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Witness: Jaime Haro
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0166

REBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
August, 2012

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REBUTTAL TESTIMONY

OF

JAIME HARO

CASE NO. ER-2012-0166

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jaime Haro. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom are you employed and in what capacity?

A. I am Director, Asset Management and Trading for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Are you the same Jaime Haro who filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to address Staff witness Lena Mantle's contention that the existing 95%/5% sharing mechanism in the Company's fuel adjustment clause ("FAC") does not provide sufficient incentive for the Company to prudently make off-system sales because of the difficulty in setting the base off-system sales level for purposes of the FAC. I will also address Ms. Mantle's recommendation that certain language be added to the FAC tariff regarding transmission costs. Finally, I address a proposed treatment of margins from bilateral and swap transactions proposed by Missouri Industrial Energy Consumers ("MIEC") witness James Dauphinais and a similar proposal by Staff witness Erin Maloney.

II. FAC SHARING PERCENTAGE

Q. As noted, Ms. Mantle is recommending that the sharing percentage under the Company's FAC be increased to 85%/15%, from the 95%/5% level which has been in effect for all Missouri electric utilities utilizing an FAC since the FAC was established. She states that such an increase will provide Ameren Missouri with added incentives to more accurately rebase net base fuel costs ("NBFC")[1](the net fuel costs included in base rates in each rate case) and to seek out additional opportunities to make off-system sales. Is Ms. Mantle's proposal justified?

A. No, it is not. First and foremost, Ms. Mantle's proposal assumes that it is possible to accurately predict the power price used in the production cost modeling by the Company, by the Staff, and in recent cases by MIEC to set the off-system sales component of NBFC. In fact, this is a false assumption, as I will demonstrate.

Secondly, this proposal assumes that the Company has not been prudently pursuing available opportunities for off-system sales. That is simply not the case, as I will also demonstrate.

I would note that Ms. Mantle provides no evidence that supports either of her contentions; rather, she posits only unsupported theories of her own making.

Q. Please explain why one cannot assume that Ameren Missouri or any other party can accurately predict the power price used in the production cost model that establishes off-system sales revenue ("OSSR").

A. This assumption is a false one because power prices are volatile and

[1] I will use the term "NBFC" in my testimony, but would note that the Staff has recommended that this term be changed to "NBEC" ("net base energy costs"). The Company has no objection to this change in terminology.

essentially impossible to predict going forward on a reliable and consistent basis. This is true whether we use historical average power prices, or rely on the collective wisdom of the market as represented by the forward market price curves. Simply put, none of these methods is very accurate in consistently and reliably predicting what the price of power is going to be for the next twelve months, let alone for periods beyond the next 12 months.

Ms. Mantle's theory is that a change in the sharing percentage will create a greater incentive to better predict what power prices will be when rates are in effect – i.e., in the future. But since power prices are beyond our control, and since there is no way to predict what they are going to be, no amount of incentive is going to lead us to reach a more "accurate" result.

Q. Have you performed any analysis which supports your claim that future power prices cannot be accurately predicted?

A. Yes. We calculated the 1-year, 2-year and 3-year historical average day-ahead power prices for the periods ending December 31, 2008, 2009, 2010, and 2011, as well as the first seven months of 2012. We also calculated the actual average day-ahead price for calendar years 2009, 2010 and 2011. We then obtained a representation of the forward market price for the applicable annual around-the-clock[2] contract as of the end of each indicated period. Since there is not an available trading hub specific to our system (which could provide a forward price), for purposes of illustration we used a combination of the Cinergy and Indiana Hubs. The Indiana Hub has replaced the Cinergy Hub as the predominant trading hub in the footprint of Midwest Independent Transmission System Operator, Inc. ("MISO").

[2] "Around-the-clock" means the average power price for each 24-hour period (day).

Doing so gave us four different values which arguably could have been used to "predict" (or more appropriately provide a representation of) the price for the next year. We then compared these values to the prices that were actually achieved. The results are shown in the table below.

CIN/IND Trading Hub

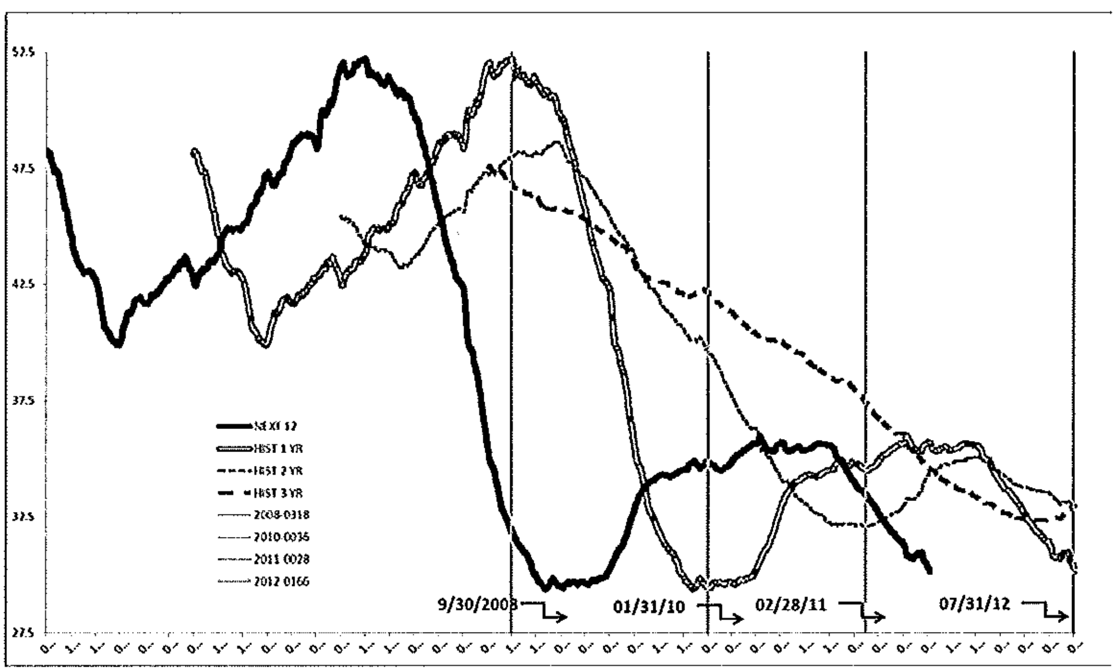
As of	12/31/2008	12/31/2009	12/31/2010	12/31/2011	07/31/2012
	CAL 2009	CAL 2010	CAL 2011	CAL 2012	CAL 2013
FWD	$ 41.27	$ 35.12	$ 32.97	$ 31.04	$ 31.14
1 Yr Avg	$ 50.78	$ 29.46	$ 34.81	$ 34.91	$ 30.40
2 Yr Avg	$ 48.42	$ 40.12	$ 32.14	$ 34.86	$ 33.02
3 Yr Avg	$ 45.75	$ 42.10	$ 38.35	$ 33.06	$ 32.91
ACTUAL	**$ 29.46**	**$ 34.81**	**$ 34.91**	????	????
				$ 29.93	<< YTD July 31
Vs. Actual	2009	2010	2011		
FWD	$ 11.81	$ 0.31	$ (1.95)		
1 Yr Avg	$ 21.32	$ (5.35)	$ (0.10)		
2 Yr Avg 12/31	$ 18.96	$ 5.31	$ (2.78)		
3 Yr Avg 12/31	$ 16.29	$ 7.29	$ 3.44		
%	2009	2010	2011		
FWD	40%	1%	-6%		
1 Yr Avg	72%	-15%	0%		
2 Yr Avg 12/31	64%	15%	-8%		
3 Yr Avg 12/31	55%	21%	10%		

Q. What does this table show us?

A. As I stated above, it shows that none of these methods was very accurate in consistently and reliably predicting what the power prices for the next twelve months will be. Sometimes the forward market price at the end of the previous year would have been more accurate; sometimes a different predictor would have been more accurate. I included the last two columns (Calendar 2012 and 2013) to illustrate that we continue to observe a fairly wide range in the various alternatives.

Q. You chose a single day at the end of each year to include in this table. Couldn't it be that these methodologies would yield a more accurate prediction at some other time of the year?

A. Only by pure chance. The data above is pulled from a larger data set. We also calculated those averages every day over a multi-year period. The graph below shows how the 1-year, 2-year and 3-year averages compared to what the actual average price for the next year ended up being. The heavy black line below is the actual average day-ahead price for the 12 months forward from a given date (it represents what the prices actually ended up being), while the other three lines are the historical averages up to that date (these represent three alternative means of trying to "predict" what the future holds). The light grey vertical lines indicate the end of the true up period for the current and past three proceedings.



Q. What can one conclude from viewing this graph?

A. This graph, like the table above, illustrates that none of these methods are accurate in consistently and reliably predicting what the price of power for the next twelve months is going to be. On any given day, one method may be closer to what happened than another, but none of them consistently predict what the actual price is going to be, and many of the gaps between the predictions and the actual prices are huge, by anyone's standards. The fact that there are points where the actual 12 month average price crosses one of the other lines is more of an illustration that "even a blind squirrel finds a nut on occasion" than it is that one of these methods is an accurate predictor of future power prices. The graph also shows that for this proceeding, these alternatives are still varying considerably.

Q. Are you saying that none of these methods should be used to set the off-system sales component of the NBFC?

A. No, I am not. We absolutely have to set a base level of the NBFC, and rebasing with more current data than we had when the NBFC were last rebased is appropriate, as all parties and the Commission have recognized. But what I am saying is that given the inherent uncertainty in the level of future power prices that supported the establishment of the FAC in the first place, it is simply unreasonable to expect any method to consistently and reliably predict what those future prices will be. Absent the unearthing of the price prediction version of the "Rosetta Stone," which would somehow enable us to reliably and consistently achieve such results, I believe the methodology which has been used over the past several cases by all parties who take an interest in off-system sales (essentially the Company, the Staff and MIEC), is reasonable, and its continued use makes sense. The three-year average, by its very nature, will have less variability than the 1-year or two-year alternatives. I am not aware of any evidence or proposal made by parties to the prior case which would have consistently resulted in a more accurate baseline.

Q. Please elaborate on your last point.

A. I was very surprised by Ms. Mantle's implied suggestion that there may be better methods for predicting future power prices as the Staff itself for three rate cases in a row has consistently submitted testimony either directly recommending, or supporting the recommendations of others, regarding inputs. These recommendations into the model from which off-system sales revenues are determined which, if adopted, would have *increased* the projected level of off-system sales revenues (and thus lowered the NBFC). When one understands that the amount of OSSR included in previous NBFC was too high and this fact was the primary contributor to the significant adjustments to date, it should be obvious that further increasing the level of off-system sales revenues would have increased the variance between the NBFC and the actual net fuel costs even more (and thus increase FAC rate adjustments; i.e., the off-system sales level would have been even *less accurate).* Moreover, in those rate cases we consistently provided testimony and analysis that showed that the Staff's proposals would in fact inject more inaccuracy, and the data shows that we were right about those contentions. To put it bluntly, I am a bit baffled that Ameren Missouri is being criticized by a Staff witness for a result which in reality, despite its magnitude, was still substantially better than the result that would have been achieved if the Staff and the other parties had been successful in increasing the level of OSSR built into NBFC.

Q. Can you demonstrate that the Company has consistently been under-recovering its fuel costs in base rates?

A. Certainly. Since the FAC has gone into effect, a simple comparison of actual net fuel costs (before accounting for amounts ordered to be refunded in Case No. EO-2010-0255) to the NBFC calculated in each of the prior cases, demonstrates that the Company was under-recovered by $292.5 million.

Q. Have you determined the cause of this under-recovery?

A. Yes. When one studies the sources of these under-recoveries at a higher level, the breakdown is as follows:

	(million)
Fuel	$ 16.4
Purch. Power	$ 24.4
OSSR	$ 314.5
MISO costs	$ (34.6)
Other	$ (28.1)
	$ 292.5

Note that with the exception of OSSR, a positive number means that a component turned out to be higher than had been assumed when the NBFC was set. For OSSR, a positive number indicates that revenue turned out to be less than had been assumed.

Q. Do you have an idea of whether the $314 million variance associated with OSSR is related to price differences or changes in volume?

A. Yes. Our analysis clearly demonstrates that price is the overwhelming cause of this difference.

In order to determine this, we first identified what the total volume and average price was that was included in the NBFC calculation for Case Nos. ER-2008-0318 and ER-2010-0036. For the last case (Case No. ER-2011-0028), we did this only for the non-summer periods, as we are currently within the first summer accumulation period following the date the rates set in that case became effective.

We then determined what the total actual OSSR and associated megawatt-hour ("MWh") amounts were for the first twelve full months following the effective date of the rates set in Case Nos. ER-2008-0318, and ER-2010-0036, and the first two full (8 months) non-summer accumulation periods following the effective date for rates set in Case No. ER-2011-0028.

Next we determined the difference in sales volumes between the NBFC calculation and the actuals. This amount was multiplied by the average power price from the NBFC calculation to obtain a rough but reasonable estimate of how much of the variance in OSSR was a result of the sales volume change. Any remaining difference in the OSSR variance was attributed to price changes.

The results of this analysis are presented below.

		1st 12 mos	1st 12 mos	(non-summer)
		ER-2008-0318	ER-2010-0036	ER-2011-0028
NBFC	OSSR	$ 451,748,000	$ 382,137,460	$ 252,144,114
NBFC	MWH	10,082,818	10,567,835	7,787,658
NBFC	Avg. $/MWH	$ 44.80	$ 36.16	$ 32.38
ACTUAL	OSSR	$ 324,417,631	$ 312,623,919	$ 157,381,487
ACTUAL	MWH	11,630,723	10,711,966	5,615,345
ACTUAL	Avg. $/MWH	$ 27.89	$ 29.18	$ 28.03
ACT-NBFC	OSSR	$ (127,330,369)	$ (69,513,541)	$ (94,762,627)
ACT-NBFC	MWH	1,547,905	144,131	(2,172,313)
ACT-NBFC	Avg. $/MWH	$ (16.91)	$ (6.98)	$ (4.35)
Volume	MWH Var * NBFC $/mwh	$ 69,351,940	$ 5,211,839	$ (70,333,846)
Price		$ (196,682,309)	$ (74,725,380)	$ (24,428,781)

Q. What can you tell from the table above?

A. This table clearly shows that the large discrepancies between the power price that was used in the determination of the NBFC and power prices that we were actually able to realize in the marketplace were far and away the largest factor resulting in the FAC adjustments made to date. In the first two columns, it is clear that the sheer magnitude of the price differences overwhelmed any positive contribution to OSSR resulting from increased volumes.

Q. How does the foregoing discussion relate to Ms. Mantle's argument that the sharing percentage in the FAC ought to be changed from 95%/5% to 85%/15%?

A. Ms. Mantle criticizes the Company by essentially claiming that the Company must not have enough incentive (with the 5% sharing) to accurately set the NBFC, since the actual results ended up varying quite a lot from those predicted when the NBFC was set. I've shown that due to the inherent volatility of power prices – which are impossible to predict – there is no method that will allow us to achieve a high level of accuracy that she must assume is possible for the single most significant factor affecting variances in the NBFC.

I've also shown that had we used other parties' recommendations (including the Staff's) in past rate cases the variance between the NBFC and the Company's actual net fuel costs would have been even greater. The bottom line is that the inaccuracy in setting NBFC has nothing to do with incentives. Rather, it is driven by market volatility and by the inability of history or forward market price curves to accurately predict future power prices.

Q. Do you have any other observations relevant to this issue?

A. Yes, I do. Except for MIEC's initial recommendation three rate cases ago that forward prices be used (instead of an historical average price), no party has recommended the use of a different method to calculate power prices for purposes of setting NBFC other than using some form of historical averages. Staff has used a three-year average, and so has MIEC. From the Company's perspective, in the absence of being able to use a forecasted/forward price, we've used a multi-year average because, in general, when a cost or revenue item is prone to variability, such a cost or revenue is often normalized in the ratemaking process and using a multi-year average is a common method of normalization. Staff brought this same issue up in our last case, but in this case too they continued to use a three-year average and so did MIEC.

Q. But isn't the Staff just following the Company's lead with regard to this issue?

A. If they are then it is a departure from what they normally do. In my experience the Staff has its own mind and if it believes a Company methodology isn't accurate enough, it takes issue with it and proposes a different methodology. If our use of a three-year average reflects a "lack of incentive to get it right," as Ms. Mantle contends, then arguably the customers' share should not be reduced from 95% to 85% because then the Staff and MIEC will have less incentive to get it right too. After all, in that scenario customers will bear less of the "inaccuracy" that, as I've shown, is inherent in trying to predict what volatile and uncontrollable power prices will be.

Q. Has Ms. Mantle made this argument before?

A. Yes, and the Commission rejected it just 13 months ago. The Commission stated:

> Staff argues that Ameren Missouri's willingness to accept what it believes to be a flawed basis for the calculation demonstrates that it does not have a sufficient incentive to "get it right." The Commission finds that Ameren Missouri's pragmatic acceptance of the use of historical average sales in the calculation of future off-system sales simply reflects the company's acceptance of the position the Commission clearly stated in previous Ameren Missouri rate case.
>
> This issue was presented to the Commission in File Number ER-2007-0002. In that case, certain parties argued the Commission should establish the amount allowed for off-system sales based on Ameren Missouri's future budgets. In refusing to allow for the use of future budgeted amounts, the Commission stated:
>
> > [s]ince the Commission uses historical expenses and revenues to set rates, it would be fundamentally unfair to reach forward to grab a single budget item to reduce AmerenUE's cost of service, while ignoring other anticipated costs that might increase that cost of service.
>
> Far from evidencing a lack of incentive to "get it right", Ameren Missouri's decision to settle the fuel cost issue simply illustrates the company's willingness to comply with a position clearly stated in a recent Commission decision[3].

We have exactly the same issue here. The NBFC (and as part of it, the power price used to determine OSSR) were settled among the parties in the last rate case as well and the price used in the settlement reflected the three-year average through the true-up period at that time.

Q. Do you have any other evidence that the Staff is not just following your lead?

[3] Case No. ER-2011-0128, Report and Order (effective July 31, 2011) pp. 81-82.

A. Yes. In the last rate case concluded just over a year ago, Ms. Mantle specifically testified that the Staff believed the net base fuel cost numbers that were settled upon in that case and the prior case were reasonable.[4] In fact, as I noted in the last case, and in this case, the Staff is using the same three-year average for power prices that I am using. Ms. Mantle had this to say about use of the three-year average just over one year ago:

> *Q. Staff's been recommending the three-year average of power prices throughout this case; isn't that true?*
> *A. Throughout this case, yes.*
> *Q. And the – and the reason the Staff is doing that is because its [sic] Staff's best judgment that a three-year historical average was the best it could do to predict what the average hourly market price was going to be after rates are set; isn't that right?*
> *A. That is correct.*[5]

Q. Are there other reasons the three-year average continues to be used?

A. Aside from the fact that, as I demonstrated above, it is not clear that another method would yield a more "accurate" result, the Staff at least has made clear that it would object to using forward market prices, as Ms. Mantle's prior testimony demonstrates:

> *Q. And just to be clear, Staff's not going to support using a forward price to set the off-system sales price using the fuel modeling in this case, is it?*
> *A. No, it will not*[6].

So what we have in this case is Ms. Mantle taking us to task for using a methodology the Staff has also used in three cases in a row (and asking us to absorb more prudently incurred net fuel costs). At the same time, she has told us that the Staff would

[4] Case No. ER-2011-0028, Tr. p. 1592, l. 4 – p. 1593, l. 20.
[5] Id., p. 1598, l. 14 – 23.
[6] Id. p. 1598, l. 24 – p. 1599, l. 3.

oppose at least one of the other available methodologies for predicting future power prices.

Q. What would the impact of Ms. Mantle's sharing percentage proposal be?

A. Ms. Mantle's proposal would do one of two things – neither of which will provide us an incentive to accomplish something which quite frankly isn't realistically possible. Those two things are to either unjustly punish or unduly enrich the Company for no other reason than actual power prices ended up being lower or higher than those used to set the NBFC. Neither punishing the Company nor rewarding it under these circumstances is fair or reasonable. Whenever power prices fall – and off-system sales revenue along with them – Ms. Mantle would have the Company put into a position of failing to recover even more of the prudently incurred fuel and purchase power costs it must incur to serve its customers simply based on the fortuity that we were unable to accurately predict future power prices. Alternatively, when power prices rise, her proposal would put customers in the position of foregoing the benefit of lower FAC rates that would be realized as a result of the higher power prices.

In effect, Ms. Mantle's proposal is analogous to creating a lottery ticket for the customers and the Company. If prices go up $1 per MWh, the Company cashes in with an additional $1 million.[7] If prices go down by $1 per MWh, the customers cash in for an additional $1 million. But the $1 million payout in neither case will have been the result of an action or inaction on the part of Ameren Missouri, nor will it have been the result of anything within our control.

Q. What do you mean when you say that Ms. Mantle's proposal would not provide you with an incentive to accomplish something which isn't realistically possible?

A. Ms. Mantle is suggesting that if we had an adequate incentive to "get it right," we would more accurately predict what the price of energy will be a year or two from now. But when energy prices are outside our control, and when there simply is no consistently reliable means of predicting what the prices will be, no amount of "incentive" can achieve the increased accuracy she seeks. In short, no amount of additional incentive will suddenly enable us to do something we have no power to do. Put another way, just because someone is standing over our proverbial shoulders with a big stick (loss of 15% of prudently incurred fuel and purchase power costs) that does not change the fact that not only do we not have a crystal ball into the future, we have no ability to establish the prices at which the market ultimately clears once the NFBC is established.

Q. Aside from the fact that you cannot control power prices and that no one can consistently, reliably predict them, is there other evidence that increasing the sharing percentage in the FAC is not needed to provide the Company greater incentive to seek out additional off-system sales?

A. Yes. We already sell all of our available, "in-the- money" generation.[8] Doing so is simply a function of the MISO market. We don't have to seek out counter-parties to make sure that our generation is economically dispatched. As the parties to this

[7] The $1 million is based on the fact that the Company generally makes about 10 million megawatt-hours of off-system sales each year, thus a $1 change in price equates to $10 million dollars, and Ms. Mantle has proposed increasing the sharing percentage by an additional 10%.

case are well aware, we offer our units into the MISO market, and the MISO clears these units when their cost of generation is lower than the market price. If the cost of dispatching the unit is higher than the market price, the unit does not "clear," it won't be dispatched, and we won't make the sale. It's that simple.

Additionally, we operate within the boundaries of our Risk Management Policy. Despite four prior rate cases over the past approximately five years, and two prudence reviews of the operation of our FAC, our operations have not been criticized. We have not been accused of not making an off-system sale we should have made, or of not realizing an appropriate price. Our Risk Management Policy has not been criticized. We have operated within our Risk Management Policy, as is appropriate, for to do otherwise could expose our customers to unacceptable risks as well as leaving us susceptible to having a transaction deemed imprudent.

Q. What are the consequences of having a transaction deemed imprudent?

A. Simply put, the Company would be responsible for 100% of any incremental costs (i.e., incremental net fuel costs) associated with that decision. That fact alone is more than sufficient incentive to ensure that we reasonably and prudently manage our portfolio.[9]

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[8] "In-the-money" means that the marginal cost of generating additional megawatt-hours will be less than the price we can realize.

[9] And while the Staff may claim that we were imprudent for how we classified the two contracts at issue in Case No. EO-2012-0074, the Staff affirmatively agrees we were prudent for entering into those contracts, and the "classification" of them has nothing to do with prudence.

III. PROPOSED ADJUSTMENTS FOR BILATERAL TRANSACTIONS AND FINANCIAL SWAPS

Q. MIEC Witness Dauphinais and Staff Witness Maloney both recommend that the Commission include a new component in off-system sales revenues – namely the inclusion of incremental margins related to bilateral sales and financial swaps. Do you agree with this recommendation?

A. No. I maintain that their recommendation is unnecessary as it will not, on average, reflect an improvement in the accuracy of setting a base level of OSSR as part of the determination of NBFC.

Q. Please explain.

A. The proposal to include these revenues effectively accomplishes one thing in this case – it increases the amount of OSSR which serves as an offset to fuel and purchased power expenses. Simply put, it lowers the NBFC. This recommendation essentially assumes that Ameren Missouri consistently realizes essentially the same prices for all energy sold, whether at spot or in bilateral transactions or in swaps, as the production cost modeling in the rate case assumed it would realize. If this assumption were correct then I would tend to agree that it may be appropriate to account for the margins associated with bilateral and financial swap transactions (both purchases and sales) in OSSR, as this would theoretically lead to a more accurate setting of the NBFC. However, as I have illustrated above, the fact is that Ameren Missouri does not consistently realize the power prices assumed in the modeling. Moreover, since the FAC was established, the variance from the base is not symmetrical between over- and under-recoveries, as we have been under-recovered in seven out of eight accumulation periods, including each of the last seven, since the FAC was implemented. As discussed previously, the under-recovery was mostly attributable to power prices.

It must also be recognized that had we included such an adjustment in our prior cases, the under-recoveries would have been even larger.

Q. Why do you highlight this latter point?

A. I highlight it because, as I stated above, it illustrates that this adjustment, regardless of its theoretical basis, simply does not reliably improve the accuracy of the starting point. Yes we have, on average, been achieving positive margins relative to spot prices over the past several years. I'm not debating that. That doesn't change the fact that stacking this adder on top of OSSR in the past three cases would have worsened the result. If prices turn around and start to increase and we are able to continue to realize positive margins on average going forward, then it might improve the result. If they don't, it might worsen it yet again. Neither is certain though.

Q. You seem to indicate in this last point that continuing to realize positive margins on these transactions is not certain. Is that correct?

A. Yes. Ameren Missouri enters into bilateral transactions and financial swaps for the purpose of hedging its price exposure. This is important because it has to be recognized that our hedging is not speculation. It is not done to ensure the highest possible price over time, but rather to mitigate the volatility of price movements, for the Company and its customers, over a given period. In simple terms, when someone hedges their sales they are trading the possibility of gains from potential price increases for protection against potential prices drops. Conversely, when they hedge their purchases they trade the possibility of price drops for protection against price increases. The purpose of hedging is not to beat, outsmart or outperform daily or real time markets; it is to lower volatility and ensure some measure of price stability. The transactions at issue were entered into not only to hedge the price received for generation, but also to hedge the price paid for displaced generation – for example when a unit was committed in the day-ahead market but subsequently trips off-line.

It is also important to recognize the simple reality that if prices fall after a fixed price sale transaction is entered into, the trade will show a positive margin, and conversely, if prices increase the transaction will show a negative margin. Given that hedging transactions are entered into in advance of delivery, in some cases months in advance, the margins realized on these transactions are simply a function of where the market moves in the future – a future which I have demonstrated above is unpredictable. Mr. Dauphinais' own workpapers show that for the 24 month period he studied margins were <u>negative</u> in 12 of those months.

Q. Can you summarize your position regarding the inclusion of bilateral and financial swap transactions in the determination of NFBC?

A. Yes. The inclusion of these transactions would not consistently or reliably improve the accuracy of the NBFC, and as such is unnecessary.

IV. <u>TREATMENT OF TRANSMISSION EXPENSE IN THE FAC</u>

Q. Staff has recommended that the following sentence be added to the definition of the cost of purchased power ("PP") in the FAC tariff sheets to be approved in this case: "Only transmission costs incurred for the purchase or sale of electricity shall be included." Is the Staff's recommendation appropriate?

A. It doesn't appear to be.

Q. Please explain.

A. First, the Staff has not provided a sufficient explanation (either in the Staff's Cost of Service Revenue Requirement Report or in the Staff's Rate Design Report) to allow us to understand what problem it is that they are seeking to solve with this new language and why it is only now appropriate to cease accounting for particular charge types through the FAC.

Second, Staff has failed to identify what charges which have previously been accounted for in the FAC, should now be removed from the calculation. They have not provided any clarity on what characteristics would result in disqualifying a particular transmission charge from being considered to have been incurred for the "purchase or sale of electricity."[10]

Third, Staff's proposal may ignore the fact that while Ameren Missouri is a member of the MISO, it also has load which is not electrically connected to MISO's system, and as a result, is required to acquire transmission service (and related charges) on a third party system in order to serve that load, even with its own resources.

Finally, to the extent that Staff may be seeking to exclude charges that Ameren Missouri is required by the MISO tariff to incur in order to secure and utilize network transmission service to serve its load, such exclusion is inappropriate, particularly given that Ameren Missouri's customers served via this network transmission service are enjoying significant market-based benefits which would not reasonably be expected to exist if we were not members of the MISO. These market-based benefits result in a net

[10] Counsel advises that my testimony on this issue should not be taken as a waiver of the Company's right to file additional testimony on this issue if the Staff provides further explanation or support for its proposal that should have been provided when it made its proposal.

reduction to the NBFC and fluctuations are accounted for in the FAC. It is appropriate that transmission costs such as those that Staff may be seeking to exclude, which only exist because of the same MISO relationship which gives rise to these benefits, also be accounted for in the FAC.

Q. Please explain your first and second points.

A. Staff has indicated that the changes to the FAC it has proposed in this case are designed to "clean up" the tariff and make the language in all Missouri FAC tariffs more consistent, and that with the exception of the proposed change to the sharing percentage, there is no intent to change the tariff's substantive meaning. With respect to this transmission cost language, the Staff hasn't provided enough clarity to determine what costs, which are currently accounted for in the FAC, they are now seeking to exclude. Staff also has not provided a reasonable justification on why those unspecified charges no longer warrant the treatment they have had these past years. Without this clarity, there cannot be a clear definition of what constitutes transmission costs for the "purchase or sale of electricity." As a consequence, while Staff purports to be doing this to reduce confusion, they will likely be creating it – where none exists today that I am aware of.

Q. Please explain your third point.

A. Ameren Missouri has load which is located in the Missouri Bootheel. This load is electrically located inside of the Entergy system, not the MISO system. We have established the necessary arrangements which allow us to serve this load with our MISO based resources – including securing the necessary network transmission service from Entergy to serve this load, for which we are invoiced. To the extent that Staff's proposal would be interpreted to exclude the charges from Entergy for service required to serve our load, it is inappropriate – just as it would be inappropriate to exclude charges from the MISO which we must take in order to serve our load.

Q. Please expand on your final point.

A. Ameren Missouri's load (with the exception of the Bootheel load noted above) is electrically located within the MISO footprint, and our entire load (including the Bootheel load) settles within the MISO market. As the Commission may be aware, as a function of the MISO market we purchase and settle with the MISO for 100% of our load. Conversely, we essentially sell 100% of our generation into the MISO. From a practical standpoint, given that we generally have more "in the money" generation to sell than we have load at a given point in time, these amounts effectively net out, leaving us a net seller. Consequently, MISO does indeed issue us "net" settlement statements. This "net" settlement does not erase the fact, however, that we are required to take network service from the MISO to serve our load and as part of taking that service we are billed certain transmission charges by the MISO, which are based upon the amount of load which we serve.

Network service enables us to transmit energy acquired from the MISO market (including that injected by our own generators) to our customers. That service is governed by the MISO tariff and there are a variety of charges from the MISO which may be incurred as the result of utilizing that service. These charges are not ala carte – we cannot pick and choose which ones we have to pay. Even though they exist as distinct schedules, they are required charges if one is using the system to serve load, which we do.

Having our load in the MISO market isn't a one-sided issue of cost though. While our customers do indeed incur these costs as a function of the Company's membership in the MISO, they are also enjoying substantial market-based benefits from being so situated.

While I am aware that there may be differing opinions on how to measure these benefits and that we will be performing a large scale study to again examine this very issue in the next few years, I am also aware that none of the participants in our recent proceeding to extend the Commission's approval to remain in the MISO denied that our customers receive a substantial benefit from our MISO membership, at least for the near future. This benefit arises from the operation of the MISO market and our access to it. As net sellers, we expect to obtain a net margin for our excess generation which we could not reasonably expect to obtain as a stand-alone entity or as a member of another entity without an organized market. Since the revenues from these sales are credited against our fuel costs, our customers are receiving the benefit (or 95% of the benefit) of these enhanced sales. Fluctuations in these revenues from those used to establish the base NBFC are properly accounted for in the FAC.

I am unaware of anyone arguing for, or even hinting at removing from the FAC the benefits which exist because of our MISO membership. However, the Staff's proposed language may reflect a suggestion that we should now cease accounting for some subset of transmission charges within the FAC, even though MISO transmission charges are required as a function of the very same market participation that is delivering the market-based benefits to customers. That is inequitable and unreasonable.

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	)	Case No. ER-2012-0166
Increase Its Revenues for Electric Service.	)	

AFFIDAVIT OF JAIME HARO

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

Jaime Haro, being first duly sworn on his oath, states:

1. My name is Jaime Haro. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Director, Asset Management and 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 24 pages and Schedule(s) N/A 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.

Jaime Haro

Subscribed and sworn to before me this 13 day of August, 2012.

Notary Public

My commission expires:

CARLETTE GIESLER
MY COMMISSION EXPIRES 11/02/13
NOTARY PUBLIC
NOTARY SEAL
COMMISSION #09401289
STE. GENEVIEVE COUNTY
STATE OF MISSOURI