**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of a Proposed Amendment to the Commission's Fuel Adjustment Clause Rules.	)))	File No. EX-2016-0294

ADDITIONAL COMMENTS OF AMEREN MISSOURI

COMES NOW Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or the "Company"), and submits additional comments to address matters raised in earlier-filed comments on the proposed amendments to 4 CSR 240-20.090, as follows:

1. In these Additional Comments and in lieu of providing these details verbally during the upcoming hearing on the proposed rule, Ameren Missouri will address the most important aspects of other comments filed on August 6 which it may not have already addressed in its Initial Comments (also filed on August 6), or which bear further explanation. Failure to address a specific aspect of the other parties' August 6 comments should not be taken as an endorsement of them, nor should it necessarily suggest disagreement.

A. Staff Comments

2. To the extent the Company disagrees with a Staff Comment, the disagreement is not philosophical, but in most if not all cases deals with drafting and consistency in the proposed rule. The Company agrees with most of the Staff's Comments, specifically the following:

a. 20.090 Purpose; 20.090(1)(A); 20.090(1)(K)3., 4., and 5.; 20.090(1)(Q); 20.090(1)(T); 20.090(2); 20.090(2)(A); 20.090(2)(A)7; 20.090(2)(A)9.B.; 20.090(2)(A)10[1]; 20.090(2)(A)13; 20.090(3)(A); 20.093(3)(A)4; 20.090(5); 20.090(5)(B); 20.090(5)(J)4. and 5; 20.090(6)(A)1.L; 20.090(6)(A)6; 20.090(7);

[1] Staff's change will eliminate the need for the added language reflected in 20.090(2)(A)(9) in Exhibit A (at page 8) to Ameren Missouri's Initial Comments.

20.090(8); 20.090(8)(B); 20.090(8)(B)1.G., G(I), (II), and (III), and H[2]; 20.090(8)(C); 20.090(8)(J)3; 20.090(9)[3]; 20.090(9)(A)2. and 3; 20.090(9)(C); 20.090(9)(D); 20.090(10); and 20.090(17).

b. With respect to 20.090(1)(O), the Company does not object to Staff's apparent intent, but believes Staff's addition "for determination of FPA amount including" is uncertain in meaning. To resolve the uncertainty, the Company recommends the following change to Staff's suggested provision:

> (O) Interest means monthly interest at the utility's short term borrowing rate to accurately and appropriately remedy: ~~for determination of a FPA amount including~~ 1) any over- or under-billing of the FPA amount during an accumulation period and a recovery period, and 2) any commission ordered refund of imprudently incurred costs.

c. With respect to 20.090(2)(A)14, while removing paragraph 14 partially addresses the Company's previously stated concern (see the Company's Initial Comments), and complying with paragraph 15 is feasible from the utility perspective, paragraph 15 (now 14, under Staff's edit) is still unlikely to provide additional value in establishing that the RAM rate is just and reasonable. The remaining paragraph still requires the justification of the RAM rate design in the context of how net energy costs are allocated in base rates. Removing the part of the section that requires "...a detailed explanation of the methodology used to allocate fuel and purchased power costs and fuel-related revenue to specific customer classes in the base rates...", but maintaining the requirement to justify how the RAM rate design is "consistent with the methodology used to allocate fuel costs...in base rates" does little to avoid the issues the Company previously raised. Staff

[2] After making sure that any numbering/lettering changes required by Ameren Missouri's Initial Comments on these same provisions are accounted for.
[3] Except that the phrase "fuel adjustment rates" should be replaced with "FARs" since that is a previously defined term.

seems to acknowledge in its Comments something that is very similar to the Company's earlier point - that using a dollar per kWh FAR rate obviates the need for this detailed allocation information. And yet by retaining 15 (now 14) the Staff would maintain the requirement to justify that very rate design considering the allocations that are no longer required to be discussed in detail. This still seems like an exercise in checking a box without a real benefit. However this issue is resolved, the proposed rule will need to be appropriately re-numbered with any cross-references also corrected.

d. With respect to 20.090(2)(C)3, the Company does not object but suggests it would be more accurate to replace "recovered in base rates" with "included in the determination of base rates" since customers pay rates that provide revenues utilities then use to cover utility costs, but customers do not pay costs.

e. With respect to 20.090(8)(F), the Company in its Initial Comments suggested clarifying changes to these provisions. For consistency with those changes, Staff's suggested phrase "cost types and revenues types" should be replaced with "market settlement types or schedules."

f. With respect to 20.090(8)(F)1.A.(I), Staff's suggested edit is unnecessary given the clarifications provided by the Company in its Initial Comments.

g. With respect to 20.090(8)(F)1.B.(II) and C.(II), the Company has no objection, except the word "charge" should not be added in C.(II) per the Company's Initial Comments and use of the phrase "market settlement type" because not all market settlement types reflect "charges."

h. With respect to 20.090(9)(F), the language "If it determines that the true-up amount is incorrect" should be retained. There should be no rejection of the true-up filing if the true-up amount is correct. The Company agrees with the tariff sheet portion of the deletion.

i. With respect to 20.090(13), see the Company's suggested language in this provision, as discussed below in connection with OPC's Comments.

B. <u>OPC Comments</u>

3. OPC's comments are consistent with its ongoing attempts to either outright prevent utilities from utilizing fuel adjustment clauses ("FACs"), or to make them far less effective in doing what they are designed to do. FACs track legitimate fuel and purchased power costs (including transportation) while (in the case of all Missouri FACs in place today) offsetting those costs with the revenues received by utilities for making off-system sales in (primarily) the RTO markets in which they operate.[4] This tracking allows utilities to recover the legitimate costs of powering their generators and otherwise obtaining the energy needed to serve their customers, while giving customers the benefit of offsetting fuel-related revenues through the FAC line item that appears on customer bills. FACs also support utility credit ratings, which promotes lower debt costs, and allow Missouri utilities to compete not just for debt capital but for the equity capital they need to maintain and improve their utility systems while maintaining a balanced capital structure. Indeed, if Missouri's utilities did not have FACs, or had FACs that were ineffective in tracking fuel and purchased power costs, Missouri utilities (and ultimately

[4] Those costs net of those revenues are referred to as "net energy costs."

their customers) would be at a distinct disadvantage to other utilities, all of which operate with FACs.[5]

4. OPC has made no secret of its hostility to FACs, as OPC's proffered expert on FAC matters Lena Mantle has admitted: "[OPC has been] . . . "very negative about fuel adjustment clauses from the beginning". Mantle Deposition, File No. ER-2014-0258, p. 230, l. 8-11; *see also Report and Order*, File No. ER-2016-0285, p. 27, where the Commission itself noted that OPC has a "philosophical objection to Fuel Adjustment Clauses." When the issues raised by OPC (in a clear effort to defeat or weaken FACs) have been litigated, the Commission has rightly rejected such efforts, including efforts by OPC to impose more sharing, to deny a utility of an FAC entirely, or to disable the FAC's effectiveness by drastically reducing the costs eligible for inclusion in a manner that would severely undermine the FAC's effectiveness.

5. In the workshop processes that led to the current rule proposal, OPC made most of the suggestions it now makes in this docket. It has also made such suggestions in recent rate cases. Wisely, the clear majority of OPC's suggestions were not adopted by Staffs' draft rule versions under discussion in those workshops, nor in the rule proposed by the Commission in this docket that is under consideration now, and for good reason. Therefore, the Company supports most the proposed rule's provisions, and as earlier noted, the Company has only minor issues with the Comments the Staff submitted on August 6. In contrast, however, the Company has severe concerns about most of OPC's <u>83</u> separate comments and suggested changes to the rule proposed in this docket.

[5] The Commission has repeatedly been presented with and accepted evidence of the importance of FACs to Missouri utilities. *See, e.g., Report and Order*, File No. ER-2014-0258 ("Ameren Missouri still needs a fuel adjustment clause to help alleviate the effects of regulatory lag as net fuel costs continue to rise. In addition, Ameren Missouri still must compete in the capital markets with other utilities, and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness."

6. Why does the Company point to this history? Because it is through the lens of that history that the Commission should evaluate these 83 OPC comments. In many respects, OPC's comments are simply an attempt to take another bite of the apple having failed to succeed in implementing its anti-FAC positions in prior cases.

7. It is also important to keep in mind, as pointed out in the Company's Initial Comments, the current rules have largely worked. Just as important is the fact that the current rules, for the most part, do not tie the Commission's hands before the Commission even reaches the point of making FAC-related decisions in the future. Nor do the current rules adopt policy stances that a party – be it an intervenor or OPC – might try to wield as a sword to chop down an FAC request entirely, or to otherwise cut away key terms of an FAC in a manner the undermines its purpose and effectiveness.

8. Ironically, OPC agrees with the "don't be prescriptive" or "don't tie one's hands" approach when it suits it, but at the same time, advocates for rule provisions that would prescribe certain policy outcomes when the outcome is one that it favors. This can be seen in literally OPC's very first comment, OPC1 on page 1 of OPC's Attachment A (*See also* OPC24). In OPC1, OPC objects to setting the design of an FAC charge on a volumetric per kWh basis, instead proposing language that will let OPC and others support the design they see fit to support in each rate case for a given utility. Ameren Missouri agrees. The rules should provide for an orderly process to make FAC filings (initial requests, continuations, to change FAC rates, the process for prudence reviews, etc.), require basic information, and otherwise create a fair but objective process that allows the Commission to hear and evaluate whatever proposals may be made, as well as the arguments against them or in favor of modifying them.

9. While OPC1 is consistent with those principles, some of OPC's other comments are not. For example, OPC5 and OPC6 attempt to prescriptively limit the costs that can be included in an FAC. If these prescriptive limits were adopted it would immediately render the FACs of every utility in this state inconsistent with such a rule. The problems, including policy concerns, inherent in such attempted limitations were addressed in detail in the testimonies attached Ameren Missouri's Initial Comments as Exhibits B and C, with similar testimony also having been submitted in Ameren Missouri's last rate case, which is attached to these Additional Comments as Exhibits AC1 and AC2. Everyone understands, as the history discussed earlier shows, that OPC favors an extremely limited FAC (if it favors one at all). To be clear: OPC is free to argue in each case for the costs or revenues that OPC believes ought to be included (or excluded), and why, but the rule should not agree with OPC's point of view in advance. It is OPC, on policy grounds, that wants the Commission to excise from the FAC many cost components that the Commission for years has agreed are legitimate components of fuel and purchased power costs. We can have that debate (again) if need be, but the outcome of the debate should not be prescribed before the debate has even begun.

10. Indeed, as we noted in our Initial Comments, OPC's attempts to limit legitimate fuel and purchased power cost components (via its suggestions in OPC5 and OPC6), were rejected by the Commission just over a year ago in Kansas City Power & Light Company's ("KCPL") last completed rate case. There, OPC advocated for essentially the definition of "fuel" it advocates in these rules, and attempted to exclude many essential components of purchased power costs, but the Commission rejected OPC's position. In doing so, the Commission found that OPC's fuel definition would be "contrary to the costs identified in . . . FERC's Uniform System of Accounts ("USoA") 501 ("Fuel")", going on to find that OPC's claim that its fuel

definition would simplify the FAC or reduce errors was false: "Rather than simplify the FAC or reduce the likelihood of errors, such a change as proposed by OPC would increase the complexity of FAC accounting and require deviations from standard USoA procedures." *Report and Order*, File No. ER-2016-0285, p. 26. The Commission also rejected OPC's attempt to exclude from purchased power costs all components other than energy and capacity, stating that "[c]ontrary to what OPC would prefer, Commission approved FACs include more than just energy and capacity." *Id.*, p. 27. The Commission recognized, as Ms. Barnes and Mr. Meyer testified, that RTO costs and revenues are "inextricably joined" to permit purchase power and sales to be reflected in the FAC." *Id.*

11. Regardless, an FAC rule is no place to dictate the outcome of arguments over what components should or should not be an in FAC.

12. In the remainder of this Section of these Additional Comments, the Company will endeavor to address OPC's specific comments one-by-one, in the order presented:

a. <u>OPC1</u> – See above; no objection.

b. OPC2 – Unnecessary, potentially confusing and, given past OPC positions, potentially intended by OPC to provide support for arguments OPC has made in the past about cost inclusion in an FAC. The proposed rule's existing definition is perfectly clear as-is.

c. OPC3 – Please see the Company's discussion of OPC 27. For the reasons given there, the Company opposes this addition.

d. OPC4 – The Company agrees that "during" may not be the best word, but suggests that the word "for" is a more accurate replacement than "of."

e. OPC5 and OPC6 – As discussed above and in Exhibits B and C to Ameren Missouri's Initial Comments and Exhibits AC1 and AC2 to these Additional Comments, the Commission should not prescriptively adopt OPC's narrow view of what constitutes fuel and purchased power in this or any other rule.

f. OPC7 – Consistent with the Company's view that the costs/revenues to be included in an FAC are for decision when an FAC is requested (or requested to be continued), the Company agrees with this comment.

g. OPC8 – OPC's suggested edits appear to reflect a desire to make sure transmission costs associated with off-system sales of energy are captured in the FAC. Conceptually, the Company does not disagree, but the manner in which OPC's language goes about this in effect would dictate (and require changes to) the Company's accounting. In fact, the Company is not sure how it would identify or tie specific transmission charges to off-system sales of energy. Transmission charges (all of them, whether associated with purchased power or off-system sales of energy) are recorded in Account 565 but they are not tracked to MWh's purchased or sold. To solve this problem, OPC's suggested language "net of the cost of transmission associated with such sale" should be rejected.

h. OPC9, OPC10, OPC11, OPC 12 – The Company agrees.

i. OPC13 – The Company agrees <u>if</u> the words "including transportation" are added between "power costs" and "net of".

j. OPC14 – The Company agrees.

k. OPC15 – The Company disagrees as it is proposed to be written. In every rate case where it has requested an FAC, the Company has provided an example of each type of bill it utilizes. One bill type covers most of its rate classes; another bill type covers the rest. While perhaps not intended, as literally proposed the Company would have to provide 8 different examples. To be more accurate, the rule should read "An example customer bill(s) covering all of its rate classes showing how…." For Ameren Missouri, two examples would be provided that would cover all 8 of its rate classes.

l. OPC16 – The Company agrees.

m. OPC17, OPC18, OPC19 – As discussed in ¶ 9 of the Company's Initial Comments, the language OPC seeks to edit should not appear in the rule at all.

n. OPC20 – There is no universally-accepted definition of a "subaccount." Consequently, such a term should not be used. Utilities are in full compliance with Commission accounting rules if they keep their books in accordance with the Uniform System of Accounts[6] and the Commission could require other designations in an FAC request/continuation case. The rule as proposed contemplates this authority already. *See, e.g.,* 20.090(K) (after changes suggested by the Company in its Initial Comments, "(K)" would be "(I)" due to the elimination of duplication explained there). The question of what designations beyond the USoA (if any) should be required should be dealt with on a case-by-case basis when FACs are considered for a utility. The Commission has imposed certain requirements in this regard on KCPL and Empire, and the Company has committed to certain reporting via the approved Stipulation in its last rate proceeding. The rule need not, and should not, prescribe a one-size-fits-all accounting requirement.

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[6] See 4 CSR 20.030, which requires utilities to keep their books according to the USoA.

o. OPC21 – The Company agrees. A staff edit in its August 6 Comments, with which the Company agrees, also addresses this issue.

p. OPC22, OPC 23 – The Company takes no position.

q. OPC24 – The Company agrees.

r. OPC25 – This is another example of OPC seeking to get a leg up on arguments it likely will want to make in FAC request or continuation cases. Consistent with the current (and proposed) rule's requirement for information on business risk of an FAC (Item 16 just above the provision at issue in this comment), the word "any" should remain. "Any" does not presuppose the existence of, or absence of, a risk. Omitting the word is an attempt to presuppose the existence of a risk. For consistency with Item 16, the language should read "any change in risk . . .." This language has been in the FAC rule since it was first adopted in 2007. No difficulties or advantage (or disadvantage) on the issue of whether an FAC impacts business risk has arisen because of such language, which fairly raises the question without suggesting an answer to the question.

s. OPC26 – Others (Dogwood) raised an issue similar to the issue raised by OPC. Conceptually, the Company does not object to OPC's language, but the language needs to be modified to reflect the reality (and the technology allowing it) that a "test" is not always how the efficiency of a unit is determined. As has been explained in prior filings by Ameren Missouri, for the Company's major units the Company utilizes ongoing monitoring technology to obtain heat rate *results*. To more accurately reflect the practice, OPC's suggestion should be edited as follows:

> A level of efficiency for each of the electric utility's generating units determined by the results of heat rate/efficiency tests ~~and~~/or ~~efficiency~~

~~tests~~ monitoring that were conducted or obtained on each of the electric utility's steam generators, including nuclear steam generators, heat recovery steam generators, steam turbines and combustion turbines within twenty-four (24) months preceding the filing of the general rate increase case. A.The results ~~of the heat rate tests~~ should be filed in a table format by generating unit type, rated megawatt (MW) output rating, the numerical value of the latest result ~~heat rate test~~ and the date of the latest result ~~heat rate test~~; B. The electric utility shall provide documentation of the actual ~~heat rate~~ test/monitoring procedures. The electric utility may, in lieu of filing the documentation of these procedures with the commission, provide them to the staff, OPC, and to other parties as part of the workpapers it provides in connection with its direct case filing. If the electric utility submits the results ~~heat rate tests and/or efficiency test~~ in workpapers, it will provide a statement in its testimony as to where the results can be found in workpapers;

t. OPC27 – The Company opposes adding yet another integrated resource planning requirement to the Commission's rules. Under the current rules, utilities must (a) submit a triennial integrated resource plan, (b) notify the Commission if the preferred resource plan changes, (c) file an annual update of its resource plan, and (d) comply with the IRP rules' special contemporary issues requirements. OPC complains that resource planning cases are "long and confusing" but then, paradoxically, wants to inject resource planning issues into the FAC rule. OPC and other parties are capable of participating in the resource planning process and in all of the related processes identified above. They can ask discovery questions related to any determined or claimed deficiencies (including in rate cases where FACs are at issue), and they can raise whatever concerns or arguments they want. OPC27 would simply be an unnecessary burden and barrier to requesting an FAC.

u. OPC28 – The Company agrees.

v. OPC29 – The Company does not agree with OPC's justification for this change, but does not object to the proposed language.

w. OPC30 – The rule need not and should not prescriptively tell the Staff what it should provide.

x. OPC 31 – The language is unnecessary but not objectionable.

y. OPC 32 – OPC32 is yet another attempt by OPC to dictate, via the rule, the factors, policies, and standards the Commission must (since rules have the force and effect of law) use to evaluate FAC requests. One can easily imagine OPC applications for rehearing and appeals whenever OPC advances opposition to an FAC or attempts to substantially limit its components or effectiveness if the Commission does not scrupulously adhere to each and every one of the 6 dictated standards (1A-C; 2A-B; 3) OPC advocates for in OPC32, or if the Commission resolves such factors in the utility's favor. The Commission can decide in each case whether some of the concepts OPC wants to codify in the rule are relevant in the case and give them the weight the Commission believes they deserve, if in a given case they deserve weight at all. The Commission's hands should not be tied by prescriptive measurements. Moreover, OPC32 would effectively amend Section 386.266 by defining for all utilities (devoid of the facts of a given case) what "reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity"[7] means, and by imposing extra-statutory and vague factors ("harmful"; "inappropriate") on the exercise of the Commission's discretion when considering FAC requests.

z. OPC33, OPC 34 – The language OPC seeks to modify or eliminate should remain in the rule. OPC provides little if any justification for eliminating these provisions, and it goes without saying that the Commission could only use a "lawful" factor.

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[7] See Section 386.266.4(1).

aa. OPC 35 – The Company does not object to this suggestion.

bb. OPC36 – OPC's alternative language should be rejected. The proposed rule's language requires that the tariff sheets outline how and when the true-up will be recovered including, <u>but not limited to</u>, *any* recalculation. Consequently, if there is no recalculation the rule works. If there is, the rule still works.

cc. OPC37 – It appears OPCs alphanumeric designation suggestion is correct.

dd. OPC38 – Consistent with earlier comments, OPC's suggestion should be rejected because it seeks to prescribe the standard by which the Commission would make its decision and, like OPC32, arguably effectively amends Section 386.266 by modifying one of the statutory findings the Commission must make. We repeat: the rule need not dictate to the Commission what standards it must follow when deciding these issues, thereby opening the Commission up to OPC claims of legal error if the Commission fails to follow the standard to OPC's satisfaction.

ee. OPC39, OPC40, and OPC41 – While the Company may (and has) agreed to give OPC access to these materials, the Commission's rule should not in effect expand OPC's limited statutory authority. Public Counsel is not a regulator. Indeed, its powers and duties, set forth in Section 386.710, are to *represent* the public. Public Counsel does not automatically have access to the utility's books and records, but rather, must request access from the Commission and must establish good cause. Section 386.450. "Good cause," by definition, should depend on the facts and circumstances of the issue at hand.

ff. OPC42 – It has been clear to the Company over the 9-plus years it has had an FAC that the 12 reports it submits every year go largely unused by the parties, including by the Staff and OPC, except in prudence reviews or perhaps in later rate cases. Indeed, many of the data requests the Company receives in such cases are for information that the Company has already provided in those reports. The Company's reports are robust and have been substantially augmented over the years with a vast array of information sought by Staff and OPC. Can the Company prepare monthly reports? Of course it can, but the proposed rule's relief of part of the administrative burden associated with an FAC by reducing the frequency of the reports should be implemented as proposed. This is consistent with the Commission's overall effort to streamline and reduce the burden of its rules where it can. Under the proposed rule, the Company will submit three reports each year, with information by month, year-to-date, and for the prior calendar year. This will provide parties, including OPC, with appropriate information in great detail for any period covered by a prudence review and leading up to any rate case where an FAC is at issue. Finally, if OPC's suggestion were accepted, the new requirement in the proposed rule to provide year-to-date and prior calendar year information should be eliminated. Report recipients can add or combine the monthly data however they choose without requiring the Company to add yet another step to the FAC reporting process. That added step was reasonable if, as the rule proposes, the frequency of the reports was to be cut from (in Ameren Missouri's case) 12 reports per year to 3 reports per year.

gg. OPC44 through OPC51 – The Company's Initial Comments provided specific edits and explanations for those edits to provide the parties with relevant, clear, and non-duplicative information in periodic FAC reports. The fact that the Company has submitted over 100 monthly reports with virtually no problems (or information concerns)[8] is proof enough that the current process (which the Company's suggestions codifies) is working. OPC's suggestions in this area should be rejected. OPC suggestions reflect (a) duplication of information (as did the proposed rule), (b) essentially seek data that is not readily reportable or used for financial reporting (per GAAP, SEC, FERC requirements), (c) that is highly prescriptive (without a showing of the value of such prescriptiveness), and (d) that has no real value except perhaps in a prudence review and it is not clear what its value would be there. To the extent this level of detail has arisen from the dispute in KCPL's last reported rate case about how production cost modeling results are presented (gross versus net, etc.), the Company does not and has not had a similar issue. In that case, the Commission required KCPL to follow FERC Order 668, resolving the issue for KCPL. In other words, the Commission sided with Staff and OPC and said that the *net* should be provided. This is how the information appears in the Company's general ledger. The FAC rule should not in effect address a single-company dispute that the Commission has already resolved. The Company's suggestions in this area should be adopted and OPC's suggestions should be rejected.

hh. OPC52 – OPC54 – The Company agrees.

ii. OPC55 – While it is possible to breakdown commodity from transportation for gas and coal, it is not possible to do so for nuclear fuel assemblies amortized to fuel expense as they are burned. OPC's suggested change therefore must exclude nuclear fuel.

[8] Very early-on the Company worked with the parties, including Staff and OPC, to come up with a specific reporting format that has worked very well for years.

jj. OPC56 – OPC's suggested addition should be rejected. The provision at issue is simply an information requirement when an FAC rate change is filed. The FAC tariff of each utility will prescribe what can and cannot be included. Such a tariff has the force and effect of law. If the tariff does not allow a cost or revenue to be included, then it can't be included. An FAC rate adjustment filing that went beyond what the tariff allows would be nonconforming and could be rejected.

kk. OPC57 – OPC59 – The Company does not object.

ll. OPC60 – This is a numbering issue that the Commission should resolve.

mm. OPC61 – The Company does not object to OPC's suggested addition "(C)". With respect to "(D)", the General Assembly set the limits of the Commission's authority if a utility fails to follow a Commission order, rule, or relevant statute. The Commission has no power – and Section 386.266 did not give it such power – to impose yet additional punitive sanctions on a utility for failing to follow a rule. Moreover, there is absolutely no evidence or even any allegation that a problem in this area has ever existed. OPC's suggestion is unlawful and unnecessary.

nn. OPC62, OPC63 – The Company agrees.

oo. OPC64 – The Company does not object to the addition of "4" and, if modified, does not object to the addition of "5", which should read: 5. An explanation that details the factors which contributed to the FPA amount." The rest of "5" should be rejected. As for "I" and "II" the comparison sought would be irrelevant. The FPA amount is determined compared to the net *base* energy costs, not prior period *actuals*. Moreover, the FAR (the rate the customers pay) is impacted by changes in the FPA amount for the current accumulation period as compared to the FPA amount from the prior *two* accumulation periods. In addition, these provisions are subjective and could easily lead to disputes about the adequacy of the explanation (and what would be meant by a "RAM cost" or RAM revenue".) As for "III", this information is provided in periodic reports (no reason to duplicate here) and in any event, if there are issues about hedging costs or revenues those should be dealt with in a prudence review. The question for an FAR rate adjustment cases is whether the tariff and rules were followed – nothing more.

pp. OPC65 – The Company agrees.

qq. OPC 66 – The Company agrees that "costs of purchased power" here duplicates (II).

rr. OPC67 – The Company agrees.

ss. OPC68 – This appears to be a valid question.

tt. OPC69 – For the same reasons given in connection with OPC61, this suggestion should be rejected.

uu. OPC70 – The Company can appreciate OPC's desire to reduce the 20-day response period provided for by 4 CSR 240-2.090(2), but suggests that a reduction to 15 days is more appropriate. FAC rate adjustment filings (as noted, the Company has completed more than 25 of them) are generally straightforward and contain the same information (different numbers, but qualitatively the same). OPC has 40 days from filing to respond. Even if OPC were to take 10 days after the filing to submit a data request, it would have responses 15 days before its response is due. In addition, the time limit for giving notice of the need for additional time and to object needs to be adjusted as well as the time for response. To implement these changes, OPC's suggested language should be rejected in favor of the following: "In filings to adjust the FAR, the 20- and 10-day time limits in 4 CSR 240-2.090(2) shall be reduced to 15 and 7 days, respectively."

vv. OPC71 – It makes no sense to impose a rule that in effect would take an affirmative recommendation that an FAC rate filing be approved (i.e., that it conforms to the tariff and rules) but at the same time allow the recommendation to later be disavowed. Not only does that make no sense, but OPC's suggestion is another solution in search of a problem. As for "silence," the Company is unaware of any instance where a true mistake in an FAC rate filing (that was overlooked by the Staff) or where a cost or revenue was included (or excluded) that should have been included was overlooked could not be remedied later. For example, in the prudence review following the ice storm that shut down Noranda's aluminum smelter in 2009 Staff, OPC and others recommended a "prudence" disallowance, that was ordered and upheld, even though the off-system sales revenues that were ultimately found to be included in the FAC were excluded in the FAR case. The Company questions both the need for this provision, and OPC's motives in offering it.

ww. OPC72 – The Company does not understand OPC's suggestion, and doubts its necessity.

xx. OPC73, OPC74 – The Company does not object.

yy. OPC74 – The language should match the suggested language outlined in connection with OPC70.

zz. OPC76 – For the reasons given in connection with OPC71, this suggestion should be rejected.

aaa. OPC77 – OPC79 – While the Company is not intimately familiar with all aspects of the dispute OPC had with Empire (with the Commission siding with Empire), it appears that these suggestions relate to OPC's arguments in that case. The FAC rule need not and should not attempt to restate, paraphrase, or codify/dictate legal principles and standards that have developed in caselaw. If there is a prudence review and a dispute therein, the parties are well capable of briefing the appropriate legal standards and the Commission can apply the law to the facts. OPC's language is also imprecise in that the "burden of proof" has multiple aspects (production, persuasion). OPC's language is unnecessary, potentially inaccurate, and should be rejected.

bbb. OPC80, OPC81 – As outlined in the Company's Initial Comments and above in addressing Staff's Comments, this provision should be eliminated from the proposed rule. OPC's suggestions are thus unnecessary.

ccc. OPC82, OPC 83 – The Company does not object.

C. <u>DOGWOOD'S COMMENTS</u>

13. The Company generally supports Dogwood's suggestions, some of which were addressed by Staff Comments and some of which were addressed by previously suggested Company edits. With respect to Subsection (11), "including transportation," should be inserted after "purchased power costs."

D. <u>EMPIRE'S COMMENTS</u>

14. The Company agrees that all transmission charges associated with power purchased from an RTO market and power sold to an RTO market should be included in utility FACs. However, consistent with its view that the FAC rules should not prescribe the

components of fuel and purchased power, including transportation, that should be included, the Company does not believe the proposed rule need be revised to address these issues.

Respectfully submitted,

SMITH LEWIS, LLP

/s/ James B. Lowery
James B. Lowery, #40503
111 South Ninth Street, Suite 200
P.O. Box 918
Columbia, MO 65205-0918
(573) 443-3141
(573) 442-6686 (Facsimile)
lowery@smithlewis.com

Wendy K. Tatro, #60261
Director & Assistant General Counsel
Ameren Missouri
One Ameren Plaza
1901 Chouteau Avenue
P.O. Box 66149 (MC 1310)
St. Louis, MO 63166-6149
(314) 554-3484
(314) 554-4014
AmerenMissouriService@ameren.com

Attorneys for Ameren Missouri

Dated: August 12, 2018

Exhibit No.:	
Issue(s):	Fuel Adjustment Clause Transmission Cost/Revenue Tracker, FERC ROE Refunds; SPP/MISO Dispute
Witness:	Lynn M. Barnes
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2016-0179
Date Testimony Prepared:	January 20, 2017

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

REBUTTAL TESTIMONY

OF

LYNN M. BARNES

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January 2017

** **Highly Confidential Information Removed****

NP

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REBUTTAL TESTIMONY

OF

LYNN M. BARNES

FILE NO. ER-2016-1079

I. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Lynn M. Barnes. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Are you the same Lynn M. Barnes who filed direct testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

The purpose of my rebuttal testimony is to address certain aspects of the Office of the Public Counsel's ("OPC") recommendations to materially change the Company's fuel adjustment clause ("FAC"). In addition, I am addressing positions of various witnesses on the topics of the proposed transmission tracker and the refunds resulting from changes in the return on equity ("ROE") utilized in the determination of transmission charges paid by the Company to the Midcontinent Independent System Operator, Inc. ("MISO"), as determined by the Federal Energy Regulatory Commission ("FERC") (and reduced transmission revenues arising from a MISO/Southwest Power Pool dispute). Regarding the FAC, more specifically, the primary areas that I address are:

- OPC's overly restrictive attempt to define "fuel costs" in a manner that is at odds with the common understanding of the components of fuel costs and that would, if adopted, improperly exclude from the FAC legitimate fuel cost components that have been included in the FAC since its inception, as well as drastically change the components included in the Company's FAC as compared to the components

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the Commission has approved for inclusion since its inception nearly eight years ago.

- Why OPC's overall justifications for attempting to restrict the fuel and other cost components that can be included in the FAC fail to withstand scrutiny.

- Why OPC's already-rejected and still unsupported proposal to change the sharing mechanism in the existing FAC from 95%/5% to 90%/10% (which is the same as OPC's attempt in Ameren Missouri's last rate case to change it to 90%/10%) should be rejected. For years, the Commission has repeatedly and properly rejected numerous attempts to change the sharing percentage in FACs where, as here, there is no justification offered (aside from one witness's speculative opinion) that there is any need to expose the utility to further under-recovery of net energy costs when those net energy costs rise, or deprive customers of an even greater share of reductions when net energy costs fall.

- Why OPC's proposed changes to the FAC are truly a solution in search of a problem, given the fact that FACs in Missouri have operated without any significant problems for nearly a decade.

- Why adopting OPC's significant changes to the FAC would undermine regulatory consistency in Missouri, which is critical to utilities and their investors.

Q. What recommendations has OPC made regarding Ameren Missouri's FAC?

A. OPC's proposal is detailed on pages 4-5 of Ms. Mantle's direct testimony. With respect to fuel costs, she effectively recommends restricting the components of fuel costs to just the lumps of coal, molecules of gas, and barrels of oil literally burned in the boiler, and to the nuclear fuel assemblies that are in the nuclear reactor, plus the transportation of those items paid to the railroad, trucking or barge company, or pipeline (and applicable taxes). As Ameren Missouri witness Andrew M. Meyer discusses in his rebuttal testimony, she also seeks to greatly restrict the components of purchased power and transmission that would be included in the FAC. Her recommendations would significantly reduce the components currently included in the FAC as compared to the components the Commission has approved for inclusion in Ameren Missouri's original

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FAC (approved nearly eight years ago). The Commission has since re-authorized their inclusion on four separate occasions. However, unlike her fuel, purchased power, and transportation cost component recommendations, she seeks to continue to include all the off-system sales revenues that are currently included in the FAC. As noted, Ms. Mantle also wants the Commission to impose more sharing through the FAC, this time using a sharing ratio of 90%/10%.

Q. Do you agree with OPC's recommendations?

A. No, I do not.

Q. What benefits does Ms. Mantle claim would result from the adoption of OPC's proposal?

A. Ms. Mantle claims on pages 2-3 of her testimony that OPC's proposal "minimizes the complexity of Ameren Missouri's FAC while providing Ameren Missouri with a reduction in risk regarding its recovery of its fuel and purchased power expenses . . . [and] offers a more meaningful incentive for Ameren Missouri to manage, to the extent it is able, the fuel and purchased power costs and off-system sales revenues through recovery of all the fuel costs included in base rates and 90% of the FAC cost above what is included in base rates." On pages 5-6, she goes on to list seven specific claimed benefits:

1. Consistency with Section 386.266.1 RSMo;
2. Increases transparency of the costs and revenues included in the FAC;
3. Limits the disincentive for implementation of efficiencies;
4. Simplifies FAC prudence audits;
5. Simplifies FAC tariff sheets;
6. Recovers the majority of Ameren Missouri's current FAC costs; and

7. Provides an incentive for Ameren Missouri to effectively manage fuel, purchased power and off-system sales.

Q. Do you agree with Ms. Mantle's claim that OPC's proposal would "provide Ameren Missouri with a reduction in risk regarding its recovery of its fuel and purchased power expenses"?

A. No, Ms. Mantle's claim is incorrect. Exposing Ameren Missouri to the risk of increases in fuel, purchased power, and transportation costs by excluding the majority of the components of these items currently part of the FAC can only serve to *increase* the risk that changes in the cost of fuel, purchased power and transportation between rate cases will not be fully recovered.

Ms. Mantle's attempt to justify this claim on page 20 of her testimony that "(i)mportantly, OPC's recommendation would still result in Ameren Missouri recovering increases in true fuel and purchased power costs thus reducing the risk to Ameren Missouri of increases in fuel and purchased power costs" makes it clear to me that she is comparing the Company's risk with a substantially pared-back FAC to what it would be if Ameren Missouri *did not have an FAC at all*. However, Ameren Missouri has an FAC that includes many components OPC now seeks to exclude. Excluding components of fuel, purchased power and transportation from the FAC would increase its risk.

Q. Do you agree with Ms. Mantle's seven other claims of benefits?

A. No. At best, her claims are unsupported, and several of her claims are simply incorrect.

First, to the extent Ms. Mantle implies that the costs and revenues currently in Ameren Missouri's FAC are not "consistent with" the FAC statute (section 386.266.1, RSMo) because the statute does not contain a detailed listing of every component that makes up fuel, purchased power, and transportation, she is, in my opinion, wrong. While I am not an attorney, I can read the statute. What it says is that FACs can be implemented to cover "fuel and purchased power costs, including transportation." The legislature did not restrict the language to the "cost of the fuel commodity" (e.g., to the lump of coal or molecule of gas).

In approving FAC tariffs that quite clearly include far more components in "fuel costs" and "purchased power costs" and "transportation costs," the Commission has never, in the nearly a decade since the FAC was first implemented in Missouri, interpreted the statute so restrictively; nor has its Staff or, for that matter, OPC. Ms. Mantle herself has supported inclusion of a broad variety of costs in the FAC in previous cases.

In this case, Ms. Mantle recognizes that the terms "fuel," "purchased power," and "transportation" are undefined by the FAC statute. She notes that the "statute does not mention fuel adders, fuel handling, contractor costs, spinning reserve costs, startup costs, hedging costs, and a myriad of other costs and revenues." Lacking statutory definitions, Ms. Mantle goes on to propose a definition of "purchased power" that consists only of "energy" and "capacity," even though neither the term "energy" nor "capacity" appears anywhere in the statute.[1] As Mr. Meyer explains, while energy and capacity are two components of "purchased power costs," there are many more. The same is true of fuel costs. While the lump of coal or molecule of gas are fuel cost components, there are

[1] Existing, approved FAC tariffs for Missouri's electric utilities clearly reflect the Commission's understanding that many components (none of which are listed in the FAC statute) make up fuel, purchased power, transportation, and off-system sales. This is evident from a review of Ameren Missouri's current FAC tariff, Kansas City Power & Light Company's ("KCP&L") current FAC tariff, and FAC tariffs approved by this Commission in just the past few months for Kansas City Power & Light Company – Greater Missouri Operations ("KCP&L-GMO") and The Empire District Electric Company ("Empire").

many additional legitimate components of fuel costs that are necessary for utilities to prudently acquire fuel and deliver it to their generating units for purposes of calculating the FAC. Moreover, based on Ms. Mantle's premise, their exclusion may provide the very disincentive that Ms. Mantle claims her proposal would eliminate.

Second, I disagree that Ms. Mantle's proposal would increase the transparency of the costs and revenues included in the FAC. Instead, it just limits the list of the legitimate components of fuel and purchased power costs, including transportation, which would be included. Transparency is not dependent on brevity. To the contrary, transparency depends on whether information is available to identify the fuel and purchased power costs, including transportation. Not only do FAC tariffs in Missouri already contain tremendous detail, but additional detail is provided in monthly FAC reports, work papers, and schedules supplied with FAC rate adjustment filings. Ms. Mantle is the very person who insisted on adding this detail to the tariffs and reports. Oddly enough, if Ms. Mantle's proposal were to be adopted, these same monthly reports would now be stripped of the data for the excluded components of fuel, purchased power, and transportation – arguably significantly reducing the transparency of our costs and revenues between rate cases. Even if one were to agree that transparency in the FAC was somehow increased by Ms. Mantle's recommendation (which I do not), any incremental benefit gained from such incremental transparency is dwarfed by the increased risk borne by the utility and its customers from the elimination of legitimate fuel, purchased power, and transportation costs from the FAC.

Third, I disagree that Ms. Mantle's proposal limits the disincentives for implementation of efficiencies. In fact, if such disincentives as described by Ms. Mantle exist, it is a creation of the OPC's and her own aggressive actions. Those actions include advocating for the addition of ever-increasing and prescriptive levels of detail into the FAC tariff, coupled with then attempting to limit any changes to any of the components thus detailed in between rate cases even if the nature of those components is consistent with those listed in the detailed tariff.

Fourth, Ms. Mantle's claim that her proposal will simplify prudence audits is a red herring at best. Her proposal would exclude a large list of components of fuel, purchased power, and transportation costs from the FAC, including many which serve as an offset to costs remaining in the FAC. If anything, this would increase, not decrease, the complexity of the prudence review as the audit would have to look at the interaction between activities both within and outside the FAC to ensure that the utility is not taking actions which benefit them based solely on whether they are included or excluded from the FAC. Reviews would be further complicated as Ms. Mantle's proposal would mean that substantial components are no longer in the FAC and thus no longer covered by monthly FAC reports and FAC rate adjustment filings, including the work papers that underlie those filings. For these reasons, FAC prudence reviews would likely be more complicated than they are today.

Fifth, it seems ironic that Ms. Mantle touts her proposal as simplifying the very tariffs that she and the OPC have fought so hard to *make as detailed, and consequently as "complex," as possible.* If she believes they are too complicated, it is because of positions that the OPC itself has advocated for. These tariffs have not always been this complicated, and do not need to be as complicated as they are. Moreover, just because the tariffs contain a detailed listing of many cost components does not make them "complex."

Sixth, the purported benefit that Ameren Missouri would recover the "majority" of its FAC costs under Ms. Mantle's proposal misses the point of having an FAC. Ameren Missouri would recover the "majority" of its current FAC costs even if the FAC were eliminated. The focus must be on the fact that FACs track *changes* in the cost and revenue components included in the FAC between rate cases. In most jurisdictions, electric utilities recover 100% of their fuel costs through a tracking mechanism. Ms. Mantle's proposal would exacerbate Missouri's out-of-the-mainstream exclusion of legitimate fuel and purchased power costs from the FAC.

Seventh, I disagree that Ms. Mantle's proposal would increase the incentive for Ameren Missouri to effectively manage fuel, purchased power and off-system sales. As I will describe later, it may in fact decrease that incentive in certain areas.

II. <u>FUEL COSTS</u>

Q. What are the commonly understood components of fuel costs?

A. Fuel costs and the components that make them up are commonly defined by reference to the FERC Uniform System of Accounts ("USOA") for electric utilities (principally FERC Accounts 501, 518 and 547). I have included the USOA definitions for each of those accounts in Schedule LMB-R1 to my testimony. Those definitions make it very clear that fuel costs consist of many components, certainly far more components than Ms. Mantle wants to recognize. These definitions have been in place and utilized for decades.

Q. Has the Commission recognized that fuel costs consist of far more components than Ms. Mantle recommends for inclusion in Ameren Missouri's FAC?

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A. Yes. This is obvious since all the Commission-approved FACs in Missouri over the last decade include many more components of fuel costs than proposed by Ms. Mantle. In addition, since FACs include many more components than recommended by OPC, it follows that when the Commission approves the many FAC adjustment filings that have been made, it has approved inclusion of many more components than OPC would recognize.

Not only has the Commission approved FAC tariffs and adjustment filings that reflect many more components of fuel, purchased power, and transportation costs than Ms. Mantle proposes, it has had the benefit of receiving detailed FAC monthly reports, rate adjustment filing work papers, and rate case filings and work papers where the base for the FAC is set. The Commission, based on affirmative recommendations from its Staff and Ameren Missouri's filings, has approved 22 separate FAC rate adjustments that reflect many fuel cost components Ms. Mantle now seeks to exclude based on her contention that these components are not sufficiently "pure." Similarly, five prudence reviews have been completed with no allegation whatsoever that any cost had been included as a fuel cost when it should not have been.

Q. I take it then that you disagree with Ms. Mantle's contention that costs for just the fuel "commodity" (e.g., the lump of coal) is the "purest" definition of fuel costs?

A. Yes, I do. The definition Ms. Mantle argues for now is completely at odds with the FERC USOA, industry practice, and this Commission's own definition of fuel costs, as evidenced by its treatment of these cost components over a period of many years. A far more accurate descriptor for OPC's position is that the cost of just the fuel commodity is the "narrowest possible" definition of fuel costs there could be.

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Q. Ms. Mantle's first justification for recommending this narrowest possible definition of fuel costs is that it would be consistent with the FAC statute. Please address her argument.

A. Since Ms. Mantle is not an attorney, I am assuming she is not attempting to draw legal conclusions about what the FAC statute does or does not provide for. As noted earlier, I, too, won't attempt to engage in legal interpretation of the statute. I will note, however, that she seems to be suggesting that existing FAC tariffs do not comply with the FAC statute, the implication being that everyone – the Commission, Staff, the utilities – have all been getting it wrong for all this time. I strongly disagree.

As I noted before, the fact that FERC and the industry use the term "fuel costs" much more broadly than Ms. Mantle recommends, and that the Staff and the Commission (and for that matter, OPC, until recently) have obviously recognized that fuel costs within the meaning of the FAC statute include many more components than Ms. Mantle now recommends. This strongly suggests that it is OPC's recommendation that seeks a far narrower definition of fuel costs than contemplated by the statute.

It is important to note here that the statute also includes the provision that "(t)he commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities." As discussed elsewhere in my testimony, ensuring that components of costs and revenues that serve to offset other components of fuel, purchased power, transportation, or off-system sales remain tied together provides an incentive for the efficient and cost-effective management of fuel, purchased power, transportation, and off-system sales.

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In my opinion, Ms. Mantle's recommendation to exclude a significant number of the components of fuel, purchased power and transportation from the FAC is significantly *less consistent* with the FAC statute than the current handling of fuel cost components in Ameren Missouri's and other Missouri FACs.

III. <u>OPC'S OTHER PURPORTED JUSTIFICATIONS</u>

Q. Ms. Mantle's second argument for stripping fuel cost components out of the FAC is that doing so will improve transparency. Do you agree?

A. No, I do not, as demonstrated by Ameren Missouri's long history of providing transparency into the components included in the FAC. In sum, there is no need to artificially re-define and narrow what fuel costs are to provide transparency for components that make up fuel costs included in the FAC. For example, several years ago, we worked with the Staff and other stakeholders to go above and beyond the reporting requirements of the Commission's FAC rules to provide a detailed disaggregation of the components of fuel costs, purchased power costs, transmission costs, and off-system sales revenues that are included in the FAC. We disaggregated these components by FERC account. I have attached the page containing this disaggregation from our September 2016 report to my testimony as Schedule LMB-R2 (also attached are pages that disaggregate our total purchase power and transmission costs, and off-system sales). We also provide additional supplemental information (again, far beyond that required by the Commission's FAC rules) broken down by the managerial accounting that we have chosen to utilize. This, too, is not required by the FAC rules, but we were asked to provide it and have done so. We also go above and beyond the rule requirements by providing all the General Ledger entries that back up the costs and revenues included in the FAC for that month, and we provide the keys that

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explain the coding that is used in the General Ledger. In addition to the monthly reporting, we provide highly detailed work papers with each FAC rate adjustment filing. Over 22 such filings, there have been only a few instances where the Staff (or other parties who may choose to review them) had questions for us, and in each instance, we were able to address the questions. The Staff (which previously included Ms. Mantle) has recommended approval of all those adjustments, and no party has ever claimed (aside from Ms. Mantle in our last rate case) that our reports or other filings were deficient or lacked transparency.[2]

OPC recently claimed, in a filing verified by Ms. Mantle, that our 23rd FAC rate adjustment filing lacked certain information and on that basis argued the entire filing should not be approved. OPC's claims were made in a filing opposing the Staff's verified recommendation which had (a) confirmed that our filing *did* comply with the FAC, (b) confirmed that the proposed rate was correct, and (c) recommended the filing be approved. In response, the Staff disagreed and renewed its recommendation that the filing should be approved, explaining that our filing was in fact accurate, both in its calculation of the proposed rate and in terms of the testimony filed to support and explain that rate. We too disagreed with OPC and demonstrated that the entire premise of OPC's opposition was flawed and that OPC's filing contained numerous errors and completely lacked any claim that the filing itself was in fact incorrect. *See Ameren Missouri's*

[2] Early this year we had an issue regarding the calculation of the so-called "N Factor" in our FAC tariff, which occurred during the first FAC rate adjustment filing where an amount arising under the N Factor was included. We agreed not to include the N Factor sum in that particular adjustment and then worked with the parties to achieve an agreed-upon calculation that was reflected in subsequent adjustments. The stipulation resolving the issue was approved by the Commission. Over nearly eight years of operation, there have been only two other instances of arguable dispute about FAC calculations. One arose from File No. EO-2010-0255, involving two wholesale contracts entered into after the 2009 ice storm that damaged the New Madrid smelter and the other involved a true-up calculation about which both Ameren Missouri and the Staff had made a simple mistake (File No. EO-2010-0274). The Commission disagreed with us on the two contracts arising from the ice storm, but agreed with us on the true-up issue.

Verified Response to Public Counsel's Reply to Staff's Response filed on January 10, 2017 in File No. ER-2017-0147. It is worth noting that OPC made these claims without having so much as picked up the telephone to call the Company to discuss OPC's claims or concerns about missing or inaccurate information, despite having had seven weeks before it made its filing to do so. In my opinion, this reflects a continuing pattern of general OPC hostility to the FAC.

Ms. Mantle herself admits that OPC is hostile to FACs.[3] Experience shows that the FAC can in fact both properly include the many components that make up fuel costs, and provide transparency into what those costs are. The fact that Ms. Mantle seeks to eliminate legitimate cost components from the FAC instead of advocating for the use of tools that are, or could be, available to it seems telling; it suggests to me that she is less concerned with transparency and more concerned with advancing some philosophical agenda aimed at eliminating legitimate cost components from the FAC. It should also be noted that should OPC be successful in these arguments, much of the detail currently contained in the monthly reports would be removed, as it would no longer pertain to the calculation of the FAC.

Q. Didn't OPC claim deficiencies in Ameren Missouri's "explanations" in Ameren Missouri's last rate case?

A. Yes, OPC made that claim. The Staff has never claimed any such deficiency, nor has the Commission ever found any such deficiency to exist. Moreover, we fully demonstrated that the information we provided in each rate case had been consistently accepted by the Staff and even OPC (until then) as being in accordance with

[3] As Ms. Mantle has admitted, OPC has been "very negative about fuel adjustment clauses from the beginning" [of FAC requests in Missouri]. Mantle Deposition, File No. ER-2014-0258, p. 230, l. 8-11.

the Commission's rules. In any event, we resolved our differences with OPC in that case and agreed to work together with OPC reasonably and in good faith to develop additional descriptions of all FAC cost and revenue items. We did so, and those were filed as part of one of the schedules to my direct testimony in this case.

Q. Do you have any observations about OPC's continued effort to remove components from the FAC that have always been included, and about which there has been little or no controversy, under the guise of arguing that more "transparency" may be needed?

A. Yes, I do. While there have been a couple of changes to the FAC since its inception, the vast majority of the charges and revenues covered by it have remained unchanged.[4] As earlier noted, the FAC tariff itself now has a lot more detail than it did at its inception, but even before this detail was added, the monthly reports contained significant levels of detail. Adding additional detail to the report did not change what was recovered under the FAC. In fact, the monthly reports we have been providing for years are the product of significant collaboration with the Staff (when Ms. Mantle was on the Staff), OPC and others. We were asked several years ago to add additional detail, we did so, and those parties all indicated that the revised reporting met their needs. To that monthly reporting detail has been added the additional descriptions of which I just spoke. In summary, we have worked very hard to be responsive to stakeholders who believe

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[4] Emissions were added several years ago, and since they were added, have always reflected revenues that offset total net energy costs. Consumables that are added to fuel for air quality control were added several years ago by agreement and since then no party, except OPC (and perhaps Consumers Council of Missouri, which has consistently opposed FACs in their entirety), has expressed any concern about it. A significant portion of total transmission costs were excluded in 2015 when the Commission rendered its finding about "true" purchased power. Finally, MISO has added a new "charge types" (six times over the past few years) as its market has evolved, at least three of which added *revenues* to the FAC to the benefit of our customers.

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they need additional information. OPC's recommendation is truly a solution in search of a problem.

Q. Ms. Mantle's next claim is that stripping cost components from the FAC would simplify prudence reviews. Is she right?

A. No. In fact, if anything, stripping components from the FAC will increase, not decrease, the complexity of the review as the audit would then have to look at the interaction of activities both within and outside of the FAC to ensure that the utility is not taking actions that benefit them based solely on whether the costs associated with such activities are in or out of the FAC. Reviews would be further complicated as OPC's proposal would also result in the elimination of a substantial amount of information from the existing monthly reports and FAC-related filings and work papers, which report and reflect activity within the FAC.

For example, Ms. Mantle proposes to include all components of off-system sales in the FAC (these are revenues) while stripping out components of purchased power, which are offset by some of those off-system sales components. Similarly, she proposes to strip out some components of purchased power from other components she would leave in the FAC, yet most of the components she proposed to strip out are inextricably linked to those she would leave in, as Mr. Meyer explains in his rebuttal testimony. Also, while she has not specified exactly which MISO charges types OPC is recommending for inclusion in Ameren Missouri's FAC, she has recommended the elimination of the provision in the FAC allowing for the inclusion of new charge types in between rate cases, even if the new charge type possesses the characteristics of or is in the nature of an existing charge type.

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Adoption of these recommendations would not simplify prudence reviews or the FAC generally. To the contrary, they would add complexity. For example, Mr. Meyer's testimony includes a discussion of MISO's implementation of a new charge type for capacity revenues in June of 2013. If changes in between rate cases had been prohibited at that time, we would have found ourselves in the situation where if we sold capacity through the MISO auction we could keep all of the revenue for ourselves, but if we sold it bilaterally we would have to include it in the FAC. I would have expected a prudence review of our capacity sales for that period to focus in no small part on our possible motives in choosing one alternative (the auction) over the other (bilateral) - regardless of what price we were able to obtain for the capacity.

Similarly, if a cost component is excluded from the FAC but an offsetting cost component is included, I would expect a prudence review to scrutinize whether we took an action which resulted in a shifting of costs and revenues between these two components, simply based on whether the component was or was not included in the FAC.

Removing the component from the FAC doesn't simplify the process. Leaving the tariff as it is does.

Q. There does seem to be some superficial appeal to the notion that if the FAC only included the commodity cost, e.g., the cost of the lumps of coal and the railroad bill, that prudence reviews would be simpler because the auditor would not have to worry about other procurement costs, ash handling, etc. Please respond.

A. As I noted above, these other cost components *are* fuel cost components, and under the FERC USOA they *must* be recorded (for coal) in Account 501. The auditor must pay attention to those costs, whether they are included or excluded from the cost of coal used in the FAC calculations, because the auditor must examine the ledger entries in Account 501 in their entirety. The larger the list of fuel cost components that are recorded to fuel accounts that are *excluded* from the FAC, the more work that must be done to make sure they were *all* excluded. In addition, monthly FAC reports are by their nature reports of activity *within the FAC.* The very detailed disaggregation included in Ameren Missouri's reports (and work papers that underlie FAC rate filings) provides transparent information that the Staff is receiving month in and month out. Staff doesn't have to seek the information they need just within a 180-day prudence review window.

Ms. Mantle, who is neither an auditor nor an accountant, is speculating about the degree to which auditors can and should do their jobs. I don't see the Commission's duty (through its Staff) to conduct prudence reviews as the FAC statute requires to be any different than the Commission's duty to regulate public utilities generally. Does that regulation require a lot of time and effort? Yes. Is there complexity in electric utility industry? Yes. Are these reasons to exclude legitimate costs from the FAC? No. (Note that Ms. Mantle looks to exclude costs, but does not similarly suggest excluding the various components of off-system sales *revenues*, which offset fuel costs).

Q. Ms. Mantle next attempts to support her recommendation by effectively contending that her recommendation is not a big deal because of her claim that Ameren Missouri would still recover the "majority" of its fuel, purchased power and transportation costs. Does this claim support her recommendations?

A. No, it does not. Ameren Missouri's total fuel, purchased power, and transportation costs are quite large relative to its overall operations and maintenance expenses. In each rate case, a base level is set, and that base is undoubtedly large – with or without an FAC. However, the FAC tracks *changes* in those costs (net of off-system sales revenue changes) in between rate cases.

The amounts in question are indeed a very big deal. When we look at the actual annual totals for just those two components of purchased power that Ms. Mantle would exclude from the FAC, we can see that year-over-year changes are as great as $25 million.[5] Ms. Mantle would seemingly have the Commission believe that $25 million is not a big deal, because Ameren Missouri could collect the "majority" of the prudently incurred actual net energy costs. I am confident that it is obvious to the Commission that $25 million is, indeed, a big deal.

As the Staff (as an example) indicates in its revenue requirement report filed in this case, fuel and purchased power costs and associated transportation costs, net of off-system sales, are large, volatile, and largely beyond the Company's control. The Commission has repeatedly drawn the same conclusion for Ameren Missouri since it first approved the FAC in 2009. That being true, *changes* in fuel and purchased power costs and associated transmission costs, net of off-system sales, can be significant between rate cases, and the utility can't control them. It should not matter if a utility over time could theoretically "recover" 97 or 98 or 99%.[6] Every percentage or fraction thereof that the utility does not recover is simply a failure to recover *prudently incurred costs*. A strong case can be made that Ameren Missouri (and other Missouri utilities) ought to recover 100% of prudently incurred net energy cost changes between rate cases, as do more than 80% of all other similarly situated utilities.

[5] See Mr. Meyer's rebuttal testimony and his table showing ARR/FTR revenues.
[6] As discussed further below, Ms. Mantle's claim that such a high percentage would be recovered under her proposal is misleading and exaggerated.

Q. Ms. Mantle's final purported justification for OPC's recommendations is that they would create an incentive for Ameren Missouri to properly manage its fuel and purchased power costs, including transportation costs, net of off-system sales revenues. How do you respond?

A. My response is the same as the response I have given before when Ms. Mantle had repeatedly made the same argument to support her attempt to make FAC changes in the past: OPC presents no evidence to support the conclusion that Ameren Missouri does not already have the appropriate incentives to properly manage the costs and revenues in its FAC. Just because Ms. Mantle says that her proposal will improve incentives does not make it so. Her supposition about incentives is just that: supposition.

Despite years of trying, Ms. Mantle has not once actually demonstrated that utilities are making imprudent decisions that negatively impact net energy costs tracked in an FAC because they have an FAC or because of the terms of the FAC tariff. I acknowledge that the Commission's order involving the AEP and Wabash contracts in Ameren Missouri's second prudence review case contains language that indicates Ameren Missouri was "imprudent" for not including those contracts' revenues in the FAC. However, the heart of the dispute was that Ameren Missouri believed the FAC tariff excluded those contracts and others disagreed. The Commission sided with those who disagreed. However, the issue in that case had nothing to do with incentives and it had nothing to do with "prudence." Indeed, when Ms. Mantle has argued in the past that the AEP/Wabash case (File No. EO-2010-0255) somehow demonstrated that Ameren Missouri needed more incentive to manage its net energy costs properly, the Commission expressly rejected the argument. *Report and Order*, File No. ER-2011-0028, p. 82 ("The Commission did not find that Ameren Missouri acted imprudently in that prudence review. * * * In short, the Commission's decision in EO-2010-0255 does not support the argument that Ameren Missouri needs a larger financial incentive within the fuel adjustment clause.").

IV. OPC'S PROPOSAL TO CHANGE THE SHARING MECHANISM

Q. Please address OPC's proposal to change the sharing mechanism in the FAC from its current 95%/5% to 90%/10%.

A. OPC's proposal is unsupported and is nothing more than a repeat of the same or similar proposals this Commission has, on numerous occasions, rejected in the past.

Q. Please explain.

A. In the first couple of years after the FAC statute was adopted, the Commission began approving FACs for Missouri's electric utilities: first for Aquila, Inc. (2007) (now KCP&L-GMO); then for Empire (2008); then Ameren Missouri (2009); and lastly, KCP&L (2015). Starting early-on, various parties have argued for more sharing. For years now, the Commission has concluded that FACs should continue to include the 95%/5% sharing mechanism the Commission implemented nearly 10 years ago. In fact, the Commission has rejected calls to impose more sharing on 17 separate occasions, as detailed in Schedule LMB-R3 to my testimony.

The following is a sampling of Commission statements in support of retaining its 95%/5% sharing mechanism while rejecting calls to increase those shares:

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- "A 95% pass through provides AmerenUE sufficient incentive to operate at optimal efficiency . . ." [rejecting an OPC attempt to impose 50%/50% sharing].[7]

- Imposing a less favorable [to utilities] pass through provision "would signal to investors that [the utility] was less well regarded by . . ." the Commission.[8]

- "[C]hanging the sharing percentage without good reason to do so would lead investors to question the future of [the utility's] fuel adjustment clause."[9]

- "Most fuel adjustment clauses around the county [sic] provide for a 100 percent pass through of costs."[10]

- "MIEC and Public Counsel advocated for a revised sharing mechanism . . . However, the testimony those parties presented was based on little more than the opinions of their witnesses . . . No party presented any evidence that would indicate how the 95% sharing mechanism is working in practice . . . Certainly, no evidence was produced to show that [the utility] had acted imprudently. . ."[11]

I see no evidence in any of the direct testimony filed in this case to suggest that Ameren Missouri has acted imprudently or that the 95%/5% sharing percentage isn't working.

The bottom line is that every "justification" put forth by OPC to increase Ameren Missouri's sharing percentage suffers from the same flaw from which past arguments in support of changing the sharing percentage have suffered: they amount to speculative opinions of individuals who have no experience in managing net energy costs, advanced by a party with demonstrated hostility toward FACs. They also lack any basis in facts showing that the utility has failed to prudently manage its net energy costs or that the

[7] *Report and Order*, File No. ER-2008-0318, pp. 73-74 (citing five reasons that the 95/%/5% sharing was sufficient, including financial performance incentives for employees that would give them an incentive to minimize net energy costs, the Commission's use of historical instead of projected costs in FACs, which creates greater exposure to rising net energy costs for utilities, the Commission's heat rate/efficiency testing requirements, and the fact that having an FAC is a privilege, not a right, which itself gives utilities an incentive to properly manage net energy costs.).
[8] *Id.*
[9] *Report and Order*, File No. ER-2011-0028, p. 85; *Accord Report and Order*, File No. ER-2010-0036, pp. 77-78 (Discussing concerns about overturning "regulatory stability" in Missouri, and increased investment risk caused if the Commission were to change sharing mechanisms given that investors value "certainty, fairness, stability and predictability").
[10] *Id.*, p. 75; *Report and Order*, File No. ER-2010-0036, p. 76 (same).
[11] *Id.*, pp. 76-77 (OPC's testimony in this case also consists of nothing more than unsupported opinions).

existing 95%/5% sharing and the other incentives utilities possess to properly manage net energy costs (as recognized by the Commission) are in any way insufficient.

Q. Doesn't OPC argue that an apparently high percentage of cost recovery justifies greater sharing?

A. Yes, OPC makes that argument, but the argument misses the point.

First, Ms. Mantle's table showing recovery percentages is misleading, and her conclusions drawn from those values are exaggerated.

Second, even though flawed, OPC's own math confirms the obvious: greater sharing would deprive customers of additional dollars of reductions in net energy costs and greater sharing would deprive Ameren Missouri of additional *prudently incurred* net energy costs. If the percent of recovery is "high," that is exactly how it should be, given that the very nature of the FAC only allowed prudently incurred costs to be recovered. Illustrating the math neither shows nor tends to show that there is an "imprudence problem" that needs to be addressed.

Q. Why is Ms. Mantle's table misleading?

A. Ms. Mantle's table purports to demonstrate that Ameren Missouri would suffer little harm from her proposals. However, her table has a glaring omission – Ms. Mantle has not only recommended that the Commission increase the sharing percentage, but that the Commission also exclude a significant portion of the components of fuel, purchased power, and transportation from the FAC. For those items excluded from the FAC, Ameren Missouri would bear the full consequences of increases and decreases in between rate cases, i.e., for the excluded components the "sharing mechanism" is effectively 0%/100%. For those items remaining in the FAC, Ameren Missouri's share

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would double from 5% to 10%. However, her table completely fails to account for changes between rate cases in costs *which would no longer be included in the FAC.*

When we account for both of those components that are in *and* out of the FAC, it is clear that Ms. Mantle has exaggerated her claim.

Q. Can you illustrate this exaggeration?

A. Yes. To do so, I started with Ms. Mantle's chart and its 90%/10% sharing column, then assumed that (a) 6% of fuel costs currently in the FAC would be excluded, and (b) 40% of any change in actual net energy costs ("ANEC"[12]) as compared to the base established in the rate case would be attributable to items excluded from the FAC per OPC's recommendation. The table, reflecting those assumptions, clearly illustrates that the combination of both OPC's 90%/10% sharing for items remaining in the FAC and 0%/100% sharing for items excluded from the FAC yields much different results than Ms. Mantle's original table:

			60% of Chg. In ANEC	C x 90%			
	A	B	C	D	A+ B + D		
<u>ANEC (incl. amounts excluded from FAC</u>	Base FAC	Base Excl.	Change in FAC	FAC Adj (90/10)	Total Recovery	% Of ANEC	Mantle
120	94	6	12	10.8	110.8	92.33%	98.30%
110	94	6	6	5.4	105.4	95.82%	99.10%
BASE - 100	94	6	0	0	100	100.00%	100%
90	94	6	-6	-5.4	94.6	105.11%	101.10%
80	94	6	-12	-10.8	89.2	111.50%	102.50%

The assumed splits between costs that are in and out of the FAC and the assumed drivers of changes in ANEC are illustrative. However, the point is that one cannot do

[12] Including for this purpose amounts currently included in the calculation of ANEC that would be excluded from ANEC under OPC's proposal.

what Ms. Mantle did and ignore the fact that under OPC's proposal, there would be costs outside the FAC and changes in those costs would not be recovered or returned, as the case may be. In the above illustration, I assumed that 40% of the difference between ANEC and the base was caused by components that would be moved outside the FAC if OPC's recommendation were adopted. If that percentage is higher (e.g., if 50% of the difference arises from components moved outside the FAC), the under-recovery (if ANEC went up) or over-recovery (if ANEC went down) will be even greater.[13] Instead of supporting more sharing, a table like Ms. Mantle's supports *no sharing at all* because it is the sharing that causes under-recovery of prudently incurred costs, and that precludes passing back to customers all the reduction in net energy costs when those reductions occur.

Q. Do you have any other observations on this issue?

A. Yes. We have repeatedly stated, and the Commission has repeatedly acknowledged, that having an FAC is a privilege, and not a right, and that this provides a powerful incentive for utilities to properly manage their net fuel costs.[14] Missouri is unique in that we have a statute mandating we come in and file a rate case and ask to continue our FAC at least every four years. The statute also mandates regular prudence reviews – we just completed our fifth prudence review in the past nearly eight years. The

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[13] E.g., if 50% of an increase in ANEC versus the base was driven by components moved outside the FAC, the percent recovered would drop to just 90.8%.

[14] Ms. Mantle agrees: In her sworn deposition in File No. ER-2011-0028, she testified as follows: "Q **Okay. Do you agree if there is imprudence the Commission has the power and the obligation to disallow any costs related to the imprudence?** A Yes. Q **And would you agree that that is a powerful incentive for a utility to avoid imprudent behavior?** A Yes. Q **Would you agree with me that the use of a fuel adjustment clause in Missouri is a privilege and not a right for utilities?** A That is correct. Q **And isn't it true that the Commission can take away a utilities [sic] fuel adjustment clause if it believes the utility is misusing it?** A Yes. Q **And doesn't that also provide a powerful incentive for utilities to act reasonably and prudently with respect to their FACs?** A Yes." Lena Mantle Deposition, File No. ER-2011-0028, April 13, 2011, p. 44, l. 7 – p. 45, l. 18.

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bottom line is that utilities have plenty of incentives to properly manage the components in the FAC without any sharing at all. They could lose the FAC entirely or suffer prudence disallowances. Even without a single prudence disallowance, Ameren Missouri has failed to recover tens of millions of dollars of prudently-incurred net energy cost increases over the past several years, caused solely by the 5% sharing mechanism.

As alluded to earlier, it is a very bad idea for the Commission to make changes in an important, mainstream mechanism like the FAC in the absence of a strong justification for making the change. Regulatory consistency is important to utilities as they plan and budget to provide service to their customers, and it is important to the investors on whom they depend for the huge sums of capital they need to do so. Ms. Mantle has been attempting to change the FAC and its sharing mechanism for years. Her latest attempt to radically re-shape the FAC should be rejected, as have the others.

Ms. Mantle's 90%/10% proposal in this case, like her prior 85%/15% proposal (made while she worked for the Staff) and her prior 90%/10% proposal (made in Ameren Missouri's last rate case and in this rate case), is nothing more than an unjustified experiment – an experiment for which no need has been shown.

Q. How would an even greater sharing percentage for Ameren Missouri compare to FACs of the other 97 utilities operating in non-restructured states?

A. Only about 18% of utilities have sharing of costs *at all*. From an investor standpoint, and from the standpoint of putting Missouri electric utilities on comparable footing with their peers, even the 5% share of net energy cost increases that Missouri utilities must bear places them at a disadvantage. That disadvantage should not be exacerbated just because Ms. Mantle or OPC, or both, seem to "believe" the sharing should be greater.

V. <u>OPC'S ATTEMPT TO ELIMINATE FAC TARIFF FLEXIBILITY</u>

Q. Another proposal by OPC is to eliminate a provision in the FAC that originated in the FAC tariff approved for Ameren Missouri in 2012; that is, the provision that allows costs *and revenues* that may arise after an FAC tariff is implemented but before it is re-implemented in the next rate case to flow through the FAC if the cost/revenue is similar; is of the same nature as costs/revenues that were included when the tariff was implemented. Please explain this provision.

A. In Ameren Missouri's 2012 rate case (File No. ER-2012-0166), Ms. Mantle, then working for the Staff, advocated for including a very detailed listing of each component of fuel, purchased power, transportation, and off-system sales in the FAC tariff itself. This necessitated adding significant detail to (in particular) the purchased power and transmission provisions of the tariff since MISO chooses to break purchased power and transmission charges into a fairly large number of distinct "buckets." As noted, Mr. Meyer addresses these components in more detail in his rebuttal testimony. As part of settling fuel/FAC-related issues in that case, Ameren Missouri agreed to add these details to the FAC tariff because it had no problem with being more explicit; more "transparent" as OPC might say, but with a very important caveat: if the FAC tariff was to become highly prescriptive, as Ms. Mantle desired, there had to be a mechanism to allow changes in cost/revenue *categorization* to be accounted for in the FAC between rate cases. Otherwise, customers or utilities could unfairly bear cost and revenue changes that in the words of the tariff provision at issue, possess "the characteristics of, and is of the nature of" costs and revenues that were already listed. In other words, the RTO might simply recategorize or rename a cost or revenue, or might add a cost or revenue that truly

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is a component of purchased power or off-system sales, and there needed to be a way to reflect that cost or revenue in the FAC.

This provision was modified to some extent in Ameren Missouri's last rate case, and has essentially become a standard feature in all FAC tariffs in Missouri.

Q. Can you illustrate its operation?

A. Yes, it is rather straightforward in its operation. Since the provision first appeared in Ameren Missouri's FAC tariff, MISO has implemented new "charge types" (the phrase "charge type" is a misnomer because a charge type may in fact reflect revenues) on six occasions. On at least three of those occasions the new charge types implemented by MISO were revenues (i.e., they lower net energy costs in the FAC). Some of the new charge types also reflected credits against costs (which also lower net energy costs in the FAC). In each case, Ameren Missouri followed the process provided for in the FAC tariff.

Under that process, if MISO institutes a new charge type involving moving a cost or revenue already being included in the FAC to a new type, or if MISO starts charging/providing a new cost/revenue under a new charge type that is in the nature of an existing cost or revenue already being included in the FAC, Ameren Missouri can include the cost or revenue in its FAC. However, *before it can do* so, Ameren Missouri must *specifically call it out and explain it* in a filing with the Commission (at least 60 days in advance).[15] Moreover, all another party must do to challenge the inclusion of the new charge type, or to challenge a utility's failure to include a new charge type (e.g., a party

[15] In testimony I filed on this topic in KCP&L's pending rate case, I mistakenly indicated that notice must be given in the Company's monthly FAC reports. I had overlooked that while that used to be the process, in our last rate case the process was modified slightly so that a filing is made with the Commission. Our last such filing was made in April, 2016, when we gave notice of two new charge types that allowed RTO *revenues* to be included in the FAC.

would not want a new charge type that involves revenues to be left out), is file a pleading raising the challenge. If such a challenge is made, Ameren Missouri *bears the burden of proof* to justify the inclusion/exclusion. If a party challenges the inclusion/exclusion of a new charge type, and if in the Commission's view Ameren Missouri fails to carry the burden of proof, Ameren Missouri must refund charges/provide revenues (as the case may be) with interest.

Q. What do you say to OPC's claim that for reasons of simplicity the provision should be removed?

A. I could not disagree more. First, the provision is eminently fair, and it is not complex or difficult to follow. As noted, it has been utilized by Ameren Missouri six times without any difficulty and without complaint by any party, including OPC. Second, it is an absolutely essential feature of an FAC tariff (which Ms. Mantle advocated for) that is highly prescriptive. If simplicity were the goal, then it would be far easier to list the relevant FERC Accounts to which costs/revenues components of fuel, purchased power, transmission and off-system sales are recorded, include all the costs/revenues in those accounts and utilize FAC reporting for whatever transparency is warranted. Third, as noted, the provision is fair. The Commission approves participation by utilities in RTOs because, among other things, the markets those RTOs operate bring significant efficiencies (that manifest themselves as benefits) to the industry and ultimately those efficiencies benefit utility customers. Utilities don't control how those RTOs break apart purchased power or transmission or off-system sales components. Missouri's utilities are RTO market participants. Missouri FACs need to accommodate changes in how the RTOs operate or administer those markets.

Fourth, Ameren Missouri's experience with the provision shows that it works. Ameren Missouri has utilized it twice to add charge types that were purely revenues, and two other times to add charge types that included both costs and revenues. But for the provision, the new charge types that reflected only revenues would not have been passed through to customers until a later rate case occurred. Mr. Meyer addresses one instance in his rebuttal testimony. On the cost side, Ameren Missouri utilized it to include new charge types implemented by MISO to reflect transmission charges that Ameren Missouri was formerly charged by Entergy for service to Ameren Missouri's Bootheel customers. The only reason there were new charge types is because Entergy joined MISO, but the nature of the charges (which were, without controversy, included in the FAC before Entergy joined MISO) was the same before and after the new charge type was established.

The provision is fair, reasonable, workable and necessary.

Q. So, can a Missouri utility dictate the inclusion of costs and revenues not approved by the Commission in their FACs?

A. As I previously stated, no, they cannot. As I understand it, utilities must follow their FAC tariffs. They must follow the process outlined above. That process is part of the tariff. By including it in the tariff, the Commission is approving the inclusion of the cost/revenue under the new charge type, subject to proper challenge, and if a challenge occurs, subject to the ultimate decision of the Commission. Moreover, the new charge type is filed with the Commission before it can be included. This means that it is the *Commission* that decides the components in the FAC.

VI. <u>MISCELLANEOUS FAC ISSUES</u>

Q. Are there any other recommendations made by OPC regarding the

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FAC that you wish to address?

A. Yes, I will briefly address OPC's recommendations regarding net insurance recoveries, subrogation recoveries, and settlement proceeds. In general, I agree that if there is insurance (e.g., replacement power insurance) for an FAC component (like purchased power), the insurance proceeds should be included in the FAC. The same would be true if a utility recovered sums on a subrogation claim or through a settlement (e.g., the utility recovers damages because of a cost increase or revenue loss, to the extent that the cost increase or revenue loss was reflected in the FAC). OPC hasn't proposed any specific language, which means that language reflecting this intention would have to be developed to ensure both the utility and customers are treated fairly. Assuming the language is appropriate, I have no problem with the general concept OPC proposes.

VII. TRANSMISSION TRACKER

Q. Missouri Industrial Energy Consumers ("MIEC") witness Nicholas L. Phillips opposes Ameren Missouri's proposed transmission tracker.[16] What are his reasons?

A. Mr. Phillips cites two reasons why he opposes the transmission tracker, in addition to the fact that he opposes all trackers, in general. The two reasons he cites are: 1) that the tracker represents single-issue ratemaking; and 2) that the tracker eliminates the utility's incentive to minimize expenses and maximize revenues between rate proceedings.

Q. Does the transmission tracker represent single-issue ratemaking?

[16] The Staff Report indicated the Staff did not support the tracker either, but specifically indicated that Staff would not address why until it filed rebuttal testimony. Consequently, my testimony only addresses MIEC's position.

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A. No, it does not. While I am not an attorney, counsel advises that because the Commission would make the determination to recognize the tracked sums in a future rate case after the regulatory asset or liability created by the tracker has arisen, with rates to only then be adjusted prospectively, the courts have ruled that trackers do not constitute single-issue ratemaking. That makes sense to me, given that there is a long history in Missouri of Commission use of trackers or similar deferral mechanisms as part of the regulatory process. This has particularly been true in cases where it is difficult to determine the level of cost that should be included in base rates by utilizing an historical test year, traditional normalization methods, or where the nature of the costs or revenues is such that the utility has little or no control over them. The nature of the transmission costs and revenues that we are proposing to include in the tracker have similar traits as other costs that have been historically included in trackers (e.g., vegetation management and inspection costs, storm restoration costs).

Q. Do you agree with Mr. Phillips' notion that trackers reduce the Company's incentive to optimize costs?

A. No, I do not. By tracking costs for which developing an appropriate base level amount is difficult, customers are assured that they will only pay for costs that are prudently incurred by the Company. Moreover, to have an incentive to "control" a cost, the cost must be subject to control. Ameren Missouri has little or no control over MISO transmission charge changes that arise almost entirely from substantial new transmission construction in MISO's footprint that Ameren Missouri is not itself constructing.[17]

[17] Report and Order, File No. ER-2012-0166 (The Company has "has little control over MISO transmission charges.").

Q. How do you respond to Mr. Phillips' assertions that tracked expenses or revenues need to be "large enough to present a threat to the financial well-being of utility; volatile; and cannot be reasonably managed by the utility"?

A. The factors listed by Mr. Phillips have historically been used when trackers have been considered. My direct testimony includes support for each of these factors as they relate to transmission expenses and revenues. Specifically, my direct testimony demonstrates the magnitude of these costs, as well as why it is difficult to set an appropriate level in base rates due to the volatility and uncontrollability of these costs. The Commission has already acknowledged that these costs are volatile and outside of the control of the Company.[18] In addition, despite the Commission's decision to remove these items from the FAC, the Commission has not indicated that these costs were imprudently incurred or that they shouldn't be recovered at all.[19]

Q. Is there any question but that the transmission charges at issue are substantial and volatile?

A. No. While the MISO transmission charges under Schedule 26A (arising from Multi-Value Projects) for 2017 are being reflected in the revenue requirement in this case at a level of $42.36 million, according to information provided by MISO, they are currently estimated to rise to approximately **[redacted]** by the end of 2019 – an increase of about **[redacted]** *per year* from 2018-2019.[20] While Mr. Phillips is correct that in one case in 2008 (File No. ER-2008-0318), the Commission suggested that a rise

[18] *Id.* ("MISO transmission charges are volatile because no one knows for sure how much those MVP projects will cost once construction is complete.").
[19] In fact, the Commission recognizes that the costs should be recovered. *Id.* ("All parties agree that Ameren Missouri must be able to recover the MISO transmission charges in some manner. If the charges are not flowed through the FAC, the Commission will need to allow the company to recover those charges in base rates.").
[20] Response to Staff Data Request 0523.

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in costs did not make them volatile, as just noted, more recently the Commission specifically recognized, in the context of the very charges at issue here, that the costs are volatile.

Q. Do you believe that by having a tracker, the Company is shifting risk to customers as Mr. Phillips suggests?

A. No, I do not, and Mr. Phillips' risk-shifting argument misses the point. We have asked for the tracker because these are large, uncontrollable, and rapidly increasing (although the amount of the increase and exact timing is uncertain) charges from an RTO from which our customers gain great benefit (e.g., more efficient power markets, the benefits of which are manifested in the FAC; increased capacity revenues, also reflected in the FAC). We cannot avoid the charges. As these charges rise, if we are going to have a reasonable chance to earn a fair return, we are forced to make expense cuts (that we have thus far been able to make while maintaining safe and adequate service) that ideally for our customers we would not make. Or, we are forced to cut investment in our system to levels that we do not believe are optimal. The tracker would mitigate those problems for us and for our customers.

VIII. <u>FERC ROE REFUNDS; SPP/MISO DISPUTE</u>

Q. OPC witness Charles R. Hyneman disagrees with Ameren Missouri's proposed rate treatment of refunds related to FERC orders lowering the ROEs for historical periods. What is Mr. Hyneman's position?

A. Mr. Hyneman makes a very general claim premised on his apparent belief that all refunds should be returned to customers irrespective of whether or not transmission costs were included in the FAC during the related historical periods since transmission costs were included in base rates and thus paid by customers. However, Mr.

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Hyneman declines to elaborate on his reasons, indicating that he will address who "actually paid" the transmission expenses in later testimony. Consequently, I will only briefly respond to Mr. Hyneman's general contention now and will reserve the right to fully respond when Mr. Hyneman actually properly supports his position. So far, all Mr. Hyneman has said is that he disagrees but he fails to explain why.

Q. Do you agree with Mr. Hyneman's general assertion?

A. No, I do not. Mr. Hyneman's claim appears to be based on the view that customers "pay for" costs through base rates. They do not. While I am not an attorney, counsel advises that the courts have clearly indicated that customers pay for service, but do not pay for individual cost components used as proxy to set base rates.

Q. Please explain from the standpoint of how base rates are set.

A. When base rates are developed, historical (sometimes normalized or annualized) levels of specific costs and revenues are examined and a revenue requirement is then developed based on the premise that this historical level of costs and revenues will be representative of (provide a proxy for) the future, i.e., of the period after which base rates take effect. I will not debate here whether that premise is correct or incorrect. The point is that absent implementation of a tracker or a rate adjustment mechanism (like a fuel adjustment clause) for specific costs or revenues, ongoing costs and revenues are not tracked or segregated and customers do not "pay" them.

Q. What refunds are at issue in this case?

A. As summarized in the Staff Report (pages 83-86), there are two different FERC ROE cases that will ultimately lead to refunds. The first case is complete, but refunds have not yet been made by MISO and it is not expected that they will be made until later in 2017. Ameren Missouri has estimated the refunds it expects to receive from

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the first FERC ROE case and has recorded an accrual based on that estimate on its books. The second case has not yet been decided.

Q. How does the Company propose to address the first case refunds in this case?

A. The first case addresses a period when all transmission charges were included in the Company's FAC. If all transmission charges were still in the Company's FAC, the Company would not have needed to address the refunds in this case at all. Instead, once received, Ameren Missouri simply would have included the refunds in the FAC and 95% of them would have flowed back to customers. However, in our last rate case, the Commission effectively stripped almost all transmission charges out of the FAC (only 3.5% were allowed) so that option is not available. Consequently, to get to the same result, the Company is proposing to record a regulatory liability equal to 95% of the first case refunds (approximately $1.206 million) which would be amortized back to customers (i.e., reduce base rates) through a 5-year amortization of approximately $0.241 million.[21] Our proposal would be to include such an amortization in the determination of base rates in this rate case using the estimates accrued on our books. Once we know the actual amount of refunds, we could effectively true-up the regulatory liability amount in our next rate case to capture the actuals. In the end, customers would get back through the amortization the same sum of money they would have gotten back had we been able to simply include the refunds in the FAC.

Q. Is there another similar item in this case?

[21] Response to Staff Data Request 0418.

A. Yes. There are reduced transmission revenues arising from a separate FERC case involving a dispute between the Southwest Power Pool ("SPP") and MISO, arising from Entergy joining MISO.[22] In that case, MISO was ordered to reduce through and out charges, which in turn, required Ameren Missouri to return some transmission revenues that it had received from MISO. The period covered by this case corresponds almost entirely to a period when all of Ameren Missouri's transmission revenues were in our FAC. As a result of the Commission's order in our last rate case, those transmission revenues are no longer in our FAC, meaning we cannot reflect the lower transmission revenues in the FAC now. To the extent the higher transmission revenues flowed to customers in the FAC (i.e., reduced net energy costs charged to customers), it is appropriate that the lower transmission revenues for that same period be reflected in customer rates now (just as it is appropriate that the lower transmission charges be reflected in customer rates, as just discussed). Consequently, we have also included an amortization of a regulatory asset in our revenue requirement in this case in the amount of approximately \$0.148 million, reflecting a regulatory asset of approximately \$0.744 million of reduced transmission revenues applicable to the period when transmission revenues were included in the FAC amortized over five years.[23] As noted, this mimics what would have happened had the lower transmission charges from the first FERC ROE case been eligible for inclusion in the FAC and had the lower transmission revenues from the SPP/MISO dispute been eligible for inclusion, as they both were when the original transmission charges/revenues were paid/received.

Q. What about the second FERC ROE case?

[22] The Staff refers to this case as the "Entergy Complaint" in its cost of service report.
[23] Response to Staff Data Request 0418.

A. We do not know what those refunds will be or when that case will be resolved, so it is not an issue for this rate case. It is our intention when we have our next rate case to reflect 95% of any refunds we receive from that case that arose from charges while all transmission charges were in our FAC in a regulatory liability that would be returned to customers through an amortization in a future rate case, as well as that percentage of any refunds that corresponds to the percentage of transmission charges in our FAC at a given time for transmission charges arising when only a fraction of total transmission charges were in the FAC.

Q. Do you have any comments on the Staff's cost of service report discussion on these issues?

A. While Staff recites the facts relating to the two FERC ROE cases and the SPP/MISO dispute accurately, the Staff's report is somewhat unclear on how it proposes to address the refunds and lower transmission revenues. I believe that for the first FERC ROE case, the Staff and the Company are largely in agreement, although Staff may have a different view on the timing of starting the amortization or on the amortization period. On the SPP/MISO dispute, it appears the Staff and the Company are in agreement, although Staff is proposing a three-year amortization. Staff's position on the second FERC ROE case is less clear. In any event, I am told that Staff will be clarifying its positions on these cases in its rebuttal testimony, so I will respond to the Staff's positions in surrebuttal testimony, once the positions are fully supported by the Staff.

Q. Does this conclude your rebuttal testimony?

A. Yes.

EXHIBIT AC-1

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	**File No. ER-2016-0179**

AFFIDAVIT OF LYNN M. BARNES

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Lynn M. Barnes, being first duly sworn on her oath, states:

1. My name is Lynn M. Barnes. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Vice President, Data Analytics & Insights.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 37 pages and Schedule(s) LMB-R1 through LMB-R3, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Lynn M Barnes
Lynn M. Barnes

Subscribed and sworn to before me this 17th day of January, 2017.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2018
Commission Number 14839811

EXHIBIT AC-1

FERC USoA ACCOUNT DEFINITIONS

501 Fuel.

A. This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.

B. The cost of fuel shall be charged initially to account 151, Fuel Stock (for Nonmajor utilities, appropriate fuel accounts carried under account 154, Plant Materials and Operating Supplies) and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to account 152, Fuel Stock Expenses Undistributed (for Nonmajor utilities, an appropriate subaccount of account 154, Plant Materials and Operating Supplies). In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.

ITEMS

Labor:

1. Supervising purchasing and handling of fuel.

2. All routine fuel analyses.

3. Unloading from shipping facility and putting in storage.

4. Moving of fuel in storage and transferring fuel from one station to another.

5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler-house structure.

6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc.

Materials and Expenses:

7. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).

8. Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).

9. Cost of fuel including freight, switching, demurrage and other transportation charges.

10. Excise taxes, insurance, purchasing commissions and similar items.

11. Stores expenses to extent applicable to fuel.

12. Transportation and other expenses in moving fuel in storage.

13. Tools, lubricants and other supplies.

14. Operating supplies for mechanical equipment.

15. Residual disposal expenses less any proceeds from sale of residuals.

NOTE: Abnormal fuel handling expenses occasioned by emergency conditions shall be charged to expense as incurred.

547 Fuel.

This account shall include the cost delivered at the station (see account 151, Fuel Stock, for Major utilities, and account 154, Plant Materials and Operating Supplies, for Nonmajor utilities) of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation.

518 Nuclear fuel expense (Major only).

A. This account shall be debited and account 120.5, Accumulated Provision for Amortization of Nuclear Fuel Assemblies, credited for the amortization of the net cost of nuclear fuel assemblies used in the production of energy. The net cost of nuclear fuel assemblies subject to amortization shall be the cost of nuclear fuel assemblies plus or less the expected net salvage of uranium, plutonium, and other byproducts and unburned fuel. The utility shall adopt the necessary procedures to assure that charges to this account are distributed according to the thermal energy produced in such periods.

B. This account shall also include the costs involved when fuel is leased.

C. This account shall also include the cost of other fuels, used for ancillary steam facilities, including superheat.

D. This account shall be debited or credited as appropriate for significant changes in the amounts estimated as the net salvage value of uranium, plutonium, and other byproducts contained in account 157, Nuclear Materials Held for Sale and the amount realized upon the final disposition of the materials. Significant declines in the estimated realizable value of items carried in account 157 may be recognized at the time of market price declines by charging this account and crediting account 157. When the declining change occurs while the fuel is recorded in account 120.3, Nuclear Fuel Assemblies in Reactor, the effect shall be amortized over the remaining life of the fuel.

Ameren Missouri
Additional Information Ordered by the Commission
Report 5(M)
September 2016

	2016 September Total	Rider FAC Factor	Source
Fuel For Load Acct 501	[redacted]	FC	Report 5C p1, line 2
Fuel For Load Acct 518	[redacted]	FC	Report 5C p1, line 3
Fuel For Load Acct 547	[redacted]	FC	Report 5C p1, line 4
Fly Ash Acct 501	[redacted]	FC	Report 5C p1, line 5
Fuel Additives Acct 502	[redacted]	FC	Report 5C p1, line 6
Fixed Gas Supply Costs for Load Acct 547	[redacted]	FC	Report 5C p1, line 8
Fuel For OSS Acct 501	[redacted]	FC	Report 5C p1, line 12
Fuel For OSS Acct 518	[redacted]	FC	Report 5C p1, line 13
Fuel For OSS Acct 547	[redacted]	FC	Report 5C p1, line 14
(Gains)/Losses on Gas Sales Acct 547	[redacted]	FC	Report 5C p1, line 15
Fly Ash Acct 501	[redacted]	FC	Report 5C p1, line 16
Fuel Additives Acct 502	[redacted]	FC	Report 5C p1, line 17
Fixed Gas Supply Costs for OSS Acct 547	[redacted]	FC	Report 5C p1, line 19
Fuel Costs Total	[redacted]		

	FERC 501 Diaggregation	[redacted]
	Coal Commodity - Includes quality and SO2 adjustments, semi-annual inventory adjustments, broker fees and coal hedging (gains)/losses	[redacted]
	Coal Freight - Includes trucking expenses for high sulfur coal, fuel surcharges (net of hedging) and semi-annual inventory adjustments	[redacted]
	Railcar - Includes depreciation, lease costs, switching, repair and maintenance	[redacted]
	Coal (Gains)/Losses on Coal Sales	[redacted]
	Fly Ash (Revenues)/Expenses	[redacted]
	Oil Costs	[redacted]
	Gas Costs	[redacted]
A	FERC 501 subtotal	[redacted]
	FERC 502 Diaggregation	[redacted]
	Limestone	[redacted]
	Activated Carbon	[redacted]
B	FERC 502 subtotal	[redacted]
	FERC 518 Disaggregation	[redacted]
	Nuclear Fuel Commodity - Includes nuclear fuel hedging costs	[redacted]
	Waste Disposal Expense	[redacted]
C	FERC 518 subtotal	[redacted]
	FERC 547 Disaggregation	[redacted]
	Gas Commodity - Includes gas storage withdrawals/(injections)	[redacted]
	Gas Capacity Reservation	[redacted]
	Gas Transportation	[redacted]
	Gas Storage	[redacted]
	Gas Hedging	[redacted]
	(Gains)/Losses on Gas Sales	[redacted]
	Oil Costs	[redacted]
D	FERC 547 subtotal	[redacted]
A + B + C + D	Fuel Costs Grand Total - Ties Above	[redacted]

Ameren Missouri
Additional Information Ordered by the Commission
Report 5(M)
September 2016

	2016 September Total	Rider FAC Factor	Source
Emissions Acct 411.8, 411.9 and 509	-	E	Report 5C p1, line 7
Emissions Acct 411.8, 411.9 and 509	-	E	Report 5C p1, line 18
Emissions Total	-		
Purchased Power for Load Acct 555	[redacted]	PP	Report 5C p1, line 9
Purchased Power for OSS Acct 555	[redacted]	PP	Report 5C p1, line 20
MISO Day 2 Account 555	[redacted]	PP	Report 5C p1, line 26
Ancillary Services Account 555	[redacted]	PP	Report 5C p1, line 27
PJM Account 555 expense	[redacted]	PP	Report 5C p1, line 28
Transmission by Others (Acct 565)	[redacted]	PP	Report 5C p1, line 29
Transmission Revenues (Acct 456.1)	[redacted]	PP	Report 5C p1, line 30
Purchased Power Total	[redacted]		

	FERC 411.8, 411.9 and 509 Disaggregation	[redacted]
	Costs for SO_2 and NO_x emission allowances	[redacted]
	Revenues for SO_2 and NO_x emission allowances	[redacted]
A	Emissions Total - Ties Above	[redacted]
	FERC 555 Disaggregation	[redacted]
	Energy	[redacted]
	Losses	[redacted]
	Congestion	[redacted]
	Financial Transmission Rights	[redacted]
	Auction Revenue Rights	[redacted]
	Capacity less than 1 year	[redacted]
	Revenue Sufficiency Guarantees	[redacted]
	Revenue Neutrality Uplift	[redacted]
	Net inadvertent Energy Distribution	[redacted]
	Ancillary Services	[redacted]
	Regulating Reserve Service	[redacted]
	Energy Imbalance Service	[redacted]
	Spinning Reserve Service	[redacted]
	Supplemental Reserve Service	[redacted]
	Hedging	[redacted]
A	FERC 555 subtotal	[redacted]
	FERC 565 Disaggregation	[redacted]
	Network Transmission Service	[redacted]
	Point-to-Point Transmission Service	[redacted]
	System Control and Dispatch	[redacted]
	Reactive Supply and Voltage Control	[redacted]
	MISO Schedule 11 or its successor	[redacted]
	MISO Schedules 26, 26A, 37 and 38 or their successors	[redacted]
	MISO Schedule 33	[redacted]
	MISO Schedules 41, 42A, 42B, 45 and 47	[redacted]
B	FERC 565 subtotal	[redacted]
A + B	Purchased Power Costs Grand Total - Ties Above	[redacted]

Ameren Missouri
Additional Information Ordered by the Commission
Report 5(M)
September 2016

	2016 September Total	Rider FAC Factor	Source
Off-System Energy Sales (Acct 447)	[redacted]	OSSR	Report 5C p1, line 36
MISO Day 2 Revenues - Make Whole Payments (Acct 447)	[redacted]	OSSR	Report 5C p1, line 37
MISO Day 2 Revenues - Inadvertant Distribution (Acct 447)	[redacted]	OSSR	Report 5C p1, line 38
Capacity Sales (Acct 447)	[redacted]	OSSR	Report 5C p1, line 39
Financial Swaps (Acct 447)	[redacted]	OSSR	Report 5C p1, line 40
Ancillary Services Revenue (Acct 447)	[redacted]	OSSR	Report 5C p1, line 41
Load & Generation Forecasting Deviation	[redacted]		Report 5C p1, line 42
Off-System Sales Revenues	[redacted]		

FERC 447 Disaggregation	[redacted]
Capacity	[redacted]
Energy	[redacted]
Regulating Reserve Service	[redacted]
Energy Imbalance Service	[redacted]
Ancillary Services	[redacted]
Spinning Reserve Service	[redacted]
Supplemental Reserve Service	[redacted]
Revenue Sufficiency Guarantees	[redacted]
Net inadvertent Energy Distribution	[redacted]
Hedging	[redacted]
FERC 447 Total	[redacted]
Off-System Sales Adjustment[1]	[redacted]
FERC 447 Total - Ties Above	[redacted]

[1]As provided for in Ameren Missouri's FAC tariff (sheet 73.4 and 73.7) an adjustment to OSSR is made when service classification 12M or 13M (Noranda) billings fall 40,000,000 KwH below the normalized monthly billing determinants established in Case No. ER-2014-0258. See 5D and 5D2 for an explanation and calculation of the September 2016 adjustment.

Non-Utility FAC Sharing Mechanism Proposals
Other than 95%/5%

Case Number	Utility	Party	Sponsoring Witness	FAC Sharing Mechanism Proposal
ER-2007-0002	Ameren Missouri	AARP	Ronald Binz (Nancy Brockway)	Sharing bands
		The Commercial Group	Kevin Higgins	50/50
		MIEC	Maurice Brubaker	80/20 with deadband and sharing bands
ER-2007-0004	Aquila	AARP	Nancy Brockway	50/50
		SIEU, AG-P & FEA	Donald Johnstone	50/50
ER-2008-0093	Empire	MIEC	Maurice Brubaker	95/5 with deadband and sharing bands
		Staff	Lena Mantle	60-80% pass through with 70 mid-point
		OPC	Ryan Kind	60/40
ER-2008-0318	Ameren Missouri	MIEC	Maurice Brubaker	80/20
		State of Missouri	Martin Cohen	80/20 Alternate: 85/15 for cost increases 95/5 for cost decreases
		OPC	Ryan Kind	50/50
ER-2009-0090	KCPL-GMO	Ag Processing FEA SIEUA Wal-Mart	Maurice Brubaker	
ER-2010-0036	Ameren Missouri	Staff	John Rogers David Roos	95/5
		MIEC	Maurice Brubaker	80/20
		OPC	Ryan Kind	80/20
ER-2010-0130	Empire	Staff	Matt Barnes	95/5

Case Number	Utility	Party	Sponsoring Witness	FAC Sharing Mechanism Proposal
ER-2010-0356	KCPL-GMO	Staff	David Roos	75/25
		OPC	Ryan Kind	75/25
ER-2011-0004	Empire	Staff	Matt Barnes	85/15
		OPC	Ryan Kind	85/15
ER-2011-0028	Ameren Missouri	Staff	Lena Mantle	85/15
		OPC	Ryan Kind	85/15
ER-2012-0166	Ameren Missouri	Staff	Lena Mantle	85/15
		MIEC	None	85/15
		AARP/CCM	None	50/50
ER-2012-0175	KCPL-GMO	Staff	Matt Barnes	85/15
ER-2012-0345	Empire	Staff	Matt Barnes	85/15
ER-2014-0258	Ameren Missouri	OPC	Lena Mantle	90/10
		CCM	None	50/50
ER-2014-0351	Empire	OPC	Lena Mantle	90/10
ER-2014-0370	KCPL	Staff	Dana Eaves	95/5
		OPC	Lena Mantle	50/50
		MECG	Michael Brosch	95/5 (or anything higher than 0)
ER-2016-0023	Empire	Staff	David Roos	95/5
ER-2016-0156	KCPL-GMO	Staff	Matt Barnes	95/5
		OPC	Lena Mantle	90/10

Case Number	Utility	Party	Sponsoring Witness	FAC Sharing Mechanism Proposal
ER-2016-0179	Ameren Missouri	OPC	Lena Mantle	90/10
ER-2016-0285	KCPL	OPC	Lena Mantle	90/10

Exhibit No.:	
Issue(s):	Fuel Adjustment Clause; Off-System Sales
Witness:	Andrew Meyer
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2016-0179
Date Testimony Prepared:	January 20, 2017

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

REBUTTAL TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January, 2017

EXHIBIT AC-2

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EXHIBIT AC-2

REBUTTAL TESTIMONY

OF

ANDREW MEYER

Q. Please state your name and business address.

A. Andrew Meyer, 1901 Chouteau Avenue, St. Louis, MO 63103.

Q. Are you the same Andrew Meyer that filed direct testimony in this proceeding?

A. Yes I am.

I. PURPOSE AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address the Office of the Public Counsel's ("OPC") arguments regarding the inclusion of purchased power and transportation costs in Ameren Missouri's fuel adjustment clause ("FAC"), which are sponsored by OPC witness Lena Mantle. Specifically, I explain why OPC's attempt to redefine the terms "purchased power" and "transportation" inappropriately excludes many components that are well-understood by regulators and the industry to make up the cost of purchased power and associated transportation.

I will also address the calculation of the bilateral transaction margin adjustment to off-system sales performed by Staff Witness Erin Maloney.

Q. **Please summarize your main conclusions regarding Ms. Mantle's testimony.**

A. Purchased power and associated transmission costs consist of a variety of components, including many that OPC is attempting to improperly exclude from the

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FAC, as confirmed by the understanding of those terms in the industry and by regulators, including the Federal Energy Regulatory Commission ("FERC"), this Commission's Staff, and this Commission itself. These components of purchased power, which were once bundled together as a single product, are now visible through a combination of the regional transmission organization ("RTO") market settlement structure and the utility's managerial accounting decisions to record a higher level of detail than any rule requires. OPC is simply picking and choosing components that it favors, while ignoring others. OPC is also attempting to exclude legitimate transmission costs from the FAC by recycling arguments it has already (twice) lost.

OPC's attempt to ignore many key cost components that comprise the total cost of purchased power is directly at odds with its recommendation that all components that make up total off-system sales revenues ("OSSR") should be included in the FAC.[1] Consequently, OPC's proposal, if it were to be adopted, would create a mismatch because while all components of OSSR would remain in the FAC, there would be components of purchased power costs that those OSSR revenues offset that would improperly be excluded. The Commission should reject the separation of costs and revenue components from other components which offset their value or are otherwise inextricably tied together.

OPC's proposal would also exclude from the FAC certain components of purchased power which offset *other* purchased power components. Those offsets provide a hedge for cost exposure *for customers*. All these components make up the total cost of purchased power and, just as revenues that are part of OSSR should not be separated

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[1] All components of OSSR that make up total OSSR revenues have been included in Ameren Missouri's FAC from its inception in 2009.

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from purchased power components that they offset, components of purchased power that offset other components of purchased power should similarly not be separated.

Q. Please summarize your main conclusions regarding Ms. Malony's testimony.

A. I recommend that the bilateral transaction margin adjustment be calculated using actual bilateral sale and purchase transaction prices and volumes and the corresponding actual spot market prices. I recommend that the calculation utilize 36 months of actual data ending December 31, 2016, adjusted for the Polar Vortex period of January 2014-March 2014.

II. OPC'S RECOMMENDATIONS ARE BASED ON AN INCORRECT INTERPRETATION OF WHAT CONSTITUTES PURCHASED POWER AND TRANSMISSION COSTS

Q. Why are OPC's recommendations based on an incorrect interpretation of what constitutes purchased power and transmission costs?

A. Section 386.266, which is commonly referred to as the "FAC statute," authorizes the Commission to approve FACs that allow rate adjustments based on changes in "prudently incurred fuel and purchased power costs, including transportation." The questions then are what are fuel costs, what are purchased power costs, and what are the associated transportation costs?[2] Ameren Missouri witness Lynn M. Barnes will address the fuel and associated transportation costs issue in her rebuttal testimony filed in this docket. At its core, OPC's position, based on (apparently) nothing more than Ms. Mantle's opinion, is that the Commission should redefine what "purchased power" and

[2] In this context, I will refer to "transportation" costs as "transmission" costs. It is my understanding that the Missouri courts have confirmed that in the context of the FAC statute, "transportation" encompasses transmission.

EXHIBIT AC-2

"transmission" costs are. More specifically, OPC argues that only the charges paid by Ameren Missouri for a very few components of purchased power (some components of energy and capacity costs) should be included in the costs of purchased power included in the FAC. OPC also wants to also severely limit the definition of "transmission." With respect to purchased power, while charges for energy and capacity are indeed two of the components that make up the cost of purchased power, there are many others (including some components of energy and capacity themselves) that OPC either ignores or fails to understand.[3] With respect to transmission costs, point-to-point ("PTP") and network integration transmission services ("NITS") charges are also two components of total transmission costs, but again, there are many others that OPC improperly ignores or mischaracterizes.

A. <u>Purchased Power Costs</u>

Q. Earlier you seemed to suggest that what constitutes purchased power and transportation before and after the establishment of the Midcontinent Independent System Operator, Inc. ("MISO") market remains the same. Please explain.

A. Prior to the establishment of the MISO market, we operated in a purely bilateral market. We bought and sold with other utilities, as well as power marketers. Purchased power was a bundled product. The bundled product was priced in a manner to cover everything needed up to the point of delivery. For example, if a marketer was selling to Ameren Missouri, they had to make sure that the price they charged covered their incremental costs – not only production cost, but also transmission service, ancillary

[3] As discussed further below, OPC's recommendation regarding including "energy" and "capacity" is at best, vague.

services, losses, risk premiums related to delivery risk (should the utility's transmission service be curtailed), or loss of resources, etc. The same was true for independent power producers, non-asset owning power marketers, and other utilities selling to Ameren Missouri. Sellers priced their products to cover their costs plus an expectation of profit. From Ameren Missouri's perspective, however, all we saw was the total cost of the purchased power: X megawatt-hours ("MWh") at $Y/MWh. We did not see a list of all the components that made up that purchased power, with individual line item charges. These bundled bilateral transactions continue to exist as an alternative to purchasing power from the MISO market.

RTO energy and ancillary service markets, including MISO's, were established to foster wholesale competition and contribute to improved system reliability. They were designed in a manner which promoted a more efficient use of resources. Later in my testimony I will discuss the concept of a co-optimized market and provide an example which illustrates how market participants (and their customers) benefit from such efficiencies.

As a result of this market design, the variety of cost components that used to be bundled together as charges for purchased power are now disaggregated. Buyers acquiring purchased power in the MISO market can now see the individual components of purchased power rather than simply seeing the bundled cost. The various charge and revenue types used in MISO settlements are themselves a byproduct of the more efficient market design.

This does not mean, however, that the components which were formerly bundled as part of overall purchased power costs have now lost their character as a component of

EXHIBIT AC-2

purchased power costs. The nature of a component of purchased power is not changed just because someone put a different label on it for settlement purposes.

Q. You also mentioned that the components of purchased power costs are more visible as a result of managerial accounting decisions. Please explain.

A. Utilities are not required to utilize the level of detail in their accounting records that we actually do. There are a wide range of reasons for why an individual sub-account, resource type or activity code may be developed, including a desire to monitor a particular sub-component, greater transparency in reporting, ease of data retrieval, etc. These additional levels of detail provide greater information regarding the sub-components of fuel, purchased power and transportation, but they don't lose their character as part of the overall cost of those items just because the utility elects to break them out in into managerial accounting codes created at the utility's discretion.

Q. Does FERC, which exercises primary jurisdiction over the wholesale power markets, provide guidance as to what components make up the cost of purchased power?

A. Yes. The FERC Uniform System of Accounts ("USOA"), which Missouri utilities, including Ameren Missouri, must follow per this Commission's rules (4 CSR 240-20.030), provides a definition of each of the accounts included in the USOA. One such definition is for Account 555, titled "Purchased Power," as follows:

> *This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. Distinct purchases and sales shall not be*

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recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

FERC recognizes that purchased power costs are made up of more than just the charges incurred by a utility for energy or capacity. While the definition does not list all the purchased power cost components (since the advent of RTOs, these are now broken-out in greater detail on RTO settlement statements), all those components make up the total cost of purchased power. As discussed further below, it is obvious that FERC itself recognizes that all these components are part of purchased power costs as well.

Q. Do you have any evidence to support your contention that those components make up the total cost of purchased power?

A. Yes. FERC recently completed a detailed audit of Ameren Missouri's compliance with the USOA (FERC Docket No. FA12-2-000). The audit covered a seven-year period, January 1, 2008 through December 31, 2014. All the components that make up the total cost of purchased power that are included in Ameren Missouri's FAC today are recorded in Account 555.[4] The Audit Report issued March 27, 2005 *did not contain a single finding that asserted that Ameren Missouri had improperly recorded any expenses in Account 555* – including those which OPC now wants the Commission to believe should not be viewed by this Commission as components of purchased power costs. FERC would not accept the recording of costs to Account 555 if those costs were not proper components of purchased power costs.

Q. Is there other evidence that these costs should be included as components of purchased power costs?

[4] All these components have been included in purchased power costs in Ameren Missouri's FAC since its inception in 2009.

A. Yes. FERC requires public utilities to make a yearly FERC Form 1 filing. Similarly, this Commission requires the filing of an Annual Report, which consists of part of that same FERC Form 1 filing. The purchased power costs included in those filings consist of far more than simply capacity and energy and, in fact, expressly call out many non-energy and non-capacity purchased power components, including Auction Revenue Rights ("ARR"), Inadvertent Energy, Energy Losses, Revenue Neutrality Uplift ("RNU"), Revenue Sufficiency Guarantees ("RSG"), Financial Transmission Rights ("FTR"), Ancillary Regulation, Ancillary Spinning and Ancillary Supplemental. I am unaware of any challenge by FERC, this Commission, the Staff, OPC or any other entity to the accuracy of Ameren Missouri's FERC Form 1 or Commission Annual Report filings.

Q. Has the Staff taken actions that suggest that it recognizes that there are far more components of purchased power than just energy and capacity?

A. Yes. Staff's workpapers in Ameren Missouri's general rate proceedings routinely reflect the Staff's inclusion of components of fuel, purchased power and transmission costs in the Staff's calculated values for fuel, purchased power and transmission costs which OPC would now have the Commission believe are not or should not be components of fuel, purchased power or transmission costs and thus should be excluded from the FAC. This includes numerous components of purchased power costs that OPC seeks to exclude, including components for RSG, RNU, congestion, losses, ARR, FTR, inadvertent, and a variety of ancillary service charges.

It would be illogical for Staff to treat all these charges as components of total purchased power (or transmission, as the case may be) costs, and use them to set the net base energy costs that set the base in Ameren Missouri's FAC, if those components were not properly a part of total purchased power and transmission costs.

Q. Please state your understanding of what purchased power costs would be included in the FAC if OPC's proposal were adopted.

A. Ms. Mantle's testimony on page 7, l. 8-11 states "OPC's recommended FAC limits purchased power costs to the cost of energy from long-term bilateral contracts, capacity charges from bilateral contracts that change annually or more frequently, and capacity and energy purchased through RTO markets to meet native load or to make off-system sales."

Q. Can one tell from Ms. Mantle's direct testimony how she is defining "energy purchased through RTO markets"?

A. No. Her testimony is vague. I would note that in quite similar direct testimony filed in File No. ER-2016-0285, Ms. Mantle was more specific. It is my assumption, therefore, that she is taking the same position in this case as she took in that case regarding what constitutes "energy" and "capacity" costs. If this assumption is correct, Ms. Mantle seeks to exclude a large number of legitimate purchased power components that have always been included in Ameren Missouri's FAC because purchased power consists of far more than just energy and capacity, as I believe she defines those terms.

Q. Was Ms. Mantle involved in issues regarding the FAC when it was first approved for Ameren Missouri in 2009?

A. Yes. According to her supplemental direct testimony in File No. ER-2010-0036 (page 2 lines 15-16), Ms. Mantle indicates that she helped draft the FAC tariff approved in that case.

Q. Did that tariff include more than just the two components of purchased power, as OPC apparently defines those components for purposes of this case?

A. Yes, significantly more.

Q. Are you aware of any component of purchased power OPC now seeks to exclude that the Staff has argued does not belong in Ameren Missouri's FAC?

A. No. I am not aware that Staff has sought to exclude any component of purchased power from our FAC, including when Ms. Mantle was the Staff's FAC witness.

Q. Aside from the foregoing, is there other evidence that purchased power costs within the meaning of the FAC statute are not limited to only the two components favored by OPC – capacity and energy - as OPC defines those terms?

A. Yes. The first, and most obvious, is that the Commission itself acknowledged the existence of a multitude of components comprising purchased power costs when it: approved Ameren Missouri's FAC tariffs in the Company's five prior general rate proceedings; issued approval orders in all five of the Ameren Missouri's FAC prudence review proceedings; and approved 22 of Ameren Missouri's FAC rate adjustment filings. All of these proceedings pertained to FACs that include as purchased power costs the very components that OPC now seeks to exclude. In addition, Ameren

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Missouri has filed an FAC monthly report in every month for the past nearly eight years containing significant detail on all of these components.

Q. Do you have any other observations about OPC's attempt to redefine purchased power costs?

A. Yes. OPC witness Mantle states that the FAC statute "does not mention fuel adders, fuel handling, contractor costs, spinning reserve costs, startup costs, hedging costs, and a myriad of other costs and revenues." Mantle Direct, p. 7, l. 2-5. The point she is apparently attempting to make is that since these components are not explicitly listed, they should be excluded from the FAC. But neither "energy" nor "capacity" are listed in the statute either. Simply put, the General Assembly obviously chose not to list all of the individual components of purchased power (and fuel, and transmission) in the statute, but the failure to list a component does not mean that the component is not a part of purchased power costs.

The bottom line is that the Commission and its Staff, and the utilities that operate in the relevant markets, have had it right all along. OPC's improper attempt to redefine the components covered by the FAC should be rejected.

B. <u>Transmission Costs</u>

Q. What is the basis for Ms. Mantle's claim that the only components of transmission that should be included in the FAC are those categorized as point-to-point or network integration transmission service?

A. Ms. Mantle appears to rest her proposal upon her claim that these are the only components of transmission that can be "directly tied" to Ameren Missouri's ability

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to purchase power for its native load or to make off-system sales. Mantle Direct, p. 10, l. 19.

Q. Is Ms. Mantle correct that these are the only components that can be "directly tied" to Ameren Missouri's ability to purchase power for its native load or to make off-system sales?

A. No. Ameren Missouri's (and in fact any MISO market participant's) ability to make purchases and/or sales in the MISO market is predicated on the market participant meeting its obligations under the entirety of the applicable MISO tariffs – not just those associated with a specific transmission wire. The participants cannot simply pick and choose which of the mandatory transmission charges they want to pay to buy or sell power in the market. The numerous components of transmission costs that Ms. Mantle seeks to exclude from the FAC are all for transmission services required to engage in those transactions.

Q. How does one know if a transmission charge is "directly tied" to purchases or sales?

A. Directly tying a transmission charge to purchased power or off-system sales is as simple as evaluating the basis for the charge; that is, if the charge is based on the amount of energy acquired or sold (either on a peak demand or total volume basis), then there is a direct link. For example, MISO's Schedule 26A charges for Multi-Value Projects ("MVP") being built in MISO are based upon the MWh of energy bought by the utility (e.g., Ameren Missouri) from MISO's market. I simply don't see how one could validly argue that those charges aren't "directly tied" to that purchase if the cost itself is *based on the amount purchased*.

I would also note that in her surrebuttal testimony filed on behalf of the Staff in File No. ER-2012-0166 (on page 4), when discussing whether Ameren Missouri should be allowed to include charges for MISO's Schedule 26A charges in its FAC, Ms. Mantle acknowledged that Schedule 26A charges *are* directly tied to Ameren Missouri's load when she stated, "just because a cost is incurred to deliver energy to Ameren Missouri customers, does not mean the cost should flow through the FAC."

Q. Given that these transmission charges clearly are directly tied to purchases of energy Ameren Missouri must make to serve its load, what do you make of OPC's attempt to treat such charges as if they are not transmission charges within the meaning of the FAC statute?

A. The OPC's position appears to be an end-run around an argument that it has already lost.

Q. Please explain.

A. In each of Ameren Missouri's last two rate cases (File Nos. ER-2012-0166 and ER-2014-0258), Ms. Mantle argued that Schedule 26A charges arising from MISO MVP projects are not transmission charges, but instead are the "cost of building" transmission lines.[5] The Commission has twice rejected that argument. As it states on page 91 of its Report and Order in File No. ER-2012-0166,

> *However, both Staff's reliance* [via Ms. Mantle's testimony] *on the anti-CWIP statute and its public policy argument rely on a mischaracterization of the nature of the transmission charges that Ameren Missouri seeks to flow through the fuel adjustment clause. MISO may use those charges to allow the transmission owner to recover the cost of constructing the transmission. But from Ameren Missouri's perspective, it*

[5] In File No. ER-2012-0166, Ms. Mantle's argument was that Schedule 26A charges would violate Missouri's "anti-CWIP" statute. In File No. ER-2014-0258, Ms. Mantle didn't mention that statute, but continued her attempt to re-characterize what these charges are.

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is paying a FERC approved transmission charge, nothing more and nothing less. To Ameren Missouri it makes no difference how the transmission owner uses the revenue it receives through FERC.

The Commission went on to say:

> *When Ameren Missouri pays the transmission charges it is in the same position as an Ameren Missouri customer who pays their electric bill. The customer pays an established rate for the amount of electricity used. It is meaningless to try to parse out how much of that payment is for the cost of a new transformer in the neighborhood, or how much is paid toward the CEO's salary. The customer is paying a legally established charge that covers all the costs associated with the electricity used and Ameren Missouri is paying a legally established charge that covers all the costs associated with the transmission services it is using.*

Ms. Mantle is making the same argument again, albeit using different language. Basically, having failed at the anti-CWIP/"cost-of-transmission-lines" argument, Ms. Mantle has now come up with a new "directly tied" argument which, like the others, is belied by the facts, including the nature of the charges themselves. That the new argument is, in reality, the old (rejected) argument is obvious when you read Ms. Mantle's discussion of MISO charges arising from the MVPs. Specifically, she states that:

> MISO members are charged as these transmission project costs are incurred. Once the line is built, the users of that line are charged to recover the cost of building the transmission. If Ameren Missouri uses this transmission to purchase power or make off-system sales, MISO will charge Ameren Missouri in order to return investment to the members that paid for the line to be built.

Mantle Direct, p. 10, l. 9-13.

Ms. Mantle also questions the inclusion of costs for MISO's Schedule 42,[6] saying that it is not clear or transparent what this charge is or why it should be considered a transmission charge. It is a transmission charge for the same reason Schedule 26A and

[6] Schedule 42 is titled, "Charge to Recover Accrued and Paid Interest Associated with Prepayments From Entergy Operating Companies' Pricing Zones."

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all of the other MISO transmission service schedules are transmission service charges – from Ameren Missouri's perspective, it is simply paying a mandatory, FERC-approved transmission charge based on the volume of purchases the Company makes from the MISO market - nothing more and nothing less - as the Commission clearly understands.

Q. Does that mean that all the dollars of transmission charges OPC seeks to exclude from the FAC would be included in the FAC?

A. Not unless the Commission decides to change its mind regarding its "true purchased power" conclusion first reached in Ameren Missouri's last rate case.[7] Ameren Missouri chose not to re-argue the issue when it filed this rate case. Instead, Ameren Missouri opted to take other steps to address transmission charges, such as reflecting a level of Schedule 26A charges in its revenue requirement that is as current as possible, and asking for a transmission charge and revenue tracker. Consequently, only a small fraction (1.86%) of all transmission charges (including Schedule 26A charges) are proposed to be included in Ameren Missouri's FAC in its current case.[8] Including all of the components of transmission costs in the FAC would not change that percentage. The point of properly defining transmission costs, however, in the context of this case, is that OPC is simply wrong in claiming that MVPs are not transmission charges at all – they clearly are. And putting aside the true purchased power issue, the applicable percentage of *all* the transmission charges should be included in the FAC, as they are now.

Q. When addressing the components of purchased power costs, you made note of several items of evidence demonstrating that purchased power costs

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[7] Report and Order, File No. ER-2014-0258.

[8] That percentage can vary from case-to-case, depending on the volume of "net" sales and purchases during the historic period used to rebase net energy costs in each rate case. This amount will be updated as part of the true-up process.

consist of many components beyond those recognized by OPC. Does that same evidence demonstrate that transmission costs are also made up of additional components that OPC seeks to exclude from the FAC?

A. Yes, it does. The FERC audit of Ameren Missouri's books found no instance where a transmission charge, including transmission charges that OPC would exclude from the FAC, was not properly recorded as a transmission charge in FERC Account 565. All of Ameren Missouri's FAC tariffs, FAC rate adjustment filings, and prudence reviews have involved FACs that include all these transmission cost components, which have also been detailed in all of Ameren Missouri's monthly FAC reports. Ameren Missouri's FERC Form 1 and Commission Annual Reports have similarly categorized all these components as transmission costs.

Q. Ms. Mantle provides a description of the current methodology used to determine the level of transmission costs (the 1.86% determined for this case noted above) that are included in the FAC on page 9 of her direct testimony. Is this description accurate?

A. No. While Ms. Mantle is correct that the current methodology uses the ratio of what the Commission characterized as "true purchased power" to the Company's total load, her statement that this ratio "is applied to each utility's non-administrative RTO costs" is incorrect.

Q. Please explain.

A. The ratio is only applied to total *transmission* charges recorded in FERC Account 565. It is not applied to any other MISO purchased power cost or off-system sales revenue component recorded in FERC Accounts 555 or 447.

Q. Why is it important to understand to what the percentage is, and is not, applied?

A. Because Ms. Mantle's failure to distinguish between "RTO costs" that reflect RTO transmission charges versus those that reflect RTO charges for the energy and operating reserve or capacity markets could mislead others into believing that Ameren Missouri is not properly administering its FAC tariff.

Q. Couldn't Ms. Mantle simply have been confused by Ameren Missouri's FAC tariff as to what MISO costs the percentage was to be applied?

A. I don't see how. Ameren Missouri's FAC tariff is very specific that this percentage is applied to "the transmission service costs reflected in FERC Account 565." The FAC tariff is also quite specific regarding the MISO purchased power cost components arising from MISO's markets that are included in the purchased power factor (Factor "PP") in the tariff. Nowhere does the tariff state or imply that this percentage is applied to those components.

Q. On page 11 of her testimony, Ms. Mantle is asked "(w)hat is OPC's proposal regarding other MISO costs of which a percentage are currently included in the FAC?" Her response was "(n)o other MISO costs and revenues would be included. While all of these costs and revenues are for necessary services, they are not fuel and purchased power costs or revenues." Do you have any observations regarding Ms. Mantle's response?

A. Yes. First, as I have discussed above, I disagree with Ms. Mantle's proposal to exclude any transmission charges under the guise of claiming that they are not for "transmission." They are indeed for transmission, as explained above and as has been consistently recognized by the Commission.

Second, it is obvious to me that Ms. Mantle's response was intended to be limited to only those MISO transmission charges and revenues, and not all MISO costs and revenues.

Q. Why do you believe that Ms. Mantle's response was intended to be limited to only those MISO transmission charges and revenues, and not all MISO charges and revenues?

A. First, the question refers to "other MISO costs of which a percentage are currently included in the FAC." As just explained, the only MISO charges in Ameren Missouri's FAC that are limited to a specified percentage are MISO transmission charges (there are no revenues of any kind to which the percentage is applied).

Second, the question immediately followed a question and answer regarding which transmission charges Ms. Mantle believes are directly tied to Ameren Missouri's purchased power and off-system sales.

Third, Ms. Mantle's own testimony makes it obvious that she would include other MISO charges and revenues in the FAC. This is obvious since Ms. Mantle specifically identifies capacity and energy purchased through RTO markets to meet native load or to make off-system sales as items OPC recommends including in the FAC. She also recommends the inclusion of off-system sales revenues that are received from the RTO. If Ms. Mantle's response were intended to exclude all MISO costs and revenues other than transmission charges for PTP and NITS, then she would be recommending the

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exclusion of all the Company's capacity and energy costs and revenues obtained from MISO. She clearly does not intend to do that.

Q. Please summarize your recommendation regarding the inclusion of transmission costs in the FAC.

A. As has always been the case with Ameren Missouri's FAC, all the transmission costs recorded in FERC Account 565 should be included in our FAC, either in an amount that equates to those transmission costs for "true" purchased power (if the Commission does not reconsider its true purchased power decision), or in an amount equaling all its transmission costs if it does. Either way, components of transmission costs should not simply be excluded from the FAC on the mistaken theory that they are not transmission costs at all.

III. OPC'S POSITION IMPROPERLY SEPARATES COST AND REVENUE COMPONENTS THAT ARE INEXTRICABLY LINKED

A. OPC's Position Regarding the Inclusion of OSSR in the FAC

Q. What is OPC's position regarding the inclusion of OSSR in the FAC?

A. OPC's position is arguably unclear. This is because at one place in Ms. Mantle's direct testimony (page 4-5) she seems to suggest that only the margin on off-system sales (a fraction of the total off-system sales revenues) should be included in the FAC, yet elsewhere (page 11) she states that "OPC is recommending the inclusion of off-system sales revenue and the cost to generate or purchase power to make those sales" in the FAC. If all the fuel, purchased power, and transmission costs to make those sales are included in the FAC, but only off-system sales revenue above the costs remains in, that necessarily means that the remaining amount of revenue – equal to the cost of the fuel, purchased power and transmission required to make those sales – would reside outside of the FAC. If this is OPC's recommendation, as with other OPC recommendations, the Commission should reject the separation of costs and revenues from components which offset their value.

Q. Do you believe this is OPC's recommendation?

A. I don't think so for the simple reason that such a recommendation is inconsistent with Ms. Mantle's rationale for why OSSR should remain in the FAC. Specifically, Ms. Mantle states that OSSR should be included in the FAC "because the determination of costs to make off-system sales is an after-the-fact accounting assignment of costs." Mantle Direct, p. 11, l. 12-13. She elaborates on this view by stating "[n]ot including off-system sales revenue in the FAC opens an avenue for errors, resulting in parties having different positions regarding the appropriate fuel cost to allocate to off- system sales, increasing the potential for improper assignment of fuel and purchased power costs." Mantle Direct, p. 11, l. 15 to p. 12, l. 2. In her direct testimony in Kansas City Power & Light Company's current general rate proceeding, File No. ER-2016-0285, she was even more pointed in her response, stating that "(n)ot including off-system sales revenue in the FAC opens an avenue for errors, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales, and would increase the potential for imprudence."

Q. Assume that OPC's recommendation is in fact to include all of the OSSR and all the fuel, purchased power and transportation costs (as Ms. Mantle would define those terms) to make those sales in the FAC. What concerns would you have with that recommendation?

A. That recommendation would fail to recognize a wide variety of incremental costs of off-system sales that are required to make those sales – the same cost components which OPC is seeking to have excluded from the FAC. Ms. Mantle would seemingly have the Commission believe that the only incremental costs of off-system sales are fuel, purchased power and transportation ***as she defines those terms***. That is incorrect.

Q. Why would it be problematic to exclude certain incremental costs of making off-system sales if those costs are found not to be fuel, purchased power or transportation?

A. It is problematic as it disconnects changes in those incremental costs from the changes in the benefit provided by the OSSR. The OSSR only exist if the costs are incurred. If these costs incurred to make the sales are excluded, we are now faced with a situation that whenever off-system sales volumes increase, Ameren Missouri must now bear the entire burden of the increase in these costs, while customers enjoy 95% of increased OSSR that would not have existed if that cost had not been incurred. Conversely, whenever off-system sales volumes decrease, Ameren Missouri would retain all the reduction in those costs while customers would bear 95% of the burden of the reduction in OSSR. Either way, such a result is illogical and unfair.

Q. Do you agree with Ms. Mantle's recommendation on page 11 to include all OSSR in the FAC?

A. Yes. I agree that OSSR should be included in the FAC. Including OSSR in the FAC maintains the tie between revenues and the cost components which they offset and the benefits that are provided. I also agree with Ms. Mantle that one cannot

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objectively determine the split between fuel, purchased power [and transmission] costs (as either of us would define those terms) for load and for off-system sales. Such a determination necessarily varies due to subjective judgments utilities must make to develop estimates of those splits. Where I differ with Ms. Mantle is that she would exclude a wide variety of incremental costs of off-system sales that are required to make those sales. As just explained, all the incremental costs of making those sales should be included in the FAC.

Q. How does Ms. Mantle's recognition of the difficulty of determining the appropriate split between load and off-system sales relate to OPC's recommendation to exclude many components of purchased power, as discussed above?

A. The very same difficulty about which Ms. Mantle rightly expresses concern regarding OSSR would also exist if components of purchased power costs that are offset by certain components of OSSR are excluded from the FAC, or if certain components of purchased power costs that offset other components of purchased power costs are excluded. Yet Ms. Mantle recommends that these mismatches should occur.

B. <u>General Concerns Regarding the Separation of Cost and Revenue Components</u>

Q. Please elaborate on why it is improper to separate cost and revenue components of purchased power, transmission and off-system sales from other components of purchased power, transmission and off-system sales.

A. As already discussed, purchased power, transmission, and OSSR consist of their various components. Certain of these components are inextricably tied together, either due to one component serving to partially mitigate against the risk of adverse price

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movements in the other components (providing a hedge for customers' benefit) or because the component itself is a result of the cost of the other component not by itself being reflective of the total cost of the purchased power or transmission.

Q. What are some examples of these components?

A. Forward energy and capacity transactions at fixed prices, whether physical or financial in nature, are used to mitigate (hedge) the risk of adverse price movements for the energy component of purchased power costs and revenues from off-system sales of energy which otherwise would be priced only in the day-ahead or real-time spot markets. Similarly, components of purchased power recorded in Account 555, such as ARRs and FTR offset other components of purchased power recorded in Account 555, that is, the cost of congestion which is embedded in the locational marginal price[9] of the day-ahead energy acquired to serve the utility's load. Another example is ancillary services revenue recorded in FERC Account 447, which offset the cost of acquiring the ancillary services component of purchased power recorded in Account 555. There are other examples, including MISO make-whole payments recorded in Account 447 that are funded by the revenue sufficiency guarantee and revenue neutrality uplift components of purchased power recorded in Account 555. All of these components are inextricably connected to each other and should not be separated.

C. <u>Forward Energy and Capacity Transactions in Account 555</u>

Q. Has Ms. Mantle recommended the exclusion of forward energy transactions from the FAC?

[9] The locational marginal price ("LMP") that is paid for a MWh of energy bought or sold in MISO's market itself consists of three components: energy, congestion and losses. MISO does not break out those components in their billings, but Ameren Missouri (and probably other utilities) attempt to isolate each component of the LMP for managerial accounting purposes.

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A. Not by name. However, by recommending that the only purchased power costs included in Ameren Missouri's FAC are the costs of energy from long-term bilateral contracts or spot energy from MISO's market, she has effectively recommended that energy charges from bilateral contracts of less than one year and all financial swaps should be excluded. This means again that she has excluded many components of purchased power, including all financial swaps and short-term bilateral energy contracts, which mitigate the risk of adverse price movement for the energy component of purchased power, just as the long-term bilateral contracts she has decided can be included in the FAC would. This makes no sense.

Q. Can you discuss this concern further?

A. Yes. Ms. Mantle's proposal does not provide for the inclusion of financial swaps of *any* term or the cost of short-term bilateral contracts for energy. Excluding these items from the FAC is illogical given that she has specifically recommended the inclusion of the cost of energy from long-term bilateral contracts.

Q. Why is it illogical to exclude the cost components of purchased power related to financial swaps and short-term bilateral contracts for energy?

A. First, it is illogical because Ms. Mantle seems to be differentiating between a financial swap and a fixed price bilateral contract even though both transactions accomplish *exactly the same thing*: fixing the price of power for a future period.

Second, it simply does not make any sense that Ms. Mantle would only support allowing Ameren Missouri to enter into transactions to mitigate its price risk if that transaction is at least one year in length, whether it was a swap or a bilateral transaction.

It becomes even more nonsensical if one were to believe that long-term is somewhere between three and five years,[10] as Ms. Mantle has opined in the past. (The generally accepted market definition of long-term is at least one year). Under Ms. Mantle's position, the utility's customers would illogically bear the full risk of adverse price movement for periods of less than at least one year.

Q. Please explain how a physical bilateral contract and a financial swap serve the same purpose of fixing the price for a forward period.

A. They fix the price of a transaction that would otherwise settle at a spot market price in the future. In the case of a physical bilateral contract, the utility will make a purchase at a fixed price and take delivery of energy from the counterparty at a specified point. The utility will still purchase energy from MISO to serve its load, but the energy acquired through the bilateral contract will also be settled (sold) into the MISO market. This means that the utility pays the bilateral contract counterparty a fixed price for the energy and sells it into the MISO market and receives a variable spot market price. The utility then purchases energy from the MISO market to meet its load obligation at that same variable spot price. Since it both received and paid a variable spot price, the utility is left having paid a fixed price for the energy. In the same manner, financial swaps include a fixed price which settles against the variable spot price.

In the case of a financial swap, the utility enters into a financial arrangement with a third party which "swaps" the utility's spot price exposure for a fixed price, with the agreement specifying what price point in the market will be used to calculate the settlement value. When the transaction comes to delivery, the utility purchases the

[10] Mantle Deposition, File No. EO-2010-0255, p. 30, l. 23 to p. 31, l. 7 (Indicating that "long-term" was between three and five years).

energy from the MISO market to meet its load obligation at the variable spot price. Unlike the physical bilateral contract, the utility does not buy energy at a fixed price which is then sold into the market at the variable spot price, but simply makes a financial settlement with the counterparty for the difference between the fixed price and the variable price. Since the variable spot price is netted out, this leaves the utility paying an amount equal to the fixed price – just as it would with the physical bilateral contract. One advantage of the financial transaction over the physical bilateral transaction is that it avoids certain market settlement charges which are based on transaction volumes, and thus may be a lower cost option, which benefits customers.

Q. If the financial swap provides an identical benefit as a physical bilateral contract and is potentially a lower cost option to mitigate the risk of adverse price movements for purchased power, what would the effect of OPC's proposal to allow the cost component for long-term bilateral contracts to remain in the FAC but exclude the cost component for financial swaps be?

A. This is in some ways the same scenario that Ms. Mantle describes in her testimony regarding Ameren Missouri making the choice between treating coal with activated carbon versus trona. Mantle Direct, pp. 16-17. Setting aside any question of the accuracy of Ms. Mantle's characterization of what functions activated carbon or trona perform, her example is meant to discuss two alternatives to address the same issue. In her example, and with bilateral contracts and financial swaps, there are two tools available to accomplish a purpose (fix the price of energy, treat fuel before it is burned), but if OPC had its way only one is included in the FAC. Ms. Mantle believes that having one tool in an FAC and another tool outside it creates disincentive for the utility to use the tool outside the FAC. If that were true, though, it would necessarily follow that excluding financial swaps or short-term bilateral contracts while including long-term bilateral contracts in the FAC would create a similar disincentive to use financial swaps or short-term bilateral contracts which would be outside the FAC, even if the circumstances warrant their use.

Simply put, these two examples – trona versus carbon and bilateral contracts versus financial swaps – are neither identical in nature nor truly analogous. In Ms. Mantle's activated carbon versus trona example, the utility *must* use one of those two tools to treat the coal. In the case of short-term bilateral contracts and swaps, the utility is *not* required to hedge the underlying price risk at all; it does so to mitigate price risk *on behalf of its customers*. The cost of providing that mitigation should not be divorced from the mitigation itself.

As Ameren Missouri witness Jaime Haro testified in File No. ER-2014-0258 (surrebuttal testimony, p. 20, l. 5-9), "(a)s soon as the tie between the underlying risk (price volatility for excess generation) and the hedging transaction is broken, the financial swap is no longer a hedging instrument, it is a speculative instrument. Ameren Missouri is not a merchant generator and we do not speculate on energy transactions. As a consequence, we would cease entering into such transactions." While Mr. Haro was speaking to Ms. Mantle's recommendation in that case that the costs and revenues associated with financial swaps entered into for off-system sales be excluded from the FAC, this principle applies equally to hedges entered into for purchased power. If the financial swap component of purchased power were removed from the FAC, those transactions would no longer serve as hedges, leaving only the long-term bilateral contract as an available tool – one which may have a higher cost for customers.

Q. Why does it not make sense to only allow Ameren Missouri (or presumably any Missouri utility) to only enter into long term transactions to mitigate price risk on behalf of customers?

A. It is unreasonable to believe that Ameren Missouri or any utility only has long-term price exposure. MISO operates an energy and ancillary services market. That market is co-optimized – i.e., by their very nature, energy and ancillary services markets work together. The energy market, however, is not forward in nature; the longest period ahead of delivery for which it transacts is the next day – and then only for the day-ahead market. As such, when a utility has an open position in the market – either long (projected to have more resources than load obligation) or short (projected to have more load obligation than resources) – it is at risk of adverse price movements in the MISO spot market. The utility does not know what the price will be when its generation and/or load ends up clearing in the marketplace. When a utility has a long position, it is generally concerned with the risk that the market prices will decrease from current expectations and may seek to lock in a price with a forward contract – either physical or financial in nature. Similarly, when a utility has a short position, it is generally concerned with the risk that the market prices will rise from current expectations and will seek to mitigate that risk by locking in a price for the energy component of purchased power now.

Certain utilities are always short – they have a load obligation and own no resources. Others are always long – they have resources and no load obligation. Many more, however, have both resources and loads. While these utilities may tend to be generally long or generally short, there is no way to know that this will always be the case. This is especially true when one recognizes that the determination of a short or long position is made by calculating the amount of resources that are not only available, but are also *economically* available to offset the cost of serving the load with energy purchased from the market. It is sound (and long-standing) practice for utilities to rely on the marketplace when the cost of doing so is lower than the cost of generating energy from their own resources.

OPC's recommendation would create a situation in which a utility could not project itself in a short position and still be able to hedge that exposure unless the contract used to hedge the exposure was at least one year in length. Indeed, it would be illogical – and potentially imprudent – to make a bilateral purchase for a full year if the short condition did not exist for at least that long. The only option available to the utility would be simply waiting and purchasing the energy in the spot market at the going price.

Q. Isn't your concern simply hypothetical, given that Ameren Missouri is generally long on generation?

A. No. Far from being hypothetical, the concern is quite real. For example, Ameren Missouri's Callaway Nuclear Plant is its single largest generating unit. Callaway must be taken out of service every 18 months for refueling. In accordance with long-standing, prudent practice, these outages are timed to coincide with time periods that historically have low market prices for power. Ameren Missouri projects its forward energy position using forward market prices. If these market prices fall below Ameren Missouri's projected cost of generation, its projected "in the money" generation will decrease. If a sufficient amount of generation is projected to be "out of the money," it will project a short condition. This does not mean that the Company does not own sufficient generation resources to meet its load obligation; it simply means that these units are projected to operate at lower levels due to economic dispatch considerations, resulting in an increase in net purchased power on its books. Ameren Missouri obviously does not know what the actual market prices will be during the scheduled outages, but the opportunity exists for the Company to lock in a price for purchased power now that is lower than its cost of generation to hedge that cost exposure. Under OPC's proposal however, Ameren Missouri would not have any reason to enter into such a hedge – whether it be with a swap or a bilateral contract – as the exposure only exists for a short period of time. Customers then would be left bearing the spot market costs, whatever they may be, when the outage comes about.

Other examples exist for time periods as short as a few hours, for example when a utility finds itself short inside the market day for a few hours across the peak due to an unplanned unit outage. OPC's proposal would exclude recovery of any cost related to fixing the price for the balance of the day and leave the customer exposed to real time prices later in the day. There are far more potential scenarios involving a utility being short for periods of less than one year than there are of a utility being short for periods of one year or more.

Q. Would a utility that is normally a net purchaser be harmed by OPC's proposal?

A. Yes. Such a utility, and more importantly its customers, would be harmed by OPC's proposal because the amount by which the utility is short would not be the

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same in every month, let alone every week or every hour. When the only tool available to mitigate a utility's spot market price exposure is long-term bilateral contracts, that utility is left with two options: 1) continuing to carry a considerable amount of spot market exposure, whether it purchases the absolute minimum load for every hour of a year and buys the rest, or it buys something greater than the minimum and sells its excess or buys its deficiency in the spot market; or 2) enter into a full requirements, load-following purchased power agreement with a third party.

The first option carries all the downsides related to prohibiting short-term price mitigation discussed above. The second option carries a cost premium to compensate the seller for bearing all the utility's load variability risk; a premium that may well be greater than the cost of the utility managing its own risk.

D. <u>Auction Revenue Rights and Financial Transmission Rights in Account 555</u>

Q. Why would it be improper to exclude ARRs and FTRs from the FAC?

A. As noted earlier, ARRs and FTRs are components of purchased power (actually, they are revenue streams recorded in Account 555, which some view as a "negative cost") that serve to offset the cost of congestion embedded in the LMP for energy purchased to serve load. Again, the Commission should reject the separation of costs and revenue components from other related components that offset their value.

Q. What does it mean that ARRs/FTRs offset the cost of congestion?

A. To understand how ARRs/FTRs offset the cost of congestion, I will provide a bit of history on the development of the LMP that Ameren Missouri pays to purchase energy from the MISO market and that it receives for the energy that it sells into that same market.

LMP is made up of three components: a marginal energy component ("MEC"), a marginal losses component ("MLC"), and a marginal congestion component ("MCC"). For a given hour, in the day-ahead or the real-time market, the MEC is the same for every commercial pricing node ("CpNode") in the MISO market.[11] The other two components are unique to each CpNode and are based on the current conditions of the transmission system. When the LMPs for two points are compared, the difference is attributable to losses (the difference in the MLC component) and congestion (the difference in the MCC component).

Prior to the use of LMP in centrally administered RTO markets, transmission congestion on the system was addressed by instructing market participants to terminate energy schedules between transmission control areas. While non-firm transmission schedules were the first to be "cut," firm schedules could also be cut if non-firm cuts didn't resolve the situation. Since these corrective actions were not directed at specific generators or loads that would be best able to resolve the situation, it was frequently necessary to cut a very large amount of transmission schedules to obtain the desired congestion relief. These orders to cut schedules were called "TLRs," which stood for "transmission loading relief."

While transmission schedules between control areas were being cut, inside a utility's own control area, the energy just flowed between the generators and the load – what MIEC witness Dauphinais termed as self-supplied power in File No. ER-2014-0258 – unless there was an emergency which required the curtailment of load. The frequency

[11] A CpNode is a location in the market.

and magnitude of these TLRs was quite disruptive, and the process overall was an inefficient means of solving congestion problems.

The inherent market inefficiency and disruptiveness of a system that relied on TLRs led to the establishment of the LMP-based markets we have today, both in MISO and the Southwest Power Pool ("SPP") (and elsewhere). In an LMP-based market, it is no longer necessary for the system operators to order TLRs between areas, as the necessary response from both load and generation is achieved through price signals. This means that the scope of curtailments is greatly reduced, resulting in fewer system disruptions and much greater efficiency.

Q. How does LMP address congestion, reducing the disruption and increasing the efficiency of the market?

A. When congestion on the system occurs (in real-time) or is modeled to occur (in day-ahead), the LMP received by generators or paid by load on the low (less congested) side of the congestion is depressed because the MCC of the LMP at that CpNode is lower. This provides an incentive for price sensitive loads to increase their demand and for generators to reduce their output. In certain cases, the LMP may actually go negative if necessary – requiring the generator to pay the RTO if it continues to generate or allowing the load to be paid to take energy. On the other, high (more congested) side of the congestion, the price paid by the load or received by generators is increased. This provides an incentive for generation on that side to increase its output (or if the unit is off-line, to be brought on-line) and for loads to reduce their demand. It is generally true that congestion exists between the load and generation. The further apart load is from generation, the more likely that there will be congestion and the higher the differential in the MCC will be.

Unlike TLRs, the use of LMP targets exactly those resources and loads that are best able to resolve the issue on the system. LMP also allows market participants to determine what is in their best financial interests rather than simply being on the receiving end of a TLR. Under LMP, if a market participant has a transaction from point A to point B, as long as it is willing to pay the net LMP (LMP paid at the load point minus the LMP paid at the resource point), it can continue to use its own resource to offset the cost of servicing its load through self-scheduling. However, market participants generally find it in their financial best interest to back down their generation in response to a price signal, which helps relieve the congestion and lower the LMP at the point they the energy is acquired to serve their load. As a result, their overall cost of purchasing power for their load is lowered.

Q. How does this LMP-based system relate to ARRs and FTRs?

A. Load serving entities ("LSE"), including vertically integrated utilities (those who both own generation resources and those with a load obligation) like Ameren Missouri, were rightfully concerned that the advent of LMP-based markets might increase their own costs to serve their load obligations, since the price received from selling all their resources into the market was expected to be less than the price paid to the market for purchasing their load requirements, due to greater market efficiencies made possible by the LMP-based market. While part of this difference represents transmission losses, which also existed prior to the advent of LMP, the rest of the difference represents the cost of congestion within the purchase price.

To address the LSE's concerns (and undoubtedly the concerns of their regulators), and to maintain the historical relationship to the use of the system for their resources and their loads, FTRs were created. FTRs compensated LSEs for the difference in the congestion components in the day-ahead LMP that existed between the resources they had historically utilized to meet their load obligations, and the loads themselves. In doing so, these entities were placed back into the same relative financial position (for the portion of their generation that hedged the cost of their load obligations) that they would have been in without the LMP-based market and using the firm transmission service (either through firm point-to-point or firm designated network service) that was traditionally used to serve their load.

Later, the RTOs replaced the allocation of FTRs with lump-sum ARRs, which are cash payments. Owners of ARRs have the option to either take the lump sum payment or convert the ARRs to FTRs. The payments received from the RTO for an FTR are based on the actual hourly congestion amounts. As such, FTRs track changes in congestion throughout their effective period, and arguably provide a more complete hedge against the cost of congestion embedded in the purchase price than simply taking the lump-sum ARR payments. As with other hedges, this value will fluctuate as the underlying cost fluctuates. Consequently, FTR revenues will increase when the cost of the congestion component of purchased power increases, and will decrease when the cost of congestion component of purchased power decreases.

Q. You have explained how ARRs/FTRs provide a hedge against the cost of congestion embedded in the purchase price, but can you explain why it is appropriate to include those items in purchased power?

A. Yes. The level of ARR/FTR revenues is inextricably tied to the cost of the day-ahead energy purchased from the RTO to serve the utility's load obligation. In the absence of ARRs and FTRs, the utility's total purchased power expense – a cost ultimately borne by its customers – would be higher. It is the *combination* of these offsetting cost and revenue components that establishes the cost of purchased power.

Q. Are the dollars associated with congestion and ARR/FTR revenues significant?

A. Yes. Ameren Missouri's actual totals for these amounts in recent years are shown in the table below (negative numbers reflect revenues).

	Congestion	*ARR/FTR*	*Net*
2010	$16,455,474	($16,936,072)	($480,598)
2011	$12,912,706	($20,750,528)	($7,837,822)
2012	$14,771,232	($26,858,744)	($12,087,512)
2013	$26,576,317	($43,106,464)	($16,530,147)
2014	$14,764,545	($17,212,626)	($2,448,081)
2015	$19,914,424	($26,523,789)	($6,609,365)
YTD2016	$9,647,081	($13,729,981)	($4,082,900)
TOTAL	**$115,041,779**	**($165,118,204)**	**($50,076,425)**

Q. What would the consequences be if OPC's proposal was adopted, excluding ARRs and FTRs from the FAC?

A. The first and most obvious consequence of implementing OPC's proposal is that, should history repeat itself, an average of more than $23 million in FTR revenues would be excluded from the determination of total purchased power costs in the FAC *each year* (approximately $165 million/6 years and 11 months).

This would be yet another break between underlying congestion risk and the very tools included in the market's operation to manage that risk. By breaking that link (once again taking Ms. Mantle's activated carbon versus trona disincentive argument at face

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value) means the utility would no longer have an incentive to actively manage the congestion exposure.

The utility would also find itself in another untenable situation. Any time the cost of congestion increased relative to what was included in the determination of net base energy costs that set the base in the FAC, customers would be required to absorb the higher congestion costs. At the same time the utility would not be able to offset the increased cost of congestion with the related increase in the value of the ARRs and FTRs (as congestion increases, so does the value of the ARRs and FTRs) because the ARR and FTR components would not be in the FAC. Conversely, any time the cost of congestion fell, the utility would be required to not only absorb the drop in the value of the ARRs and FTRs because again, they would not be in the FAC. At the same time, the utility would be required to pass through to its customers the value of the reduction in congestion that led to the loss in ARR/FTR value in the first place since the congestion *is* reflected in the FAC.

The intertwined relationship between ARR/FTR and energy costs is obvious; because ARRs and FTRs are inextricably tied to the underlying cost of congestion (which is itself embedded in the LMP), those ARRs and FTRs should not, as a matter of logic, fairness and operation of the markets, be excluded from the FAC.

Q. Couldn't this problem be solved by excluding the congestion cost component of the LMP from the FAC as well?

A. For the same reasons given by Ms. Mantle for including OSSR in the FAC, the answer is "no." There is also no need to do so – ARRs and FTRS are a component of purchased power costs inextricably linked to the energy component of those costs.

Q. Why is the answer "no?"

A. First, as noted previously, to determine the cost of congestion, one must compare the marginal congestion component in the LMP paid for energy purchased to serve load to the marginal congestion component in the LMP received by the generators whose output has been designated as offsetting the cost of energy to serve the load. This is similar to being able to determine the split between the cost of fuel or energy purchased to make sales versus to serve load.

To calculate the cost of congestion attributable to load entails exactly the same process that Ms. Mantle states would require an "after-the-fact accounting assignment of costs" and that would open "an avenue for errors, resulting in parties having different positions regarding the appropriate fuel cost to allocate to off-system sales, increasing the potential for improper assignment of fuel and purchased power costs." Being able to identify what generation resources are allocated to load or allocated to sales is exactly the same process – the only difference being if you are looking at the top or the bottom of the generation stack (i.e., the dispatch order of each generating unit). In either case, the determination is made through an internal calculation at the utility, based on subjective decisions made by the utility, just as is the case when attempting to separate fuel and power purchases for load versus for sales. This is not a simple or standardized process, as Ms. Mantle recognizes.

Secondly, there are no FTRs to offset congestion in the real-time market. As such, if we keep ARRs/FTRs together with the congestion cost component of purchased

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power that they offset (as we must). Assume that FTRs/ARRs and the congestion they offset were removed from the FAC: we would have a situation where the energy cost component of purchased power in the day-ahead market would be defined differently than the energy cost component of purchased power in the real-time market. This result makes no sense. Such a scenario would unnecessarily complicate the administration of the FAC tariff and, in Ms. Mantle's own words, open "an avenue for errors, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales, and would increase the potential for imprudence."

E. <u>Ancillary Services Costs in Account 555</u>

Q. Why would it be improper to exclude the ancillary services component of purchased power from the FAC?

A. Ancillary services are a component of purchased power. Their cost is offset by the revenues received for the sale of ancillary services, which are reflected as OSSR in Account 447. The Commission should reject the separation of costs and revenue components from other components which offset their value.

Q. Why do you say the cost of this component of purchased power is offset by the revenues received for the sale of ancillary services that are a component of off-system sales?

A. As with energy, utilities in RTOs with an ancillary services market (such as MISO) purchase their entire ancillary service requirements for load from the RTO market and sell all the ancillary services provided by their generators into that same market. Unlike the energy market, however, there is no FERC-mandated netting requirement for accounting purposes.

In the energy market, in an hour in which the utility has more MWhs of generation sold to the market than MWhs of energy purchased to serve load, the utility will record a net sale for the difference in both MWhs and dollars. A net purchase is recorded if it purchases more than it sells.

In the ancillary services market, however, the utility records all the costs of ancillary services purchases in Account 555 and all revenues from ancillary services sales in Account 447.

Q. Why is this lack of netting for accounting purposes important in this discussion?

A. It is important because OPC is recommending the exclusion of all ancillary services cost components from the FAC without a commensurate recommendation that any of the revenue components of ancillary services should be excluded from the FAC. As such, OPC would have significant revenues remain in the FAC that only exist because we now record significant costs to purchase ancillary services from the market rather than self-supply them (as was done before the RTOs created the ancillary services markets).

Q. Can you explain what you mean by this?

A. Yes. At the time the FAC statute was drafted, vertically integrated utilities such as Ameren Missouri provided their own ancillary services, allocating the required level of ancillary services across their generating units. To be able to provide spinning reserve and regulating reserve, generating units that might otherwise have been dispatched at higher generation levels to provide energy were held back enough to allow the unit to respond. The decision regarding which units should be backed down was restricted to the number of units under the utility's control. There was not, however, an explicit purchase of ancillary services to meet the requirements of the utility's load as there is now. Sales of ancillary services were generally limited to those taking transmission services within the utility's control area.

With the advent of ancillary services markets within the RTOs, utilities no longer self-provide their ancillary service requirements; it is more efficient to utilize the ancillary services market which, in fact, works in tandem with the energy market (i.e., they are co-optimized markets). Today, we purchase all of our ancillary services requirements from the market and sell all of the ancillary services provided by our generators into the market – just as we do for energy.

Q. Why is it more efficient for Ameren Missouri to buy all its ancillary service requirements from the market and then sell all ancillary services to the market?

A. Because the co-optimized ancillary services and energy markets lower overall costs. This is because less generation must be held back to provide ancillary services and more generation (when economic in a given hour) can be used to provide energy. As noted, prior to the advent of ancillary services markets, utilities self-provided their ancillary service requirement, so they had limited choices of where to hold those reserves. In an RTO-administered ancillary service market, there is a much greater pool of resources available to provide those services. By administering both the energy and the ancillary services market simultaneously, the RTO can co-optimize those two markets. Additionally, when the ancillary service requirements of all the loads were combined, the aggregate amount of ancillary services required of the pool was less than the total of all the individual requirements under the prior system.

The resources that are most cost efficient *to* provide energy *will* provide energy. Those most cost efficient *to* provide ancillary services *will* provide ancillary services. With very limited exceptions, if a generator is clearing for ancillary services, it is because it is more profitable for it to do so than to clear for energy.

Generation resources are no longer limited in the amount of ancillary services utilities can sell by their own control area requirements and, as such, have new sources of revenue available to them.

Through this co-optimization, the utilities' purchased power costs net of off-system sales revenue is lower than it would be if it self-supplied all its own ancillary services. Schedule AM-R1 to my testimony provides an example of how co-optimization works.

Q. Your example has illustrated why co-optimization is better than self-supply, but how does this support your argument that the ancillary services cost component of purchased power should not be excluded from the FAC?

A. This example further demonstrates that one cannot separate cost and revenue components that offset each other without completely ignoring the fact that the energy and ancillary services markets are co-optimized. Moreover, it makes no sense to do so; that co-optimization, by design, lowers costs through more efficient market operations and those reductions are reflected in the FAC.

Q. How do you recommend that the Commission treat ancillary service costs in the FAC?

The Commission should reject the separation of costs and revenue components from other components that offset their value. All the ancillary service revenue components of off-system sales and all the ancillary service cost components of purchased power should remain in the FAC.

Q. Couldn't that be accomplished by excluding the offsetting ancillary service revenues from the FAC?

A. Excluding both the offsetting ancillary service revenue components of off-system sales *and* the ancillary service cost components of purchased power would seemingly avoid the problems associated with separating these components. However, this would be at a significant cost, adding extreme levels of complexity to the administration of the FAC tariff. It also does not help to exclude all ancillary service revenues from the FAC (and not just those which offset ancillary service costs) because customers would lose the benefit of increases in those revenues between rate cases.

Q. How would removing the offsetting ancillary service revenues from the FAC complicate the administration of the FAC?

A. The amount of any given ancillary service that a utility purchases in an hour is not equal to the amount of that service it sells in that hour. In some hours, it purchases more of a given service than it sells, and in other hours, it sells more than it purchases. This is the same situation as exists with the purchase and sale of energy – but here it exists for *three different ancillary services*.

Excluding the offsetting ancillary service revenues from the FAC along with the ancillary services cost components of purchased power requires basically the same process (except in triplicate) that Ms. Mantle states would require "an after-the-fact accounting assignment of costs" and that would open "an avenue for errors, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales, and would increase the potential for imprudence." The utility would have to be able to identify which ancillary service sale by a given generation resource for a given type of ancillary service would be allocated to offset the cost of what was purchased by load. That determination is made through an internal calculation at the utility, based on subjective decisions made by the utility.

F. RSG and RNU Charges

Q. Why would it be improper to exclude these components of purchased power from the FAC?

A. MISO make-whole payments to generators (recorded as revenues in Account 447) are inextricably tied to the cost of energy. RTOs, including MISO, are revenue neutral by nature. The amount that they pay out to generators must be collected from those purchasing energy from the MISO market. In a perfect world, the revenue paid to generators via the LMP would exactly equal the energy costs paid by the loads via LMP. However, we don't live in a perfect world; these revenues do not perfectly match. When they result in more revenues paid to the generators than amounts collected from the loads for purchased power, the shortfall is collected from the loads through the RSG and RNU component of purchased power. Had the price charged for the energy adequately compensated the generator, then the LSEs would not need to pay more to cover the true cost of the power. However, when the price does not provide adequate compensation, the charges are necessary. Clearly, then, the RSG and RNU are components of the total cost of purchased power. Notably, OPC has not recommended the exclusion of any revenue component for make-whole payments, even though it wants to exclude the charges that create the pool of dollars needed to make those payments.

Q. What leads to make-whole payments for generators, and thus the RSG and RNU components of purchased power needed to fund them?

A. The various causes of make-whole payments are relatively complex, but at their core is a common cause: these are revenues from MISO to the generator caused by MISO's dispatch of the utility's generation when the variable market price is lower than the offered cost of the generation. These make-whole payments restore the generator to a position no worse than it would have been in had it not allowed MISO to dispatch its units in this manner.

Q. How do loads benefit from generators allowing MISO to dispatch them in this manner?

A. The cost of purchasing power from the MISO market is lower, and the overall reliability of the MISO dispatch is retained. Generators are required to follow MISO's instructions to dispatch them in this manner. Without these market features, MISO would be required to either commit more expensive resources, carry greater levels of spinning reserve, or in extreme cases, potentially curtail loads.

Q. Are there other costs that are collected through RSG or RNU?

A. Yes. In particular, real-time imbalances in congestion are settled through RNU on a load ratio share. MISO calculates the total amount of congestion costs for entities acquiring energy in real-time and compares that to the total amount of congestion revenues received by selling energy into the market. Any difference – positive or negative – is allocated on a load ratio share through RNU. If LMPs were perfectly calculated every five seconds, this would be unnecessary. These differences collected through RNU, therefore, simply represent an under- or over-payment for purchased power.

Q. How do you recommend the Commission treat the MISO make-whole payment cost components of purchased power in the FAC?

A. The Commission should reject the separation of costs and revenue components from other components that offset their value. All the MISO make-whole payment components of purchased power should remain in the FAC.

IV. <u>INCENTIVES</u>

Q. In her discussion of why OPC is recommending a change to Ameren Missouri's FAC incentive mechanism (moving from 95%/5% to 90%/10%), Ms. Mantle claims that Ameren Missouri decided that it changed how it managed its capacity within the MISO market as a result of the "shutdown of the Noranda aluminum facility." Is she correct?

A. No. Ameren Missouri could not have changed how it managed its capacity within MISO because the smelter shut down, because we changed how we managed our capacity within MISO *nearly a year before* the smelter shut down.

Q. Does OPC know this?

A. It should. I explained this in detail in my direct testimony filed in this case more than six months ago.

Q. Despite Ms. Mantle's mistake regarding why Ameren Missouri changed its strategy for managing its capacity, is a discussion of that decision relevant to any of Ms. Mantle's recommendations in this case?

A. Yes it is.

Q. Why?

A. Because what we did directly rebuts Ms. Mantle's claim that there ought to be greater sharing in the FAC. We made a change in our approach for participating in MISO's capacity market that saved our customer $27 million in one year, and did so with a sharing percentage of 95%/5%. Obviously, we don't need a "greater incentive" to take steps to minimize our net energy costs for the benefit of customers.

V. <u>NEW CHARGE TYPES FROM THE RTO</u>

Q. Ms. Mantle claims that "(w)ith the MISO costs limited as proposed by OPC, there would no longer be a need for a process to include new MISO charges and revenues that are 'like' MISO costs and revenues already included in the FAC." (pg. 19 l. 13-16). What is her point?

A. I believe Ms. Mantle is suggesting that if the Commission opted to adopt OPC's recommendation,[12] then the need for a provision that has (with some modifications) been in the Company's FAC tariff since 2013 would be eliminated. This provision allows for the inclusion of costs and revenues that did not fall within an existing RTO charge type when the FAC tariff was approved, so long as the new RTO charge type reflecting the costs or revenues possess the characteristics of, and are of the nature of, existing costs and revenues in the FAC. Ameren Missouri witness Lynn M. Barnes also addresses why this provision should remain in the FAC tariff in her rebuttal testimony filed in this case.

[12] Specifically, the OPC's recommendation to only allow in Ameren Missouri's FAC those MISO charges that are "capacity and energy purchased through RTO markets to meet native load or to make off-system sales" and charges for Point-to-point ("PTP") and network integration transmission service ("NITS").

Q. Do you agree with Ms. Mantle's claim that the need for this provision would be eliminated if OPC's recommendations for the FAC were adopted?

A. No. The need for this provision will exist so long as the cost and revenue components of purchased power, off-system sales, and transmission included in the FAC tariff are prescriptively tied to charge types and identified MISO schedules that happened to exist when the FAC became effective after each rate case.

Q. Are you sure Ms. Mantle isn't addressing the general "energy" and "capacity" provisions in the FAC tariff?

A. I see nothing to indicate that her recommendations are limited in that fashion. There is nothing in her testimony (in this case or any past case) indicating to me that she is now willing to abandon her long-held position that the FAC tariff must include a prescriptive listing of every charge type and schedule.

Not only would this be contrary to her past positions, but the fact that she still believes such a prescriptive list must be in the FAC tariff is reinforced by her quite recent testimony in KCP&L's pending rate case (File No. ER-2014-0285), where she recommended limiting SPP integrated market costs and revenues in purchased power to four very specific SPP charge types.

Q. If Ms. Mantle were to state which MISO charge types should be included in the FAC, and if she were to claim that there could never be any others until another rate case occurs, would you agree?

A. No, I would not agree. Ms. Mantle's testimony suggests that the Commission simply assume that when MISO implements or even modifies a new charge type that the related cost or revenues are new (i.e., they would not be for purchased

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power, off-system sales or transmission). In many, if not most cases, that simply is not true – MISO is simply rearranging how existing costs and revenues arising from its market are accounted for and settled. If indeed a charge type was implemented that did not possess the characteristics of, and were not of the nature of, existing costs and revenues in the FAC, Ameren Missouri's tariff already would not permit those costs and revenues to be included in the FAC.

Ms. Mantle's testimony also suggests that the Commission assume the implementation of a new charge type that reflects changes in where and when a cost or revenue occurs, or that divides it into smaller portions, somehow makes it into something other than fuel, purchased power or transportation. It does not.

Q. Please explain this last statement.

A. The statute refers to fuel, purchased power and transportation. It doesn't say "purchased power, but only if the contract for that purchased power is more than a year." And it doesn't say that if the purchased power is from an RTO, it is only really "purchased power" if the RTO labels it a certain way and had done so when a particular FAC tariff took effect.

Q. Given Ms. Mantle's historical insistence on a prescriptive FAC tariff and the existence for the past several years of a provision that allowed charge type changes to be recognized, are there examples of situations where the absence of such a provision would have been highly detrimental to customers?

A. Absolutely. Less than six months after the Commission re-approved Ameren Missouri's FAC in File No. ER-2012-0166 (which was the first case where the FAC tariff became highly prescriptive and where a change provision was included), MISO changed from a monthly capacity auction to its current annual auction format. Coincident with that change, MISO also implemented a *new charge type* used to settle these capacity transactions. That charge type obviously was not listed in the FAC tariff.

Q. You noted that MISO changed the charge type used to settle capacity when it changed from a monthly auction to an annual auction. What would the impact on customers have been if Ms. Mantle had succeeded in keeping this change provision out of the FAC tariff approved in File No. ER-2012-0166?

A. Without this provision in our FAC tariff, beginning in June 2013, Ameren Missouri would have kept 100% of its net capacity revenues from this new MISO capacity auction. Even if those capacity revenues stayed at the same level as had been assumed when the base for the FAC had been set in that case, customers would have seen higher FAC charges because the offset to net energy costs in the FAC provided by MISO capacity revenues would have completely gone away. Moreover, if capacity revenues had gone up above the base, customers would have missed out on receiving 95% of the increase.

Q. Have you determined what the harm to customers would have been as a result of MISO changing the charge type for capacity transactions if the change provision had been excluded from the FAC?

A. Yes. The Rider FAC tariff from File No. ER-2012-0166 became effective in January 2013 and remained in effect through May 2015. The new charge type became effective in June 2013.

Between June 2013 and May 2014, there would not have been any effect on customers since Ameren Missouri's net capacity revenue under the new MISO charge

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type was zero – all our excess capacity sales were bilateral (with parties other than MISO), and the new charge type would not have affected inclusion of those revenues in the FAC.

Between June 2014 and May 2015, however, Ameren Missouri had net capacity revenues of $7.3 Million – which was $1.6 million higher than the $5.7 million included in determining the FAC base factors. Of that difference, 95% ($1.5 Million) was credited to customers through the FAC.

If OPC's position had been adopted and the change provision had not existed, all $2.8 million of the net capacity revenues from the MISO capacity auction under the new charge type would have been excluded from the FAC. That would have left only $4.5 million in bilateral capacity sales revenues in the FAC, resulting in a $1.2 million under-recovery as compared to the $5.7 million included in determining the FAC base factors. Of this shortfall, 95% ($1.1 million) would have been recovered from our customers.

The bottom line is, having the change provision in the FAC *in just this one instance* saved our customers over $2.6 million (they received $1.5 million of higher capacity revenues, instead of being charged rates in the FAC reflecting a $1.1 million increase in actual net energy costs).

Q. Ameren Missouri has seen its net capacity revenues increase substantially since then, hasn't it?

A. Yes. For the period of June 2015 through May 2016, a new FAC was in place. During that period, the $49.9 million net capacity revenues under the new charge type would have been included even without the change provision because we had a rate case that concluded in May 2015. Consider, however, what would have happened had

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we filed that rate case just six months later than we did, delaying the effective date of the tariffs from that case by six months. Had there not been a change provision, customers would have lost almost $25 million of higher net capacity revenues – all because MISO changed the label on preexisting costs and revenues.

Q. Do you have any final observations regarding Ms. Mantle's recommendation regarding such a change provision?

A. Yes. In its Report and Order in File No. EO-2010-0255 (p. 21), the Commission stated that "calling a dog a duck does not make it quack." Similarly, MISO changing a label or re-slicing components of purchased power, off-system sales, or transmission into different charge types does not mean the cost or revenue represented by the new charge type loses its essential character. The capacity example is an apt one. These were capacity costs and revenues before MISO set up charge types labeled "Real-Time Resource Adequacy Auction Amount" and they remained capacity costs and revenues afterward.

VI. BILATERAL CONTRACTS/FINANCIAL SWAPS

Q. What issue do you wish to address regarding the bilateral contracts/financial swaps margins included in the calculation of a base level of off-system sales in this case?

A. I do not entirely agree with Staff witness Erin Maloney's methodology for calculating this margin. Her calculation is shown in her work paper provided with the Staff Cost of Service Report (MaloneyWorkpaperHC_corrected.xlsx). Note that for the purposes of this testimony, it should be understood that the term "bilateral" refers to

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"physical bilateral transactions," since the "financial swaps" actually include "financial bilateral transactions."

Q. What is your specific disagreement with Ms. Maloney's methodology?

A. I disagree with Ms. Maloney's use of the annual, around-the-clock average of the weighted average hourly energy prices used in the production cost modeling instead of the *actual* costs of these bilateral transactions.

Q. Please explain why you disagree.

A. Bilateral transactions and financial swaps are hedging mechanisms to mitigate some of the volatility from OSSR, but they do not replace the off-system energy sales themselves. Since bilaterals are physical transactions, the energy and the associated fuel has already been accounted for in the production cost model, whether PROSYM or PLEXOS (the model used by Staff). However, these models price the energy at the day-ahead spot market price. A bilateral transaction replaces that price with a fixed price – thus the purpose of the adjustment for these margins is to capture the difference between the spot price and the fixed price.

A review of Ms. Maloney's work paper indicates that she first calculated the net revenue by month for bilateral transactions, subtracting the cost of bilateral purchases from the bilateral sales revenue. She then calculated a cost of these transactions by multiplying the difference between the volumes of bilateral purchases and sales by the normalized, around-the-clock average market price for energy derived from the hourly prices used in the production cost model ("normalized price").

This method of calculation is incorrect. Bilateral transaction margins should be calculated by taking the difference between the actual price received and the price that would have been received had the transaction settled at the spot market for the CPNode specified by the transaction and multiplying that difference by the volume. (For a bilateral purchase, the calculation is reversed – it is a comparison of the fixed price paid to the spot price which would have been paid). While Ms. Maloney's methodology uses the actual price of the bilateral transaction, she has replaced the actual price at which that transaction settled with the normalized price. Using this price creates two issues.

The first issue is that using a normalized price instead of the actual spot market price breaks the relationship between the actual price of the transaction and the actual spot price that would have been received. The two are inextricably linked. The price of a bilateral transaction is based in large part on the counterparty's expectation of what the spot market price will be during the period of delivery. The normalized price is developed using 33 months of data, which is then averaged into on-peak and off-peak prices by month, which are subsequently shaped into hourly prices. There is no correlation between the actual price of our bilaterals and the normalized price for any given hour used in the production cost model.

The second issue is that Ameren Missouri's actual bilateral sales varied in both price and volume throughout the normalization period. They were not at the same volume in every hour of the period. Maloney's use of an annual price does not recognize that fact. Thus, even if it were proper to use normalized prices instead of actual hourly prices, it would be necessary to apply the normalized price for a given hour to the volume of bilateral sales for the same hour, instead of the normalized annual average price. Doing so would require normalizing bilateral sales volumes by hour for each hour of either the true-up period or the test year.

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Q. Did you have any additional observations regarding the calculation of bilateral margins?

A. Yes. The first is that Ms. Maloney's calculation used 36 months of data, adjusted for the Polar Vortex. The calculation of bilateral margins included in my direct testimony only covered the 12-month period ending March 31, 2016. Ms. Maloney's use of 36-month of data is consistent with the normalization period used in File No. ER-2014-0258. My calculation of the bilateral margin for the true up period will be corrected to utilize the 36-month period ending December 31, 2016, adjusted for the Polar Vortex. (I would note that this same issue exists for the calculation of financial swap margins, and accordingly, we will adjust that calculation as well).

Additionally, the margin for the transactions with the Missouri municipalities was erroneously included in the bilateral margins in my direct testimony. While these are indeed bilateral transactions, these transactions were specifically included in the production cost model. As such, any margin associated with these contracts has already been accounted for in the production cost model results. Including them in the bilateral margin calculation would be a double-count of the associated margins. These transactions will be excluded from the true-up calculation of bilateral margin. They will be included in the true-up production cost model run.

Q. Do you have a recommendation regarding the calculation of the bilateral margin adjustment to off-system sales revenue to be included in the calculation of off-system sales revenue?

A. Yes. I recommend that this adjustment be calculated using actual bilateral sale and purchase transaction prices and volumes and the corresponding actual spot market prices. I recommend that the calculation utilize 36 months of actual data ending December 31, 2016, adjusted for the Polar Vortex period of January 2014-March 2014.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.))) File No. ER-2016-

AFFIDAVIT OF ANDREW MEYER

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Andrew Meyer, being first duly sworn on his oath, states:

1. My name is Andrew Meyer. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Director, Energy Management & Trading.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 56 pages, and Schedules AM-R1, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Andrew Meyer
Andrew Meyer

Subscribed and sworn to before me this 17th day of January, 2017.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2018
Commission [illegible]

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The following is a very simple co-optimization example based on the following assumptions:

- Utility A owns Resource A and Utility B owns Resource B. Both resources are 100 MW generating units capable providing both energy and spinning reserve.
- Utility A's load is 90 MWhs and it has a spinning reserve requirement of 15 MW. The cost of Resource A is $15.
- Utility B's load is 80 MWhs and it has a spinning reserve requirement of 10 MW. The cost of Resource B is $20.
- Any purchase or sale of energy will be at the cost of the seller.
- The price of any spinning reserve purchased or sold is $1/MW

<u>Prior to the establishment of a RTO administered ancillary services market</u>, in a given hour Utility A would dispatch Resource A at a level of 85 MW so that it could meet its 15 MW spinning reserve requirement. This would require it to purchase 5 MWhs of energy from Utility B to meet its load in that hour. Utility B would also dispatch Resource B at 85 MW which is equal to Utility B's load plus the 5 MWhs sold to Utility A leaving 10MW to meet its 10 MW spinning reserve requirement. The table below summarizes the hour just described:

Gen MWh	*Fuel Cost*	*Pur/(Sale) $ Energy*	*Pur/(Sale) $ Spin*	*Net*
A 85	$1,275	$100		$1,375
B 85	$1,700	($100)		$1,600
170	$2,975	$ -	$ -	$2,975

As shown in the table above, Utility A would have a fuel cost of $1,275 and a purchased power cost of $100 for a net fuel and purchased power cost of $1,375. Utility B would have fuel costs of $1,700 and off-system sales revenues of $100 for a net fuel and purchased power cost of

$1,600. The net system cost combining Utility A and B's operations in that hour would be $2,975.

<u>With the establishment of a RTO administered ancillary services market</u>, it would be expected that the total spinning reserve requirement would drop. As an example, using the same Utility A and B described above, assume that the total spinning reserve requirement becomes 20 MW instead of the combined 25 MW under the prior system, with Utility A's requirement being 12 MW and Utility B's requirement being 8 MW.

Utility A's generation would now be dispatched by the market at its full 100 MW as it is the cheapest resource to provide energy. Utility A would purchase all 12 MW of its spinning reserve requirement and have a 10 MWh net sale of energy.

Utility B's generation would be dispatched at 70 MWs. The full 20 MWs of spinning reserve would be provided by Utility B's unit. Utility B would have a net purchase of 10 MWh and it would have a net sale of spinning reserve of 12 MWs. The table below summarizes the hour just described:

	Gen MWh	*Fuel Cost*	*Pur/(Sale) $ Energy*	*Pur/(Sale) $ Spin*	*Net*
A	100	$1,500	($200)	$12	$1,312
B	70	$1,400	$200	($12)	$1,588
	170	$2,900	$ -	$ -	$2,900

As illustrated in the table above, Utility A would now have higher fuel costs and would also now have purchased power costs for acquiring spinning reserve, but those increases are more than offset by the revenues received from selling energy that was previously held back to self-provide spinning reserve. Utility A's net cost dropped from $1,375 to $1,312. Utility B's fuel costs have also fallen significantly and it now receives ancillary services revenues above its ancillary services purchases. This net reduction in cost is partially offset by the cost of the energy that it now purchases. In total, however, its net cost has also been reduced to $1,588 from $1,600. Thus, the co-optimized RTO markets resulted in an overall cost reduction for Utility A and B in this one hour of $75. Simply stated, the co-optimization allowed Utility A's cheaper unit to be dispatched to its full potential instead of having to be held back to provide spinning reserves while Utility B's unit, more efficiently provide the spinning reserves (by producing less energy since it is a higher cost unit).