claims supported by documentation, and rarely do they relate to the customary standards for sufficient and efficient service. More importantly, I reject the idea that the road to lower cost is through driving higher costs onto others. This is a race to higher electric transmission prices for everyone, including the ones building it.

Q. Does MCR also view it as a race?

A. Yes, their website at www.mcr-group.com references a white paper prepared by MCR entitled "The Transmission Arms Race Continues: Are You Obtaining Your Share of Transmission Investment?". Basically, the paper abstract implies that if you are not investing as fast as everyone else, you are carrying higher costs from "them", when, by investing more yourself, they could be carrying more of your costs.

Q. Is any of this activity occurring or is it just hypothetical?

A. It is occurring. I refer to South Central MCN, LLC's ("South Central") activity with Tri-County Electric Cooperative, Inc. Originally, Tri-County submitted a filing through SPP to FERC to uplift the costs of its facilities to the SPS[16] pricing zone. SPP filed the request with FERC and FERC subsequently approved the request. SPS became aware that its rates had risen because of the uplift. Xcel Energy Services Inc. (XES), on behalf of SPS, complained to FERC and FERC subsequently ruled the Tri-County facilities were radial and not eligible for uplift. These facilities have since been acquired by South Central. South Central has again filed for uplift of the facility costs based upon significant new capital investments. XES has again complained. See the Comments of XES in FERC Docket ER18-1267, attached hereto as **Exhibit HDR-9**.

Q. Does the Tri-County/South Central filing epitomize the new business model?

A. It does and XES's comments could not sum up the concerns any better. I found the following XES comments and allegations instructive:

[16] Southwest Public Service Company (SPS) is a utility operating company affiliate of Xcel Energy Services Inc.

- Page 7. "As XES previously warned, South Central is attempting to cram significant new capital into potentially unneeded transmission development so South Central can then transfer control to SPP and earn its rate of return on those investments from other SPP transmission service customers who receive no benefits from those facilities and had no role or opportunity for input on the planning of those facilities."

- Page 8. "The centrality of cost-shifting in the South Central business model is also highlighted by South Central's ability to force Tri-County to buy back all of the facilities if the cost shift to SPP is not successful. As stated in South Central's Section 203 application in Docket No. EC15-206-000, once the expected upgrades are completed, the costs of those upgrades as well as the formerly radial Tri-County facilities "are expected to be included in a larger SPP pricing zone, thereby reducing [Tri-County's] overall transmission costs."

- Page 9. "But even though South Central was a public utility transmission provider when these facilities were planned and developed, South Central never followed any planning procedures outlined in a tariff when developing those facilities and that planning was not subject to SPP oversight. Moreover, South Central did not follow any of the Commission's open access requirements for transmission planning despite stating that the assets it acquired from Tri-County "will be subject to the open access policies of the Commission." Instead, the facilities to be developed were agreed upon by Tri-County and South Central as part of the initial acquisition, without any claim that those facilities were needed."

Q. Could these issues impact Kansas?

A. Yes. Closer to home, GridLiance, the parent company of South Central, is working with KPP and the City of Winfield to purchase a line owned by the City of Winfield.[17]

Q. What strategies are employed to achieve shifting costs to others?

A. The number of strategies keeps increasing but I have identified the following:

1. **Bypass local planning** (or change local planning or get your own local planning) - This allows an entity to build what it wants, without consideration of the implications on others. This is one of the issues cited by XES in the South Central docket. South Central is employing its own local planning criteria to build what it

[17] See article attached as **Exhibit HDR-10.**

wants and then uplifting it to the SPS zone so others can pay for it. At issue is "Does the local planning criteria of the uplift zone (SPS) have priority over the local planning criteria of the uplifting transmission owner (South Central)?"

2. **Loop a Line –** Lines that are looped, and not radial, are easier to uplift to achieve cost shifting. This is also an issue in the XES comments. South Central is converting radial lines to looped lines by building additional facilities. XES is concerned that this is driven solely by the cost shift benefits.
3. **Increase the Voltage –** Higher voltage lines are easier to uplift and can shift out of local planning to SPP planning, where oversight is sometimes less.
4. **Connect to a Different Zone –** This is similar to "Loop a Line" but connecting to a different zone increases the likelihood of uplift under SPP rules.
5. **Add a Customer –** Connecting an additional customer aids in classifying facilities as transmission. The value of the cost shift can easily exceed the cost to interconnect a new customer, or even to entice a new customer to interconnect.

Q. Does KPP embrace these cost shift strategies?

A. Yes. KPP is already using "bypass local planning." KPP has rejected the least cost results of the local planning process in favor of a more expensive project that increases KPP's opportunity to shift costs to others. KPP, as a public utility, should put the public interest ahead of its self-interest, which in this instance means seeking and supporting the option that provides the lowest total cost to serve the public.

Q. Your analysis shows a net public cost for the Kingman Direct Connection. Why does KPP show a benefit from this project?

A. The Kingman Direct Connection only produces a net benefit to KPP by being able to shift the LADS charges to other ratepayers. It does not produce a net benefit to the public.

Q. How will those costs shifts occur?

A. Even without uplift to the zone, by building a more expensive project than necessary, KPP will shift the cost of its LADS charges to other customers. The LADS cost shift is valued by KPP at up to $11.6M[18] and is the largest benefit identified by KPP. As discussed above, KPP's second largest benefit, selling its excess capacity for the next 20 years, is not achievable because KPP does not have excess capacity after 2022. The LADS cost shift benefit to KPP is sufficient to pay for the higher cost of the project to KPP. This LADS charge shift will occur even without uplifting the project to the Mid-Kansas zone. In pursuing the Kingman Direct Connection project, KPP has put its self-interest ahead of the public interest.

Q. Are you saying customers should never be allowed to leave the 34.5 kV system?

A. No. There will certainly be occasions where the least cost project to serve the public results in (not justifies) a customer leaving the local access system.

Q. Does KPP discuss any additional cost shift strategies to achieve uplift?

A Yes. KPP discusses the "Add a Customer" strategy. In his Direct Testimony, pp. 23-24, Mr. Holloway testifies:

> "…KPP stands ready, willing and able to work with the City of Kingman to provide direct access to SPP OATT service, up to and including placing applicable portions of the Kingman Direct Connection and Kingman's existing 34.5 kV line under the SPP OATT. Should other entities in the area wish to access the SPP transmission network by interconnection with these facilities, KPP and the City of Kingman will provide the necessary transmission service without the needless restrictions SPEC places on transmission service on use of its 34.5 kV transmission service."

[18] Holloway direct testimony, Exhibit LWH-3, page 14, Table 11.

By "needless restrictions" he means "cost". Mr. Holloway is saying KPP is actively looking at strategies to also shift its $5M of project costs and O&M costs to others as well.[19] Such a customer addition would effectively provide both KPP and the interconnecting customer with free use of the Kingman Direct Connection facilities. KPP would potentially be able to shift those costs to the Mid-Kansas zone, where 97% would be paid for by others. Rather than the new customer paying a reasonable portion of the Kingman Direct Connection, nearly all the costs would be shifted to other ratepayers. Since making this happen could shift an additional $5M or more in costs to others, the financial incentives to entice another customer to connect are high.

Q. Are you saying customers should never be allowed to connect to new or different facilities?

A. No. Since the Semcrude Substation Upgrade is electrically equivalent but at a lower cost, any new customer connecting to the Kingman 34.5 kV line will be still be served at a lower total cost to the public.

Q. Does KPP discuss some of the other cost shift strategies to achieve uplift?

A. Yes. KPP indirectly discusses "Loop a Line" and "Connect to a Different Zone". At Exhibit LWH-3, p. 2, under a section titled "Alternatives Not Considered", KPP considers interconnections at Rago, Westar (a different zone), and other locations. KPP discusses these in the context of service and reliability. However, these interconnections, while bringing more costs and likely few benefits, would potentially allow KPP to shift all the costs of multiple projects (the Kingman Direct Connection, the existing Kingman 34.5 kV line, as well as the new interconnection) to the Mid-Kansas zone. Since they would only

[19] Holloway Direct Testimony, pp. 23-24.

pay 3% of the final costs, they could afford to spend well over $60 million on such a project and still come out ahead because of the cost shift. Effectively, there is no cost barrier.

Q What would be the likely driver of such projects?

A. As described above, these are projects are not driven by sufficient public benefits, but rather, by shifts in allocated costs to other customers. If not constrained by the public utilities themselves, then these costs can only be constrained by the Commission.

34.5 kV Business Model

Q. What is the advantage of keeping the LADS as a separate charge apart from the SPP revenue requirement?

A. One consideration is that it more closely associates the payment costs with those who should pay it. It adds cost discipline by more closely aligning charges with cost causers. The current model is nothing new or out of the ordinary. The separate charge is a continuation of the Aquila tariffs. Aquila had a FERC approved separate charge for its lower voltage system back to at least 1995. There are customers who are only on the high voltage system who do not benefit from the low voltage system. By having a separate charge for the low voltage system, only those customers who are on the low voltage system are charged to use it. If the cost are socialized among all customers, customers who don't use the low voltage system are forced to pay for it. This separate charge attempts to assign greater costs to cost causers on the lower voltage system rather than socializing those costs across both those customers only on the higher voltage system and those customers on the lower voltage system. This approach drives greater investment discipline and keeps costs lower for all customers. Waste will not be minimized and efficiency maximized when valuable limited resources (transmission capacity) can be obtained for free. Our members have clearly not chosen the path of least resistance. However, the member owners feel it is the path that is more likely to keep rates lower for all customers while maintaining reliable service, all in the public interest.

Q. In your opinion, is the approval of the Kingman Direct Connection in the public interest?

A. No. The Kingman Direct Connection is more than twice the net cost to the public of the least cost project that came out of the Commission approved local planning process. The planning process determined that the SemCrude Substation Upgrade was the least cost option for the public. My analysis supports the local planning recommendation. Furthermore, the Commission approval of KPP's application will greatly undermine the objectives of local planning in achieving the least cost solution.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION OF DAVIS ROONEY

STATE OF KANSAS)
) ss
COUNTY OF ELLIS)

The undersigned, Davis Rooney, upon oath first duly sworn, states that he is the Vice President and Chief Financial Officer for both Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc., and that the foregoing testimony was prepared by him or under his supervision, that he is familiar with the contents thereof, and that the statements contained therein are true and correct to the best of his knowledge and belief.

Davis Rooney

Davis Rooney

Subscribed and sworn to before me this 9th day of July, 2018.

NOTARY PUBLIC - State of Kansas
Reneé K. Braun
My Appt. Expires 4/30/2022

Reneé K. Braun

Notary Public

My appointment expires: April 30, 2022

Exhibit HDR-1

O&M Costs

		KPP Direct		SPEC Project
	NPV at SPP Discount Rate	$ 2,057,955		$ 1,195,384
	Inputs			
	Transmission Capital Costs	$ 3,021,106		$ 1,754,840
	O&M Rate as percent of Net Transmission Plant	6.00%		6.00%
	First Year O&M Cost	$ 181,266		$ 105,290
	Escalation Rate	2%		2%
Year				
2020		$ 181,266		$ 105,290
2021		$ 184,892		$ 107,396
2022		$ 188,590		$ 109,544
2023		$ 192,361		$ 111,735
2024		$ 196,209		$ 113,970
2025		$ 200,133		$ 116,249
2026		$ 204,135		$ 118,574
2027		$ 208,218		$ 120,946
2028		$ 212,382		$ 123,364
2029		$ 216,630		$ 125,832
2030		$ 220,963		$ 128,348
2031		$ 225,382		$ 130,915
2032		$ 229,890		$ 133,534
2033		$ 234,487		$ 136,204
2034		$ 239,177		$ 138,928
2035		$ 243,961		$ 141,707
2036		$ 248,840		$ 144,541
2037		$ 253,817		$ 147,432
2038		$ 258,893		$ 150,381
2039		$ 264,071		$ 153,388

Exhibit HDR-2

Determination of O&M Rate

Docket No. 12-KPPE-630-MIS				**Docket 18-SPEE-477-RTS**	
Staff Testimony In Support of S&A. Gatewood. P4				**Exhibit 3-B p1-3**	
	Winfield Costs			**SPEC**	
O&M	81,102	3.46%		1,293,444	5.68%
A&G	35,393	1.51%		103,495	0.45%
Rate Case	8,000	0.34%			
City Services	21,015	0.90%			
Property Tax	-	0.00%		included above	
Total OM, AG, Tax/City Service	**145,510**	**6.21%**		**1,396,939**	**6.13%**
Transmission Net plant	2,344,187			22,774,084	
Gross Transmission Plant				29,310,492	
Accum Depr Transmission Plant				(6,536,408)	
Annual Transmission Depr				677,892	
Approximate Average Age				9.64	
O&M rate as percent of transmission net plant		**6.00%**			

Exhibit HDR-3

Area Loss Study
kW Losses

		Current Status	**Niniscah 115 kV Options - Kingman at AQ Load Forecast**	
	Scenario	Base	Kingman Direct Connection	SemCrude Upgrade
	Source	Pratt 34.5 kV	New 115 kV Tap	SemCrude 34.5 kV
	Projects	No Projects Kingman at 6 MW	New 115 kV Tap 6 MVAR Capacitor SemCrude 5% Boost	6 MVAR Capacitor SemCrude 5% Boost
Area Losses (kW)	**2018**	1,341	1,497	1,529
	2019	1,342	1,542	1,575
	2020	1,342	1,613	1,649
	2021	1,343	1,664	1,701
	2022	1,344	1,741	1,781
	2023	1,346	1,824	1,866
	2024	1,347	1,912	2,022
	2025	1,347	1,974	2,024
	2026	1,349	2,069	2,118
	2027	1,351	2,171	2,223
	2028+	1,351	2,171	2,223

Exhibit HDR-4

Area Loss Study
Valuation of Losses

			Kingman Direct Connection	SemCrude Upgrade
	20 Year Change from Base Case Cost/(Benefit)		-$321,056	-$261,617
	Assumptions			
	Energy Cost $/kWh	0.050	0.050	0.050
	Inflation	2%	2%	2%
	Discount	8%	8%	8%
	Load Factor	60%	46%	46%
	Loss Factor	0.3984	0.2467	0.2467
	20 Year NPV	$2,668,523	$2,347,467	$2,406,906

Year	Year	Base	Kingman Direct Connection	SemCrude Upgrade
1	**2018**	$234,003	$161,891	$165,352
2	**2019**	$238,861	$170,093	$173,733
3	**2020**	$243,639	$181,483	$185,533
4	**2021**	$248,697	$190,965	$195,212
5	**2022**	$253,859	$203,798	$208,481
6	**2023**	$259,322	$217,784	$222,799
7	**2024**	$264,705	$232,857	$246,254
8	**2025**	$269,999	$245,216	$251,427
9	**2026**	$275,808	$262,158	$268,366
10	**2027**	$281,741	$280,584	$287,304
11	**2028**	$287,376	$286,195	$293,050
12	**2029**	$293,124	$291,919	$298,911
13	**2030**	$298,986	$297,758	$304,889
14	**2031**	$304,966	$303,713	$310,987
15	**2032**	$311,065	$309,787	$317,207
16	**2033**	$317,286	$315,983	$323,551
17	**2034**	$323,632	$322,302	$330,022
18	**2035**	$330,105	$328,748	$336,623
19	**2036**	$336,707	$335,323	$343,355
20	**2037**	$343,441	$342,030	$350,222

Exhibit HDR-5

Kingman Current Energy Savings from 6MW Import				
Calculated Same Way KPP Calculated Incremental Energy Savings in Their Response to Staff DR 8				
				Percent of Energy
	Kingman Annual Energy Forecast - 2019	51,535	MWh	100.0%
	Average Kingman Self Generation	2,539	MWh	4.9%
	Average Kingman Import with 6MW limitation	48,996	MWh	95.1%
	Cost for Kingman to Self Generate per MWh	$70	per MWh	
	Cost to Self Generate	$ 3,429,749		
	Cost for KPP to Supply per MWh - 2019	$ 29.44	per MWh	
	Cost for KPP to Supply	$ 1,442,454		
	Annual benefit -2019	$ 1,987,294		
	Growth rate	2%	Same rate used by KPP for incremental energy savings	
	Annual benefit - 2020	$ 2,027,040		
	KPP Discount Rate	2%	Same rate used by KPP for incremental energy savings	
	NPV at 2% (KPP Rate)	**$39,745,888**		
Year				
2020		$ 2,027,040		
2021		$ 2,067,581		
2022		$ 2,108,933		
2023		$ 2,151,111		
2024		$ 2,194,134		
2025		$ 2,238,016		
2026		$ 2,282,777		
2027		$ 2,328,432		
2028		$ 2,375,001		
2029		$ 2,422,501		
2030		$ 2,470,951		
2031		$ 2,520,370		
2032		$ 2,570,777		
2033		$ 2,622,193		
2034		$ 2,674,637		
2035		$ 2,728,129		
2036		$ 2,782,692		
2037		$ 2,838,346		
2038		$ 2,895,113		
2039		$ 2,953,015		

Exhibit HDR-6

Portion of KPP Response to Staff DR 18 Showing Kingman Resources Reported as Firm

6	**Resource Identificati**	**Firm Capacity - Summer**			
7	Plant Name - 1	2018	2019	2020	2021
8	Kingman Municipal Power and Light Plant	3.3	3.3	3.3	3.3
9	Kingman Municipal Power and Light Plant	2.3	2.3	2.3	2.3
10	Kingman Municipal Power and Light Plant	2.4	2.4	2.4	2.4
11	Kingman Municipal Power and Light Plant	2.4	2.4	2.4	2.4
12	Kingman Municipal Power and Light Plant	6.0	6.0	6.0	6.0

Exhibit HDR-7

KPP Response to Mid-Kansas DR 11.

KANSAS POWER POOL RESPONSE TO MID-KANSAS ELECTRIC COMPANY, INC.
INFORMATION REQUEST #11

Company Name	Kansas Power Pool
Docket Number	18-KPPE-343-COC
Request Date	June 20, 2018
Response Date	July 3, 2018

Please Provide the Following:
What is KPP's weighted average cost of capital?

Response:
The KPP is not required to calculate a weighted average cost of capital. KPP is a municipal energy agency, not a corporation.

Submitted By:	Kansas Power Pool
Submitted To:	Mid-Kansas Electric Company, Inc.

Exhibit HDR-8
Page 1 of 7

Net Present Value of Revenue Requirements (PVRR) Recap

	Kingman Direct Connection	SPEC Semcrude Upgrade
KPP Portion	$ 6,017,146	$ 2,720,750
SPEC Portion		$ 848,650
Total	**$ 6,017,146**	**$ 3,569,399**

Net Present Value of Revenue Requirements (PVRR)
Kingman Direct Connection - Summary

SPP Transmission Project:			
Present Value Revenue Requirement / Carrying Charge Analysis			
		All Costs in $	
Line	Assumptions:	Value	Notes
1	Investment	$ 3,021,106	
2	Tax Life	15	
3	Book Life	40	
4	Discount Rate	8.00%	
5	Composite Tax Rate	0.00%	See Wkst 3A
6	Property Tax Rate	0.00%	See Wkst 3B
7	Rate Base Adjustment (annual, year 1)	$ -	See Wkst 3C
8	O&M (annual, year 1)	$ 181,266	See Wkst 3D
9	A&G (annual, year 1)	$ -	See Wkst 3E
10	Other Annual Costs	$ -	See Wkst 3F
11	AFUDC (adds to investment to get total project cost)	$ -	See instruction to the right
12	Tax Basis for Land Costs (informational only)	$ -	
13	Tax Basis Reductions (AFUDC-Equity, Land, etc.)	$ -	
	Results:		
14	**Present Value Revenue Requirement**	**$4,422,782**	
	Present Value Revenue Requirement as of In-Service Year	**$ 6,017,146**	

Bidders: Enter bid-specific values in yellow shaded cells, and make no changes in gray or other cells

CWIP Recovery Assumptions	
Recover CWIP (Yes: 1; No: 0)	0
Percent of Total CWIP in Rate Base (up to 50%)	0.00%
	Spend Per Year
Year -3 Spend Percentage	0.00%
Year -2 Spend Percentage	0.00%
Year -1 Spend Percentage	0.00%
Year - 0 Spend Percentage	0.00%
Total Project Spend (should be 100%)	0.00%

Bidder Name:	**KPP - Kingman Direct Connection**

Net Present Value of Revenue Requirements (PVRR)

Kingman Direct Connection – Detail

SPP Transmission Project:

Present Value Revenue Requirement / Carrying Charge Analysis

Bidders: Enter bid-specific values in yellow shaded cells, and make no changes in gray or other cells

All Costs in $

Line	Assumptions:	Value	Notes
1	Investment	$ 3,021,106	
2	Tax Life	15	
3	Book Life	40	
4	Discount Rate	8.00%	
5	Composite Tax Rate	0.00%	See Wkst 3A
6	Property Tax Rate	0.00%	See Wkst 3B
7	Rate Base Adjustment (annual, year 1)	$ -	See Wkst 3C
8	O&M (annual, year 1)	$ 181,266	See Wkst 3D
9	A&G (annual, year 1)	$ -	See Wkst 3E
10	Other Annual Costs	$ -	See Wkst 3F
11	AFUDC (adds to investment to get total project cost)	$ -	See instruction to the right
12	Tax Basis for Land Costs (informational only)	$ -	
13	Tax Basis Reductions (AFUDC-Equity, Land, etc.)	$ -	
	Results:		
14	**Present Value Revenue Requirement**	$4,422,782	
	Present Value Revenue Requirement as of In-Service Year	$ 6,017,146	

CWIP Recovery Assumptions	
Recover CWIP (Yes: 1; No: 0)	0
Percent of Total CWIP in Rate Base (up to 50%)	0.00%
	Spend Per Year
Year -3 Spend Percentage	0.00%
Year -2 Spend Percentage	0.00%
Year -1 Spend Percentage	0.00%
Year - 0 Spend Percentage	0.00%
Total Project Spend (should be 100%)	0.00%

Bidder Name:	KPP - Kingman Direct Connection

Instructions for calculating AFUDC Allowed in Rate Base at In-Service Date

Title 18: PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

Electric Plant Instructions, 3. A (17) : Allowance for funds used during construction (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$A_i = s(S/W) + d(D/D + P + C)(1-S/W)$

$A_e = [1-S/W][p(P/D+P+C)+c(C/D+P+C)]$

A_i = Gross allowance for borrowed funds used during construction rate.

A_e = Allowance for other funds used during construction rate.

S = Average short-term debt.

s = Short-term debt interest rate.

D = Long-term debt.

d = Long-term debt interest rate.

P = Preferred stock.

p = Preferred stock cost rate.

C = Common equity.

c = Common equity cost rate.

W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.

Bidders Must provide supporting calculations for AFUDC, reduced for any CWIP in Rate Base

b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in §35.13 of the Commission's Regulations Under the Federal Power Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdictions. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

Note: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as *Electric Plant in Service* and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

Bidders should make no changes to any text, formulas, numbers or empty cells below this line

Year	Investment	CWIP	Book Depreciation	Net Plant	Bonus Depreciation (Wkst G)	Tax Depreciation (Note A)	Residual Plant	Deferred Income Tax (Note B)	Accumulated Deferred Income Tax	Adjustment to Rate Base (Wkst C)
-4		0								
-3		$ -								
-2		-								
-1		-								
0		-								
0	$ 3,021,106			$ 3,021,106						
1			$ 75,528	$ 2,945,578	$ -	$ 151,055	$ 2,870,051	$ -	$ -	$ -
2			75,528	2,870,051	-	287,005	2,583,046	-	-	-
3			75,528	2,794,523	-	258,305	2,324,741	-	-	-
4			75,528	2,718,995	-	232,625	2,092,116	-	-	-
5			75,528	2,643,468	-	209,363	1,882,753	-	-	-
6			75,528	2,567,940	-	188,215	1,694,538	-	-	-
7			75,528	2,492,412	-	178,245	1,516,293	-	-	-
8			75,528	2,416,885	-	178,245	1,338,048	-	-	-
9			75,528	2,341,357	-	178,547	1,159,500	-	-	-
10			75,528	2,265,830	-	178,245	981,255	-	-	-
11			75,528	2,190,302	-	178,547	802,708	-	-	-
12			75,528	2,114,774	-	178,245	624,463	-	-	-
13			75,528	2,039,247	-	178,547	445,915	-	-	-
14			75,528	1,963,719	-	178,245	267,670	-	-	-
15			75,528	1,888,191	-	178,547	89,123	-	-	-
16			75,528	1,812,664	-	89,123	0	-	-	-
17			75,528	1,737,136	-	-	0	-	-	-
18			75,528	1,661,608	-	-	0	-	-	-
19			75,528	1,586,081	-	-	0	-	-	-
20			75,528	1,510,553	-	-	0	-	-	-
21			75,528	1,435,025	-	-	0	-	-	-
22			75,528	1,359,498	-	-	0	-	-	-
23			75,528	1,283,970	-	-	0	-	-	-
24			75,528	1,208,442	-	-	0	-	-	-
25			75,528	1,132,915	-	-	0	-	-	-
26			75,528	1,057,387	-	-	0	-	-	-
27			75,528	981,859	-	-	0	-	-	-
28			75,528	906,332	-	-	0	-	-	-
29			75,528	830,804	-	-	0	-	-	-
30			75,528	755,277	-	-	0	-	-	-
31			75,528	679,749	-	-	0	-	-	-
32			75,528	604,221	-	-	0	-	-	-
33			75,528	528,694	-	-	0	-	-	-
34			75,528	453,166	-	-	0	-	-	-
35			75,528	377,638	-	-	0	-	-	-
36			75,528	302,111	-	-	0	-	-	-
37			75,528	226,583	-	-	0	-	-	-
38			75,528	151,055	-	-	0	-	-	-
39			75,528	75,528	-	-	0	-	-	-
40			75,528	0	-	-	0	-	-	-
Check Sum			$ 3,021,106		$ -	$ 3,021,106		$ -		

Year	Rate Base	Average Rate Base	Return of Interest (Note C)	Return on Equity (Note C)	Income Taxes	Property Taxes (Wkst B)	O&M (Wkst D)	A&G (Wkst E)	Other (Wkst F)	Annual Rev Requirement	Annual Carrying Charge Rate	Annual Rev Req Excl. Bk Depr	Annual Carrying Charge Rate
-4	0									0			
-3	$ -	$ -	$ -	$ -	$ -					$ -	0.00%	$ -	0.00%
-2	-	-	-	-	-					-	0.00%	-	0.00%
-1	-	-	-	-	-					-	0.00%	-	0.00%
0	-	-	-	-	-					-	0.00%	-	0.00%
0	$ 3,021,106												
1	$ 2,945,578	$ 2,983,342	$ 159,574	$ 86,673	$ -	$ -	$ 181,266	$ -	$ -	$ 503,041	16.86%	$ 427,513	14.33%
2	2,870,051	2,907,815	154,734	91,349	-	-	184,892	-	-	506,502	17.42%	430,974	14.82%
3	2,794,523	2,832,287	149,635	96,275	-	-	188,590	-	-	510,027	18.01%	434,499	15.34%
4	2,718,995	2,756,759	144,262	101,466	-	-	192,361	-	-	513,616	18.63%	438,089	15.89%
5	2,643,468	2,681,232	138,601	106,935	-	-	196,209	-	-	517,272	19.29%	441,744	16.48%
6	2,567,940	2,605,704	132,636	112,697	-	-	200,133	-	-	520,993	19.99%	445,466	17.10%
7	2,492,412	2,530,176	126,352	118,767	-	-	204,135	-	-	524,783	20.74%	449,255	17.76%
8	2,416,885	2,454,649	119,732	125,164	-	-	208,218	-	-	528,641	21.54%	453,113	18.46%
9	2,341,357	2,379,121	112,756	131,903	-	-	212,382	-	-	532,568	22.39%	457,041	19.21%
10	2,265,830	2,303,593	105,406	139,003	-	-	216,630	-	-	536,567	23.29%	461,039	20.01%
11	2,190,302	2,228,066	97,663	146,484	-	-	220,963	-	-	540,637	24.26%	465,109	20.88%
12	2,114,774	2,152,538	89,504	154,365	-	-	225,382	-	-	544,779	25.31%	469,251	21.80%
13	2,039,247	2,077,010	80,908	162,670	-	-	229,890	-	-	548,995	26.43%	473,467	22.80%
14	1,963,719	2,001,483	71,851	171,419	-	-	234,487	-	-	553,285	27.64%	477,758	23.87%
15	1,888,191	1,925,955	62,309	180,637	-	-	239,177	-	-	557,651	28.95%	482,124	25.03%
16	1,812,664	1,850,427	52,256	190,350	-	-	243,961	-	-	562,094	30.38%	486,566	26.29%
17	1,737,136	1,774,900	41,663	200,583	-	-	248,840	-	-	566,614	31.92%	491,086	27.67%
18	1,661,608	1,699,372	30,503	211,364	-	-	253,817	-	-	571,212	33.61%	495,684	29.17%
19	1,586,081	1,623,844	18,745	222,724	-	-	258,893	-	-	575,889	35.46%	500,362	30.81%
20	1,510,553	1,548,317	6,356	234,692	-	-	264,071	-	-	580,647	37.50%	505,119	32.62%
21	1,435,025	1,472,789	-	-	-	-	269,352	-	-	344,880	23.42%	269,352	18.29%
22	1,359,498	1,397,262	-	-	-	-	274,739	-	-	350,267	25.07%	274,739	19.66%
23	1,283,970	1,321,734	-	-	-	-	280,234	-	-	355,762	26.92%	280,234	21.20%
24	1,208,442	1,246,206	-	-	-	-	285,839	-	-	361,366	29.00%	285,839	22.94%
25	1,132,915	1,170,679	-	-	-	-	291,556	-	-	367,083	31.36%	291,556	24.90%
26	1,057,387	1,095,151	-	-	-	-	297,387	-	-	372,914	34.05%	297,387	27.15%
27	981,859	1,019,623	-	-	-	-	303,334	-	-	378,862	37.16%	303,334	29.75%
28	906,332	944,096	-	-	-	-	309,401	-	-	384,929	40.77%	309,401	32.77%
29	830,804	868,568	-	-	-	-	315,589	-	-	391,117	45.03%	315,589	36.33%
30	755,277	793,040	-	-	-	-	321,901	-	-	397,429	50.11%	321,901	40.59%
31	679,749	717,513	-	-	-	-	328,339	-	-	403,867	56.29%	328,339	45.76%
32	604,221	641,985	-	-	-	-	334,906	-	-	410,433	63.93%	334,906	52.17%
33	528,694	566,457	-	-	-	-	341,604	-	-	417,131	73.64%	341,604	60.31%
34	453,166	490,930	-	-	-	-	348,436	-	-	423,964	86.36%	348,436	70.97%
35	377,638	415,402	-	-	-	-	355,405	-	-	430,932	103.74%	355,405	85.56%
36	302,111	339,874	-	-	-	-	362,513	-	-	438,040	128.88%	362,513	106.66%
37	226,583	264,347	-	-	-	-	369,763	-	-	445,291	168.45%	369,763	139.88%
38	151,055	188,819	-	-	-	-	377,158	-	-	452,686	239.75%	377,158	199.75%
39	75,528	113,291	-	-	-	-	384,701	-	-	460,229	406.23%	384,701	339.57%
40	0	37,764	-	-	-	-	392,395	-	-	467,923	1239.08%	392,395	1039.08%
Check Sum										18,850,918		15,829,812	

Notes

A Tax Depreciation includes the tax calculation using WACOC Tax Table data, plus Bonus Depreciation.

B Deferred Income Tax calculation accounts for Net Operating Loss (if applicable) associated only with this individual project.

C Based average of Beginning of Year and End of Year rate base amounts.

Exhibit HDR-8
Page 4 of 7

Net Present Value of Revenue Requirements (PVRR)
SemCrude Substation Upgrade – Capital Cost Portion Direct Assigned to KPP- Summary

SPP Transmission Project:				**Bidders: Enter bid-specific values in yellow shaded cells, and make no changes in gray or other cells**	
Present Value Revenue Requirement / Carrying Charge Analysis					
		All Costs in $			
Line	**Assumptions:**	Value	Notes	**CWIP Recovery Assumptions**	
1	Investment	$ 1,366,042			
2	Tax Life	15		Recover CWIP (Yes: 1; No: 0)	0
3	Book Life	40		Percent of Total CWIP in Rate Base (up to 50%)	0.00%
4	Discount Rate	8.00%			
5	Composite Tax Rate	0.00%	See Wkst 3A		Spend Per Year
6	Property Tax Rate	0.00%	See Wkst 3B	Year -3 Spend Percentage	0.00%
7	Rate Base Adjustment (annual, year 1)	$ -	See Wkst 3C	Year -2 Spend Percentage	0.00%
8	O&M (annual, year 1)	$ 81,963	See Wkst 3D	Year -1 Spend Percentage	0.00%
9	A&G (annual, year 1)	$ -	See Wkst 3E	Year - 0 Spend Percentage	0.00%
10	Other Annual Costs	$ -	See Wkst 3F	Total Project Spend (should be 100%)	0.00%
11	AFUDC (adds to investment to get total project cost)	$ -	See instruction to the right		
12	Tax Basis for Land Costs (informational only)	$ -			
13	Tax Basis Reductions (AFUDC-Equity, Land, etc.)	$ -		**Bidder Name:**	**Semcrude Substation Upgrade - Portion Funded by KPP**
	Results:				
14	**Present Value Revenue Requirement**	**$1,999,832**			
	Present Value Revenue Requirement as of In-Service Year	**$ 2,720,750**			

Exhibit HDR-8

Page 5 of 7

Net Present Value of Revenue Requirements (PVRR)

SemCrude Substation Upgrade – Capital Cost Portion Direct Assigned to KPP- Detail

SPP Transmission Project:

Present Value Revenue Requirement / Carrying Charge Analysis

Bidders: Enter bid-specific values in yellow shaded cells, and make no changes in gray or other cells

All Costs in $

Line	Assumptions:	Value	Notes
1	Investment	$ 1,366,042	
2	Tax Life	15	
3	Book Life	40	
4	Discount Rate	8.00%	
5	Composite Tax Rate	0.00%	See Wkst 3A
6	Property Tax Rate	0.00%	See Wkst 3B
7	Rate Base Adjustment (annual, year 1)	$ -	See Wkst 3C
8	O&M (annual, year 1)	$ 81,963	See Wkst 3D
9	A&G (annual, year 1)	$ -	See Wkst 3E
10	Other Annual Costs	$ -	See Wkst 3F
11	AFUDC (adds to investment to get total project cost)	$ -	See instruction to the right
12	Tax Basis for Land Costs (informational only)	$ -	
13	Tax Basis Reductions (AFUDC-Equity, Land, etc.)	$ -	
	Results:		
14	**Present Value Revenue Requirement**	$1,999,832	
	Present Value Revenue Requirement as of In-Service Year	$ 2,720,750	

CWIP Recovery Assumptions	
Recover CWIP (Yes: 1; No: 0)	0
Percent of Total CWIP in Rate Base (up to 50%)	0.00%
	Spend Per Year
Year -3 Spend Percentage	0.00%
Year -2 Spend Percentage	0.00%
Year -1 Spend Percentage	0.00%
Year - 0 Spend Percentage	0.00%
Total Project Spend (should be 100%)	0.00%

Bidder Name: Semcrude Substation Upgrade - Portion Funded by KPP

Instructions for calculating AFUDC Allowed in Rate Base at In-Service Date

Title 18: PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

Electric Plant Instructions, 3. A (17) : Allowance for funds used during construction (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$A_i = s(S/W) + d(D/D+P+C)(1-S/W)$

$A_e = [1-S/W][p(P/D+P+C)+c(C/D+P+C)]$

A_i = Gross allowance for borrowed funds used during construction rate.

A_e = Allowance for other funds used during construction rate.

S = Average short-term debt.

s = Short-term debt interest rate.

D = Long-term debt.

d = Long-term debt interest rate.

P = Preferred stock.

p = Preferred stock cost rate.

C = Common equity.

c = Common equity cost rate.

W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.

Bidders Must provide supporting calculations for AFUDC, reduced for any CWIP in Rate Base

b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in §35.13 of the Commission's Regulations Under the Federal Power Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdictions. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

Note: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as *Electric Plant in Service* and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

Bidders should make no changes to any text, formulas, numbers or empty cells below this line

Year	Investment	CWIP	Book Depreciation	Net Plant	Bonus Depreciation (Wkst G)	Tax Depreciation (Note A)	Residual Plant	Deferred Income Tax (Note B)	Accumulated Deferred Income Tax	Adjustment to Rate Base (Wkst C)	Rate Base
-4		0									0
-3		$ -									$ -
-2		-									-
-1		-									-
0		-									-
0	$ 1,366,042			$ 1,366,042							$ 1,366,042
1			$ 34,151	$ 1,331,891	$ -	$ 68,302	$ 1,297,740	$ -	$ -	$ -	$ 1,331,891
2			34,151	1,297,740	-	129,774	1,167,966	-	-	-	1,297,740
3			34,151	1,263,589	-	116,797	1,051,169	-	-	-	1,263,589
4			34,151	1,229,438	-	105,185	945,984	-	-	-	1,229,438
5			34,151	1,195,287	-	94,667	851,317	-	-	-	1,195,287
6			34,151	1,161,136	-	85,104	766,213	-	-	-	1,161,136
7			34,151	1,126,985	-	80,596	685,616	-	-	-	1,126,985
8			34,151	1,092,834	-	80,596	605,020	-	-	-	1,092,834
9			34,151	1,058,683	-	80,733	524,287	-	-	-	1,058,683
10			34,151	1,024,532	-	80,596	443,690	-	-	-	1,024,532
11			34,151	990,380	-	80,733	362,957	-	-	-	990,380
12			34,151	956,229	-	80,596	282,361	-	-	-	956,229
13			34,151	922,078	-	80,733	201,628	-	-	-	922,078
14			34,151	887,927	-	80,596	121,031	-	-	-	887,927
15			34,151	853,776	-	80,733	40,298	-	-	-	853,776
16			34,151	819,625	-	40,298	(0)	-	-	-	819,625
17			34,151	785,474	-	-	(0)	-	-	-	785,474
18			34,151	751,323	-	-	(0)	-	-	-	751,323
19			34,151	717,172	-	-	(0)	-	-	-	717,172
20			34,151	683,021	-	-	(0)	-	-	-	683,021
21			34,151	648,870	-	-	(0)	-	-	-	648,870
22			34,151	614,719	-	-	(0)	-	-	-	614,719
23			34,151	580,568	-	-	(0)	-	-	-	580,568
24			34,151	546,417	-	-	(0)	-	-	-	546,417
25			34,151	512,266	-	-	(0)	-	-	-	512,266
26			34,151	478,115	-	-	(0)	-	-	-	478,115
27			34,151	443,964	-	-	(0)	-	-	-	443,964
28			34,151	409,813	-	-	(0)	-	-	-	409,813
29			34,151	375,662	-	-	(0)	-	-	-	375,662
30			34,151	341,510	-	-	(0)	-	-	-	341,510
31			34,151	307,359	-	-	(0)	-	-	-	307,359
32			34,151	273,208	-	-	(0)	-	-	-	273,208
33			34,151	239,057	-	-	(0)	-	-	-	239,057
34			34,151	204,906	-	-	(0)	-	-	-	204,906
35			34,151	170,755	-	-	(0)	-	-	-	170,755
36			34,151	136,604	-	-	(0)	-	-	-	136,604
37			34,151	102,453	-	-	(0)	-	-	-	102,453
38			34,151	68,302	-	-	(0)	-	-	-	68,302
39			34,151	34,151	-	-	(0)	-	-	-	34,151
40			34,151	(0)	-	-	(0)	-	-	-	(0)
Check Sum			$ 1,366,042		$ -	$ 1,366,042		$ -			

Year	Average Rate Base	Return of Interest (Note C)	Return on Equity (Note C)	Income Taxes	Property Taxes (Wkst B)	O&M (Wkst D)	A&G (Wkst E)	Other (Wkst F)	Annual Rev Requirement	Annual Carrying Charge Rate	Annual Rev Req Excl. Bk Depr	Annual Carrying Charge Rate
-4									0			
-3	$ -	$ -	$ -	$ -					$ -	0.00%	$ -	0.00%
-2	-	-	-	-					-	0.00%	-	0.00%
-1	-	-	-	-					-	0.00%	-	0.00%
0	-	-	-	-					-	0.00%	-	0.00%
0												
1	$ 1,348,966	$ 72,154	$ 39,190	$ -	$ -	$ 81,963	$ -	$ -	$ 227,458	16.86%	$ 193,307	14.33%
2	1,314,815	69,966	41,305	-	-	83,602	-	-	229,023	17.42%	194,872	14.82%
3	1,280,664	67,660	43,532	-	-	85,274	-	-	230,617	18.01%	196,466	15.34%
4	1,246,513	65,230	45,879	-	-	86,979	-	-	232,240	18.63%	198,089	15.89%
5	1,212,362	62,671	48,352	-	-	88,719	-	-	233,893	19.29%	199,742	16.48%
6	1,178,211	59,974	50,958	-	-	90,493	-	-	235,576	19.99%	201,425	17.10%
7	1,144,060	57,132	53,703	-	-	92,303	-	-	237,289	20.74%	203,138	17.76%
8	1,109,909	54,139	56,595	-	-	94,149	-	-	239,033	21.54%	204,882	18.46%
9	1,075,758	50,984	59,642	-	-	96,032	-	-	240,809	22.39%	206,658	19.21%
10	1,041,607	47,661	62,852	-	-	97,953	-	-	242,617	23.29%	208,466	20.01%
11	1,007,456	44,160	66,235	-	-	99,912	-	-	244,458	24.26%	210,307	20.88%
12	973,305	40,471	69,799	-	-	101,910	-	-	246,331	25.31%	212,180	21.80%
13	939,154	36,584	73,554	-	-	103,948	-	-	248,237	26.43%	214,086	22.80%
14	905,003	32,489	77,510	-	-	106,027	-	-	250,177	27.64%	216,026	23.87%
15	870,852	28,174	81,678	-	-	108,148	-	-	252,151	28.95%	218,000	25.03%
16	836,701	23,628	86,070	-	-	110,311	-	-	254,160	30.38%	220,009	26.29%
17	802,550	18,839	90,697	-	-	112,517	-	-	256,204	31.92%	222,053	27.67%
18	768,399	13,792	95,572	-	-	114,767	-	-	258,283	33.61%	224,132	29.17%
19	734,248	8,476	100,708	-	-	117,063	-	-	260,398	35.46%	226,247	30.81%
20	700,097	2,874	106,120	-	-	119,404	-	-	262,549	37.50%	228,398	32.62%
21	665,945	-	-	-	-	121,792	-	-	155,943	23.42%	121,792	18.29%
22	631,794	-	-	-	-	124,228	-	-	158,379	25.07%	124,228	19.66%
23	597,643	-	-	-	-	126,712	-	-	160,863	26.92%	126,712	21.20%
24	563,492	-	-	-	-	129,247	-	-	163,398	29.00%	129,247	22.94%
25	529,341	-	-	-	-	131,832	-	-	165,983	31.36%	131,832	24.90%
26	495,190	-	-	-	-	134,468	-	-	168,619	34.05%	134,468	27.15%
27	461,039	-	-	-	-	137,158	-	-	171,309	37.16%	137,158	29.75%
28	426,888	-	-	-	-	139,901	-	-	174,052	40.77%	139,901	32.77%
29	392,737	-	-	-	-	142,699	-	-	176,850	45.03%	142,699	36.33%
30	358,586	-	-	-	-	145,553	-	-	179,704	50.11%	145,553	40.59%
31	324,435	-	-	-	-	148,464	-	-	182,615	56.29%	148,464	45.76%
32	290,284	-	-	-	-	151,433	-	-	185,584	63.93%	151,433	52.17%
33	256,133	-	-	-	-	154,462	-	-	188,613	73.64%	154,462	60.31%
34	221,982	-	-	-	-	157,551	-	-	191,702	86.36%	157,551	70.97%
35	187,831	-	-	-	-	160,702	-	-	194,853	103.74%	160,702	85.56%
36	153,680	-	-	-	-	163,916	-	-	198,067	128.88%	163,916	106.66%
37	119,529	-	-	-	-	167,194	-	-	201,345	168.45%	167,194	139.88%
38	85,378	-	-	-	-	170,538	-	-	204,689	239.75%	170,538	199.75%
39	51,227	-	-	-	-	173,949	-	-	208,100	406.23%	173,949	339.57%
40	17,076	-	-	-	-	177,428	-	-	211,579	1239.08%	177,428	1039.08%
Check Sum									8,523,748		7,157,706	

Notes

A Tax Depreciation includes the tax calculation using WACOC Tax Table data, plus Bonus Depreciation.

B Deferred Income Tax calculation accounts for Net Operating Loss (if applicable) associated only with this individual project.

C Based average of Beginning of Year and End of Year rate base amounts.

Exhibit HDR-8

Net Present Value of Revenue Requirements (PVRR)
SemCrude Substation Upgrade – Capital Cost Portion Funded by Southern Pioneer- Summary

SPP Transmission Project:

Present Value Revenue Requirement / Carrying Charge Analysis

Bidders: Enter bid-specific values in yellow shaded cells, and make no changes in gray or other cells

All Costs in $

Line	Assumptions:	Value	Notes
1	Investment	$ 388,798	
2	Tax Life	20	
3	Book Life	40	
4	Discount Rate	8.00%	
5	Composite Tax Rate	26.53%	See Wkst 3A
6	Property Tax Rate	0.00%	See Wkst 3B
7	Rate Base Adjustment (annual, year 1)	$ -	See Wkst 3C
8	O&M (annual, year 1)	$ 23,328	See Wkst 3D
9	A&G (annual, year 1)	$ -	See Wkst 3E
10	Other Annual Costs	$ -	See Wkst 3F
11	AFUDC (adds to investment to get total project cost)	$ -	See instruction to the right
12	Tax Basis for Land Costs (informational only)	$ -	
13	Tax Basis Reductions (AFUDC-Equity, Land, etc.)	$ -	
	Results:		
14	**Present Value Revenue Requirement**	**$623,783**	
	Present Value Revenue Requirement as of In-Service Year	**$ 848,650**	

CWIP Recovery Assumptions	
Recover CWIP (Yes: 1; No: 0)	0
Percent of Total CWIP in Rate Base (up to 50%)	0.00%
	Spend Per Year
Year -3 Spend Percentage	0.00%
Year -2 Spend Percentage	0.00%
Year -1 Spend Percentage	0.00%
Year - 0 Spend Percentage	0.00%
Total Project Spend (should be 100%)	0.00%

Bidder Name:	**Semcrude Substation Upgrade - Portion Funded by Southern Pioneer**

Exhibit HDR-8
Page 7 of 7
Net Present Value of Revenue Requirements (PVRR)
SemCrude Substation Upgrade – Capital Cost Portion Funded by Southern Pioneer- Detail

SPP Transmission Project:

Present Value Revenue Requirement / Carrying Charge Analysis

Bidders: Enter bid-specific values in yellow shaded cells, and make no changes in gray or other cells

All Costs in $

Line	Assumptions:	Value	Notes
1	Investment	$ 388,798	
2	Tax Life	20	
3	Book Life	40	
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6	Property Tax Rate	0.00%	See Wkst 3B
7	Rate Base Adjustment (annual, year 1)	$ -	See Wkst 3C
8	O&M (annual, year 1)	$ 23,328	See Wkst 3D
9	A&G (annual, year 1)	$ -	See Wkst 3E
10	Other Annual Costs	$ -	See Wkst 3F
11	AFUDC (adds to investment to get total project cost)	$ -	See instruction to the right
12	Tax Basis for Land Costs (informational only)	$ -	
13	Tax Basis Reductions (AFUDC-Equity, Land, etc.)	$ -	
	Results:		
14	**Present Value Revenue Requirement**	$623,783	
	Present Value Revenue Requirement as of In-Service Year	$ 848,650	

CWIP Recovery Assumptions	
Recover CWIP (Yes: 1; No: 0)	0
Percent of Total CWIP in Rate Base (up to 50%)	0.00%
	Spend Per Year
Year -3 Spend Percentage	0.00%
Year -2 Spend Percentage	0.00%
Year -1 Spend Percentage	0.00%
Year - 0 Spend Percentage	0.00%
Total Project Spend (should be 100%)	0.00%

Bidder Name:	Semcrude Substation Upgrade - Portion Funded by Southern Pioneer

Instructions for calculating AFUDC Allowed in Rate Base at In-Service Date

Title 18: PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

Electric Plant Instructions, 3. A (17) : Allowance for funds used during construction (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$A_b = s(S/W) + d(D/D + P + C)(1-S/W)$

$A_s = [1-S/W][p(P/D+P+C)+c(C/D+P+C)]$

A_b = Gross allowance for borrowed funds used during construction rate.

A_s = Allowance for other funds used during construction rate.

S = Average short-term debt.

s = Short-term debt interest rate.

D = Long-term debt.

d = Long-term debt interest rate.

P = Preferred stock.

p = Preferred stock cost rate.

C = Common equity.

c = Common equity cost rate.

W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.

Bidders Must provide supporting calculations for AFUDC, reduced for any CWIP in Rate Base

b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in §35.13 of the Commission's Regulations Under the Federal Power Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdictions. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

Note: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as *Electric Plant in Service* and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

Bidders should make no changes to any text, formulas, numbers or empty cells below this line

Year	Investment	CWIP	Book Depreciation	Net Plant	Bonus Depreciation (Wkst G)	Tax Depreciation (Note A)	Residual Plant	Deferred Income Tax (Note B)	Accumulated Deferred Income Tax	Adjustment to Rate Base (Wkst C)
-4		0								
-3		$ -								
-2		-								
-1		-								
0		-								
0	$ 388,798			$ 388,798						
1			$ 9,720	$ 379,078	$ -	$ 14,580	$ 374,218	$ 1,289	$ 1,289	$ -
2			9,720	369,358	-	28,067	346,151	4,868	6,157	-
3			9,720	359,638	-	25,960	320,191	4,308	10,465	-
4			9,720	349,918	-	24,016	296,175	3,793	14,258	-
5			9,720	340,198	-	22,212	273,963	3,314	17,572	-
6			9,720	330,478	-	20,548	253,415	2,873	20,445	-
7			9,720	320,758	-	19,004	234,410	2,463	22,908	-
8			9,720	311,038	-	17,581	216,829	2,086	24,994	-
9			9,720	301,318	-	17,348	199,481	2,024	27,018	-
10			9,720	291,599	-	17,344	182,136	2,023	29,040	-
11			9,720	281,879	-	17,348	164,788	2,024	31,064	-
12			9,720	272,159	-	17,344	147,444	2,023	33,087	-
13			9,720	262,439	-	17,348	130,096	2,024	35,111	-
14			9,720	252,719	-	17,344	112,751	2,023	37,133	-
15			9,720	242,999	-	17,348	95,403	2,024	39,157	-
16			9,720	233,279	-	17,344	78,059	2,023	41,180	-
17			9,720	223,559	-	17,348	60,711	2,024	43,204	-
18			9,720	213,839	-	17,344	43,367	2,023	45,226	-
19			9,720	204,119	-	17,348	26,018	2,024	47,250	-
20			9,720	194,399	-	17,344	8,674	2,023	49,273	-
21			9,720	184,679	-	8,674	0	(277)	48,995	-
22			9,720	174,959	-	-	0	(2,579)	46,417	-
23			9,720	165,239	-	-	0	(2,579)	43,838	-
24			9,720	155,519	-	-	0	(2,579)	41,259	-
25			9,720	145,799	-	-	0	(2,579)	38,681	-
26			9,720	136,079	-	-	0	(2,579)	36,102	-
27			9,720	126,359	-	-	0	(2,579)	33,523	-
28			9,720	116,639	-	-	0	(2,579)	30,944	-
29			9,720	106,919	-	-	0	(2,579)	28,366	-
30			9,720	97,199	-	-	0	(2,579)	25,787	-
31			9,720	87,480	-	-	0	(2,579)	23,208	-
32			9,720	77,760	-	-	0	(2,579)	20,630	-
33			9,720	68,040	-	-	0	(2,579)	18,051	-
34			9,720	58,320	-	-	0	(2,579)	15,472	-
35			9,720	48,600	-	-	0	(2,579)	12,894	-
36			9,720	38,880	-	-	0	(2,579)	10,315	-
37			9,720	29,160	-	-	0	(2,579)	7,736	-
38			9,720	19,440	-	-	0	(2,579)	5,157	-
39			9,720	9,720	-	-	0	(2,579)	2,579	-
40			9,720	(0)	-	-	0	(2,579)	0	-
Check Sum			$ 388,798		$ -	$ 388,798		$ 0		

Year	Rate Base	Average Rate Base	Return of Interest (Note C)	Return on Equity (Note C)	Income Taxes	Property Taxes (Wkst B)	O&M (Wkst D)	A&G (Wkst E)	Other (Wkst F)	Annual Rev Requirement	Annual Carrying Charge Rate	Annual Rev Req Excl. Bk Depr	Annual Carrying Charge Rate
-4	0									0			
-3	$ -	$ -	$ -	$ -	$ -					$ -	0.00%	$ -	0.00%
-2	-	-	-	-	-					-	0.00%	-	0.00%
-1	-	-	-	-	-					-	0.00%	-	0.00%
0	-	-	-	-	-					-	0.00%	-	0.00%
0	$ 388,798												
1	$ 377,789	$ 383,293	$ 17,258	$ 11,547	$ 4,170	$ -	$ 23,328	$ -	$ -	$ 66,023	17.23%	$ 56,303	14.69%
2	363,201	370,495	17,001	11,792	4,258	-	23,794	-	-	66,566	17.97%	56,846	15.34%
3	349,173	356,187	16,731	12,050	4,351	-	24,270	-	-	67,123	18.84%	57,403	16.12%
4	335,660	342,416	16,447	12,322	4,450	-	24,756	-	-	67,694	19.77%	57,974	16.93%
5	322,626	329,143	16,147	12,608	4,553	-	25,251	-	-	68,279	20.74%	58,559	17.79%
6	310,033	316,330	15,832	12,909	4,662	-	25,756	-	-	68,878	21.77%	59,159	18.70%
7	297,850	303,942	15,500	13,226	4,776	-	26,271	-	-	69,493	22.86%	59,773	19.67%
8	286,045	291,947	15,151	13,560	4,896	-	26,796	-	-	70,123	24.02%	60,403	20.69%
9	274,301	280,173	14,783	13,911	5,023	-	27,332	-	-	70,770	25.26%	61,050	21.79%
10	262,558	268,430	14,396	14,280	5,157	-	27,879	-	-	71,432	26.61%	61,712	22.99%
11	250,814	256,686	13,989	14,669	5,297	-	28,437	-	-	72,112	28.09%	62,392	24.31%
12	239,072	244,943	13,560	15,079	5,445	-	29,005	-	-	72,810	29.73%	63,090	25.76%
13	227,328	233,200	13,109	15,510	5,601	-	29,585	-	-	73,525	31.53%	63,805	27.36%
14	215,585	221,457	12,634	15,964	5,764	-	30,177	-	-	74,259	33.53%	64,539	29.14%
15	203,842	209,714	12,134	16,441	5,937	-	30,781	-	-	75,013	35.77%	65,293	31.13%
16	192,099	197,970	11,608	16,944	6,118	-	31,396	-	-	75,786	38.28%	66,066	33.37%
17	180,355	186,227	11,054	17,473	6,309	-	32,024	-	-	76,580	41.12%	66,861	35.90%
18	168,613	174,484	10,471	18,030	6,511	-	32,665	-	-	77,396	44.36%	67,676	38.79%
19	156,869	162,741	9,857	18,616	6,722	-	33,318	-	-	78,233	48.07%	68,513	42.10%
20	145,126	150,998	9,211	19,233	6,945	-	33,984	-	-	79,094	52.38%	69,374	45.94%
21	135,684	140,405	8,531	19,883	7,180	-	34,664	-	-	79,977	56.96%	70,257	50.04%
22	128,542	132,113	7,815	20,566	7,427	-	35,357	-	-	80,885	61.22%	71,165	53.87%
23	121,401	124,972	7,062	21,286	7,686	-	36,064	-	-	81,819	65.47%	72,099	57.69%
24	114,260	117,831	6,269	22,044	7,960	-	36,786	-	-	82,778	70.25%	73,058	62.00%
25	107,119	110,689	5,434	22,841	8,248	-	37,521	-	-	83,764	75.67%	74,044	66.89%
26	99,977	103,548	4,555	23,680	8,551	-	38,272	-	-	84,778	81.87%	75,058	72.49%
27	92,836	96,407	3,630	24,564	8,870	-	39,037	-	-	85,821	89.02%	76,101	78.94%
28	85,695	89,266	2,657	25,494	9,206	-	39,818	-	-	86,894	97.34%	77,174	86.45%
29	78,554	82,124	1,632	26,472	9,559	-	40,614	-	-	87,998	107.15%	78,278	95.32%
30	71,412	74,983	553	27,503	9,931	-	41,427	-	-	89,134	118.87%	79,414	105.91%
31	64,271	67,842	-	-	-	-	42,255	-	-	51,975	76.61%	42,255	62.28%
32	57,130	60,701	-	-	-	-	43,100	-	-	52,820	87.02%	43,100	71.00%
33	49,989	53,559	-	-	-	-	43,962	-	-	53,682	100.23%	43,962	82.08%
34	42,847	46,418	-	-	-	-	44,842	-	-	54,562	117.54%	44,842	96.60%
35	35,706	39,277	-	-	-	-	45,738	-	-	55,458	141.20%	45,738	116.45%
36	28,565	32,136	-	-	-	-	46,653	-	-	56,373	175.42%	46,653	145.18%
37	21,424	24,994	-	-	-	-	47,586	-	-	57,306	229.28%	47,586	190.39%
38	14,282	17,853	-	-	-	-	48,538	-	-	58,258	326.32%	48,538	271.87%
39	7,141	10,712	-	-	-	-	49,509	-	-	59,229	552.93%	49,509	462.19%
40	(0)	3,571	-	-	-	-	50,499	-	-	60,219	1686.51%	50,499	1414.29%
Check Sum										2,844,921		2,456,123	

Notes

A Tax Depreciation includes the tax calculation using WACOC Tax Table data, plus Bonus Depreciation.

B Deferred Income Tax calculation accounts for Net Operating Loss (if applicable) associated only with this individual project.

C Based average of Beginning of Year and End of Year rate base amounts.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

South Central MCN LLC	)	Docket Nos. ER18-1267-000
	)	ER18-1267-001
	)	ER18-1267-002
	)	ER18-1267-003

COMMENTS OF
XCEL ENERGY SERVICES INC.

Pursuant to Rule 212 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission")[1] and the June 18, 2018 Notice of Filing in this proceeding, Xcel Energy Services Inc. ("XES"), on behalf of its utility operating company affiliate Southwestern Public Service Company ("SPS"), respectfully submits these comments in response to the June 18, 2018 filings by South Central MCN LLC ("South Central") in the above-captioned proceedings ("Deficiency Filing").[2] The Deficiency Filing responds to a notice of deficiency issued by the Commission on June 1, 2018, and provides further explanation of and revisions to South Central's proposed Open Access Transmission Tariff ("OATT"). South Central previously held a waiver of the obligation to maintain an OATT for the radial facilities at issue in its initial filing.

XES is concerned that South Central has undertaken significant development of its Commission-jurisdictional facilities contrary to the Commission's open access policies and outside the local transmission planning rules proposed in this proceeding and modified by the Deficiency Filing. Radial facilities owned by public utility transmission providers typically would not experience significant transmission upgrades and development in this manner. Partly

[1] 18 C.F.R. § 385.212 (2018).

[2] On April 20, 2018, XES filed a timely doc-less motion to intervene in the instant proceeding on behalf of SPS. XES is thus a party to this proceeding.

for that reason the Commission has granted waivers from the obligation to have an OATT for those facilities.[3] Here, South Central has sidestepped its obligations under Order No. 890[4] to conduct coordinated, open, and transparent local planning when planning and commencing construction of significant new facilities. This is particularly troubling when South Central was required to have an OATT in place more than a year before it filed the tariff proposed in this proceeding and only owned the facilities at issue for a matter of months before receiving a request for service, triggering the OATT filing obligation. Because South Central's behavior is contrary to the OATT waiver that South Central received and contrary to the Commission's open access transmission planning principles, the Commission should make clear that all aspects of rate recovery for those facilities remain subject to future comment, protest, and consideration by the Commission in any future Section 205 proceeding where South Central may receive rate recovery from other customers through the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("SPP Tariff").

I. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications regarding this filing should be directed to the following persons, who should be placed on the Commission's official service list in this proceeding:[5]

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[3] *See Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211 at P 35 (2015), *order on reh'g*, Order No. 807-A, 153 FERC ¶ 61,047 (2015) ("[A] number of sections of the pro forma OATT, such as the provisions regarding network service, ancillary services, and planning requirements, are arguably inapplicable to most or all ICIF owners.").

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 ("Order No. 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[5] Mr. Johnson was listed as an e-service recipient in the XES doc-less intervention filed April 20, 2018. XES respectfully requests that Ms. Eaton, Mr. Grant, Mr. Spina and Mr. Skees be added to the official e-service list as additional representatives of XES.

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II. BACKGROUND

A. South Central OATT Filing

On March 30, 2018, as amended on April 2, 2018, South Central filed a proposed OATT to govern the terms of transmission service over its facilities that are not under the functional control of the SPP (the "Radial Facilities"). The Radial Facilities consist of 410 miles of transmission lines and other facilities operated at 115 kV and 69 kV in the panhandle of Oklahoma that were acquired by South Central from Tri-County Electric Cooperative, Inc. ("Tri-County") in a transaction that was approved by the Commission in 2016 and consummated later that year.[6] As South Central explained, although the Radial Facilities are in the SPP area, they do not meet the SPP criteria for transmission facilities and thus are not eligible for cost recovery under the SPP OATT.[7] Currently, the Radial Facilities are used to provide wholesale

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[6] *South Central MCN LLC*, 154 FERC ¶ 61,174 (2016). Tri-County had acquired the Radial Facilities from SPS in 2006. Section 203 authorization was not required for the transaction because the aggregate value of the facilities was below $10,000,000. *See Xcel Energy Servs. Inc.*, Letter Order in Docket No. EC06-40-000 (Apr. 19, 2006) (approving withdrawal of Section 203 application).

[7] OATT Filing at 2.

distribution service to Tri-County. South Central also noted that it planned to acquire assets from the City of Nixa, Missouri, and turn those assets over to the functional control of SPP, thereby becoming a Transmission Owner in SPP as of April 1, 2018.[8] South Central explained that its OATT filing was necessitated by a prior Commission directive in Docket No. ER16-605-000 requiring South Central to submit an OATT within 60 days of the date that it receives a request for transmission service over the Radial Facilities.[9] South Central received such a request from States Edge Wind 1 Holdings LLC on November 11, 2016, but South Central failed to submit the OATT Filing within 60 days.[10]

1. Proposed Attachment K

South Central explained that its proposed OATT is based on the Commission's *pro forma* OATT, but with certain variations to reflect the unique nature of the Radial Facilities and the service they provide to Tri-County. Among those deviations is a new transmission planning process South Central proposed as Attachment K to its OATT (the "Local Planning Process" or "LPP"). The LPP involves the development of an annual plan that identifies transmission enhancements needed to maintain the reliability of South Central's facilities, maintain interconnection and transmission services across those facilities, and reliably serve connected load.[11] South Central stated that the LPP was intended to meet anticipated future transmission needs of South Central's customers who are receiving generator interconnection services and transmission services on or across South Central's facilities subject to the proposed OATT.[12]

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[8] OATT Filing at 2. South Central also describes its plans to acquire additional facilities from Tri-County within the SPP footprint. *Id.*; *South Central MCN LLC*, 162 FERC ¶ 62,143 (2018).

[9] *South Central MCN LLC*, 154 FERC ¶ 61,090 (2016).

[10] OATT Filing at 4.

[11] *Id.* at 8-9.

[12] *Id.* at 8.

On April 20, 2018, Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. (together, the "Protestors") filed a Motion to Intervene and Protest to South Central's OATT Filing arguing that the proposed LPP does not satisfy the Commission's Order No. 890 transmission planning principles. On May 2 and May 24, 2018, South Central filed separate Answers in response to the Protestors, proposing to revise certain aspects of its LPP in proposed Attachment K.

B. <u>South Central Deficiency Filing</u>

On June 1, 2018, the Commission issued a notice concluding that South Central's OATT Filing is deficient and requesting additional information. Included in the deficiency notice was a request by the Commission for South Central to clarify its proposed revisions to the Attachment K that were discussed in South Central's May 2, 2018 and May 24, 2018 Answers. On June 18, 2018, South Central filed its responses and a revised OATT to address the deficiencies noted by the Commission ("Deficiency Filing"). In the Deficiency Filing, South Central explained that its changes to the proposed Attachment K were based on an agreement it reached with the Protestors with respect to the LPP, and that Protestors had agreed not to protest or oppose the Deficiency Filing.[13] South Central also requested a shortened comment period, such that comments are due by June 28, 2018.

III. <u>COMMENTS</u>

XES is concerned that South Central's proposed OATT, particularly the Attachment K planning provisions revised in response to the June 1, 2018 deficiency letter, are too little, too late given the significant transmission development that occurred between South Central's

[13] Deficiency Filing at 6.

acquisition of the Tri-County facilities on April 1, 2016[14] and South Central's submission of the OATT on March 30, 2018. Assuming the proposed OATT is accepted with an effective date of March 31, 2018 as South Central has requested, South Central will have managed to commence major transmission system upgrades outside of any open and transparent planning process and in violation of the Commission's February 8, 2016 order accepting South Central's Wholesale Distribution Service Agreement and Wholesale Distribution Operating Agreement with Tri-County.

The absence of an open and transparent transmission planning process as required by the Commission's open access policies raises significant questions about the prudency of South Central's transmission development. Once South Central transfers these facilities to the operational control of SPP, other transmission customers in the SPS Rate Zone (Zone 11), and particularly SPS's wholesale and retail ratepayers, may be responsible for a significant portion of the costs for those facilities depending on whether South Central is assigned its own zone or added to an existing zone. Due to those concerns, XES respectfully requests that the Commission confirm that XES and other affected entities will have a full opportunity to challenge all aspects of South Central's right to recover the cost of these facilities through the SPP Tariff when South Central and SPP file to amend the SPP Tariff to accommodate that recovery. In doing so, the Commission should also recognize that South Central's noncompliance with the Commission's February 8, 2016 order by not filing an OATT as required creates serious doubt as to the prudence of that expenditure, and therefore places on

[14] Notice of Consummation of Transaction, Docket No. EC15-206-000 (April 11, 2016).

South Central the burden of demonstrating prudency in the transmission planning that occurred prior to the effective date of the OATT.[15]

A. <u>South Central's Transmission Planning Is Poised to Create a Massive, Unexamined Cost Shift</u>

From the very beginning of South Central's ownership of the former Tri-County facilities, South Central's goal has been the development of those facilities so that they qualify as transmission facilities eligible for recovery under the SPP Tariff and the cost responsibility for those facilities can be largely shifted to SPP transmission service customers other than Tri-County. By failing to file a transmission tariff on time—and filing problematic planning language that was then subject to the instant deficiency response—South Central has maximized its discretion to undertake this transmission development project without *any* of the controls against undue preference outlined in the Commission's open access policies.

As XES previously warned, South Central is attempting to cram significant new capital into potentially unneeded transmission development so South Central can then transfer control to SPP and earn its rate of return on those investments from other SPP transmission service customers who receive no benefits from those facilities and had no role or opportunity for input on the planning of those facilities.[16] When South Central acquired the facilities from Tri-County, they were radial facilities that did not qualify as transmission facilities eligible for recovery under the SPP Tariff. South Central's agreement with Tri-County was premised on

[15] *Entergy Servs., Inc.*, Opinion No. 505, 130 FERC ¶ 61,023 at P 52 (2010) (citing *Kentucky Utilities Co.*, 62 FERC ¶ 61,097 at 61,698 (1993)) ("The utility does not have the burden of demonstrating that expenditures are prudent. Rather, a challenger to prudence must create a 'serious doubt' as to the prudence of an expenditure; however, once that serious doubt is created, the burden shifts to the applicant to demonstrate that the expenditure in question was prudent.").

[16] Motion to Intervene and Protest of Xcel Energy Services Inc., Docket No. EC15-206-000, at 12 (Oct. 5, 2015) ("SCMCN's business model would set aside reasonable planning considerations associated with the decision about when to loop facilities serving radial load, instead providing essentially a bounty to SCMCN if it can: (1) loop the radial facilities to be acquired from TCEC; and (2) thereby shift the costs of the acquired TCEC facilities and the new SCMCN facilities required to loop them to other customers in the SPS zone or SPP region.").

changing this and thereby shifting the costs of those facilities onto other entities. Under the terms of the agreements providing for the transfer of radial facilities from Tri-County to South Central, the parties agreed to identify and develop a list of specific projects South Central would construct with the intention of seeking recovery in an SPP pricing zone. In addition, the parties agreed that because the new upgrades would change the existing radial transmission facilities to looped transmission facilities, South Central would seek rate recovery of those assets in an SPP pricing zone as well.[17] The centrality of cost-shifting in the South Central business model is also highlighted by South Central's ability to force Tri-County to buy back all of the facilities if the cost shift to SPP is not successful.[18] As stated in South Central's Section 203 application in Docket No. EC15-206-000, once the expected upgrades are completed, the costs of those upgrades as well as the formerly radial Tri-County facilities "are expected to be included in a larger SPP pricing zone, thereby reducing [Tri-County's] overall transmission costs."[19]

Since closing that transaction in April 2016, South Central has moved forward with its development of the transmission projects outlined in its original plan. XES has only recently learned that multiple new substations and multiple new high-voltage lines are under construction and intended to be turned over to SPP as transmission facilities. Based on an initial analysis of information currently available to XES, it appears that South Central may first transfer to the operational control of SPP and seek recovery in other pricing zones for one new line and two new substations. The addition of these new facilities along with other upgrades may also turn a

[17] *See* Application for Authorization to Acquire Transmission Facilities Pursuant to Section 203 of the Federal Power Act, Docket No. EC15-206-000, Exhibit E (Sep. 14, 2015) ("Prior to closing on the APA the parties will add two mutually-agreeable schedules to the Rate Management Agreement (Agreement). One will list the specific projects GridLiance plans to construct in order for substantially all of the transferred assets to qualify under SPP Attachment AI for recovery in a larger SPP pricing zone, expected to be Zone 11.").

[18] *Id.*

[19] *Id.*

significant portion of the Radial Facilities into looped transmission. Based on XES's analysis, it appears that South Central may use the new facilities to attempt SPP cost recovery for as many as seven existing lines and five existing substations. Additionally, more extensive work is already underway by South Central that appears intended to result in the transfer to SPP and SPP cost recovery for as many as an additional two new lines and three new substations or switching stations. The addition of these new lines and substations may turn three additional lines and three additional substations that are currently Radial Facilities into looped transmission that South Central may turn over to SPP control in another attempt at recovery through SPP rates.[20]

But even though South Central was a public utility transmission provider when these facilities were planned and developed, South Central never followed any planning procedures outlined in a tariff when developing those facilities and that planning was not subject to SPP oversight. Moreover, South Central did not follow any of the Commission's open access requirements for transmission planning despite stating that the assets it acquired from Tri-County "will be subject to the open access policies of the Commission."[21] Instead, the facilities to be developed were agreed upon by Tri-County and South Central as part of the initial acquisition, without any claim that those facilities were needed. Instead—as South Central stated—those facilities were to be constructed "in order for substantially all of the transferred assets to quality under SPP Attachment AI for recovery in a larger SPP pricing zone, expected to be Zone 11."[22]

[20] This analysis identifying likely new and newly-looped South Central facilities was based on comparing prior system data to the information about likely facility transfers contained in a letter received from SPP on June 22, 2018, after the Deficiency Filing was submitted in this proceeding on June 18, 2018. *See* Exhibit A, attached hereto. This data was not available to XES at the time South Central submitted the March 30, 2018 filing initiating the instant proceeding. XES notes that this reflects an initial analysis based on information XES only recently received, and XES reserves the right to challenge any attempt to include any of these facilities in SPP rates. The description of the South Central facilities in this filing is not a recognition by XES that any of these facilities qualify for SPP rate recovery in any manner.

[21] *South Central MCN LLC*, 154 FERC ¶ 61,174 at P 34.

[22] *Id.*

If a transmission planning process such as the Attachment K proposed in South Central's March 30, 2018 filing and modified in its Deficiency Filing had been in place, it is possible that the transmission development of the former Tri-County radial facilities would have been very different, potentially resulting in a different revenue requirement than proposed by South Central in this proceeding. Those proposed tariff planning requirements, and the Commission's open access policies mandating coordinated, open, and transparent transmission planning act as a control to ensure that there is no undue discrimination in transmission planning.[23] Because South Central failed to follow these policies and failed to file a transmission tariff encompassing these policies when required, the transmission build-out on the former Tri-County facilities was undertaken without any transparency or scrutiny and may have been unnecessary in whole or in part. In particular, South Central's transmission planning process, despite the language in the proposed Attachment K, has lacked the following required qualities:

- *Coordination*: The planning process should provide for "appropriate lines of communication between transmission providers, their transmission-providing neighbors, affected State authorities, customers, and other stakeholders."[24] Although SPS is a neighboring transmission provider of South Central, SPS received no formal notification or consultation regarding the new facilities to determine the effects they could have on SPS. Even now, SPS has no power flow model data from South Central to study the potential impacts of those facilities on the SPS system.
- *Openness*: All transmission planning meetings must "be open to all affected parties including, but not limited to, all transmission and interconnection customers, State

[23] Order No. 890 at P 425 ("Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory.").

[24] *Id.* at P 452.

commissions and other stakeholders."[25] South Central has not conducted an open planning process, and, as far as XES is aware, has not conducted any public planning meetings.

- *Transparency*: In conducting transmission planning transmission providers must "disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans."[26] South Central has provided no transparency or information about its planning or development of any of the various projects underway, and has not posted or otherwise made available to stakeholders such as SPS any of its basic criteria, assumptions, or study methodologies. Under this principle, South Central must also "make available information regarding the status of upgrades identified in their transmission plans in addition to the underlying plans and related studies."[27] But despite the extensive ongoing build-out, South Central has provided no information regarding the ongoing or pending upgrades.
- *Information Exchange*: Transmission providers must provide guidelines and a schedule for the submittal and exchange of information in the planning process,[28] but SPS has had no opportunity to provide input into South Central's planning, to exchange model data and power flow studies with South Central, or otherwise receive the data necessary to evaluate the impacts of the ongoing development from a planning and operations perspective or submit to South Central information that would be beneficial in transmission planning.

[25] *Id.* at P 460.

[26] *Id.* at P 471.

[27] *Id.* at P 472.

[28] *Id.* at P 486.

Due to the utter lack of coordinated, open, and transparent transmission planning by South Central, the ongoing development of the former Tri-County radial facilities has occurred without any reasonable controls, creating the current situation where South Central is poised to seek recovery through the SPP Tariff of the costs of significant, unexamined transmission investment. The planning procedures proposed in this proceeding for future transmission development, and modified in South Central's deficiency response, have not been applied to any of South Central's extensive planning work, leading to what may be a potentially inflated rate base which South Central is now planning to recover under the formula rate proposed in response to the Commission's deficiency letter and in the future to recover from other SPP transmission customers, including SPS and its ratepayers and other loads in Zone 11.

B. <u>The Commission Should Make Clear that All Parties Have the Right to Address these Issues in a Future Section 205 Proceeding</u>

XES raised similar concerns in the Section 203 proceeding considering South Central's acquisition of the Tri-County facilities, explaining that South Central's business model envisions the reallocation of the costs of the transmission facilities to entities that receive no benefits from those facilities.[29] At the time, the Commission overruled these concerns as outside the scope of its Section 203 analysis, but noted that future Section 205 proceedings considering any change in the cost allocation for the former Tri-County facilities would provide "[a]ll affected parties . . . the opportunity to provide comments"[30] and that during such proceedings "interested parties will have the opportunity to challenge the revised cost allocation."[31] Because South Central's plan appears to be as XES feared previously—i.e. premised on shifting costs from significant investments to other SPP transmission customers—the Commission should take this opportunity

[29] *South Central MCN LLC*, 154 FERC ¶ 61,174 at P 43.

[30] *Id.* at P 50.

[31] *Id.* at P 51.

to reiterate that in any future Section 205 proceeding changing the cost allocation for South Central's facilities, interested parties can raise *all* relevant issues, including the lack of a need or justification for any facilities that South Central developed after its acquisition from Tri-County and may request the denial of any cost recovery for such facilities.

In recognizing that all parties affected by a future Section 205 filing to enable recovery by South Central under the SPP Tariff can raise any issues relevant to that recovery, the Commission should also acknowledge that South Central's violation of its commitments and the Commission requirements in both the prior Section 203 proceeding and a prior Section 205 proceeding call out for a remedy.

In Docket No. ER16-505, South Central requested waiver of the obligation to have an OATT based on the radial nature of the facilities at issue.[32] But recognizing that such a waiver would not be appropriate if a third party sought service, South Central stated that "should it receive a request for transmission service, it must file an OATT with the Commission within 60 days of the date of the request, and must comply with any additional requirements that are effective on the date of the request."[33] The Commission then conditioned the requested waiver on South Central's obligation to file an OATT within 60 days of receiving a request for transmission service.[34]

In Docket No. EC15-206, South Central addressed part of the "effect on competition" prong of the Commission's "public interest" analysis by stating that "South Central is requesting a waiver of the requirement to file its own OATT in light of the nature of the acquired assets."

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[32] South Central MCN LLC, Application for Approval of Wholesale Distribution Service Agreement and Wholesale Distribution Operating Agreement, Docket No. ER16-505-000, at 7 (Dec. 10, 2015) ("[T]he Tri-County Facilities are limited and discrete transmission facilities (i.e., facilities that do not form an integrated transmission grid). Accordingly, South Central requests a waiver of the obligation to file an OATT.").

[33] *Id.* at 9.

[34] *South Central MCN LLC*, 154 FERC ¶ 61,090 at P 34.

But at the same time, South Central agreed that if a third-party sought to use its facilities, South Central would file an OATT.[35] The Commission relied on this representation in approving South Central's application to acquire the Tri-County transmission facilities.[36]

As it came to pass, South Central did not comply with these commitments. Instead, South Central used the time between receiving a request for transmission service in November 2016[37] until the proposed effective date of its OATT (March 31, 2018) to plan and commence development on a wide range of transmission facilities. Had South Central filed a conforming OATT—including the transmission planning requirements of Attachment K—as required by the Commission on a timely basis, or had South Central lived up to its commitment that these transmission facilities would "be subject to the open access policies of the Commission" following South Central's acquisition from Tri-County, the transmission development undertaken by South Central may have been very different.

For that reason, in any ruling on the transmission planning process proposed in this proceeding the Commission should make clear that all of these concerns may be fully briefed and considered in any future Section 205 proceeding in which South Central seeks to reallocate the costs of these new transmission facilities to other SPP members.

In addition, because South Central's failure to comply with the Commission's orders and South Central's own commitments creates a "serious doubt" as to the prudence of those expenditures that resulted from transmission planning occurring outside normal *pro forma*

[35] South Central MCN LLC, Response to Deficiency Letter, Docket No. EC15-206-000, at 2 (Jan. 20, 2016).

[36] *South Central MCN LLC*, 154 FERC ¶ 61,174 at P 34 ("South Central explains that it is requesting waiver of the requirement to file its own Open Access Transmission Tariff (OATT) in light of the nature of the Tri-County Assets, but has committed to file an OATT upon receipt of a request to do so. South Central states that, as a result, if it receives a request by a third-party to use the Tri-County Assets, a mechanism will be in place for open access to be granted. South Central therefore concludes that the Tri-County Assets will be subject to the open access policies of the Commission.")

[37] March 30, 2018 Filing at 3 (explaining that the request for interconnection service was received on November 11, 2016).

OATT transmission planning openness and transparency controls, the Commission should shift to South Central the burden of demonstrating prudency for the recovery of these investments in the expected Section 205 proceeding.[38] Because these transmission investment decisions were made by South Central at the time it acquired the facilities and in a manner contrary to the Commission's open access requirements, there is serious doubt regarding whether these expenditures were those that "reasonable utility management [] would have made, in good faith, under the same circumstances, and at the relevant point in time."[39]

IV. CONCLUSION

WHEREFORE, for the foregoing reasons, XES respectfully requests that the Commission consider these comments and make clear that all aspects of rate recovery for South Central's facilities remain subject to future comment, protest, and consideration by the Commission in any future Section 205 proceeding where South Central may seek rate recovery from other customers through the SPP Tariff.

[38] XES takes no position on whether other remedies under Sections 203(b) or 316A of the Federal Power Act for noncompliance with Commission orders may be appropriate in these circumstances.

[39] *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985).

Respectfully submitted,

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Dated: June 28, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 28th day of June, 2018.

/s/ *Arjun P. Ramadevanahalli*
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Exhibit A

June 22, 2018

Bill Grant
Southwestern Public Service Company
600 S Tyler St.
Amarillo, TX 79101

Dear Mr. Grant:

As indicated in my letter of May 18, Southwest Power Pool (SPP) has received a request for electric transmission facilities to be transferred to the functional control of SPP. This transfer of functional control is requested by South Central MCN, LLC (South Central) for its facilities located in the panhandle of Oklahoma. The transfer of functional control will be accompanied by a proposed change in zonal rates to include costs of the facilities in the SPP Open Access Transmission Tariff (Tariff).

SPP has a process to review such proposed transfers of functional control and to identify the rate zone in which to include the cost. SPP has completed this review for the South Central facilities and has determined that resulting costs should be placed in Zone 11 rates. Please see the first attachment to this letter for a summary of the zonal placement review and determination. The zonal placement is contingent on Federal Energy Regulatory Commission (FERC) approval of a request to include costs related to the facilities in Zone 11 rates under the SPP Tariff. This rate request will be filed at the conclusion of the process.

The second attachment to this letter provides information regarding the estimated rate impact from adding the cost to Zone 11. The first page in the attachment provides information regarding the estimated rate impact after the proposed transfer of functional control is approved, which may occur in the fourth quarter of 2018. The second page in the attachment provides information regarding the projected rate impact after South Central completes construction and places additional facilities in service during 2019. The rate impacts are shown as estimated charges for a 12-month period. If your company has load in more than one zone, charges for the other zones will not be affected. The data includes network service delivery points located only in Zone 11. The transfer of functional control will impact only Schedule 9 rates, as shown in the column labeled “Zonal Charges - Schedule 9.” In order to show the impact relative to the rates for all SPP Tariff facilities, we also show a column with charges to the Zone 11 load under Schedule 11. The column labeled “Total Charges – Sch. 9 & 11” provides an estimate of annual charges to your Zone 11 network load for both Schedule 9 and Schedule 11 transmission facilities.

You will have an opportunity to discuss the zonal placement and the estimated rate impact with South Central and other affected parties before any filing is submitted to the FERC. SPP will help facilitate those discussions if requested.

As the process moves forward, please contact me if you have questions about the zonal placement or the estimated impact on transmission rates.

Respectfully,

Charles Locke

Charles Locke
Director, Transmission Policy and Rates
501-482-2276
CLocke@SPP.org

Zonal Placement of the South Central MCN Facilities
Located in the Panhandle of Oklahoma

In 2016, South Central MCN, LLC ("South Central") purchased from Tri-County Electric Cooperative ("Tri-County") a set of 69 kV and 115 kV facilities located in the panhandle of Oklahoma. South Central subsequently implemented a number of upgrades to these facilities and is continuing to construct additional upgrades in the area. South Central has requested that these facilities be transferred to the functional control of SPP and the associated revenue requirement be placed in SPP's zonal transmission rates. As a result, SPP is now conducting the zonal placement process endorsed by the SPP Board in July 2017. After the process has been completed, a filing will be submitted to the FERC to request the addition of the resulting revenue requirement to the SPP Tariff and modification of zonal transmission rates consistent with the outcome of the zonal placement process.

SPP staff has completed the analysis required under Step 3 of the process in order to determine whether the resulting revenue requirement should be placed in a new pricing zone, or if not, which existing zone the revenue requirement should be placed in. Based on its analysis, SPP has concluded that the revenue requirement of the South Central panhandle facilities is to be placed in Zone 11 (also referred to as the "SPS Zone") under the SPP Tariff, subject to approval by the FERC.

<u>Facilities</u>

In its notification of intent to transfer functional control, South Central listed the following facilities:

Transmission Line Facilities

- Seaboard-Thompson 69 kV (1.69 miles)
- Texas County - Thompson 69 kV (5.32 miles)
- Texas County - Seaboard 69 kV (5.88 miles)
- Hovey - Hooker 69 kV (20.47 miles)
- Thompson - Hovey 69 kV double circuit (3.51 miles)
- Powell Corner - Hovey 115 kV (8.96 miles)
- Hooker - Cole 69 kV (41.47 miles)
- Texas County - Powell Corner 115 kV (17.93 miles)

Substation Facilities

- Cole 115/69kV Substation
- Hooker 69kV Substation
- Hovey 115/69kV Substation
- Powell Corner 115/69kV Substation
- Texas County 115/69kV Interchange Substation
- Seaboard 69kV Substation
- Thompson 69kV Substation

Following the completion of facility upgrades that have been planned and have a financial commitment prior to the expected date of the facilities transfer (possibly November 1, 2018), South Central intends to transfer control of the following new and existing facilities:

Transmission Line Facilities

- Hovey - Blade 69 kV (49.27 miles)
- Cougar - Blade 69 kV (15.75 miles)
- Cougar – New Sub 69 kV (30.43 miles)
- New Sub(Panhandle) - Thrash 69 kV (1.08 miles)
- Thrash - Powell Corner 69 kV (18.89 miles)
- New Sub(Panhandle) - Powell Corner 115 kV (20 miles) [New Construction]

Substation Facilities

- Eva 69kV Tie Station
- Eva 69kV Regulator Station
- Blade 69kV Substation
- Cougar 69kV Substation
- New (Panhandle) 115/69kV Substation [New Construction]
- Thrash 69kv Substation
- Powell Corner 115/69kV Switching Station [New construction in existing substation to accommodate the new transmission line to Panhandle 115kV Substation]

South Central has separated the facilities within each of the above existing and planned substations to distinguish between equipment that will be subject to SPP's functional control and equipment that will remain under control of South Central or Tri-County.

The following discussion summarizes SPP's review and analysis of zonal placement criteria as applied to these South Central facilities.

<u>Application of Zonal Placement Criteria</u>

Criteria for Creation of a New Zone:

1. Whether the annual transmission revenue requirement (ATRR) of the South Central facilities is less than the minimum zonal ATRR benchmark. Information reviewed in applying this criterion:
   - The estimated ATRR of the South Central facilities under the South Central formula rate is currently about $5.2 million. Upon completion in 2019 of the additional upgrades for which South Central already has made a financial commitment, the total ATRR of both existing and new facilities is projected to be approximately $9.5 million.
   - The minimum zonal ATRR benchmark based on the lowest three-year average of Schedule 9 zonal ATRRs among all SPP pricing zones in 2017, as adjusted for subsequent zonal ATRR change, is $13.5 million.
2. The extent to which the South Central facilities substantively increase the SPP regional footprint. Information reviewed in applying this criterion:
   - The facilities proposed for transfer in 2018 are comprised of approximately 78 miles of 69 kV line and 27 miles of 115 kV line, for a total of 105 miles of line and associated substations. After completion of the 2019 upgrades, there will be a total of 194 miles of 69 kV line and 47 miles of 115 kV line, for a total of 241 miles transferred to the functional control of SPP in 2018 and 2019. As a point of comparison, this total amount exceeds the total miles of line

currently in SPP Zone 3. Zone 3 is modeled by SPP as having slightly over 200 miles of line with a combination of 69 kV, 161 kV, and 345 kV.

- The load served through the facilities proposed for transfer had an annual peak of approximately 145 MW and annual energy usage of approximately 872 GWh in 2017, with both quantities grossed up for losses. Tri-County customer load is the only load directly interconnected to the transferring facilities. As a point of comparison, the SPP zone with the smallest peak load during 2017 was Zone 8, with a peak load of 434 MW.[1]

3. The extent to which the load served through the South Central facilities received Network Integration Transmission Service ("network service") or Long-Term Firm Point-To-Point Transmission Service within existing Zones prior to the transfer. Information reviewed in applying this criterion:
   - No transmission service load under the SPP Tariff is being added as a result of South Central's transfer of functional control. The Tri-County load that is interconnected with these facilities already is receiving SPP network service.

Discussion of Placement in a New Zone:

Even after completion of the facilities scheduled to be placed in service in 2019, the ATRR of the South Central facilities is projected to be about 30 percent below the current minimum zonal ATRR benchmark (i.e., $9.5 million ATRR compared to the minimum of $13.5 million). Therefore, the first criterion does not support creation of a new zone.

The miles of the South Central lines sum to an amount somewhat greater than the miles associated with the current smallest zone. However, that one zone with a smaller mileage total generally has higher voltage facilities. Over half of its mileage is comprised of 161 kV and 345 kV lines, whereas the highest voltage of the transferring facilities is 115 kV. In addition, 81 percent of the transferring facilities' mileage is 69 kV.

The load directly interconnected with the transferring facilities is smaller than the load served in any SPP zone. The peak load directly interconnected to the transferring facilities is reported to be 145 MW, including losses. This is substantially lower than the annual peak of the zone with the smallest peak load, which was 434 MW in 2017. Taking into account both facilities and load, the second criterion does not support creation of a new zone.

Load interconnected with the transferring facilities has been taking network service in Zone 11 since 2006, which resulted in corresponding charges paid by that load for transmission facilities in Zone 11. Given the historical contribution of the load to recovery of Zone 11 costs, placing the cost of the South Central facilities in the same zone would allow that load to continue to pay for existing Zone 11 facilities while aligning cost of the transferring facilities with benefiting load. Therefore, the third criterion does not support creation of a new zone.

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[1] Zone 10 currently has a 12-coincident peak load for billing purposes that is smaller than 145 MW. However, that value is the result of special exclusions in the Tariff to address loads currently provided federal and non-federal transmission service by Southwestern Power Administration ("SPA"). Loads in Zone 10 have been converting from SPA service to SPP network service, with a total of 872 MW eligible to convert. SPA's non-federal transmission revenue requirement, which is available to provide SPP network service, is approximately $15.5 million. This revenue requirement corresponds to and supports the 872 MW of eligible load.

In consideration of the three criteria described above, SPP concludes that creation of a new zone for the South Central facilities is not appropriate. Therefore, existing zones are evaluated to determine which is most appropriate for placement of the South Central facilities.

Criteria for Inclusion in an Existing Zone:

The South Central facilities have electrical connections with facilities under the SPP Tariff only in Zone 11. Therefore, this zonal placement analysis addresses only Zone 11.

1. The extent to which the South Central facilities are embedded within an existing Zone. Information reviewed in applying this criterion:
   - The facilities are interconnected solely to facilities of SPS, the primary Transmission Owner in Zone 11. There are no interconnections with facilities of any other SPP pricing zone or with facilities under the control of a transmission provider other than SPP.
2. The extent to which the South Central facilities are integrated with an existing Zone. Information reviewed in applying this criterion:
   - The only interconnections of the South Central facilities to other transmission facilities are located at the Texas County and Cole substations. The Texas County substation has 115 kV interconnections with a line to the East Liberal substation (80 MVA), two (2) lines to Hitchland substation (225 MVA and 158 MVA), and a line to Cole substation (158 MVA). Cole substation has 115 kV interconnections with a line to Texas County (80 MVA due to path limitations) and a line to Ochiltree (277 MVA). Other than the line between Texas County and Cole substations, each of these interconnecting lines is owned by SPS.
   - A portion of the transferring facilities were planned and built by SPS prior to their purchase by Tri-County. At that time, the facilities were essentially radial in function.
3. The extent to which the load served through the South Central facilities received network service or Long-Term Firm Point-To-Point Transmission Service within each existing Zone prior to the transfer. Information reviewed in applying this criterion:
   - No transmission service load under the SPP Tariff is being added as a result of South Central's transfer of functional control. The Tri-County load that is interconnected with these facilities already is receiving SPP network service in Zone 11.

Discussion of Placement in an Existing Zone:

The South Central facilities are configured as looped transmission facilities above 60 kV, which is consistent with the definition of transmission facilities under Attachment AI of the SPP Tariff. The location and interconnections of the South Central facilities indicate that they are both embedded in and integrated with Zone 11 and are not embedded in or integrated with any other SPP zone. Under the first and second criteria above, the facilities should be placed in Zone 11. Because the load interconnected to the transferring facilities has been included in Zone 11 through network service charges historically, the third criterion indicates that placement of the transferring facilities in Zone 11 is appropriate in order to align cost with beneficiary. These considerations indicate that it is appropriate to place the South Central facilities in Zone 11.

Exhibit HDR-10

Gridliance Article from June 16, 2018, The Cowley CurrierTraveler

http://www.ctnewsonline.com/news/article_cfd0c2e4-70fd-11e8-b103-57bd86498e8a.html

Commission considers partnership

By REBECCA McCUTCHEON CourierTraveler Jun 16, 2018

The Winfield City Commission will consider a partnership with an electric transmission company Monday that would help the city invest in new transmission projects.

Commissioners will consider approving a non-binding letter of agreement with GridLiance, of Irving, Texas, regarding possible development and purchase of a portion of the city's electric transmission assets. If approved, the transaction would close in summer 2019.

GridLiance would pay the city $1.2 million at closing, plus make annual community support payments to the city totaling $880,000 over 15 years, with no stipulations on their use. The city would also earn annual revenue from GridLiance.

The City of Winfield will agree to provide operations and maintenance of the transmission system and a transmission upgrade project.

When discussing the potential partnership at their Thursday work session, commissioners acknowledged the city has a long history as a proud owner and producer of its own electric services, and partnering with another company to help deliver these services is not something to be taken lightly.

However, "as our infrastructure depreciates over time, sharing the risk is important," said Commissioner Phil Jarvis.

The commission will meet at 5:30 p.m. Monday in the Community Council Room, City Hall.