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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0285

REBUTTAL TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
December 2016

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REBUTTAL TESTIMONY

OF

ANDREW MEYER

I. PURPOSE AND SUMMARY

Q. Please state your name and business address.

A. My name is Andrew Meyer and my business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom are you employed and what is your position?

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") as Director, Energy Management & Trading.

Q. Please describe your educational background and employment experience.

A. In May of 1997, I received a Bachelor of Science degree in Business Administration (Emphasis in Management) and Agricultural Economics from the University of Missouri – Columbia. I began my career with Continental Grain Company, working as a Commodity Merchandiser from 1997 to 1999. In this role, I purchased grain from producers and grain cooperatives, blended for quality, and arranged barge transportation for re-sale of the grain in the Southeast grain export market. My employment with Ameren Energy, Inc., which at the time was an Ameren Corporation subsidiary, began in April of 1999. Later, Ameren Energy, Inc.'s functions were assumed by Ameren Missouri. From 1999 to 2008, I performed several roles in the trading function at Ameren Energy, Inc., and later at Ameren Missouri, including long-term energy and capacity position management, congestion hedging, analysis, real-time trading, and scheduling. In 2009, I joined Ameren Services Company as a Senior Market & Policy Consultant in the Corporate Planning department. My primary responsibility in this role was to participate in the Midcontinent Independent System Operator, Inc. ("MISO") stakeholder forums on behalf of Ameren Missouri. In October of 2009, I returned to Ameren Missouri as Managing Supervisor, Trading. My responsibilities included long and short-term energy sales management, capacity marketing, congestion hedging, full and partial requirements contract management, and real-time energy trading. In 2014, I also assumed management of gas supply for generation, and my title was changed to Sr. Manager, Trading. On May 1, 2015, I was promoted to Director, Energy Management & Trading.

Q. What is your experience regarding transactions involving purchased power and associated transportation?

A. I have approximately 17 years of experience working in the electric utility industry, including working on a day-to-day basis transacting in the markets where electricity purchases and sales are made. More specifically, I have substantial experience in these markets as they existed prior to the approval of the markets now operated by MISO, which were first approved by Federal Energy Regulatory Commission ("FERC") in 2004[1], and I have substantial experience operating in those MISO markets since they formally began operation on April 1, 2005.

Q. What is the purpose of your 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 KCP&L'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

[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61, 163 (Aug. 6, 2004) *order on reh'g*, 109 FERC ¶ 61, 157 (2004), *order on reh'g*, 111 FERC ¶ 61, 043 (2005), *reh'g denied*, 112 FERC ¶ 61,086 (2005), *aff'd sub nom. Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007). The appeal that resulted in the *Wis. Pub. Power* decision did not involve any issues about the basic operation of the energy markets at issue here.

"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.

Q. Why are you offering testimony on these matters in this case, since Ameren Missouri is a MISO member while KCP&L is a member of the Southwest Power Pool ("SPP")?

A. Decisions made in this case to exclude or include specific SPP charge types can reasonably be assumed to influence the Commission's consideration of what components of purchased power and transportation should be included in Ameren Missouri's own FAC tariff filed in its pending rate case. This is particularly true since OPC's arguments appear to be "philosophical" as opposed to being focused on KCP&L-specific facts. This is further evidenced by the fact that OPC is taking similar positions in Ameren Missouri's pending rate case. As such, the claims OPC is making about what constitutes purchased power and transportation and how purchased power and transportation costs should be treated in FAC's approved in Missouri are of significant interest to Ameren Missouri. It is Ameren Missouri's belief that the Commission will benefit from Ameren Missouri's perspectives on these issues in this case.

Additionally, while it is true that we operate in a different RTO than KCP&L, at their core, the two markets are very similar. Regardless of what entity is administering the market, or even if such a market exists, what constitutes purchased power and transportation remains the same, even if the nomenclature used to describe a specific component or collection of components is different.

Q. Please summarize your main conclusions.

A. Purchased power and associated transmission costs consist of many components that OPC is attempting to improperly exclude from the FAC, as confirmed by the understanding of those terms in the industry and by regulators, including the 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 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.[2] 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 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 from purchased power components that they offset, components of purchased power that offset other components of purchased power should similarly not be separated.

[2] All components of OSSR that make up total OSSR revenues have been included Ameren Missouri's FAC from its inception in 2009 and, as I understand it, with the exception of full and partial requirement sales to municipalities in excess of one year and revenues from capacity transactions in excess of one year, in KCP&L's current FAC, which was first approved in 2014 after KCP&L became eligible to have an FAC under the terms of its 2005 Comprehensive Energy Plan stipulation.

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.[3] 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 its own (or Ms. Mantle's) opinion, is that the Commission should redefine what "purchased power" and "transmission" costs are. More specifically, OPC argues that only the charges paid by KCP&L for a very few, specific, energy and capacity components of purchased power should be included in the costs of purchased power included in the FAC, and 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. 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 outright mischaracterizes.

[3] 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.

A. Purchased Power Costs

Q. You seem to suggest that what constitutes purchased power and transportation before and after the establishment of the RTO markets remains the same. Please explain.

A. Prior to the establishment of the RTO markets, 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 Ameren Missouri was selling to KCP&L, we had to make sure that the price we charged covered our incremental costs - not only production cost, but also transmission service, ancillary services, losses, risk premiums related to delivery risk (should your transmission service be curtailed) or loss of resources, etc. The same was true for independent power producers, and non-asset owning power marketers selling to KCP&L. Sellers priced their products to cover their costs plus an expectation of profit. From KCP&L's perspective however, all they saw was the total cost of the purchased power: X MWh's at $Y/MWh. They did not see a list of all of the components that made up that purchased power, with individual line items charges. These bundled bilateral transactions continue to exist as an alternative to purchasing power from the RTO markets.

RTO energy and ancillary service markets 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 thereby 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 were now disaggregated. Buyers acquiring purchased power in the RTO 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 RTO 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 purchased power costs.

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 or transportation, but they don't lose their character as part of the overall cost of those items just because they are broken out in a utility's chosen managerial accounting codes.

Q. Does the 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 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 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 (which since the advent of RTOs 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 also 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. The 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. It defies logic to believe that FERC would accept the recording of costs to Account 555 if those costs were not properly a component of purchased power costs.

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

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, Inadvertent Energy, Energy Losses, Revenue Neutrality Uplift, Revenue Sufficiency Guarantees, Financial Transmission Rights, Ancillary Regulation, Ancillary Spinning and Ancillary Supplemental. I am unaware of any challenge by the 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 work papers 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

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

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 Revenue Sufficiency Guarantee ("RSG"), Revenue Neutrality Uplift ("RNU"), congestion, losses, Auction Revenue Rights ("ARR"), Financial Transmission Rights ("FTR"), inadvertent, and a variety of ancillary service charges.

It simply defies reason to suggest that Staff would have treated all these charges as components of total purchased power (or transmission, as the case may be) costs, and used 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. 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 itself.

Q. Did that tariff include more than just two components of purchased power?

A. Yes.

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

A. No. I am not aware that Staff has ever made such a claim, 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 is not limited to only two components - capacity and energy?

A. Yes. the first, and most obvious, is that the Commission itself has acknowledged the existence of a multitude of components comprising purchased power costs when it has approved Ameren Missouri's FAC tariffs in the Ameren Missouri's five prior general rate proceedings, issued approval orders in all five of the Ameren Missouri's FAC prudence review proceedings, and approved all 22 of the Ameren Missouri's FAC rate adjustment filings, all of which pertain to FACs that include as purchased power costs the very components that OPC now seeks to exclude. In addition, Ameren Missouri has filed a FAC monthly report in every month for the past nearly seven years containing significant detail on all 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. 6, ll. 23-25. 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 by OPC's own admission through picking and choosing two components it favors, 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 which should be included in the FAC are those categorized as point-to-point ("PTP") or network integration transmission service ("NITS")?

A. Ms. Mantle appears to rest her proposal upon her claim that these are the only components of transmission that can be "directly linked" to KCP&L's ability to purchase power for its native load or make off-system sales**.** Mantle Direct, p. 10, l. 11.

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

A. No. KCP&L's (and in fact any SPP market participant's) ability to make purchases and/or sales in the SPP market is predicated on the market participant meeting its obligations under the entirety of the applicable SPP tariffs – not just those associated with a specific transmission wire. The participant 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 which Ms. Mantle seeks to exclude from the FAC are all transmission services required to engage in those transactions.

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

A. Directly linking 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, it is my understanding that SPP's Base Plan Upgrade charges essentially arise from transmission being built in SPP that is quite similar to the Multi-Value Projects ("MVP") being built in MISO (transmission charges for MVP projects in MISO are levied under MISO's Schedule 26A). While I am not as familiar with the Base Plan Upgrade charges as I am with MISO's Schedule 26A charges, my understanding is that the transmission charges from SPP arising from the Base Plan Upgrades are based upon the megawatt-hours ("MWh") of energy bought by the utility (KCP&L here) from SPP's market, just as is true with respect to the MISO Schedule 26A transmission charges. I simply don't see how one could validly argue that those charges aren't "directly linked" 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 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 acknowledges that Schedule 26A charges *are* directly linked 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 linked to purchases of energy KCP&L 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. It is obvious that OPC is attempting an end-run around an argument that Ms. Mantle 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 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*

[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 really are.

established charge that covers all the costs associated with the transmission services it is using."

OPC is making the same argument again, albeit using different language. Basically, having failed at her anti-CWIP argument/"cost-of-transmission-lines" argument, Ms. Mantle has now come up with a new "directly linked" 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 already-rejected argument is made obvious by Ms. Mantle's testimony in this case, where she claims that the SPP charges arising from the Base Plan Upgrades are levied "so SPP can recover the cost of these large transmission projects as they are being built. Once the line is built, then the users of that line are charged to recover the cost of building the transmission providing revenues to the members that paid for the line to be built." Mantle Direct, p. 10, ll. 1-5.

As the Commission clearly understands, from KCP&L's perspective, it is paying a FERC-approved transmission charge levied based on the volume of purchases it makes from the SPP market, nothing more and nothing less.

Q. Does that mean that all the 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.[6] While it is my understanding that KCP&L is asking it to change its mind in this case (and while Ameren Missouri believes the Commission reached the wrong conclusion on that issue in its last rate case, making KCP&L's request that the Commission reconsider its conclusion is reasonable), Ameren Missouri chose not to re-argue the issue when it filed its pending rate case. Instead, Ameren Missouri opted to take other steps to address transmission charges, such as reflecting as

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

current a level of Schedule 26A charges in its revenue requirement 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.[7] Including all 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 KCP&L's case, is that OPC is simply wrong in claiming that Base Plan Upgrade charges are not transmission charges at all, and should not be included in KCP&L's FAC at all, aside from the true purchased power issue.

Q. When addressing the components of purchased power costs, you made note of several items of evidence that demonstrated that purchased power costs 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 transmission charge 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. Please summarize your recommendation regarding the inclusion of transmission costs in the FAC.

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[7] 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.

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 KCP&L's 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. <u>OPC'S POSITION IMPROPERLY SEPARATES COST AND REVENUE COMPONENTS THAT ARE INEXTRICABLY LINKED</u>

A. <u>OPC's Position Regarding the Inclusion of OSSR in the FAC.</u>

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

OPC's position is arguably unclear. This is because at one place in Ms. Mantle's direct testimony (page 4) 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 recommends that all fuel, purchased power and transmission costs (as she attempts to define them) incurred to make those sales should be included 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 OPC's rationale for why OSSR should remain in the FAC. Specifically, Ms. Mantle states that OSSR should be included in the FAC because it "is very difficult to accurately determine the fuel costs incurred to make off-system sales." Mantle Direct, p. 11, l. 17-19. She elaborates on this view by stating "[i]f off-system sales are not included in the FAC, KCP&L would have to make a determination of the cost of fuel and purchased power used to make off-system sales and remove those costs from the FAC. Not 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." Mantle Direct,p. 11, l. 19 to p. 12, l. 4.

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 and revenue components which they offset and the benefits that provides. I also agree with Ms. Mantle that one cannot objectively determine the split between fuel [and transmission] costs for load and for off-system sales. Such a determination necessarily varies due to subjective judgments utilities must make develop estimates of those splits.

Q. How does Ms. Mantle's recognition of this difficulty 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 purchased power costs in the FAC, or if certain components of purchased power costs that offset other components of purchased power costs are excluded, yet OPC 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 cost 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 movements in the other components (the hedge for customers I mentioned earlier) 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 Auction Revenue Rights ("ARRs") and Financial Transmission Rights ("FTRs") (and their SPP equivalents), offset other components of purchased power recorded in Account 555, that is, the cost of congestion which is embedded in the locational marginal price[8] of the day-ahead energy acquired to serve the utility's load. Another example are ancillary services revenues recorded in FERC Account 447, which offset the cost of acquiring the ancillary services component of purchased power recorded

[8] The locational marginal price ("LMP") that is paid for a MWh of energy bought or sold in MISO's (or SPP's) market itself consists of three components: energy, congestion and losses. Neither MISO nor SPP 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.

in Account 555. There are other examples, including RTO 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.

C. Forward Energy and Capacity Transactions in Account 555

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

A. Not by name. However, by recommending that the only purchased power costs included in KCPL's FAC are the cost of energy from long-term bilateral contracts or spot energy from SPP'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 is completely 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 for a future period.

Secondly, it simply does not make any sense that Ms. Mantle would only support allowing KCP&L (or presumably any other Missouri utility) to only enter into transactions to mitigate their price risk if that transaction is at least one year in length, whether it was a swap or a bilateral. (While Ms. Mantle has not defined the length of time that she believes constitutes long-term (and has in fact in the past offered the opinion that it is somewhere between three and five years[9]), 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 one year.

Q. Please explain how a physical bilateral 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, 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 the RTO to serve its load, but the energy acquired through the bilateral contract will also be settled (sold) into the RTO market. This means that the utility pays the bilateral counterparty a fixed price for the energy and sells it into the RTO market and receives a variable spot market price. The utility then purchases energy from the RTO 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.

[9] Mantle Deposition, File No. EO-2010-0255.

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 energy from the RTO 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 it 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 will 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 the same 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. Quite frankly, this is in some ways the same scenario that Ms. Mantle describes in her testimony regarding KCP&L making the choice between treating coal with activated carbon versus trona. Mantle Direct, pp. 16-17. In each case, 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. Since 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, then it necessarily follows that she would also have to believe that excluding financial swaps or short-term bilateral contracts but 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.

The two examples are not identical in nature though. In her 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, but it does so to mitigate price risk on behalf of its customers.

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 KCP&L (or presumably any other Missouri utility) to only enter into long term transactions to mitigate price risk on behalf of customers?

A. It does not make sense because it is unreasonable to believe that KCP&L or any utility only has long-term price exposure. SPP (and MISO) both operate energy and ancillary services markets. Those markets are co-optimized – i.e., by their very nature they are designed to work together. These markets, however, are not forward in nature; the longest period ahead of delivery for which they transact is the next day. 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 RTO's 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, it cannot be said that that condition will always exist. This is especially true when one recognizes that the determination of a short or long position is made by calculating the amount of resources which are not only available but that 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.

The condition which OPC's recommendation would create is that whenever a utility would project itself to be in a short position, it could not hedge that exposure unless it was at least one year in length. Indeed, it would be illogical – and likely found to be 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 whatever price existed at the time.

Q. Isn't your concern simply hypothetical, given that KCP&L and Ameren Missouri for that matter are generally long generation?

A. No. Far from being hypothetical, the concern is quite real. For example, Ameren Missouri's Callaway unit 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 which historically have low market prices. Ameren Missouri projects its forward energy position using forward market prices. If these market prices fall below Ameren Missouri's projected cost of generation, it's 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 it does not own sufficient generation resources to match its load obligation, it simply means that these units are projected to operate at lower levels, thus resulting in an increase in net purchased power on its books. Ameren Missouri obviously does not know what the actual prices will be during the outage, but the opportunity to lock in a price for purchased power now that is lower than its cost of generation to hedge that cost exposure exists. 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 – 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. This is only one example. KCP&L would have the same issue with its Wolf Creek nuclear plant.

Other examples exist for time periods as short as a few hours, when a utility finds itself short inside the market day for a few hours across the peak due to a 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 many, many more examples which can be developed of a utility being short for periods of less than one year, than periods of one year or more.

Q. Would a utility which 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 it is short would not be the same in every month, let alone every week, or every hour. When the only tool available to it to mitigate its spot market price exposure is long-term bilateral contracts it 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 buys something greater that 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 wearing all the utility's load variability risk; a premium that may well likely be greater than the cost of the utility managing its own risk.

Q. Why would it be problematic that OPC's recommendation does not include potential costs for acquiring capacity from a centralized market should one develop in SPP in the FAC?

A. It is problematic because it would once again remove a tool from KCP&L's tool box. OPC has recommended that the Commission allow "capacity charges from bilateral contracts that change annually or more frequently" to remain in the FAC, but has made no provision for what would happen if SPP were to establish a centralized capacity market. If this were to happen, and the SPP capacity market was to operate in a fashion similar to MISO's capacity market, KCP&L could be exposed to considerable levels of capacity expense but could not include that expense in its FAC until a later rate case is concluded, even though the nature of the expense would be essentially the same as the nature of the capacity expense it was already including it its FAC. While I obviously cannot see into the future to know at what capacity price such a new capacity market may clear, or how much capacity KCP&L may be required to purchase in such a new SPP capacity market, I can tell you that for the MISO 2016-2017 planning year, Ameren Missouri's capacity purchases from MISO's capacity market totaled almost $200 million, with a price of capacity of only $72/mw-day. Through the operation of MISO's capacity market, that $200 million was offset by over $240 million in capacity revenues, which were reflected in Ameren Missouri's FAC and thus *lowered* the actual net energy costs charged to its customers. If SPP were to establish a capacity market which did not allow a market participant to exclude their load from the market, KCP&L would be faced with having to flow through all the capacity *revenue* that it received from the market and eating all the capacity *charges* it incurred. This is unfair, makes no sense and is completely unnecessary.

This is even more problematic since OPC has not recommended excluding anything from the definition of OSSR, including new charge types for revenues[10] which may be developed between rate cases. This would leave KCP&L in the position of having to pass all the new revenues arising under a new charge type for revenues created by the RTO through the FAC, but eat all the costs that at least a portion of those revenues offset.

Q. Isn't the solution for OPC to modify its proposal to exclude new charge types for revenues just as OPC argues that new charge types for costs should be excluded?

A. If OPC were to modify its proposal to also exclude all new revenue charge types in between cases, customers could be significantly harmed. Consider again the situation where SPP develops a new capacity market. In that case, KCP&L would be prohibited by its FAC tariff from including in its FAC both the capacity cost components of purchased power and the capacity revenue components of off-system sales. Using Ms. Mantle's activated carbon versus trona example again, this would create a situation (if her theory about disincentives were valid) where the utility would have a disincentive to engage in bilateral capacity sales even if it would have otherwise done so, since if it sold all its capacity in the SPP capacity market it could keep all of the RTO capacity revenues in excess of the capacity costs it would incur because those capacity revenues would have arisen under a new charge type for revenues that could not be included in the FAC.

Q. Isn't this all conjecture since SPP does not have a central capacity market?

A. Not entirely. While it is true that the SPP does not yet have a capacity market, this example illustrates the difficulties created by OPC's proposal whenever a new charge type for costs or revenues is created. Under OPC's proposal, KCP&L would not be permitted to

[10] Both MISO and SPP break down components of purchased power costs, fuel costs, transmission costs and OSSR into "charge types." However, the phrase "charge type" is a misnomer since many of these "charge types" reflect revenues paid by the RTO to the utility instead of charges.

incorporate any new charge types – regardless of what they represented, or what their magnitude was and even when they were in the nature of charges already included in the FAC (e.g., capacity) - into their FACs without filing a general rate case. Ms. Barnes' rebuttal testimony discusses in greater detail why there is simply no reasonable cause for the Commission to eliminate the current provision in KCP&L's (and Ameren Missouri's) FAC tariff that permits utilities or other parties from making sure new charge types (including revenues) that arise from the operation of a centralized RTO market can be included in the FAC between rate cases when those charge types reflect costs/revenues of the same character and nature of an existing cost or revenue component of purchased power, transmission or off-system sales.

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

Q. Why would it be improper to exclude ARRs and FTRs (and their SPP equivalents) from the FAC?

A. As noted earlier, ARRs and FTRs are components of purchased power (actually, they are revenue streams that are recorded in Account 555, which some view as a "negative cost") which serve to offset the cost of congestion which is embedded in the LMP for energy purchased to serve load. Again, the Commission should reject the separation of costs and revenue components from other components which 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 attempt to provide a bit of history on the development of the LMP that KCP&L (and Ameren Missouri) pays to purchase energy from SPP (or MISO) and that it receives for the energy that it sells into that same market. Recall that I earlier noted that the 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 RTO's market.[11] The other two components are unique to each node 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", if that did not resolve the situation, firm schedules would also be cut. Since these corrective actions were not directed at specific generators or loads which 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 and magnitude of these TLRs was seen to be 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 SPP (and elsewhere). In an LMP-based market, it is no longer necessary for the system operators to order

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

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, which means there is far less disruption of the system and much greater efficiency.

Q. How does LMP address congestion and thus reduce the disruption and increase 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 node 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 they continue 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 their 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 which 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, if they are willing to pay the net LMP (LMP paid at the load point minus the LMP paid at the resource point), they can continue to use their own resource to offset the cost of service their load through self-scheduling.

However, the market participants will likely find it to be in their financial best interest to back down their generation in response to a price signal, which will help to relieve the congestion and lower the LMP at the point they are acquiring energy to serve their load, thus lowering their overall cost of purchasing power for their load.

Q. How does this LMP-based system relate to ARRs and FTRs (and the SPP equivalent)?

A. Load serving entities ("LSE"), including vertically integrated utilities (those who both own generation resources and those with a load obligation) like KCP&L (and Ameren Missouri) were rightfully concerned that the advent of LMP-based markets might increase their own cost to serve their load obligations as 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 concerns of their regulators, including this Commission), 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 which existed between the resources which 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 that portion of their generation which hedged the cost of their load obligation) 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 simply take the lump sum payment, or they can 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 will 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. So, 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 which is purchased from the RTO to serve one'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 which establishes the cost of purchased power.

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

A. Yes. While I cannot speak to the amounts recorded by KCP&L, Ameren Missouri's actual totals for these amounts in recent years are contained 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 were adopted and ARRs and FTRs were excluded from the FAC?

A. The first and most obvious is that if history repeats 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) if OPC's approach in this case were applied to Ameren Missouri.

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

The utility would also find itself in the situation where 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 and 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 that the cost of congestion fell, the utility would be required to not only absorb the drop in the value of the ARRs and FTRs (again, because they would not be in the FAC), but would be required to pass through to customers the value of the reduction in congestion which led to the loss in ARR/FTR value in the first place because the congestion is reflected in the FAC.

It seems abundantly obvious to me that 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 the issue of 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 requires exactly the same process that Ms. Mantle states would require KCP&L “to make a determination of the cost of fuel and purchased power used to make off-system sales and remove those costs from the FAC” 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.” 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 power which they offset (as we must), and if the 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, which 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."

D. <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 which are a component of off-system sales?

A. As with energy, utilities in RTOs with an ancillary services market such as SPP and MISO, purchase their entire ancillary service requirement for load from the RTO market and they 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 cost 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, but OPC has not recommended 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 which 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 that the FAC statute was drafted, vertically integrated utilities such as Ameren Missouri and KCP&L provided their own ancillary services. They allocated the required level of ancillary services across their generating units. To be able to provide spinning reserve and regulating reserve, generating units which otherwise may have been dispatched at higher generation levels to provide energy were held back enough to allow the unit to respond. The decision of 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 because 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). Rather, today utilities purchase all their ancillary services requirements from the market and then sell all of the ancillary services provided by their generators into the market – just as they do for energy.

Q. Why is it more efficient for the utility 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, in total, lower overall costs 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.

Those resources which 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.

Q. Can you give an example to illustrate co-optimization?

A. Yes. Following is a very simple 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*
85	$1,275	$100		$1,375
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).

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 which 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, but at a significant cost of adding extreme levels of complexity to the administration of the FAC tariff, or if all ancillary service revenues were excluded from the FAC (and not just those which offset ancillary service cost), 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 which 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, in others it sells more than 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 KCP&L "to make a determination of the cost of fuel and purchased power used to make off-system sales and remove those costs from the FAC" 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.

E. <u>Revenue Sufficiency Guaranty ("RSG") and Revenue Neutrality Uplift ("RNU") Charges</u>

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

A. RTO make whole payments to generators (recorded as revenues in Account 447) are inextricably tied to the cost of energy. RTOs are by nature revenue neutral. The amount that they pay out to generators must be collected from those purchasing energy from the RTO 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 and 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 LSE's 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, and they are thus components of the total cost of purchased power. Notably, OPC has not recommended the exclusion of any revenue component for make whole payments but 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 the RTO to the generator caused by the RTO'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 they would have been if they had not allowed the RTO to dispatch their units in this manner.

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

A. The cost of purchasing power from the RTO market is lower, and the overall reliability of the RTO dispatch is retained. Generators are required to follow the RTO instructions to dispatch them in this manner. Without these market features the RTO 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, at least in MISO. 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 5 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 that the Commission treat RTO make whole payments cost components of purchased power in the FAC?

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

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 Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.	))))	File No. ER-2016-0285

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 45 pages, and ~~Schedule(s)~~xxxxxxxxxxxxxxxxxxxxxxxx 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 30th day of December, 2016.

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