Exhibit No.:	
Issue(s):	Production Cost Allocations; Class Revenue Requirements; Rate Design; Rider FAC
Witness:	Wilbon L. Cooper
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2012-0166
Date Testimony Prepared:	August 14, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0166

REBUTTAL TESTIMONY

OF

WILBON L. COOPER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
August 2012

Table of Contents

REBUTTAL TESTIMONY

OF

WILBON L. COOPER

CASE NO. ER-2012-0166

Q. Please state your name and business address.

A. My name is Wilbon L. Cooper. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, MO 63103.

Q. Are you the same Wilbon L. Cooper who filed direct testimony in this proceeding?

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 provide comments and evidence that address and rebut the portions of the Rate Design and Class Cost-Of-Service Report on the allocation of production plant and/or class revenue requirements sponsored by Missouri Public Service Commission Staff ("Staff") witness Michael Scheperle, and the direct testimonies on the same issues filed by Office of the Public Counsel ("OPC") witness Barbara A. Meisenheimer, and Missouri Industrial Energy Consumers ("MIEC") witness Maurice Brubaker.

Additionally, I will provide comments and evidence that address and rebut the portions of the Rate Design and Class Cost-Of-Service Report on rate design sponsored by Staff witness Scheperle, and, also, certain portions of that report and Staff's Revenue Requirement Cost-Of-Service Report sponsored by Staff witness Lena Mantle on the Company's Fuel Adjustment Clause Tariff Sheets. Other Company witnesses may also provide additional rebuttal testimony to address certain issues raised by these witnesses. In addition, I want to state that the Commission should not construe the fact that I or another Ameren Missouri witness do not specifically address a particular witness' position or argument as endorsement of that position or argument. In the interest of brevity, the Company is limiting its rebuttal testimony on allocation and rate design issues to the major points of disagreement between the parties.

I. PRODUCTION PLANT ALLOCATION

Q. Please summarize the position stated by each of the parties in direct testimony as it relates to the allocation of fixed production plant costs among the Company's rate classes for ratemaking purposes in this case.

A. The following provides a high level summary of each party's recommendation on the allocation of fixed production plant:

- Company – The Company utilized a four non-coincident peak ("4 NCP") version of the Average and Excess Demand Allocation methodology ("A&E") that gives weight to both a) class peak demands and b) class energy consumption.
- Staff – The Staff utilized a Base, Intermediate, and Peaking ("BIP") method that is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours; (2) secondary peak, or intermediate hours; and (3) base loading hours.
- OPC – OPC utilized a four coincident peak ("4 CP") version of the Peak and Average methodology ("P&A") that gives weight to both a) adjusted class peak demands and b) class energy consumption. OPC also prepared

a second study that utilized an Average and Excess Demand Allocation methodology which is similar to the Company's methodology.

- MIEC – MIEC also recommends an A&E methodology; however, MIEC'S methodology only uses the July and August system peaks. Because there is only a small difference between results produced by MIEC'S method and the Company's results, MIEC has accepted for this case the results of the Company's recommended 4 NCP version of the Average and Excess Demand Allocation methodology in order to narrow the issues.

Q. Have you prepared a table that summarizes, by customer class, the production plant allocation and associated production plant allocation factors that are produced by each of the parties' recommended methodologies?

A. Yes, Table 1 depicts this summary.

Table 1

Party	Method	RES	SGS	LGS/SPS	LPS	LTS	Lighting
Company & MIEC	4 NCP – A&E	46.89%	10.65%	28.47%	7.23%	6.04%	0.72%
MPSC Staff	Base-Intermediate-Peak	47.37%	10.70%	27.71%	7.40%	6.11%	0.70%
OPC 1 (P&A)	4 CP – A&E	41.65%	10.00%	30.49%	8.75%	8.83%	0.30%
OPC 2 (A&E)	4-NCP – A&E	46.88%	10.65%	28.47%	7.23%	6.05%	0.73%

Q. Is there a common element in the production plant allocation methods listed in Table 1?

A. Yes, the common element in all the methods is the use of class kilowatt-hours to allocate a portion of production plant. The references to "A" (Average) or "Base" for each of the methods shown in Table 1 reflects the fact that class average demands are calculated by dividing annual class energy consumption by 8,760 hours, which is the total number of hours in a year. In addition, with regard to each of the methods referenced with an "A" in Table 1, the class averages are computed as a percentage of the system average demand and are then multiplied by the system's annual load factor of approximately 55%. As a result, 55% of the Company's production plant investment is allocated on an energy basis in each of the "A" methods. The Staff's BIP method produces a comparable value of approximately 56% allocated on an energy basis. Therefore, the major differences among the parties lie with the allocation of the remaining 44%-45% of production plant investment. These differences are driven by the use of "Excess" demands associated with Non-Coincident Peaks vs. total Non-Coincident or Coincident Peaks.

Q. Please explain the differences between the A&E method, which was used by the Company, MIEC, and in the OPC's second study vs. the P&A method, which is used in the OPC's first study.

A. The A&E method first allocates production plant investment based on the average demand on the Company's system by the various customer classes. Any excess demand above the average demand is then allocated based on each class' contribution to these excess demands. The P&A method also initially allocates production plant investment to customer classes based on average demand, but instead of allocating just the excess average demand to the cost causing classes the P&A method allocates the entire peak demand to the classes.

As the Commission specifically has found in each of the Company's last two rate cases – Case Nos. ER-2010-0036 and ER-2011-0028 - the use of the P&A method is inherently flawed because it double counts the average demand of customer classes. This double counting results from the previously described use of class average demand for a portion of production plant allocation (i.e., the 55% system load factor weighting piece) and the use of class peak or non-coincident peak demands, which include an average demand component, for the remaining allocation of production plant (i.e., 44-45%). More specifically, this double counting causes customers with higher load factors to be allocated an inequitable share of production plant investment. And because high load factor customers demonstrate a better correlation between average demands and peak demands than do lower load factor customers, higher load factor customers receive a disproportionate share of the non-average demand (i.e., 44-45%) portion of production plant investment under the P&A method.

As a result of this double-counting flaw, in each of the Company's last two rate cases, the Commission found that the use of the A&E method is more equitable than the P&A method. The A&E method more appropriately and equitably deals with "Excess" demands (i.e., the <u>difference</u> between class non-coincident or peak demands and class average demands) for application of the remaining 44-45% of production plant investment, thus avoiding any double counting of demands.

Q. In the Company's most recent rate case (Case No. ER-2011-0028), what did the Commission's Report and Order say about the OPC's use of a P&A production plant investment allocation method?

A. At page 114 of the Report and Order in that docket the Commission stated: "Public Counsel's study uses an Average and Peak allocation method that the Commission has rejected as unreliable in previous cases." At page 115 of that same order, the Commission further stated that: "[T]he Peak and Average method double counts the average system usage, and for that reason is unreliable."

Q. Please comment on the Staff's use of the BIP method for allocating fixed production plant vs. the Company's use of the 4 NCP A&E.

A. There are numerous positive things that can be said about the Staff's BIP method. For example, the BIP method gives weighting to the energy requirements of customer classes. The BIP method is one of the methods for production plant investment allocation that is listed in the National Association of Regulatory Commissioners ("NARUC") Electric Utility Cost Allocation Manual, and it has been deployed by other utilities. And unlike OPC's P&A method, the BIP method that Staff used is not flawed because of double counting of demands. Consequently, it is not surprising that Staff's application of the BIP for the Company's production plant results in approximately 56% of production demand being allocated on an energy basis – an allocation which is almost identical to the 55% energy weight under the Company's 4 NCP A&E method. Therefore, at least for purposes of this case, any argument over the merits of the 4 NCP A&E method vs. the BIP method for the allocation of the Company's generation assets is academic.

Q. Please summarize the Company's overall position regarding the allocation of fixed production plant costs.

A. The Company's net investment in fixed production assets represents approximately 72% of net original cost rate base in this case. Consequently, the variations among the Company, MIEC, Staff and the OPC with respect to the allocation of the cost of these assets, as depicted in Table 1 above, contribute materially to the significant difference among the parties in class cost of service requirements in this case.

In my opinion, the Company's 4 NCP A&E allocation methodology is superior to the proposals offered by the other parties in this case because the Company's method is more balanced in its consideration of both the energy and excess demand requirements for serving each customer class. Consideration of energy usage is important due to its relevance in the type of generation on the Company's system, while the consideration of demand is also relevant due to its importance in the magnitude of the capacity of the Company's generating facilities, and both are important in determining an equitable allocation of costs. The A&E method assigns a weight of 55% to class energy requirements and 45% to class excess demands, based on the Company's annual system load factor of 55% during the study period. Additionally, the Company has utilized the 4 NCP A&E methodology for its most recent cases before the Commission and the continued use of this allocation methodology will promote cost of service stability.

The Company is not suggesting that there is a single methodology that can be deemed as the absolute, correct, and only method for the allocation of fixed production plant. However, the Commission has adopted the 4 NCP A&E method in the Company's two most recently adjudicated electric rate cases (Case Nos. ER-2011-0028 and ER-

2010-0036). It would be desirable to continue the use of the 4 NCP A&E method in this case as well because there has been no material change in the Company's load characteristics, and also because such consistency affords all parties the ability to rely upon a standardized methodology whose results could be reasonably predicted. All these considerations contribute to the prevention of material case-to-case swings in class revenue responsibility for the most significant portion of the Company's investment in rate base.

II. CLASS REVENUE REQUIREMENTS

Q. Please reiterate the Company's position on the allocation of the revenue increase authorized in this case.

A. As stated in my direct testimony, the Company is proposing to allocate the requested increase in this case on an across-the-board basis, with an equal percentage increase for all customer classes.

Q. What are the positions of the other parties on class specific revenue requirements?

A. The following Table 2 depicts a summary of the positions of the other parties:

Table 2

Party	**Class Revenue Recommendation**
MPSC Staff	• Residential and Lighting Classes 1% and 3% revenue neutral increase, respectively. • Small General Service, Large General Service/Small Service, Large Primary Service, and Large Transmission Service receive a revenue neutral decrease of approximately 1.0%. • Having made the above changes, any overall change in revenues can be applied to all classes on an equal percentage basis. • Lighting class 5(M) to have the pole and span charges removed and included in 5(M) rates.
OPC	No Revenue Neutral Adjustments to Residential and Small General Service, silent on remaining classes.
MIEC	<u>Simplified and Generalized:</u> Step 1: (Revenue neutral adjustments as follows): Residential +2% SGS Proportional decrease LGS/SPS Proportional decrease LPS Proportional decrease LTS Proportional decrease Lighting +2%. Step 2: Class specific assignment of EE revenue requirement. Step 3: Equal Percentage Increase of Remaining Revenue Requirement to Class Revenues.

Q. Considering the results of the Company's class cost of service study, which supports non-equal class percentage increases, why should the Commission adopt the Company's recommendation for an across-the-board, equal percentage increase for all classes?

A. While cost-based rates are an important starting point in developing class revenue targets and rate design, there are other factors (e.g., public acceptance particularly among the Company's largest rate class - residential customers, rate stability, and revenue stability from year to year) that also should be considered when determining class revenue requirements and designing rates. Especially in today's challenging economic conditions, these other factors take on greater importance. The Commission's Report and Order in Case No. ER-2010-0036 seems to acknowledge this fact when it states, at pages 115-116:

> In general, it is important that each customer class carry its own weight by paying rates sufficient to cover the cost to serve that class. That is a matter of simple fairness in that one customer class should not be required to subsidize another. Requiring each customer class to cover its actual cost of service also encourages cost effective utilization of electricity by customers by sending correct price signals to those customers. However, the Commission is not required to precisely set rates to match the indicated class cost of service. Instead, the Commission has a great deal of discretion to set just and reasonable rates, and can take into account other factors, such as public acceptance, rate stability, and revenue stability in setting rates.

Additionally, if the Commission were to reject the Company's across-the-board recommendation and adopt the other parties' proposed class revenue shifts, then the Commission would need to perform an analysis of potential rate migration (i.e., non-residential customers qualifying for more than one service classification opting out of their test year classification to another qualifying lower cost classification) and then make appropriate adjustments to the Company's billing units used to set rates in this case. This process would be essential if the Company is to satisfactorily design rates to meet the Commission-ordered revenue requirement in this case. But none of the parties that have proposed non-residential class revenue shifts have provided the evidence necessary for the Commission to complete such an analysis.

Q. The overwhelming majority of speakers thus far at the local public hearings held in this docket have been residential customers expressing their discontent with the potential impact on their electric bills of the increase being requested in this case. Have you performed an analysis that could aid the

Commission should it desire to take steps to mitigate the impact of a rate increase on residential customers?

A. Yes, I have. I examined the impact of shifting 1% of present revenues from the Company's Service Classification No. 1(M) Residential Service to Service Classification Nos. 11(M) – Large Primary Service and 12(M) – Large Transmission Service (i.e., the Company's service classifications with the lowest prices paid per unit of energy delivered). Utilizing present class revenues for the test year of twelve months of usage through September 30, 2011, and then shifting 1% of the residential class' revenue to the previously identified 11(M) and 12(M) classes based on these two classes' percentage of combined revenue, the resulting increase for classifications 11(M) and 12(M) would be approximately 3.5% higher than it would be if an across-the-board allocation to all classes was used.

This analysis was performed merely to provide the Commission information on the impact on class revenues if, as a matter of public policy, the Commission chose to mitigate the rate increase for residential customers given the comments from the public at the local public hearings.

III. <u>RATE DESIGN</u>

Q. On pages 21 through 23 of its Rate Design and Class Cost-Of-Service Report, Staff outlines eleven recommendations on rate design. What is the Company's position on those recommendations?

A. Two of Staff's recommendations pertain to class revenue requirements, which were addressed above, and a third, which pertains to pole and span charges associated with Service Classifications No. 5(M), is consistent with the Company's recommendation in my direct testimony.

Another of Staff's remaining recommendations addresses the uniformity of certain interrelationships among non-residential rate schedules, while six other recommendations address uniform adjustments of the respective classes' rate elements after determination of class rate increase percentages and customer charges. With regard to these seven recommendations, the Company's direct testimony in this docket reflects this same "uniformity"; therefore, the Company supports each of these seven Staff proposals as they apply to the final determination of affected rates in this docket.

Q. What about Staff's recommendation to increase the residential monthly customer charge to $9.00; does the Company agree with this recommendation?

A. No. As stated in my direct testimony, the Company's CCOS results support a residential customer charge of approximately $20. Although workpapers that accompanied Staff's Rate Design and Class Cost-Of-Service Report indicate that Staff's own study supports a value of $8.97 per month, that amount is suspect because of flaws in Staff's study. Company witness William Warwick's rebuttal testimony addresses the flaws and shortfalls of Staff's study.

Q. How does the Company's existing monthly residential customer charge compare to similar charges of other electric utilities regulated by the Commission?

A. The following Table 3 shows how the Company's existing monthly customer charge compares to other regulated electric utilities in Missouri (note: Staff provided a similar depiction in its Rate Design and Class Cost-Of-Service Study Report):

Table 3.
Current Residential Monthly Customer Charges of MO Regulated Utilities

Company	**Current Residential Customer Charge**
Ameren Missouri	$8.00
Empire District Electric Company	$12.52
Kansas City Power & Light Company	$9.00
KCP&L Greater Missouri Operations Company L&P	$9.75
KCP&L Greater Missouri Operations Company MPS	$10.43

This shows that the Company's residential customer charge is lagging behind similar charges of all of the other regulated electric utilities in the state. In fact, the Company's current monthly residential customer charge of $8 is more than 23% less than the $10.42 per month average of the other four Missouri regulated electric utilities. And increasing the customer charge to $9.00, as Staff proposes, would still make the Company's monthly residential customer charge less than the comparable charges of all but one other regulated electric utility in the state. These facts are especially ironic and troubling considering that the Company will have the most robust energy efficiency programs in the state. Lastly, the expected customer energy use reductions associated with efforts by third parties (e.g., Missouri Department of Natural Resources) or federal government standards that promote energy efficiency and demand response, and the impacts on the Company's ability to earn its authorized rate of return also provide support for the Company's recommendation. If the Commission were to approve the Company's recommended level of $12 for its residential service customer charge, then the Company's customer charge would still be less than that of The Empire District Electric Company and only approximately 15% above the average of all regulated electric utilities within the state.

Q. How does the Company's proposed monthly residential customer charge compare to similar charges of non-regulated electric coop utilities in Missouri?

A. The following Table 4 shows how the Company's proposed residential monthly customer charge of $12 compares to the majority of non-regulated coop electric service providers in Missouri.

Table 4

MISSOURI COOP MONTHLY RESIDENTIAL CUSTOMER CHARGES

Company Name	City	Monthly Customer Charge
Webster Electric	Marshfield	$18.00
Se-Ma-No Electric	Mansfield	$21.90
Southwest Electric	Bolivar	$16.00
Central Missouri Electric Cooperative	Sedalia	$14.00
Cuivre River Electric Cooperative	Troy	$15.21
Laclede Electric Cooperative	Lebanon	$11.79
Barry Electric Coop	Cassville	$20.00
Gascosage Electric Coop	Dixon	$25.00
SEMO Electric	Sikeston	$16.00
Ozark Border Electric	Poplar Bluff	$22.00
Crawford Electric	Bourbon	$25.00
Howell-Oregon Electric Coop	West Plains	$25.00
Black River	Fredericktown	$20.00
Missouri Rural Electric Cooperative	Palmyra	$25.00
Co-Mo Electric Cooperative	Tipton	$25.00
Boone Electric Cooperative	Columbia	$20.00

Intercounty Electric	Licking	$24.33
Ozark Electric Cooperative	Mt. Vernon	$20.00
West Central Electric	Higginsville	$25.00
Grundy Electric	Trenton	$25.00
Osage Valley Electric	Butler	$25.00
Consolidated Electric	Mexico	$27.50
Macon Electric Cooperative	Macon	$28.00
New-Mac Electric Cooperative	Neosho	$20.00
Farmers' Electric Coop	Chillicothe	$20.00
Pemiscot Dunklin Electric	Hayti	$22.00
Callaway Electric	Fulton	$25.00
Citizens Electric	Ste. Genevieve	$24.00
Sac Osage Electric	El Dorado Springs	$25.00
TriCounty Electric	Lancaster	$30.20
Lewis County Electric	Lewistown	$27.00
North Central Missouri Electric	Milan	$25.00
Barton County Electric	Lamar	$25.00
United Electric	Savannah	$25.00
Ralls County Electric	New London	$34.00
Atchison-Holt Electric	Rock Port	$15.50
Three Rivers Electric	Linn	$25.00
Platte-Clay	Kearney	$25.00

An examination of the monthly residential customer charges for both regulated and unregulated service providers of electric service in the State of Missouri, as shown in Tables 3 and 4 above, clearly shows that the Company's proposed monthly residential customer charge of $12.00 is not unreasonable and, also, that it would still be among the lowest charges for many electric service providers in the state.

The rebuttal testimonies of Company witnesses Mr. William Davis and Mr. William Warwick include additional support for the Company's proposed customer charge for this class.

Q. Did the Staff or the OPC make any recommendations regarding changes to the customer charge for the Company's Small General Service Classification?

A. Yes. The Staff recommended that after a revenue-neutral reduction of 1% for the Small General Service Classification, the existing customer charge should be increased by the percentage increase in revenue requirement authorized by the Commission in this case. The OPC recommended no change from the existing level of $9.74 per month.

Q. Does the Company agree with either of these recommendations?

A. Staff's class cost of service study yielded a monthly customer charge for the Small General Service of $10.98 per month, while OPC's study yielded a charge of $10.64. As stated in my direct testimony, the Company's class cost of study supported a $22 per month customer charge; however, the Company proposes to limit the increase in this case to $14.61 per month for single phase service and $29.24 for three phase service.

As was the case for the Residential class, due consideration of costs and the Company's robust energy efficiency program provide more than adequate support for the Company's recommended monthly customer charge for the Small General Service Classification.

Q. On page 30 of the Staff's Rate Design and Class Cost-Of-Service Report Staff recommends the Commission order the Company to file, within thirty (30) days of the effective dates of rates in this case, the Company's entire tariff as a single document bearing the designation "P.S.C. Mo. 6" to replace several documents currently on file. What is the Company's position regarding this recommendation?

A. As stated in Staff's report, the Staff and the Company have "spent a substantial amount of time and resources in this endeavor and completed much of the work." Therefore, absent any unforeseen events or circumstances, Staff's proposed thirty day window should provide ample opportunity for the Staff and the Company to reach consensus on the tariffs to be filed and, at the same time, not result in a "pancaking" of the proposed Schedule 6 filing with any other planned tariff filing (e.g., the Company's periodic Rider FAC tariff sheet filing). The Company expects to reach agreement with Staff on this issue prior to the evidentiary hearings in this case.

Q. On pages 31-32 of the Staff's Rate Design and CCOS Report, Staff recommends certain changes to the Company's Rider FAC tariff sheets. As described by Staff, these changes involve revisions to certain terminology used in the FAC and are proposed to support Staff's effort to promote uniformity of FAC tariffs among regulated electric utilities in Missouri. What is Ameren Missouri's position on this recommendation?

A. First, the Company fully supports Staff's effort to promote uniformity of FAC tariffs in Missouri, where practicable. As stated in Staff's report, the Company has already provided some preliminary feedback to a draft of Staff's proposed changes to the Company's Rider FAC prior to the filing of Staff's Schedules LMM-2 and LMM-3 to Staff's report. Since the filing of those two schedules, the Company has identified some additional terminology or housekeeping type changes to suggest.

Schedule WLC-ER8 to my rebuttal testimony contains exemplar FAC tariff sheets with the Company proposed changes to Schedule LMM-2 without any markings to track the proposed changes, and Schedule WLC-ER9 is a tracked version of those same proposed changes to LMM-2.

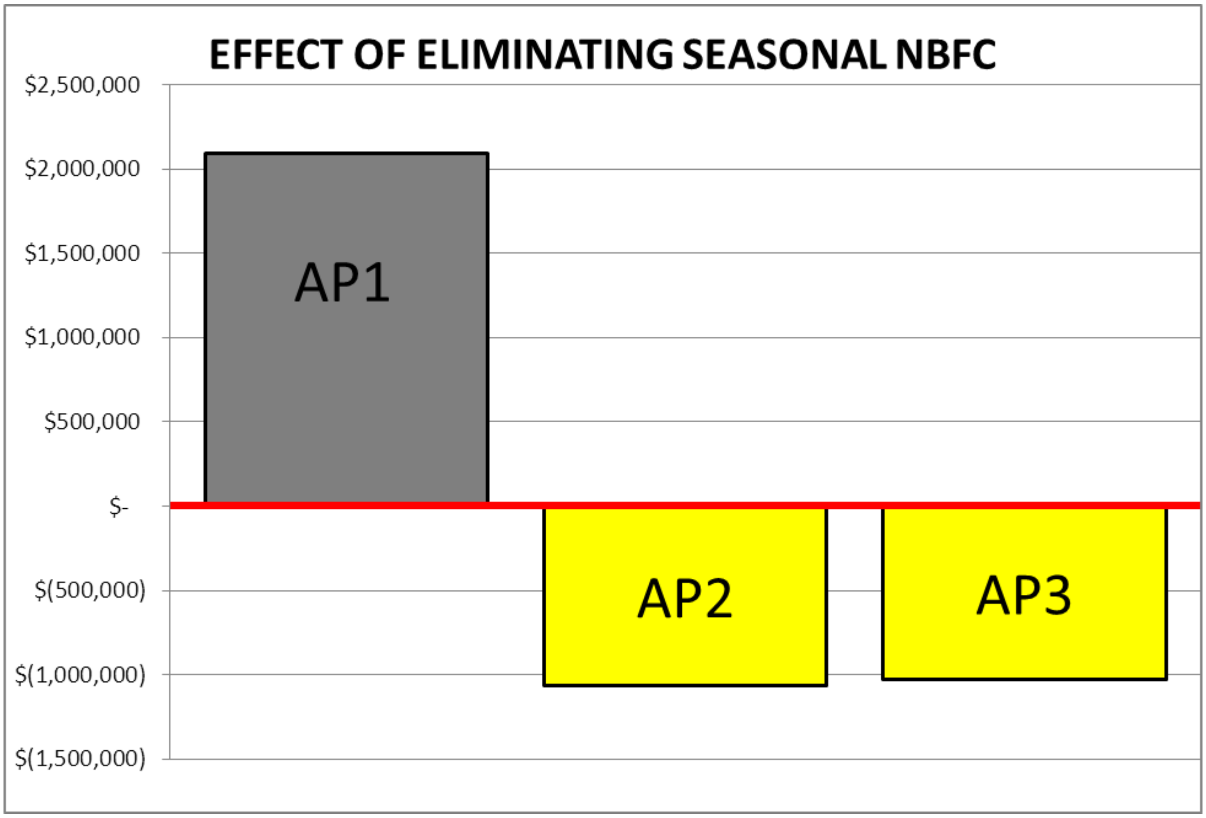
It should be noted that the changes indicated on these two schedules represent the Company's comprehensive proposed changes to the Company's Rider FAC tariffs (i.e., both housekeeping changes and material/substantive changes).

Q. Please comment on certain of the material/substantive changes.

A. I will address two areas: 1) Staff's proposal to eliminate the seasonality of the factor BF or net base energy cost factor and 2) Staff's proposal to refine the definition of factor OSS or Off-System Sales Revenue to address the potential loss of Large Transmission Service load.

Q. What are the Company's concerns with Staff's proposal to eliminate the seasonality of base fuel charges (Factor BF)?

A. The Company is concerned that the elimination of the seasonality of factor BF would likely increase volatility in the Company's monthly Rider FAC adjustment. The following graph illustrates the volatility that would result from utilizing the Company's test year sales and proposed seasonal BF's (i.e., summer 1.529¢/kWh and winter 1.533¢/kWh) vs. weighting these values consistent with Staff's recommendations (i.e., a flat BF) and assuming hypothetically "perfect" prospective FAC ratemaking:



As shown above, actual fuel costs during the summer accumulation period ("AP1") would be lower than the tariffed BF, which would produce a positive difference and credits for customers in a subsequent Recovery Period, while actual BF costs in the two winter APs (AP2 and AP3) would be higher than the tariffed BF, which would produce a negative difference and surcharges for customers' bills in a subsequent Recovery Period. Mathematically, and ignoring interest, the net effect over all three periods would be zero; however, there would be volatility reflected in customers' bills due to these seasonal differences.

Moreover, where subsequent seasonal BFs could have a greater differential than are shown in my illustration, then the volatility I spoke of a moment ago would increase.

Also, creating this increased volatility in customers' bills appears to be inconsistent with the Staff's desire, as expressed in the Cost-Of-Service and Revenue Requirement Report to reduce the volatility of the Company's FAC adjustments.

Q. Does the Company agree with Staff's recommendation to clarify the mechanics of its Rider FAC which apply in the event the Large Transmission Service "loss of load" event triggers?

A. Yes, Staff's language provides additional clarity to this provision while maintaining the overall objective of this provision of the tariff.

Q. Does the Company agree with Staff's proposals for: 1) "Additional Filing Requirements, 2) Fuel Adjustment Clause Heat Rate Efficiency Testing, and 3) FAC Adjustments for Updated System Loss Study recommendations as discussed on pages 172-175 of Staff's Revenue Requirement Cost-of-Service Report?

A. Yes, the Company agrees with Staff's recommendations.

Q. Does the Company agree with the Staff's changes regarding the sharing percentage in the FAC and regarding transmission costs?

A. No. Company witnesses Lynn M. Barnes and Jaime Haro address the sharing percentage issues, and Mr. Haro addresses the transmission cost issue.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Annual Revenues for Electric Service.	)))	File No. ER-2012-0166

AFFIDAVIT OF WILBON L. COOPER

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

Wilbon L. Cooper, being first duly sworn on his oath, states:

1. My name is Wilbon L. Cooper. I am employed by Union Electric Company d/b/a Ameren Missouri as Manager of the Rates and Tariffs Department.

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 20 pages and Schedule(s) WLC-ER8 thru WLC-ER9, 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.

Wilbon L. Cooper

Wilbon L. Cooper

Subscribed and sworn to before me this 14th day of August, 2012.

Julie Donohue

Notary Public

My commission expires: 2/17/2013

Julie Donohue - Notary Public
Notary Seal, State of
Missouri - St. Louis City
Commission #09753418
My Commission Expires 2/17/2013

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing no later than sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

**Indicates Change.

Schedule WLC-ER8

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% + I \pm P \pm T]/S_{RP}$$

Where:

ANEC = FC + PP + E – OSSR

B = BF x S_{AP}

FC = Fuel costs associated with the Company's generating plants. These consist of the following:

a) For fossil fuel plants:

(i) the following net costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account Number 501 for: coal commodity, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, oil costs, ash disposal costs and revenues, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following net costs and revenues reflected in FERC Account Number 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and powder activated carbon; and

(iii) the following net costs and revenues reflected in FERC Account Number 547 for: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation , fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

b) Net costs and revenues in FERC Account Number518 (Nuclear Fuel Expense).

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

PP = Net costs and revenues for purchased power reflected in FERC Account Numbers 555, 565, and 575, including those associated with hedging, but excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one(1) year. Also included in factor "PP" are insurance premiums in FERC Account Number 924 for replacement power insurance to the extent those premiums are not reflected in base rates. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

E = Net costs and revenues for SO_2 and NO_X emissions allowances in Accounts 411.8, 411.9, and 509, including those associated with hedging.

OSSR = Net revenues in FERC Account 447, including those associated with hedging.

**Indicates Change.

Schedule WLC-ER8

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2012-0166, an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month - No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month -An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction, or (2) off-system sales revenues up to the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2012-0166.

For purposes of factors FC, PP, E, and OSSR, "hedging" is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities)minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power and emission allowances, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors or that are not listed in such factors at all, such items shall nevertheless be included in factor FC, PP, E or OSSR.

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above plus the metered net energy output of any Company generating station operating within its

Schedule WLC-ER8

certificated service territory as a behind the meter resource in MISO.

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any Company generating station operating within its certificated service territory as a behind the meter resource in MISO.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

BF = The Base Factor, is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from Off-System Sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is $0.01529 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01553 per kWh.

T = True-up amount as defined below.

P = Prudence disallowance amount, if any, as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

$$FAR = FAR_{RP} + FAR_{RP-1}$$

where:

FAR = Fuel and Purchased Power Adjustment rate starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component from other prior FAR_{RP}.

To determine the FAR applicable to the individual Service Classifications, the FAR determined in accordance with the foregoing will be multiplied by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0575
Primary Voltage Service (VAF_{PRI})	1.0252
Large Transmission Voltage Service (VAF_{TRAN})	0.9917

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

**Indicates Change.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in T above. Interest on the true-up adjustment will be included in I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

**Indicates Change.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Calculation of Fuel Adjustment Rate for [month, day, year] through [month, day, year])**

Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending:			Month, Day, Year
1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$
2.	Net Base Energy Cost (B)	-	$
2.1	Base Factor (BF)	x	$0.00000
2.2	Accumulation Period Sales (S_{AP}))		XXXXXX kWh
3.	Total Company Fuel & Purchased Power Difference	=	$
3.1	Customer Responsibility	x	95%
4.	Fuel & Purchased Power Amount to be Recovered	=	$
4.1	Interest (I)	+	$
4.2	True-Up Amount (T)	±	$
4.3	Prudence Adjustment Amount (P)	±	
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$/kWh
9.	Fuel Adjustment Rate (FAR)	=	$/kWh
10	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0575
11.	FAR for Secondary Customers (FAR_{SEC})		$/kWh
12.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0252
13.	FAR for Primary Customers (FAR_{PRI})		$/kWh
14.	Transmission Voltage Adjustment Factor (VAF_{TRAN})		0.9917
15.	FAR for Transmission Customers (FAR_{TRAN})		$/kWh

** Indicates Change.

Schedule WLC-ER8

UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 5 SHEET NO.

CANCELLING MO.P.S.C. SCHEDULE NO. 5 SHEET NO.

APPLYING TO **MISSOURI SERVICE AREA**

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation~~,~~ ~~plus~~ and emissions costs and revenues, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing no later than sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

~~Eighty~~ Ninety five percent (~~85~~95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

**Indicates Change.

DATE OF ISSUE DATE EFFECTIVE

ISSUED BY Warner L. Baxter President & CEO St. Louis, Missouri

NAME OF OFFICER TITLE ADDRESS

Schedule WLC-ER9

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times \cancel{85}95\% + I \cancel{+} \pm P \pm\cancel{+} T]/S_{RP}$$

Where:

ANEC = FC + PP + E – OSSR

B = BF x S_{AP}

FC = Fuel costs associated with the Company's generating plants. These ~~costs~~ consist of the following:

a) For fossil fuel plants:

(i) the following net costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account Number 501 for: coal commodity, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs~~ including over the road diesel hedging~~, fuel oil adjustments included in commodity and transportation costs, ~~broker commissions and fees associated with price hedges,~~ oil costs, ash disposal costs and revenues~~ and expenses~~, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following net costs and revenues reflected in FERC Account Number 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and powder activated carbon; and

(iii) the following net costs and revenues reflected in FERC Account Number 547 for: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation ~~charges~~, fuel losses, hedging~~ costs~~,~~ broker commissions and fees associated with price hedges,~~ and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

b) Net c~~C~~osts and revenues in FERC Account Number 518 (Nuclear Fuel Expense).

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

~~For purposes of factor FC, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including futures contracts, puts, calls, caps, floors, collars, and swaps.~~

PP = Net cCosts and revenues for ~~of~~ purchased power reflected in FERC Account Numbers 555, 565, and 575, including those associated with hedging, but excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one(1) year. ~~Only transmission costs incurred for the purchase or sale of electricity shall be included.~~ Also included in factor "PP" are insurance premiums in FERC Account Number 924 for replacement power insurance to the extent those premiums are not reflected in base rates. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

E = Net ~~Emission~~ costs and revenues for SO_2 and NO_x emissions allowances in Accounts 411.8, 411.9, and 509, ~~;~~ including those associated with hedging.

OSSR = Net ~~All~~ revenues in FERC Account 447, including those associated with hedging.

**Indicates Change.

DATE OF ISSUE   DATE EFFECTIVE

ISSUED BY Warner L. Baxter   President & CEO   St. Louis, Missouri

NAME OF OFFICER   TITLE   ADDRESS

Schedule WLC-ER9

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2012-0166, an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month
- No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month
-An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction, or (2) off-system sales revenues up to the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2012-0166.

For purposes of factors FC, PP, E, and OSSR, "hedging" is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities)minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power and emission allowances, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors or that are not listed in such factors at all, such items shall nevertheless be included in factor FC, PP, E or OSSR.

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above plus the metered net energy output of any Company generating station operating within its

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certificated service territory as a behind the meter resource in MISO.

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any Company generating station operating within its certificated service territory as a behind the meter resource in MISO.

**Indicates Change.

DATE OF ISSUE		DATE EFFECTIVE		
ISSUED BY	Warner L. Baxter	President & CEO	St. Louis, Missouri	
	NAME OF OFFICER	TITLE	ADDRESS	

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

BF = The Base Factor, ~~$0.01586 per kWh~~ ~~determined by the Commission's order~~ is equal to the normalized ~~test year~~ value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), ~~plus~~ and ~~the cost of~~ emissions costs and revenues (consistent with the term E), less revenues from Off-System Sales (consistent with the term OSSR) divided by corresponding normalized ~~test year~~ retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is $0.01529 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01553 per kWh.

T = True-up amount as defined below.

P = Prudence disallowance amount, if any, as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below~~, applicable starting with the following RP~~ is calculated as:

$$FAR = FAR_{RP} + FAR_{RP-1}$$

where:

FAR = Fuel and Purchased Power Adjustment rate starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component from other prior FAR_{RP}.

To determine the FAR applicable to the individual Service Classifications, the FAR determined in accordance with the foregoing will be multiplied by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0575
Primary Voltage Service (VAF_{PRI})	1.0252
Large Transmission Voltage Service (VAF_{TRAN})	0.9917

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

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RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in "T" above. Interest on the true-up adjustment will be included in ~~item~~ I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in ~~item~~ "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in ~~item~~ "I" above.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Calculation of Fuel Adjustment Rate for [month, day, year] through [month, day, year])**

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending:			Month, Day, Year
1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$
2.	Net Base Energy Cost (B)	-	$
2.1	Base Factor (BF)~~($0.01586/kWh)~~	x	$0.00000
2.2	Accumulation Period Sales (S_{AP})–)		XXXXXX kWh
3.	Total Company Fuel & Purchased Power Difference	=	$
3.1	Customer Responsibility	x	~~85~~95%
4.	Fuel & Purchased Power Amount to be Recovered	=	$
4.1	Interest (I)	+	$
4.2	True-Up Amount (T)	±~~+~~	$
4.3	Prudence Adjustment Amount (P)	±~~-~~	
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$/kWh
9.	Fuel Adjustment Rate (FAR)	=	$/kWh
10	Secondary Voltage Adjustment Factor (VAF$_{SEC}$)		1.0575
11.	~~Fuel Adjustment Rate~~FAR for Secondary Customers (FAR_{SEC})		$/kWh
12.	Primary Voltage Adjustment Factor (VAF$_{PRI}$)		1.0252
13.	~~Fuel Adjustment Rate~~FAR for Primary Customers (FAR_{PRI}) $/kWh		
14.	Transmission Voltage Adjustment Factor (VAF$_{TRAN}$)		0.9917
15.	~~Fuel Adjustment Rate~~FAR for Transmission Customers (FAR_{TRAN}) $/kWh		

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