Exhibit No.:	
Issue(s):	Revenue Requirement and Fuel Adjustment Clause
Witness:	James R. Dauphinais
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2012-0166
Date Testimony Prepared:	September 7, 2012

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

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	**Case No. ER-2012-0166** Tariff No. YE-2012-0370

Surrebuttal Testimony and Schedules of

James R. Dauphinais

**Revenue Requirement
and
Fuel Adjustment Clause**

On behalf of

Missouri Industrial Energy Consumers

NON-PROPRIETARY VERSION

September 7, 2012

BRUBAKER & ASSOCIATES, INC.

MIEC Exhibit No. 519
Date 10/3/12 Reporter SB
File No. ER-2012-0166

Project 9553

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	)	**Case No. ER-2012-0166** Tariff No. YE-2012-0370

STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of James R. Dauphinais

James R. Dauphinais, being first duly sworn, on his oath states:

1. My name is James R. Dauphinais. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my surrebuttal testimony and schedules, which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2012-0166.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

James R. Dauphinais
James R. Dauphinais

Subscribed and sworn to before me this 6th day of September, 2012.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2013
Commission # 09706793

Maria E. Decker
Notary Public

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Surrebuttal Testimony of James R. Dauphinais

I. INTRODUCTION

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **ARE YOU THE SAME JAMES R. DAUPHINAIS WHO HAS PREVIOUSLY FILED DIRECT "REVENUE REQUIREMENT" TESTIMONY ON BEHALF OF THE MISSOURI INDUSTRIAL ENERGY CONSUMERS ("MIEC") IN THIS PROCEEDING?**

A Yes.

Q **WHAT IS THE SUBJECT OF YOUR SURREBUTTAL TESTIMONY?**

A My surrebuttal testimony addresses the Rebuttal Testimony of Union Electric Company ("Ameren Missouri" or "Company") witness Jaime Haro with regard to the issues of:

- Adjustments to Net Base Fuel Cost ("NBFC") for the Company's Bilateral Off-System Energy Sales Margins and Swap Margins; and
- Inclusion of long-term transmission expenses in the Company's Fuel Adjustment Clause ("FAC").

I also respond to Mr. Haro's misstatement of MIEC's position in ER-2008-0318 with regard to whether forward electricity prices should be used rather than historical average prices for purposes of setting the Company's NBFC for its FAC.

Finally, I respond to the Rebuttal Testimony of Company witnesses Lynn M. Barnes and Robert K. Neff regarding the Company's new proposal to include delivered coal costs beyond the July 31, 2012 end of the true-up period in this case in the Company's Net Fuel Cost ("NFC"), and, in turn, its NBFC value and base rate revenue requirement.

The fact that I do not address a particular issue raised by the Company or any other party in this proceeding should not be interpreted as approval of any position taken by the Company or other parties in this proceeding.

Q COULD YOU PLEASE BRIEFLY ADDRESS THE MISSTATEMENT BY MR. HARO WITH REGARD TO MIEC'S POSITION IN ER-2008-0318 CONCERNING WHETHER FORWARD ELECTRICITY PRICES SHOULD BE USED FOR PURPOSES OF SETTING THE COMPANY'S NBFC FOR ITS FAC?

A Yes. In Mr. Haro's rebuttal testimony, he states:

> "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." (Rebuttal Testimony of Haro at 11)

As noted in my direct testimony in this proceeding, I was MIEC's expert witness with regard to this issue in Case No. ER-2008-0318. It was <u>not</u> MIEC's position in Case No. ER-2008-0318 that forward prices be used to set the Company's NBFC for its FAC. It was MIEC's position in that proceeding that the Company's NBFC be based on normalized historical market prices in a manner that reflects the clear, known and measurable sustained trend toward higher prices that was exhibited in historical spot market prices up to the time of that proceeding. This was before the revolutionary breakthroughs in fracking and the use of horizontal drilling that, to date, have dramatically increased the availability of natural gas in this country and have led to much lower and, to date, relatively stable wholesale market prices for natural gas and electric energy. Since that proceeding, MIEC has not opposed the three-year averaging of spot market prices by the Company to set the NBFC value due to: (i) the aforementioned revolutionary change in natural gas supplies; and (ii) no indication, to date, that there is currently a known and measurable long-term prevailing upward or downward trend in wholesale spot market prices for natural gas and electric energy.

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission:

- Adopt my proposed direct testimony adjustment to reduce the Company's NBFC by its normalized level of Bilateral Off-System Energy Sales Margins and Swap Margins;
- Clarify that no MISO charges associated with the long-term provision of transmission service to Ameren Missouri's network load may be included in the Company's NBFC or recovered through the Company's FAC; and
- Require the Company to remove all MISO Schedule 26 and MISO Schedule 26-A charges assessed for Ameren Missouri's network load (along with any other long-term transmission service charges) from its NBFC value.
- Reject the Company's rebuttal testimony proposal to include delivered coal costs through January 1, 2013 in its true-up of its NFC, NFBC and base rate revenue requirement.

When these recommendations are combined with my direct testimony recommendations and the recommendations of my colleague Mr. Phillips in his direct and surrebuttal testimonies, it lowers the Company's direct case NBFC value by $18.7 million and the Company's base rate revenue requirement by $15.4 million.[1]

II. ADJUSTMENTS TO NBFC FOR BILATERAL OFF-SYSTEM ENERGY SALES MARGINS AND SWAP MARGINS

Q PLEASE DEFINE THE TERMS BILATERAL OFF-SYSTEM ENERGY SALES MARGINS AND SWAP MARGINS.

A As discussed in detail in my direct testimony, "Bilateral Off-System Energy Sales Margins" is a term I first introduced in Case No. ER-2011-0028. It refers to the off-system energy sales margins Ameren Missouri has been successful at earning from bilateral sales that are in excess of those margins that Ameren Missouri would have earned just by selling the energy into the MISO day-ahead and real-time energy market (Dauphinais Direct at 9 through 10).

"Swap Margins" are the net proceeds from swap contracts that Ameren Missouri enters into to hedge wholesale market prices for electric energy. A swap is a financial contract where one party exchanges a fixed price at a defined hub for a floating index price at that same hub (Dauphinais Direct at 14).

Both Bilateral Off-System Energy Sales Margins and Swap Margins flow back to customers through the Company's FAC.

[1]The exclusion of MISO Schedule 26 and MISO Schedule 26-A charges assessed for Ameren Missouri's network load only reduces the Company's NBFC value, not its base rate revenue requirement. Thus, my recommended NBFC reduction is larger than my recommended base rate revenue requirement reduction.

Q PLEASE PROVIDE SOME BRIEF BACKGROUND ON THIS ISSUE.

A In my direct testimony, I recommended the Company's NBFC (and, in turn, the Company's base rate revenue requirement) be reduced by a normalized level of the Company's Bilateral Off-System Energy Sales Margins and Swap Margins (Dauphinais Direct at 9 through 16). Based on historical data through April 2012, I recommended that the Company's NBFC be reduced by $3.1 million per year for Bilateral Off-System Energy Sales Margins and by $0.8 million for net Swap Margins (*Id.*). Mr. Haro opposes these adjustments in his rebuttal testimony on behalf of the Company (Haro Rebuttal at 17 throug h 19).

Q PLEASE EXPLAIN THE BASIS OF MR. HARO'S OPPOSITION.

A Mr. Haro maintains that the inclusion of Bilateral Off-System Energy Sales Margins and Swap Margins in the Company's NBFC value will not, on average, reflect an improvement in the accuracy of the Company's off-system sales revenues as part of the determination of the Company's NBFC. He claims their inclusion only accomplishes one thing in this case – lower the Company's NBFC value. He also attempts to justify their exclusion by complaining that the Company's variances in seven out of eight FAC accumulation periods to date were under-recoveries of fuel and purchased power costs. While conceding that the Company has had Bilateral Off-System Energy Sales Margins and Swap Margins relative to spot market prices the past few years, he argues that the continued realization of these positive margins is not certain (Haro Rebuttal at 17 through 19).

Q DO ANY OF MR. HARO'S ARGUMENTS JUSTIFY THE EXCLUSION OF BILATERAL OFF-SYSTEM ENERGY SALES MARGINS AND SWAP MARGINS FROM THE DETERMINATION OF THE COMPANY'S NBFC VALUE?

A No. Mr. Haro's arguments fail for the following reasons:

- Bilateral Off-System Energy Sales Margins and Swap Margins are passed through the Company's FAC.
- The Company itself has chosen to calculate a normalized level of purchased energy expenses and off-system energy sales revenues for its NBFC value based on a three-year average of spot market prices;
- The Company cannot conclusively say that it will continue to have sustained under-recovery variances for its FAC, especially since the three-year average of spot prices used to determine the NBFC value in this case, unlike in previous cases, will not include the high historical spot market prices for natural gas and electric energy that were experienced prior to 2009;
- The Company has conceded that it has consistently achieved positive Bilateral Off-System Energy Sales Margins and Swap Margins on an annual basis over the last few years (Haro Rebuttal at 18); and
- The Company has made no pledge or other commitment to refrain, in the future, from seeking to include the cost of losses from Bilateral Off-System Energy Sales Margins and Swap Margins in its NBFC value.

Q PLEASE EXPLAIN THE RELEVANCE OF THE COMPANY'S CHOICE TO USE A THREE-YEAR AVERAGE SPOT MARKET PRICE IN THE DETERMINATION OF ITS PROPOSED NBFC VALUE.

A If the Company thought that there was a compelling case that spot market prices for natural gas and electric energy are going to be significantly lower than those prices have been for the past three years on average, it, in my opinion, would not have chosen to determine its proposed NBFC value on the basis of a three-year average of recent spot market prices for these commodities. As a result, I do not believe the

Company can reasonably take the position that its NBFC value is understated if it is based on such three-year historical price averages.

Bilateral Off-System Energy Sales Margins and Swap Margins do flow through the Company's FAC. To exclude them from NBFC value would overstate the Company's NBFC value. Therefore, as I recommended in my direct testimony, in order to reasonably set the Company's NBFC value, Bilateral Off-System Energy Sales Margins and Swap Margins based on a three-year average of their historical amounts need to be included in the Company's NBFC value.

Q PLEASE EXPLAIN FURTHER YOUR POINT THAT THE COMPANY CANNOT CONCLUSIVELY SAY IT WILL CONTINUE TO HAVE UNDER-RECOVERY VARIANCES OF ITS FAC.

A The Company itself has admitted that it cannot reliably predict spot market prices (Haro Rebuttal at 15). The Company has also emphasized the sensitivity of its fuel costs to spot market prices (Haro Rebuttal at 8). For these reasons, the Company cannot reasonably conclude that it will continue to experience successive under-recovery variances with its FAC.

In addition, prior to 2009, spot market prices were significantly higher than they have been in recent years due to the revolution in natural gas supplies that I have discussed. Prior to this case, the three-year price averages of spot prices used in the determination of the Company's NBFC value included at least some spot power prices from before 2009. Mr. Haro provides some information with regard to this issue in the top-most table of page 4 of his rebuttal testimony. For the three years ending July 31, 2012, which contains no pre-2009 spot prices, the contributing annual averages of spot market electric energy prices, as calculated by Mr. Haro, range from

$30.40 per MWh to $33.02 per MWh. For the three-year periods ending December 31, 2008; December 31, 2009; and December 31, 2010, there is at least one annual spot market electric energy price average included that is $38.35 per MWh or higher. This suggests a diminished likelihood that the Company will experience FAC under-recovery variances to the degree it has in the past, or at all.[2]

Q PLEASE EXPLAIN THE RELEVANCE OF THE COMPANY NOT MAKING ANY PLEDGE OR COMMITMENT TO EXCLUDE LOSSES FROM BILATERAL OFF-SYSTEM ENERGY SALES MARGINS AND SWAP MARGINS FROM ITS NBFC VALUE IN FUTURE BASE RATE PROCEEDINGS.

A It is currently in the interest of the Company to exclude Bilateral Off-System Energy Sales Margins and Swap Margins from its NBFC value in order to retain 5% of those margins under its FAC. The Company may in the future change its position if its fortunes reverse and it experiences prudently incurred net loss from Bilateral Off-System Energy Sales Margins and Swap Margins. In arguing to keep its currently net positive Bilateral Off-System Energy Sales Margins and Swap Margins out of its NBFC value, the Company has not made a symmetrical forward-looking commitment to exclude Bilateral Off-System Energy Sales Margin losses and Swap Margin losses from its proposed NBFC value in its future base rate proceedings.

To conclude, the Company has not offered any argument that reasonably justifies the denial of my direct testimony recommendation on this issue. As

[2]As an aside, I would note that the Calendar Year 2013 forward market price used by Mr. Haro in his table is not an indicator in any way that using a three-year average of historical spot market prices for the period ending July 31, 2012 would understate the Company's NBFC value. Over the past six months, forward market prices for Indiana Hub for Calendar Years 2014, 2015 and 2016 have typically been at least $1 per MWh higher than the corresponding Indiana Hub forward price for Calendar Year 2013.

recommended in my direct testimony, the Company's NBFC value should include an offset for its Bilateral Off-System Energy Sales Margins and Swap Margins based on the average of those amounts for the three-years ending July 31, 2012. As I indicated in my direct testimony, updated through April 2012, this lowers the Company's direct testimony NBFC and base rate revenue requirement value by $3.9 million ($3.1 billion plus $0.8 billion). These values will need to be updated through July 2012 in the true-up portion of this proceeding.

III. INCLUSION OF LONG-TERM TRANSMISSION EXPENSES IN THE COMPANY'S NBFC AND FAC

Q CAN YOU PLEASE PROVIDE AN OVERVIEW OF THIS ISSUE?

A Yes. This issue revolves around what transmission expenses may be included for recovery in the Company's FAC and, as a result, should also be included in the NBFC component of the Company's base rate revenue requirement. The controversy over this issue began when the Commission Staff ("Staff") in its Revenue Requirement Cost of Service Report filed as part of its direct testimony stated the following:

> "Staff recommends that Ameren Missouri's FAC continue to only include the transmission costs Ameren Missouri incurs that are necessary for it to serve the load requirements of its customers and those that are necessary for it to make OSS. No other transmission costs or revenues should flow through Ameren Missouri's FAC without Ameren Missouri first proposing that they do so in a general rate proceeding where all parties have an opportunity to make recommendations to the Commission on the appropriateness of doing so. Staff recommends that the Commission clarify that only the transmission costs Ameren Missouri incurs that are necessary for it to serve the load requirements of its customers and those that are necessary for it to make OSS are flowed through its FAC by specifically stating that only these transmission costs and revenues are allowed to flow through Ameren Missouri's FAC. Doing so will avoid potential confusion in future prudence audits. Staff will propose tariff language changes to effectuate this clarification in the Staff's Class Cost-of-Service/Rate Design Report to be filed on July 19, 2012." (Staff Revenue Requirement Cost of Service Report at 170)

In its Rate Design and Class Cost-of-Service Report, the Staff followed up its revenue requirement testimony by recommending the following sentence be added to the definition of the cost of purchased power in the Company's FAC tariff sheets:

> "Only transmission costs incurred for the purchase or sale of electricity shall be included." (Staff Rate Design and Class Cost-of-Service Report at 32)

MIEC agreed with these direct testimony positions of Staff, and, as a result, did not offer rebuttal testimony with regard to this issue.

To MIEC's surprise, Mr. Haro aggressively responded to and opposed Staff's recommended clarification (Haro Rebuttal at 19 through 23). In addition, also to MIEC's surprise, around the time of Mr. Haro's rebuttal testimony, it became known that the Company has been including long-term transmission service charges in its FAC. Specifically, in response to Staff Data Request No. 0473 (attached as Schedule JRD-SUR-1), the Company admitted to including MISO Schedule 26 (Network Upgrade Charge from Transmission Expansion Plan) charges in its FAC filings. From a further review of the Company's workpapers and filings, I have since determined myself that the Company has included MISO Schedule 26 charges associated with its long-term transmission service[3] for its retail customers in both its previous FAC filings and its proposed NBFC values in this case and in Case No. ER-2011-0028. Furthermore, it is not clear at this time whether or not the Company is attempting to also recover MISO Schedule 26-A (Multi-Value Project Usage Rate) transmission charges associated with long-term network transmission service for its retail customers through its FAC, in addition to MISO Schedule 26

[3]Per the FERC pro forma Open Access Transmission Tariff, long-term transmission service has a term of one year or more. Short-term transmission service has a term of less than one year.

charges proper, by including them under the overall label of MISO Schedule 26 charges in its FAC reports.

Q PLEASE PROVIDE A BRIEF DESCRIPTION OF MISO SCHEDULE 26 CHARGES.

A MISO Schedule 26 charges are FERC Account 565 - Transmission Of Electricity By Others expenses incurred by the Company under MISO Tariff Schedule 26 (Network Upgrade Charge from Transmission Expansion Plan) for the: (i) long-term transmission service it takes under MISO Tariff Schedule 9 (Network Integration Transmission Service) to serve its network load (including its retail load) and (ii) short-term transmission services it takes under MISO Tariff Schedule 7 (Firm Point-to-Point Transmission Service) and MISO Tariff Schedule 8 (Non-Firm Point-to-Point Transmission Service) to make off-system sales on behalf of its retail customers to entities not located within MISO or PJM.[4]

Currently, Schedule 26 is used by MISO to recover the cost of Baseline Reliability Project ("BRP") of 345 kV or higher voltage that are included in the MISO Transmission Expansion Plan ("MTEP"). It should be noted that revenues collected by MISO under Schedule 26 are distributed to the transmission owners who have constructed the BRPs. Ameren Missouri began receiving MISO Schedule 26 revenues as a transmission owner in June 2011. Despite seeking to recover MISO Schedule 26 charges through its FAC and NBFC without Commission approval, the Company has not passed Schedule 26 revenues back to customers through its FAC and has not proposed to include such MISO Schedule 26 revenues as an offset in its proposed NBFC value.

[4]The Company must take through and out transmission service under MISO Schedule 7 or 8 in order to make off-system sales to these entities.

A copy of the current version of MISO Schedule 26 is attached to this testimony as Schedule JRD-SUR-2. In Schedule JRD-SUR-3, I provide MISO's historical Schedule 26 rates that apply to the Company for its network load (including its retail load). As can be seen in the latter schedule, the MISO Schedule 26 rate has very rapidly risen since it was first established.

Q PLEASE PROVIDE A BRIEF DESCRIPTION OF MISO SCHEDULE 26-A CHARGES.

A MISO Schedule 26-A charges are FERC Account 565 expenses incurred by the Company under MISO Tariff Schedule 26-A (Multi-Value Project Usage Rate) by the Company for the: (i) long-term transmission service it takes under MISO Tariff Schedule 9 to serve its network load (including its retail load) and (ii) short-term transmission services it takes under MISO Tariff Schedule 7 and MISO Tariff Schedule 8 to make off-system sales, on behalf of its retail customers, to entities not located within MISO or PJM.

MISO Schedule 26-A is used to recover the cost of Multi-Value Transmission Projects ("MVPs") that are included in MTEP. To date, $5.6 billion of new MVP construction has been approved by the MISO Board of Directors through 2021. MISO collects the cost of these MVPs from all MISO transmission customers on a per MWh basis and does so for the benefit of the transmission owners constructing the MVPs.[5] The revenues collected by MISO are then distributed to those transmission owners as MISO Schedule 26-A revenues. The Company does not currently receive

[5]Note that a federal court review of FERC's approval of a per MWh charge rather than per MW-month of coincident peak demand charge for this transmission capacity is currently pending. As a result, the MISO Schedule 26-A per MWh cost allocation method may change in the future.

any of these revenues, but one of its affiliates does currently receive them (Ameren Transmission Company of Illinois ("ATXI")).

A copy of the current version of MISO Schedule 26-A is attached to this testimony as Schedule JRD-SUR-4. In Schedule JRD-SUR-5, I provide MISO's historical Schedule 26-A rates that apply to the Company for energy withdrawals associated with its network load taking MISO Schedule 9 transmission service (including its retail load).

Q WHAT TRANSMISSION EXPENSES MAY THE COMPANY INCLUDE IN ITS FAC?

A The Company's FAC currently permits recovery of "FERC Account...565 [Transmission Of Electricity by Others' Expenses]...excluding capacity charges for contracts with terms in excess of one (1) year incurred to support sales to all Missouri retail electric generations" (Ameren Electric Company, MO.P.S.C. Schedule No. 5, 1st Revised Sheet No. 98.10).

The only Account 565 amounts that typically fall into this category are short-term transmission charges associated with the provision of non-firm and short-term firm transmission service to either support: (i) off-system sales to entities not located on the MISO transmission system, or (ii) to support the delivery of power purchases made from entities not located on the MISO transmission system. These are incremental transmission charges that the Company would not incur for reasons other than to make certain power purchases and off-system sales on behalf of its retail customers. As such, they are appropriately recovered in the Company's FAC and included in the Company's NBFC value.

The Company's MISO Schedule 26 and MISO Schedule 26-A charges associated with the long-term transmission service the Company takes on behalf its network load (including its retail customers) are not related to the Company's fuel and purchased power costs less off-system sales revenues. Thus, they are not appropriately collected through the Company's FAC or appropriately included in the Company's NBFC value. Furthermore, these are capacity charges[6] associated with a contract with a term greater than one year in length.[7] Thus, these charges are explicitly prohibited from recovery through the Company's FAC. The Company should not be permitted to include MISO Schedule 26 and Schedule 26-A charges associated with its network load in its FAC and NBFC.

Q MR. HARO ARGUES IT WOULD BE INEQUITABLE AND UNREASONABLE TO REMOVE ANY MISO TRANSMISSION COSTS FROM THE COMPANY'S NBFC VALUE AND ITS FAC WHILE ALLOWING THE BENEFITS OF MISO PARTICIPATION TO CONTINUE TO BE INCLUDED IN THE NBFC VALUE AND FLOW THROUGH THE FAC (HARO REBUTTAL AT 22-23). HOW DO YOU RESPOND?

A As I have discussed, MISO transmission charges associated with the short-term transmission service necessary to support power purchases or off-system sales are incremental costs directly related to the Company's fuel and purchased power cost less off-system sales margins to which the Company attributes much of the cost savings that has come from MISO participation. However, MISO transmission charges associated with the long-term transmission service taken for the Company's network load are not incremental costs incurred to enable power purchases or

[6]The MISO Schedule 26 rate is a transmission capacity charge collected from MISO Schedule 9 customers on a per MW-month of coincident peak demand by network load basis. The MISO Schedule 26-A rate is a transmission capacity charge collected from MISO Schedule 9 customers on a per MWh of energy withdrawal by network load basis.

[7]The Company's agreement with MISO to take Schedule 9 Network Integration Transmission Service for its network load (including its retail load) has a term greater than one year.

off-system sales. Furthermore, MISO Schedule 26 and MISO Schedule 26-A charges in particular are associated with regional transmission cost allocation to which the Company may have been ultimately subject to under FERC Order No. 1000 even if the Company did not participate in MISO. So, it cannot be reasonably said MISO transmission charges associated with the long-term transmission service taken from MISO by the Company for the Company's network load has enabled the savings the Company has received from MISO participation.

Q DO SOME OF THE REGIONAL TRANSMISSION UPGRADES WHOSE COSTS ARE RECOVERED IN MISO SCHEDULE 26 AND MISO SCHEDULE 26-A CONTRIBUTE TOWARD A REDUCTION IN THE COMPANY'S OVERALL FUEL AND PURCHASED POWER COSTS LESS OFF-SYSTEM SALES REVENUES?

A I would expect them to do so. However, this is no different than the generation and transmission additions and upgrades that the Company itself constructs to serve its network load. The Company's generation and transmission additions and upgrades contribute toward lowering the Company's overall fuel and purchased power cost less off-system sales revenues. This does not make the capital costs for these generation and transmission additions and upgrades recoverable in the FAC. Nor should similar benefits provided by MISO BRP and MVP additions and upgrades make MISO Schedule 26 and MISO Schedule 26-A charges associated with the long-term transmission service taken from MISO by the Company to serve the Company's network load recoverable through the FAC.

Q DO YOU HAVE ANY OBJECTION TO THE COMPANY INCLUDING MISO SCHEDULE 26 AND SCHEDULE 26-A CHARGES ASSOCIATED WITH SHORT-TERM MISO SCHEDULE 7 AND 8 TRANSMISSION SERVICE TO SUPPORT THE COMPANY'S OFF-SYSTEM SALES TO ENTITIES NOT LOCATED IN MISO AND PJM IN ITS FAC AND NBFC?

A No. Provided they are prudently incurred, those particular MISO Schedule 26 and 26-A charges are appropriately recoverable through the Company's FAC. They are incremental charges directly associated with the Company's fuel and purchased power costs less off-system sales revenues. Furthermore, they are capacity charges associated with contracts with a term of less than one year.

Q WHAT PORTION OF THE COMPANY'S DIRECT CASE ACCOUNT 565 EXPENSES INCLUDED IN ITS PROPOSED NBFC ARE ASSOCIATED WITH MISO SCHEDULE 26 AND SCHEDULE 26-A?

A Approximately $3.3 million of the $15.8 million in Account 565 expenses included in the Company's direct testimony proposed NBFC value are associated with MISO Schedule 26 and 26-A.

Q HAS THE COMPANY SPLIT THE $3.3 MILLION DOLLAR AMOUNT BETWEEN: (I) MISO SCHEDULE 26 AND 26-A CHARGES INCURRED FOR ITS LONG-TERM TRANSMISSION SERVICE FOR ITS NETWORK LOAD AND (II) MISO SCHEDULE 26 AND 26-A CHARGES INCURRED FOR ITS SHORT-TERM TRANSMISSION SERVICE TO SUPPORT ITS OFF-SYSTEM SALES TO ENTITIES NOT LOCATED WITHIN MISO AND PJM?

A No. However, inherently, the vast majority of the Company's MISO Schedule 26 and 26-A charges will be associated with its network load than its off-system sales since sales to the former greatly dwarf sales to the latter.

Q WHAT RECOMMENDATION DO YOU HAVE WITH REGARD TO ADJUSTING THE COMPANY'S PROPOSED NBFC VALUE TO ADDRESS THE ISSUE WITH MISO SCHEDULE 26 AND 26-A CHARGES?

A If and until the Company separates its MISO Schedule 26 and 26-A charges associated with short-term transmission service from those associated with long-term transmission service, the Company's proposed NBFC value should be reduced by the entire $3.3 million amount of MISO Schedule 26 and 26-A charges. Note, this only affects the Company's NBFC value, not its base rate revenue requirement. I am not opposing the recovery of the cost in base rates. I am only opposing its inclusion in the Company's NBFC value and its recovery in the Company's FAC.

Q MR HARO MENTIONS CERTAIN TRANSMISSION CHARGES THAT IT MUST PAY TO ENTERGY FOR NETWORK TRANSMISSION SERVICE TO SERVE COMPANY LOAD IN THE MISSOURI BOOTHEEL (HARO REBUTTAL AT 21 THROUGH 22). ARE THOSE ENTERGY TRANSMISSION CHARGES APPROPRIATE TO INCLUDE IN THE COMPANY'S FAC AND NBFC VALUE?

A No. If these are truly for network transmission service taken under the Entergy Open Access Transmission Tariff, the charges incurred are capacity charges associated with a contract having a term greater than one year. They can be recovered through the Company's base rate revenue requirement, but should not be included in the Company's NBFC value nor recoverable in the Company's NBFC.

Q HAVE YOU IDENTIFIED ANY SUCH TRANSMISSION CHARGES IN THE COMPANY'S NBFC WORKPAPERS IN THIS CASE?

A No. I have not been able to conclusively identify any long-term Entergy transmission charges that are included in the Company's NBFC value. However, I recommend the Commission instruct the Company that it must remove <u>all</u> long-term transmission charges from its NBFC value and may not recover those charges through its FAC.

Q DO YOU HAVE ANYTHING ELSE TO ADD WITH REGARD TO THE ISSUE OF WHICH TRANSMISSION EXPENSES SHOULD BE RECOVERABLE IN THE FAC?

A No.

VI. INCLUSION OF DELIVERED COAL COST INCREASES <u>IN NET BASE FUEL COST BEYOND THE END OF THE TRUE-UP PERIOD</u>

Q PLEASE EXPLAIIN THIS ISSUE.

A In the Rebuttal Testimony of Company witnesses Lynn M. Barnes and Robert K. Neff, the Company proposed that delivered coal cost increases through January 1, 2013 be included in the true-up of the Company's NFC, NBFC and base rate revenue requirement. The Company has estimated that this would raise its NFC, and, in turn, its NBFC and base rate revenue requirement by **_________** (Barnes Rebuttal at 11 through 13 and Neff at 8). This is a new proposal to significantly increase the Company's base revenue requirement above the Company's filed case and reaches beyond the July 31, 2012 end of the true-up period in this proceeding.

Q HOW DO YOU RESPOND TO THIS PROPOSAL?

A I recommend that this proposal be denied. First, it is inappropriate for the Company to request additional base rate revenue beyond its direct case. If the Company wanted to request approval to reach beyond the end of true-up period in order to include these costs in its base rate revenue requirement, the appropriate time to do so was when the Company filed its direct case in this proceeding -- not in its rebuttal testimony. Second, the purpose of placing a sunset on the true-up period is to ensure that all significant known and measurable changes in rate base, expenses and revenues through a defined date are accounted for through that given date in order to ensure the relationship between rate base, expenses and revenues that is expected when the proposed rates are in effect is maintained. Reaching beyond the end of the true-up period to only make known and measurable changes to select items, as the Company is proposing with delivered coal costs, seriously undermines the maintenance of the relationship between rate base, expenses and revenues. The Company was also in control of when it filed its case in this proceeding and, thus, in turn, the proposed sunset date for true-up in this case and the proposed date for new rates would go in effect. Thus, it had significant control over the timing of the end of the true-up period in this proceeding. Finally, delivered coal cost is an item tracked in the Company's FAC. As a result, even if there are not offsetting reductions in rate base and/or expenses, and/or offsetting increases in revenues, these delivered coal cost increases will be recoverable through the Company's FAC.

V. CONCLUSIONS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission:

- Adopt my proposed direct testimony adjustment to reduce the Company's NBFC by its normalized level of Bilateral Off-System Energy Sales Margins and Swap Margins;
- Clarify that no MISO charges associated with the long-term provision of transmission service to Ameren Missouri's network load may be included in the Company's NBFC or recovered through the Company's FAC; and
- Require the Company to remove all MISO Schedule 26 and MISO Schedule 26-A charges assessed for Ameren Missouri's network load (along with any other long-term transmission service charges) from its NBFC value.
- Reject the Company's rebuttal testimony proposal to include delivered coal costs through January 1, 2013 in its true-up of its NFC, NFBC and base rate revenue requirement.

When these recommendations are combined with my direct testimony recommendations and the recommendations of my colleague Mr. Phillips in his direct and surrebuttal testimonies, it lowers the Company's direct case NBFC value by $18.7 million and the Company's base rate revenue requirement by $15.4 million.[8]

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

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[8]The exclusion of MISO Schedule 26 and MISO Schedule 26-A charges assessed for Ameren Missouri's network load only reduces the Company's NBFC value, not its base rate revenue requirement. Thus, my recommended NBFC reduction is larger than my recommended base rate revenue requirement reduction.

Ameren Missouri
Response to MPSC Data Request
MPSC Case No. ER-2012-0166
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service

Data Request No.: MPSC 0473 - John Rogers

1. Please provide Ameren Missouriâ€™s complete analysis for determination of the 86% figure in the following Q&A under the FAQ link on the Companyâ€™s website http://www.lhtransmission.com: How will the line be paid for? Ameren Missouri customers will pay for approximately 86% of the project through the Fuel Adjustment Clause (FAC) which is regulated through the Missouri PSC. Customers under the MISO region will pay for the remaining portion of the project. 2. Please provide Ameren Missouriâ€™s rationale for its determination that the Lutesville to Heritage Transmission project qualifies for payment through the Ameren Missouri FAC. 3. Please provide Ameren Missouriâ€™s proposed accounting treatment for the proposed Lutesville to
Heritage Transmission project.

RESPONSE

Prepared By: Greg Gudeman (part 1); Jesse Francis (parts 2 & 3)
Title: Managing Supervisor – Transmission Regulation and Policy; Financial Specialist – Wholesale Power and Fuel Accounting
Date: 8/20/12

1. The Company did not perform this calculation. The calculation was performed by the MISO as part of its MISO Transmission Expansion Plan (MTEP) process under Attachment FF of its Tariff. Lutesville-Heritage was approved in MTEP11 as a baseline reliability project eligible for regional cost sharing. It is identified in MTEP as Project 2306.

   Attached is the MISO MTEP Cost Allocation Calculation for the Lutesville-Heritage project as well as MTEP11 Appendix 1, which provides a summary for each MTEP11 baseline reliability/generation interconnection project eligible for regional cost sharing. A line was added below the Lutesville-Heritage project which shows 86.9% of the revenue requirement reflected in rates MISO charges through its Tariff will be allocated to the AMMO pricing zone (which includes retail and wholesale loads), meaning that the remaining 13.1% is charged through MISO's Tariff to loads outside the AMMO pricing zone.

2. The MISO charges are assessed under Schedule 26 of the MISO's Tariff and are recorded in Account 565. Under the FAC tariff, costs recorded in Account 565 are included in the FAC calculations as part of Factor CPP.

3. The Lutesville-Heritage transmission project will be accounted for like all Ameren Missouri transmission.
   DR: Plant-in-Service
     CR: Cash.

SCHEDULE 26 Network Upgrade Charge From Transmission Expansion Plan Version: 4.0.0 Effective: 1/1/2012

SCHEDULE 26

NETWORK UPGRADE CHARGE FROM TRANSMISSION EXPANSION PLAN

The Transmission Customer shall compensate the Transmission Provider the current Network Upgrade Charge ("NUC") for Reserved Capacity at the sum of the applicable charges set forth below in addition to all other charges for Transmission Service for which the Transmission Customer is responsible under this Tariff. The rates are calculated using the formula included in Attachment GG of this Tariff.

The charges under this Schedule 26 shall be in addition tó any charges under Schedules 7, 8, 9, and 26-A. Grandfathered Agreements, including the provision of Transmission Service, shall not be charged this Schedule 26.

1) **Pricing Zone Rates:** The Transmission Customer shall pay the zonal rate as calculated under Attachment GG, per kW of Reserved Capacity, based upon the pricing zone where the load is located for Transmission Service (1) where the generation source is outside the Transmission Provider Region and the load is located within the Transmission Provider Region and (2) where both the generation source and the load are located within the Transmission Provider Region. The Network Customer shall pay the monthly rate as calculated under Attachment GG for the prizing zone where the load is located based on it Network Load. The rate for each pricing zone will be determined in accordance with the provisions of Attachment GG. All pricing zones will include a system-wide rate component of the NUC, as provided under Section 2 of Attachment GG and designated pricing zones will include an additional NUC rate component.

   The pricing zones are as follows:

Zone 1:	ITC Midwest LLC
Zone 2:	American Transmission Company LLC
Zone 3A:	Ameren Illinois
Zone 3B:	Ameren Missouri
Zone 4:	[Reserved]
Zone 5:	Duke Energy Indiana, Inc. (includes Indiana Municipal Power Agency and Wabash Valley Power Association)
Zone 6:	City of Columbia, Missouri
Zone 7:	City Water, Light & Power (Springfield, Illinois)
Zone 8:	Great River Energy
Zone 9:	Hoosier Energy
Zone 10:	International Transmission Company
Zone 11:	Indianapolis Power & Light Company
Zone 12:	Lincoln Electric (Neb.) System AVAILABILITY SUSPENDED
Zone 13:	Michigan Joint Zone (Michigan Electric Transmission Company LLC, Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc.)
Zone 13A:	Michigan Joint Zone Subzone
Zone 14:	Minnesota Power, Inc.
Zone 15:	Montana-Dakota Utilities Co.
Zone 16:	NSP Companies
Zone 17:	Northern Indiana Public Service Company
Zone 18:	Otter Tail Power Company

Zone 19: Southern Illinois Power Cooperative

Zone 20: Southern Minnesota Municipal Power Agency

Zone 21: Aquila, Inc. – Kansas (West Plains Energy) **AVAILABILITY SUSPENDED**

Zone 22: Aquila, Inc. – Missouri (St. Joseph Light & Power and Missouri Public Service Co.) **AVAILABILITY SUSPENDED**

Zone 23: Vectren Energy

Zone 24: MidAmerican Energy Company

Zone 25: Muscatine Power and Water

Zone 26: Dairyland Power Cooperative

Zone 27: Big Rivers Electric Corporation

Additional zones may be added if a) additional Transmission Owners transfer control of their facilities to the Transmission Provider. Such additional zones may be added only if consistent with the requirements of Schedules 7, 8 and 9 of this Tariff.

2) **NUC Out and Through Rate:** The Transmission Customer shall pay the rate specified under Attachment GG for Transmission Service (1) where the generation source is located within the Transmission Provider Region and the load is located outside of the Transmission Provider Region; and (2) where both the generation source and the load are located outside of the Transmission Provider Region.

3) **Rates to the PJM Interconnection, LLC:** In accordance with the Commission's November 18, 2004 Order in Docket Nos. ER05-6, EL04-135, EL02-111 and EL03-212, *Midwest Independent Transmission System Operator, Inc.* 109 FERC ¶ 61,168 (2004), the charge under Section 2 above for Points of Delivery at the border of the Transmission Provider Region for reservations pursuant to requests made on or after November 17,

2003, for service commencing on or after April 1, 2004, shall not apply to transactions to serve load within the area served under the open access transmission tariff on file with the Commission of the PJM Interconnection, LLC where transmission service is taken under the PJM Interconnection, LLC open access transmission tariff. Beginning April 1, 2006, the charge under Section (1) above for Points of Delivery at the border of the Transmission Provider Region shall not apply to all transactions to serve loads within the area served under the open access transmission tariff on file with the Commission of PJM Interconnection, LLC, where transmission service is taken under the PJM Interconnection, LLC open access transmission tariff.

4) **Rate Caps:** The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the weekly rate times the highest amount in kW of Reserved Capacity in any day during such week. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the daily rate times the highest amount in kW of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the weekly rate above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Credit for Charges During Transmission Loading Relief (TLR) Events:** In the event that the Transmission Provider initiates Curtailment of confirmed Point-To-Point Transmission Service on the Transmission System due to a TLR event in accordance with Attachment Q, credit will be given to the Transmission Customer(s) that are actually requested to curtail their energy schedules associated with the confirmed Point-To-Point Transmission Service. No credits will be given for: (1) TLR events external to the

Transmission System; (2) Non-Firm Secondary Point-To-Point Transmission Service under a Firm Point-To-Point reservation; or, (3) Next-Hour Transmission Service. Under no circumstances shall the amount credited exceed the amount the customer was actually curtailed nor will credit be given for any hours other than those in which the Curtailment was requested.

6) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) **Compliance with Agreements:** If the Commission has allowed agreements to become effective which require a waiver of any of the charges under this Schedule, then such charges shall be waived.

8) **Revenue Distribution to Transmission Owners and ITCs:** As and to the extent that the Transmission Provider collects revenues from Transmission Customers, it shall remit such revenues to the Transmission Owner and/or ITC's in proportion to their annual pro-rata share of the total NUC revenue requirement as determined under Attachment GG.

Ameren Missouri
Case No. ER2012-0166
MISO Rates for OATT Schedule 26

Effective Date	Rate ($/MW-MO)
1/1/2007	$1.4836
6/1/2007	$1.5013
8/1/2007	$1.4833
11/1/2007	$1.4833
12/1/2007	$1.4617
1/1/2008	$3.6645
6/1/2008	$3.8258
1/1/2009	$6.3163
6/1/2009	$7.0855
1/1/2010	$10.9238
6/1/2010	$11.8347
1/1/2011	$16.6492
6/1/2011	$59.0923
1/1/2012	$65.5705
6/1/2012	$128.0478

Source: http://oasis.midwestiso.org/documents/miso/historical_pricing.html

SCHEDULE 26A Multi-Value Project Usage Rate Version: 1.5.0 Effective: 1/1/2012

SCHEDULE 26A
MULTI-VALUE PROJECT USAGE RATE

The Multi-Value Project Usage Rate ("MUR") is a Midwest ISO System-wide rate charged to Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules. The rates are calculated using the formula included in Attachment MM of this Tariff. The charges under this Schedule 26-A shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements, except as permitted under Schedule 40, and Export Schedules and Through Schedules for deliveries that sink in the transmission system operated by PJM Interconnection, LLC shall not be charged this Schedule 26-A.

1. **Rates:** Except as provided above, Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules shall pay the MUR rate as calculated under Attachment MM.

2. **Revenue Distribution to Transmission Owners and ITCs:** As and to the extent that the Transmission Provider collects revenues from Market Participants, it shall remit such revenues to the Transmission Owner and/or ITC's in proportion to their annual pro-rata share of the total MVP revenue requirement as determined under Attachment MM.

Ameren Misouri
Case No. ER-2012-0166

Historical MISO Schedule 26-A (MVP Transmission Projects) Rate
(Applicable to all transmission service provided by MISO except that sinking in PJM)

Billing Month	MUR Rate (per MWh)	MISO Estimate Version #
January-12	$0.03566	4 (Final Value)
February-12	$0.03390	4 (Final Value)
March-12	$0.02986	4 (Final Value)
April-12	$0.03676	3
May-12	$0.03431	2
June-12	$0.03532	1
July-12	$0.04567	0*

Source: "MVP MUR by Project", 8/8/2012
https://www.midwestiso.org/MarketsOperations/MarketInformation/Pages/TransmissionPricing.aspx

* = MISO Version 0 MUR estimates to date have tended to be on the high side.

Notes:

(1) If the June 2012 MUR rate was applied to annual Ameren Missouri retail load usage at transmission of roughly 40,000,000 MWh, it would yield a rough estimate of annual MISO Schedule 26-A charges of $1.4 million.

(2) The June 2012 MUR rate is based on recovery of the current annual revenue requirement for all MVP transmission projects of approximately $18 million. This currently consists of Construction Work in Progress allowed in rate base and other pre-inservice amounts FERC is permitting MVP transmission owners to recover under the MISO Tariff via Schedule 26-A. As discussed in Mr. Dauphinais' Surrebuttal Testimony, the total MISO-authorized MVP investment is approximately $5.6 billion through 2021. Once this investment is all in service, the MVP annual revenue requirement will be on the order of $800 million, which would yield a MISO Schedule 26-A MUR rate on the order of $1.5 per MWh or Ameren Missouri annual MISO Schedule 26-A charges on the order of $60 million.