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MISSOURI PUBLIC SERVICE COMMISSION

File No. ER-2014-0258

DIRECT TESTIMONY

OF

WILLIAM R. DAVIS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
July, 2014

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DIRECT TESTIMONY

OF

WILLIAM R. DAVIS

FILE NO. ER-2014-0258

Q. Please state your name and business address.

A. My name is William ("Bill") R. Davis. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am an Economic Analysis and Pricing Manager for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Please describe your educational background and employment history.

A. I received a Bachelor of Science in Economics from Illinois State University in 2002. I subsequently received a Master of Science in Economics with an emphasis in regulatory economics from Illinois State University in 2003. I completed several internships during my college career, including an internship with Illinois Power Company. Upon completion of my master's degree, I began working full-time for Caterpillar, Inc., at its corporate headquarters in Peoria, Illinois, as an Advanced Quantitative Analyst in the Business Intelligence Group, with the primary duties of performing economic and sales analyses.

In May 2005, I joined Ameren Services Company as a Load Research and Forecasting Specialist in the Corporate Planning Department. My duties included electricity and natural gas sales forecasting, load research, weather normalization, and various other sales analyses. In September 2007, I became a Senior Load Research Specialist and then moved to the Resource Planning Group in March 2009. In October 2011, I became a Senior Corporate Planning

Analyst. In that position, I was responsible for Ameren Missouri's 2011 Integrated Resource Plan and the 2012 Missouri Energy Efficiency Investment Act ("MEEIA") filing, and was subsequently promoted to my current position in March 2013.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. My direct testimony discusses: a) the revenue increase being proposed for the Company's electric retail rate classes; b) the development and results of a class cost of service study being submitted in connection with the direct testimony of Ameren Missouri witness William M. Warwick as part of this case; and c) the design and development of rates for the individual customer classes.

Q. Please summarize your testimony.

A. I recommend the Commission approve the tariffs in Schedule WRD-1 that effectuate the requested rate increase of $264.1 million. The tariffs reflect the four basic proposals below:

1) Each customer class receives an equal percentage increase of 9.65%[1].

2) The charges for each customer class increase by the same percentage as the class total[2].

3) Approval of a residential low income exemption for energy efficiency charges.

4) Approval of a voluntary residential "Nights and Weekends" rate pilot to replace the existing residential time of day rate option.

[1] Schedule WRD-2 illustrates the effects of the proposed rates in Schedule WRD-1 upon typical monthly bills of customers served under the Company's non-lighting rate service classifications.
[2] After adjusting for the pre-MEEIA energy efficiency charges and certain charges to maintain consistency between rate classes.

II. CLASS COST OF SERVICE STUDY

a. Class Cost of Service Concepts

Q. Please explain what is meant by "class cost of service."

A. The Company currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service. The non-residential customer group is differentiated by customer size and the voltage level at which the Company provides service. The current customer classes are Residential, Small General Service ("SGS") and Large General Service ("LGS") (all of which have their service delivered at a low secondary voltage level); Small Primary Service ("SPS") and Large Primary Service ("LPS") (delivery at a high voltage level); Large Transmission Service ("LTS") (delivery at a "transmission" voltage level); and Lighting Service (both area and street lighting). A class cost of service study provides a basis for allocating and/or assigning the Company's total jurisdictional cost of providing electric service to these customer classes in a manner that reflects cost causation. The results of a class cost of service study with equalized rates of return are often referred to as "class revenue requirements." Mr. Warwick conducted a class cost of service study for this case and he is sponsoring that study in direct testimony filed in this proceeding.

Q. How are the results of a class cost of service study used by the Company?

A. These study results are typically used to develop the target level of annual revenue that the Company should recover from each customer class through the application of the rates or charges within the Company tariffs under which the various customer classes are being served.

Q. Please explain your use of the term "rate design."

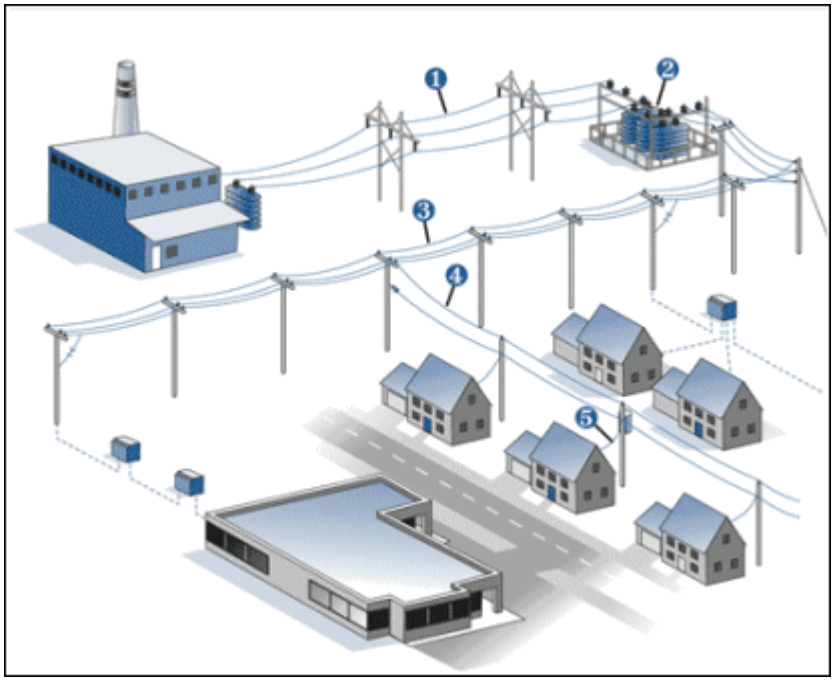
A. Generically speaking, my use of the term "rate design" refers both to the process of establishing the specific charges (e.g. monthly customer charges, dollars per kilowatt of demand and/or cents per kilowatt-hour energy charges) for each customer class, as well as to the actual structure of an individual class rate. The rate design, or structure, of a given class rate may range in

complexity from a simple structure consisting of a monthly customer charge and a flat charge per kilowatt-hour (such as the Company's summer Residential rate), to a more complex set of customer, demand, energy, and reactive charges (such as the Company's SPS, LPS and LTS rates). In all instances, however, the charges within a specific rate classification are established such that the application of these individual charges to the total annual customer class electrical usage will result in the collection of the targeted annual revenue requirement of each of the Company's retail rate classes.

Q. As background for additional discussion on the class cost of service study the Company is sponsoring in this case, please provide a general description of the various facilities utilized by the Company in producing and delivering electricity to its customers.

A. The figure below is a simplified diagram illustrative of the Ameren Missouri electric system showing how power flows from the generating station and is then transmitted and distributed to the home of a residential customer. Other customers receiving service at higher voltage levels are also served from various points on the same system.

Figure 1 – Simplified Diagram of Electrical System



1 Electrical power is produced at the Company's generating stations at voltage levels ranging from 11,000 to 23,750 volts. To achieve transmission operating economies, this voltage is raised, or stepped up, by power transformers at the generating station sites to voltages generally ranging from 138,000 to 345,000 volts for transmission to the Company's bulk substations, which are strategically located throughout its service area.

- The Company serves its only current LTS customer at 161,000 volts via a unique transmission service arrangement.

2 At a substation the electricity's voltage is lowered so that it can travel over the distribution system. Although this diagram does not show this level of detail, there are two main classes of substations: bulk substations and distribution substations. The bulk substations are used to lower the voltage but still keep the voltage relatively high (usually 34,500 or 69,500 volts) while the distribution substations lower the voltage even further (4,160 to 13,800 volts) to distribute power closer to customer premises.

- The Company serves approximately 80 customers at voltages above the 13,800 volt level. These are referred to as "high voltage" or Rider B customers.

- Approximately 720 large non-residential customers receive service at 4,160 to 13,800 volts and are referred to as "primary" voltage customers.

3 Main distribution power lines, typically 3-phase circuits, bring electricity into

communities.

4 Local distribution power lines serve neighborhoods and individual customers.

5 Service lines carry electricity from pole-mounted or pad-mounted transformers - which lowers the voltage again - to customer premises.

- Residential customers are served at either 120 or 240 volts depending upon the customer's service entrance panel size and connected appliances.
- Non-residential customers on the Company's SGS or LGS rates are served at voltages from 120 to 480 volts due to the wide variety of electrical consuming devices utilized by such customers.

Q. In your description of the Ameren Missouri generation, transmission, and distribution system are you using the term "lines" in a general sense?

A. Yes. Those "lines" may be overhead conductors or underground cables. Overhead "lines" include all poles, towers, insulators, cross arms, and all other hardware associated with such installations. Underground "lines" include direct buried cable, as well as that installed in single or multi-duct conduit, and other associated hardware.

b. Costs and Revenues in Class Cost of Service Study

Q. Please describe the components of costs and revenues that are contained in the class cost of service study that the Company is filing in this case.

A. A traditional cost of service study incorporates the aggregate jurisdictional (Missouri or Federal Energy Regulatory Commission ("FERC")) accounting and financial data normally submitted to a regulatory commission by a utility in support of a request for an adjustment in its overall rate levels. Such a study is required to determine the level of revenues necessary for the Company to recover its operating and maintenance expenses through rates, depreciation applicable to its investment in utility plant, property taxes, income and other taxes, and provide a fair rate of return to the Company's investors. The Company's class cost of service study allocates, or distributes, these

total jurisdictional costs to the various customer classes in a cost-based manner that fairly and equitably reflects the cost of the service being provided to each customer class.

Q. Was a Missouri jurisdictional cost of service study performed by the Company's Regulatory Accounting group the starting point for the class cost of service study performed and sponsored by Mr. Warwick?

A. Yes, it was. As I indicated above, the Company's class cost of service study is a continuation and refinement of the Missouri jurisdictional cost of service study discussed in the direct testimony of Ameren Missouri witness Laura M. Moore, resulting in a determination of the costs incurred in providing electric service to each of the Company's customer classes.

Q. What major categories of cost were examined in the development of the class cost of service study being sponsored by Mr. Warwick in this case?

A. A detailed analysis was made of all elements of the Company's Missouri jurisdictional rate base investment and expenses during the test year for the purpose of allocating such items to the Company's present customer classes. This analysis consisted of classifying the various elements of cost into their customer-related, energy-related, and demand-related cost categories.

Q. Why are the Company's costs classified into these three categories?

A. It is generally accepted within the industry that the costs in each of these categories result from different cost causation factors and hence should be allocated among the various customer classes by different methodologies which consider such cost causation.

Q. What are customer-related costs?

A. Customer-related costs are the minimum costs necessary to just make electric service available to the customer, regardless of the extent to which such service is utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting and customer service expenses, as well as a portion of the costs associated with the required investment in a meter,

the service line, the transformer and other distribution system facilities. The customer components of the distribution system are those costs necessary to simply provide reliable and safe service to a customer, without the consideration of the amount of the customer's electrical use.

Q. What are energy-related costs?

A. Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, interchange power costs, and a portion of production plant maintenance expenses.

Q. What are demand-related costs, which are the third category of costs to which you referred?

A. Demand-related costs are rate base investment and related operating expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. During such peak periods, this usage is expressed in terms of the customer's maximum power consumption, commonly referred to as kilowatts of demand. As defined, demand-related costs include those costs in excess of the aforementioned customer and energy-related costs. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant.

c. Cost Allocations

Q. After the Company's costs are categorized into one of the three major classifications, how are they allocated to the various rate classes?

A. Customer-related costs are normally allocated on the basis of the number of customers associated with each rate class. In some instances involving non-residential customer multiple metering installations, weighting factors may also be used. In addition, where specific costs can be identified as being attributable to one or more specific customer classes, such as credit and collection expenses, a direct assignment of such costs will be made. Energy-related costs are

allocated to the customer classes on the basis of their respective energy (kilowatt-hour) requirements at the generation level of the Company's system, which includes applicable system energy losses. Demand-related distribution costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident, or individual customer non-coincident kilowatt demands. Demand-related transmission costs are allocated to customer classes on a 12 coincident peak ("CP") basis, as that methodology is consistent with the method utilized to assign cost responsibility of the demands of the Ameren operating companies and all of the other utilities participating in the Midcontinent Independent System Operator, Inc. ("MISO"), per MISO's Attachment O Rate Formulae in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff on file at the FERC. Demand-related production costs are allocated on the basis of the Average & Excess ("A&E") Demand Method referenced in the National Association of Regulatory Utility Commissioners ("NARUC") cost allocation manual. As not all customers have demand meters, customer class and individual customer kilowatt demand data is obtained from the Company's ongoing load research program.

Q. As generation (production) plant consists of more than half of the Company's total plant investment, please summarize the most common cost allocation methodologies employed within the electric utility industry for the allocation of generation plant.

A. The most common and generally accepted methodologies used for the allocation of generation plant can be grouped into the following three categories:

Coincident Peak – Costs are allocated on the basis of the relative customer class demands at the time of occurrence of the company's system peak during the period of study (referred to as the "CP" method). One or more system peak hours, or a number of monthly or seasonal system peaks, are normally used in applying the CP methodology. For instance, transmission costs are allocated using a "12 CP" method, which is based on averaging the test year's monthly coincident peaks.

Non-Coincident Peak – Costs are allocated on the basis of the maximum peak demand of each customer class at any time during the study period, without regard to the time of occurrence or magnitude of the company's coincident system peaks (referred to as the "NCP" method). As with the CP method, the NCP methodology can employ one or more customer class peaks in its application. As a simple example, consider street lighting; the summer street lighting non-coincident peak occurs at night when the street lights are active, yet street lighting demand is zero at the time of the summer system coincident peak (usually at 4 p.m. or 5 p.m.).

Average and Excess - Costs are allocated based upon a weighting of average class demand throughout the year (kilowatt-hours ÷ 8,760 hours) and class "excess" demand(s) (referred to as the "A&E" method). The excess demand(s) used in this determination are the class NCP demand(s) in excess of the average class demand during the study period. As with the CP and NCP methodologies, this method can also employ the use of one or more customer class NCP demands to determine class excess demands. Average class demands are weighted by the Company's annual system load factor ("LF") (LF = average demand ÷ peak demand) and excess class demands are weighted by the complement of the load factor (1.0 – LF) in the development of cost allocation factors using this methodology.

Q. Which cost allocation methodology is the Company using for production plant in its class cost of service study in this case?

A. The Company is utilizing the 4 NCP version of the Average and Excess demand methodology for allocating production plant in this case.

Q. From a generation perspective, what were the considerations associated with the Company's election to utilize the A&E demand allocation methodology for production plant in this case?

A. Two major factors associated with generation capacity planning prompted the use of the A&E demand cost allocation methodology. Generally, system peak demands and, to a somewhat

lesser extent, excess customer demands, are the motivating factors which influence the amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type of capacity (base, intermediate, or peaking) that the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt-hours, that will be required to be generated by such capacity, i.e., the generation unit's utilization factor. A cost allocation methodology that gives weight to both a) class peak demands and b) class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt-hours divided by total hours in the year (8,760), and the excess NCP demands of each class. As indicated earlier, the Company's A&E cost allocation study used both the 4 NCP and average class demands in the determination of class excess demands.

Q. Is there also quantitative support for the Company's selection of the 4 NCP version of the A&E demand allocation methodology for production plant?

A. Yes. The 4 NCP version of the A&E methodology, which uses the four maximum non-coincident monthly peak demands for each customer class during the test year, was selected due to the fact that 15 of the 20 maximum 4 NCP monthly demands for the Company's major (i.e., non-lighting) customer classes occurred during the Company's summer peak demand months of June-September. The use of the 4 NCP demand option, rather than a lesser number of monthly NCP demands, also prevents the demand allocator for any customer class from being unduly influenced by any extreme demand in a given month.

Q. After the determination of customer, energy and demand allocation factors for the various components of the Company's costs, what was the next step in the completion of the Company's class cost of service study?

A. The next step was to apply the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The aggregation of such cost allocations indicates the total annual costs, or annual revenue requirement, at equalized rates of return associated with serving a particular customer class. The operating revenues of each customer class minus its total operating expenses provide the resulting net operating income for each class. This net operating income divided by the rate base allocated to each class will indicate the percentage rate of return being earned by the Company from a particular customer class. This application of allocation factors to Missouri electrical jurisdictional costs, the aggregation of the total annual cost to each of the customer classes, and a summary of the results of the Company's class cost of service study are described in detail in Mr. Warwick's direct testimony.

d. Study Results

Q. Please summarize the results of the Company's class cost of service study.

A. The table below is a summary of the class cost of service study indicating the return on rate base currently being earned on the service being provided to the Company's major retail customer classes. A more detailed summary can be found in schedule WMW-1 to Mr. Warwick's direct testimony.

Table 1 – Summary of Class Cost of Service Study

Customer Class	Actual RORB*	Target RORB*
Residential Service	2.729%	8.045%
Small General Service[3]	6.119%	8.045%
Large General and Small Primary Service	7.572%	8.045%
Large Primary Service	4.224%	8.045%
Large Transmission Service	1.644%	8.045%
Lighting Service	4.581%	8.045%
Total	**4.436%**	**8.045%**

*RORB – Return on Rate Base

[3] Includes Metropolitan Sewer District

Q. What general conclusions can be drawn from the information contained in the table above?

A. The Residential and LTS classes are providing below average rates of return, the LPS and Lighting Service are providing near average rates of return, while SGS, LGS, and SPS classes are providing above average rates of return. Overall, as is suggested by the filing of this case, the Company's return on its rate base is inadequate.

e. Class Revenue Proposals

Q. What would the base revenue requirements be if rates were set purely on the class cost of service study?

A. The table below summarizes the class base revenue requirements necessary to give the Company an opportunity, based upon test year figures with the pro forma adjustments made by Ms. Moore, to achieve an equal rate of return from each of its customer classes. A more detailed summary can be found in schedule WMW-2 to Mr. Warwick's direct testimony.

Table 2 – Cost-Based Base Revenue Requirements by Customer Class ($MM)

Customer Class	Base Revenue Requirement	Return on Rate Base
Residential Service	$1,425.3	8.045%
Small General Service[4]	$318.2	8.045%
Large General and Small Primary Service	$813.5	8.045%
Large Primary Service	$221.35	8.045%
Large Transmission Service	$181.9	8.045%
Lighting Service	$41.65	8.045%
Total	**$3,001.9**	**8.045%**

Q. Why are equal rates of return for all customer classes an appropriate starting point when designing electric utility rates?

[4] Includes Metropolitan Sewer District

A. There are several reasons why equal rates of return for all customer classes are an appropriate starting point in the consideration of rate design. First and foremost is the consideration of equity and fairness to all electric customers. Purely from a cost perspective, and ignoring all other factors, to overcharge one customer class in order to subsidize another class is not fair. A second important consideration in support of equal class rates of return is the goal of encouraging cost effective utilization of electricity by customers. To make appropriate decisions regarding the most efficient and effective use of electricity, including decisions regarding the acquisition of equipment that uses electricity, customers require correct and appropriate price signals from the Company's electric rates. Equal rates of return for all customer classes promote such price signals. A third consideration is that of competition. Cost-based electric rates permit the Company to compete effectively with alternative fuels, co-generation, and other electric providers for new commercial and industrial customers.

Q. Once the annual cost-based revenue requirements are developed by this process for all of the Company's customer classes, would the design of specific rates for each class be the next and final step in the overall rate development process?

A. If one were to base class rates solely on class cost of service and ignore other relevant factors, the response would be yes. However, the results of Mr. Warwick's study produced the revenue increases by customer class shown in the table below.

Table 3 – Cost-Based Rate Increases by Customer Class

Customer Class	Cost of Service Increase
Residential Service	15.8%
Small General Service[5]	5.1%
Large General and Small Primary Service	1.1%
Large Primary Service	9.2%
Large Transmission Service	14.1%
Lighting Service	10.0%
Total	**9.65%**

Q. Is the Company proposing that these strictly cost-based class revenue requirements be utilized in developing class rates in the case?

A. No, the Company is proposing some departure from class revenue requirements or rate design being established solely on the basis of equal class rates of return as shown in its class cost of service study.

Q. What is the Company's proposal for allocating the revenue increase requested in this case?

A. The Company is proposing to allocate the revenue increase requested in this case across-the-board, on an equal percentage of present revenue basis.

Q. Please explain the Company's proposal to allocate the revenue increase in this case on an equal percentage or across-the-board basis rather than based solely on class cost of service study results.

A. While using the results of a given class cost of service study is an important starting point in developing class revenue targets and rate design, no one class cost of service study yields "the" perfect result since class cost of service studies are estimates. That is not to say that all class cost of service studies are equally valid; instead, it means there is a reasonable range around the point

[5] Includes Metropolitan Sewer District

estimates produced by the Company's class cost of service study. Other factors – such as revenue stability, rate stability, effectiveness in yielding total revenue requirements, public acceptance, and value of service – can then be considered when determining class revenue requirements and designing rates. Those additional considerations drove the Company's equal percentage of increase proposal.

In addition, the costs and benefits of energy efficiency need to be carefully considered. For instance, the residential class has experienced above average increases in energy efficiency costs. However, with those above average costs, the residential class will also see above average benefits. Those above average energy efficiency benefits ultimately result in less costs being assigned to the residential class thus naturally pushing the class closer to its cost of service. While moving to cost of service is a worthy goal, it is also important not to overcorrect; that is, inadvertently apply an above average rate increase to a rate class only to find out in the next rate case that the same class needs a below average increase. Therefore, the Company believes that following other rate design principles like gradualism, when deciding where rates should fall within a reasonable range around the point estimates produced by a class cost of service study, is a prudent way to monitor the effects of energy efficiency; and, where possible, let rate classes naturally converge to what the class cost of service study indicates the cost of service is.

Q. Please summarize the Company's proposed rate increase.

A. The table below summarizes the proposed class revenue requirements necessary to give the Company an opportunity, based upon test year figures, to achieve its jurisdictional rate of return.

Table 4 – Proposed Rate Increases by Customer Class

Customer Class	Current Retail Revenues	Proposed Base Revenue Requirement	Required Base Revenue Adjustment*	Percentage Increase
Residential Service	$1,230,497,365	$1,349,189,352	$118,691,987	9.65%
Small General Service	$302,777,223	$331,980,401	$29,203,178	9.65%
Large General Service	$576,863,372	$632,477,169	$55,613,798	9.64%
Small Primary Service	$227,596,391	$249,536,714	$21,940,323	9.64%
Large Primary Service	$202,782,047	$222,324,039	$19,541,992	9.64%
Large Transmission Service	$159,333,049	$174,694,353	$15,361,303	9.64%
Lighting Service	$37,876,368	$41,530,084	$3,653,717	9.65%
Metropolitan Sewer District	$73,018	$80,061	$7,044	9.65%
Total	**$2,737,798,832**	**$3,001,812,173**	**$264,013,342**	**9.64%**

*Targeted increase from Company witness Ms. Laura Moore testimony is $264,099,796; however, rate rounding resulted in a shortfall of approximately $86.5K.

III. CLASS RATES

Q. Please describe the Company's rate design proposals in this case.

A. In general, the Company is proposing to increase the charges for each customer class by the same percentage. The significance of implementing a rate increase in this fashion is that it ensures all customers within each class experience the same rate increase as the customer class as a whole[6]. There are four exceptions to this proposed methodology: 1) the pre-MEEIA energy efficiency costs are explicitly accounted for in each customer class; 2) certain non-residential charges require the same increases across rate classes to maintain consistency; 3) an exemption of energy efficiency charges for low-income customers and 4) a voluntary residential time-varying rate pilot to replace the existing residential time of day rate option. I describe these two specific proposals in detail below.

Q. Why is it important to separately adjust the pre-MEEIA energy efficiency charges?

A. The pre-MEEIA energy efficiency charges are being amortized over several years but

[6] Assuming all other factors are held constant.

no new costs are being accumulated; therefore, after enough time those charges will completely disappear from customer bills. Because these costs are declining over time it would be inappropriate to apply the average class increase to the pre-MEEIA charges.

Q. Please describe what charges you are proposing to keep consistent across rate classes.

A. The four charges below need to remain consistent for SPS, LPS, and LTS because those costs are effectively the same regardless of the customer class. After increasing these four charges by 9.65%, the remaining charges were increased by each respective class's average increase (after excluding pre-MEEIA energy efficiency charges).

1) The monthly customer charge
2) The additional Time-of-Day monthly customer charge[7]
3) The Rider B credits (customer owned substation discounts)
4) The Reactive charge

Q. What was the source of the billing unit data used in the design of the Company's proposed rates?

A. Ameren Missouri witness James R. Pozzo is providing direct testimony discussing the billing unit data used in the design of the proposed rates. The data contained in Schedules JRP-1 through JRP-6 of Mr. Pozzo's direct testimony in this case was used as a resource for the individual class billing units.

Q. Are there any other rate design issues which need to be addressed?

A. Yes. As the Commission is aware, there is an active complaint on the Company's rate design filed by Noranda (File No. EC-2014-0224). Since the Commission's order in that complaint case will be issued after the filing of my direct testimony, I am unable to

[7] This incremental customer charge for Time-of-Day will also be the same for the LGS customer class.

address any issues which may arise from such an order. As such, it may be necessary to file revisions to my direct testimony and/or to provide additional testimony as needed to address such issues.

a. MEEIA Low-income Exemption

Q. Is Ameren Missouri proposing to exempt low-income customers from paying the MEEIA Rider charges?

A. Yes.

Q. Why is Ameren Missouri requesting this exemption?

A. Ameren Missouri understands that rate increases can be challenging to economically vulnerable customers. Because the legislature specifically authorized the exemption of low-income customers from the MEEIA charges, Ameren Missouri sees this as an opportunity to make sure we are using the "tools in the toolbox" to improve affordability of electricity. Although there is no traditional cost support for the exemption, the legislature made a conscious policy choice to allow such an exemption that we believe warrants the Commission's consideration.

Q. Under what authority is Ameren Missouri basing its request?

A. The MEEIA statute, §393.1075 RSMo, includes a provision that allows the Commission to approve such an exemption. Specifically subsection 6 states:

"The commission may reduce or exempt allocation of demand- side expenditures to low income classes, as defined in an appropriate rate proceeding, as a subclass of residential service."

Q. Will customers who are exempt from the MEEIA charges still be able to participate in energy efficiency programs?

A. Yes. This exemption is different than the "opt-out" provision the MEEIA statute provides for large customers. Customers who qualify for this exemption will still be able to participate in Ameren Missouri's energy efficiency programs. In fact, it would be a win-win if those low-income customers are able to leverage the exemption bill savings to participate in energy efficiency programs and create even more savings for themselves.

Q. Are you asking to eliminate all of the energy efficiency charges for low-income customers?

A. To be clear, I am proposing to exempt low-income customers from all of Ameren Missouri's MEEIA costs that do not include program costs still being recovered from programs implemented prior to 2013. In short, this means low-income customers will be exempt from the Rider EEIC charges.

Q. How are you defining "low-income"?

A. As a practical consideration, Ameren Missouri does not think it is appropriate nor does it currently have the ability to act as the agent to validate its customers' incomes. Ameren Missouri proposes to rely on existing data in its billing system to identify customers who already receive credits only available to customers who have met income requirements that are validated externally. Customers who receive credits from Missouri Energy Assistance (a.k.a. Low-Income Home Energy Assistance Program or LIHEAP), Winter Energy Crisis Intervention Program (ECIP), Summer ECIP, Keeping Current, and Keeping Cool must meet income requirements. Therefore, Ameren Missouri plans to define the low-income class as those customers who have received credits from at least one of these programs within the last 12 months of any billing month.

Q. How many customers will benefit from this exemption?

A. I have evaluated participation in the aforementioned programs in 2013 and expect nearly 3% of Ameren Missouri's customers per year could receive the exemption.

Q. How much benefit will these customers receive?

A. Based on the electricity consumption of customers who participated in the aforementioned programs in 2013, I expect customers who receive the exemption will receive a bill reduction of nearly $4.50 per month. By the time new rates from this case are effective, the savings could be closer to $5.50.

Q. Will eligible customers need to do anything to get the exemption?

A. No. Any customer who has received a credit from at least one of the five programs identified above within the prior 12 months will automatically be exempted from the MEEIA Rider charges. Each billing period, Ameren Missouri's billing system will check to see if the customer has received a credit and if a customer has received a credit within 12 months then the exemption will remain.

Q. How does Ameren Missouri expect to recover the MEEIA costs that are not collected from low-income customers?

A. Cost recovery for MEEIA is currently handled in Rider EEIC. Ameren Missouri will file its next Rider EEIC application in late November 2014 with rates effective with the February 2015 billing month. However, Ameren Missouri will not be able to include the low-income exemption as part of that Rider EEIC filing, because changes to implement the exemption are also necessary to the 1(M) Residential Service tariff. Ameren Missouri has included those changes to the 1(M) tariff (Schedule WRD-1) as part of this rate case. In addition, Schedule WRD-3 is a mark-up of the Rider EEIC tariff which illustrates the future changes to that tariff. If authorized by the Commission, the changes to the Residential tariff will

become effective June 1, 2015. Therefore, Ameren Missouri is planning another Rider EEIC filing at the end of April 2015 to become effective June 1, 2015, which will allow an updated Rider EEIC rate to be implemented concurrently with the changes in the Residential Service tariff approved in this case. At today's Rider EEIC rate, the approximately $1.5 million associated with the low-income exemption would be allocated across the remaining residential customers, which would increase costs to those customers by about $0.11 per month.

b. Residential Time-of-Day Pilot

Q. Is Ameren Missouri proposing to redesign its residential Time-of-Day rate?

A. Yes. Given the low participation and the Company's desire to offer a rate option it believes could be more attractive, Ameren Missouri is proposing several changes to its residential Time-of-Day rate option.

Q. Please describe the current Time-of-Day rate.

A. The Time-of-Day rate option is divided into on-peak and off-peak time periods. The on-peak time period is defined as a period in which demand for electricity is higher and therefore the price for electricity is higher. The off-peak period is the converse; it is the period when the demand for electricity is lower and therefore the price for electricity is lower. The current rate design considers the on-peak period to be non-holiday weekdays from 10 a.m. to 10 p.m. with any other time designated as off-peak. There is also a price difference between summer and winter, but the on-peak and off-peak periods are defined the same in each season. In addition, the customer charge applicable to the Time-of-Day rate is more than double the customer charge of the standard rate option. The overall goal of the rate option is to send a price signal for customers to conserve usage of electricity during periods of higher prices.

Q. How many customers are currently on the residential Time-of-Day rate option?

A. There are currently 34 customers enrolled in this rate option.

Q. Are those customers saving money with this rate option?

A. Eighteen of the 34 customers were worse off compared to the standard rate design in 2013.

Q. What changes are you proposing?

A. First, Ameren Missouri proposes to rename the rate option to something that provides a better description. The new name of the rate option will be "Nights and Weekends." In my opinion, "Time-of-Day" is industry jargon and it does not communicate much about what the rate option is or does. Because the rates are lower after 7 p.m. ("Nights") and on weekends, I believe the new name provides customers with a better description of the option.

Second, the Company proposes the customer charge be set at the same level as the standard rate design. A higher customer charge would reduce the savings opportunities for the customers who choose to participate in the Nights and Weekends rate option, and is akin to having a participation fee which ultimately acts as a barrier to participation.

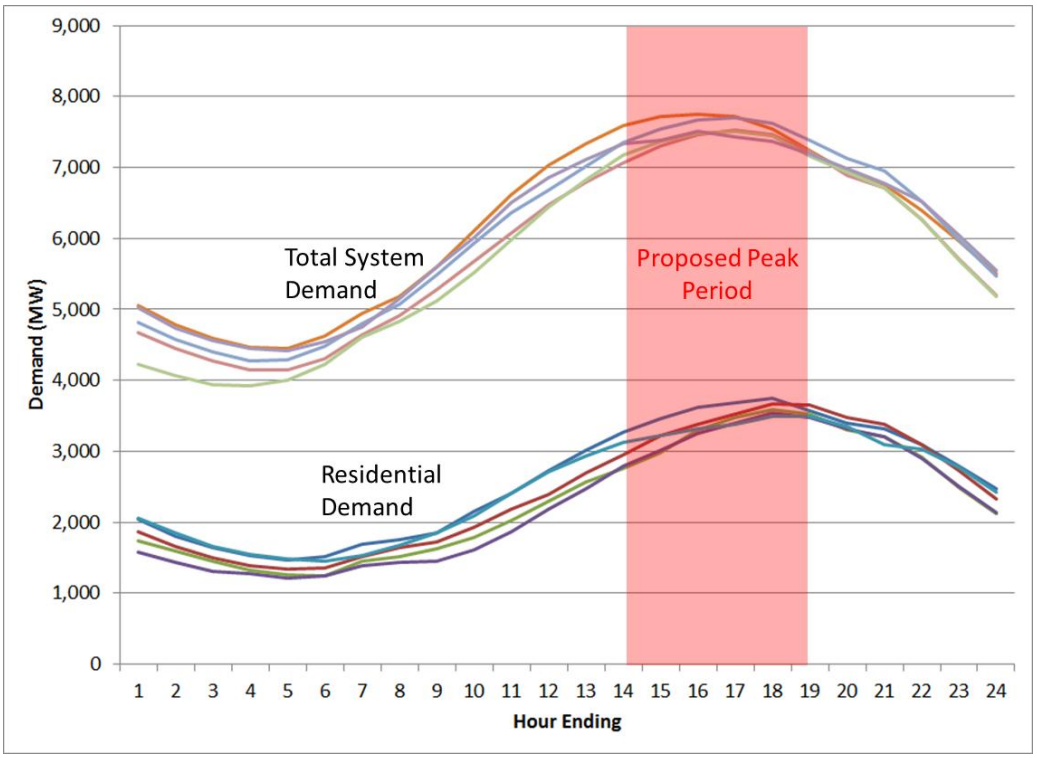
Third, Ameren Missouri proposes to limit peak pricing to summer only. It is expected that time of use pricing does not reduce overall energy consumption; instead, it reduces energy consumption during peak periods. For instance, customers may increase the temperature on the thermostat during the peak period but since the house gets hotter during that time it takes just as much total energy to cool the home back to a comfortable temperature during off-peak periods. In some cases, customers may choose to "pre-cool" or bring the home to much cooler than normal temperature before the peak period begins in order to keep a reasonable temperature in

the home without using the cooling equipment during peak periods. Regardless of the behaviors of customers, the result is that energy consumption during the peak period will be lower. Since Ameren Missouri's system peak is during the summer, it makes more sense to focus efforts on reducing the summer peak. In addition, winter days tend to require more complicated definitions of peak periods because there are two peak periods during winter days, one in the morning when customers get ready for the day and one at night when customers return home from work. In short, limiting the peak pricing to the summer will simplify the rate design. Under the Company's proposal, the winter rate will be the same as the standard rate. Further, although holidays normally would be considered off-peak – there are possibly three holidays[8] during the summer billing period – to keep the rate design as simple as possible, I am proposing to define the peak period as all summer weekdays from 2 p.m.-7 p.m., regardless of whether it is a holiday.

Fourth, as noted above, the Company proposes to shorten the on-peak period. The current on-peak period is weekdays from 10 a.m. through 10 p.m. That long on-peak window makes it difficult for customers to change their behavior. Because the typical summer peak is 4 p.m. or 5 p.m., I am proposing to limit the on-peak period to 2 p.m.-7 p.m. The chart below demonstrates that the proposed shortened on-peak window adequately spans the typical peak period for Ameren Missouri and thus will send an adequate price signal to customers. In addition, the shorter on-peak period gives participants a much better opportunity to alter their behavior because those behavioral changes only need to be implemented and sustained over a 5 hour period.

[8] Memorial Day, Independence Day, and Labor Day

Chart 2 – 2013 Summer Peak Profile (Top 5 days)



Fifth, the Company proposes to increase the price differential between on-peak and off-peak pricing. The rate option needs to provide an adequate opportunity for customers to save money on their bills in order for them to change their behavior. For instance, would we expect more participation if customers can save 10 cents or 10 dollars during the summer months? There is also some risk associated with choosing this rate option, so the reward needs to compensate for that risk. For example, the failure to reduce consumption during a peak period that is priced high will result in a much higher bill than what it would be under the standard rate. The Company proposes the peak price be set at 30.21 cents per kilowatt hour and the off-peak price be set at 8.04 cents per kilowatt hour. This will make the on-peak price about 3.75 times the off-peak price, which is much higher than the current summer ratio of 2.5.

Q. How did you determine that the on-peak price should be 30.21 cents per kilowatt hour?

A. First, I determined that there are 430 hours during the summer peak period; that is the sum of the 5 hours per weekday over the four summer months. Next, I looked at the marginal cost of new capacity for energy, generation capacity, transmission capacity, and distribution capacity. Dividing the marginal costs over the number of peak hours results in the 30.21 cents per kilowatt hour.

Q. How did you determine that the off-peak price should be 8.04 cents per kilowatt hour?

A. As a regulated utility, prices are set based on the embedded cost of service. Knowing the average total cost per customer and the on-peak price, I then solved for the off-peak price such that the bill of an average customer with average consumption during the on-peak period would be equal to the proposed Nights and Weekends rate. In short, that average customer would be indifferent between the standard rate and the proposed Nights and Weekends rate.

Q. If the average customer is indifferent between the standard rate and the proposed Nights and Weekends rate, then why would any customer sign up for it?

A. The average customer could save money under the proposed rate, but it would require a behavioral change to reduce consumption during the peak time. Even an above average usage customer could save money, but the behavioral change would need to be more dramatic.

Q. Are you proposing any limitations on the Nights and Weekends rate option?

A. Yes. I am proposing to limit the number of participants to 5,000 and to exclude customers with net metering agreements. In addition, this rate option is scheduled to expire on December 31, 2019.

Q. Could you please provide a table that summarizes the changes you mentioned about this rate option?

A. Yes. See the table below for a summary.

Current Rate	Change/Addition	New Rate
"Time-of-Day"	Change the name of the rate to be more descriptive.	"Nights and Weekends"
Peak Time: 10 a.m.-10 p.m. Weekdays, Summer and Winter	Shorten Peak Period	Summer Only 2 p.m.-7 p.m., Weekdays
$16.81 monthly customer charge vs. standard at $8	Implement same customer charge as standard rate	Same as standard customer charge
Summer Rates $0.1651/kwh for on-peak $0.0676/kwh for off-peak Winter Rates $0.0974/kwh for on-peak $0.0482/kwh for off-peak	-Increase Price differential between on-peak and off-peak -Eliminate winter time of use rates	Summer Rates $0.3021/kwh for on-peak $0.0804/kwh for off-peak Standard Winter Rates
Available to all Residential Customers (only 34 are subscribed)	Limit participation	5,000 limit, no self-generators First come, first served

c. Tariff changes and supporting testimony regarding clarification of cost recovery for damages by third parties

Q. Are there any housekeeping-type tariff changes being proposed in this filing?

A. Yes. The Company is requesting to insert language into its Rules and Regulations – General Provisions clarifying the Company's current practice of attempting to fully recover all costs (direct and indirect) to repair, replace, reroute, or relocate any Company facilities necessitated by another party's negligence.

Q. Specifically, what tariff change is the Company proposing?

A. The Company is proposing to add the following language to Sheet 106 General Rules and Regulations Section of its Schedule 6 – Schedule of Rate for Electric Service (Schedule WRD-1):

L. REIMBURSEMENT OF COSTS NECESSITATED BY NEGLIGENCE

Where Company seeks to recover the cost to repair, replace, reroute, or relocate any Company facilities necessitated by another party's negligence, the charge will include the total cost of all labor and materials, easements, licenses, permits, cleared right-of-way, and all other incidental costs, including indirect costs. The indirect costs will include, where applicable, the cost of engineering, supervision, inspection, insurance, payments for injury and damage awards, taxes, AFUDC (Allowance for Funds Used During Construction), legal and administrative and general expenses associated with the affected facilities. The percentage used for indirect costs reflects the Company's historical indirect cost experience.

Q. Why is this tariff revision necessary?

A. Over the last several years, several auto insurance carriers have challenged the Company's legal right to hold their insured liable for both direct and indirect costs. They argue that only direct costs should be charged. The proposed tariff revision clarifies that the Company is acting prudently in collecting these direct and indirect costs from the liable parties.

Q. Does the Company have similar language in its existing tariffs?

A. Yes. Similar language exists in Section III.D. of the Company's General Rules and Regulations.

Q. How is this proposed tariff addition beneficial to customers?

A. In short, it reduces costs to customers. If only a portion of the costs associated with negligence are allowed to be recovered from negligent parties or their insurers, then any remaining costs will be borne by customers who had nothing to do with the incident. This treatment is the same as is required by the Company's existing tariff for line extensions[9]. This tariff specifies that Ameren Missouri is to collect direct and indirect costs for distribution extensions. I see no reason to charge a negligent individual less for replacement of a pole than the Company charges for line extensions.

[9] MO.P.S.C. Schedule No. 6, Sheet 112

d. Low-Income Weatherization Program

Q. Please describe the low-income weatherization program and how it impacts the revenue requirement.

A. The low-income weatherization program is administered by Missouri's Department of Economic Development – Division of Energy (a division formerly within the Missouri Department of Natural Resources). The excerpt below summarizes the intent of the program and other details can be found on the Division of Energy's website[10].

"The program provides cost-effective energy-efficient home improvements to Missouri's low income households, especially the elderly, children, those with physical disadvantages, and others hit hardest by high utility costs."

The Commission approved a stipulation in File No. ER-2011-0028 which earmarked $1.2 million for the low-income weatherization program. In Ameren Missouri's most recent rate case (File No. ER-2012-0166), the Commission approved a stipulation that allows a maximum of $120,000 of those funds to be used to evaluate the effectiveness of the program.

Q. Is the low-income weatherization program part of the Company's energy efficiency portfolio?

A. No. The program is administered by the Division of Energy; therefore, Ameren Missouri does not get any credit for the energy savings or recovery of the associated throughput disincentive.

Q. Is the Company proposing any changes to the low-income weatherization program funding?

A. Not at this time. The previously stipulated $1.2 million has been included in the

[10] http://ded.mo.gov/division-of-energy/weatherization/low-income-weatherization-assistance-program-(liwap)

revenue requirement. The second evaluation of the program will be completed by July 31, 2015, and until the new evaluation is complete, the Company recommends the program remain unchanged.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)	
Customer Charge - per month	$8.77
Low-Income Pilot Program Charge – per month	$0.03
Energy Charge - per kWh	12.47¢
Energy Efficiency Program Charge – per kWh	0.11¢
Winter Rate (Applicable during 8 monthly billing periods of October through May)	
Customer Charge - per month	$8.77
Low-Income Pilot Program Charge – per month	$0.03
Energy Charge - per kWh	
First 750 kWh	8.87¢
Over 750 kWh	5.91¢
Energy Efficiency Program Charge – per kWh	0.07¢
*Optional Nights and Weekends Rate (Pilot)	
Customer Charge - per month	$8.77
Low-Income Pilot Program Charge – per month	$0.03
Energy Charge - per kWh (1)	
Summer (June-September billing periods)	
All On Peak kWh	30.21¢
All Off Peak kWh	8.04¢
Winter (October-May billing periods)	
First 750 kWh	8.87¢
Over 750 kWh	5.91¢
Energy Efficiency Program Charge – per kWh	
Summer (June-September billing periods)	0.11¢
Winter (October-May billing periods)	0.07¢

(1) On-peak and Off-peak hours applicable herein are:

Peak hours – 2:00 P.M. to 7:00 P.M., Monday through Friday.

Off-peak hours – 7:00 P.M. of Monday through Thursday to 2:00 P.M. of the following day, and from 7:00 P.M. Friday to 2:00 P.M. Monday.

*Indicates Change.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd.)

Fuel and Purchased Power Adjustment (Rider FAC). Applicable to all metered kilowatt-hours (kWh) of energy.

* Energy Efficiency Investment Charge (Rider EEIC). Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions or the low-income exemption provisions of Section 393.1075, RSMo.

Payments. Bills are due and payable within ten (10) days from date of bill and become delinquent after twenty-one (21) days from date of bill.

Term of Use. Initial period one (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

*Indicates Change.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Cont'd.)

1. RATE APPLICATION

This rate is applicable to all normal residential service supplied by the Company to individually metered residences and apartments consisting of one or more rooms for the use of one or more persons as a housekeeping unit with space for eating, living and sleeping, and permanent provisions for cooking and sanitation.

Additional service which may be provided under the provisions of this rate include any metered combination of residential and general farm service, or separately metered service related or incidental thereto, and individually metered mobile homes or boat slips intended for normal use by a single family.

All service referenced above shall be supplied, metered and billed in accordance with the provisions of paragraph (2.) herein.

2. CHARACTER OF SERVICE SUPPLIED

Company will specify and supply one standard single-phase and, for additional residential requirements, one three-phase secondary service voltage under this Service Classification, which service will be cumulated for billing purposes. Unless otherwise required for Company's engineering or other reasons, any additional service requested by customer will be provided, subject to the Company's approval, under the provisions of Section III.Q - Special Facilities. Such additional service, if any, supplied through facilities installed on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

3. TEMPORARY SERVICE

Temporary service requested for residential use will be supplied under the terms and conditions set forth under Rider D.

***4. OPTIONAL NIGHTS AND WEEKENDS (NAW) SERVICE (PILOT)**

Applicable at customer's option for all Residential Service usage, subject to the following provisions:

a. Customer will be transferred to this NAW rate option effective with NAW meter installation and transferred from this NAW rate option to the applicable non-NAW rate after the meter is removed.

*Indicates Change.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Cont'd.)

***4. OPTIONAL NIGHTS AND WEEKENDS (NAW) SERVICE (PILOT) (Cont'd.)**

b. Customer electing this NAW option, shall remain on said option for a minimum period of twelve (12) months.

c. Any customer canceling this NAW option cannot thereafter resume billing under said option for a period of one year following the last billing period on the NAW option.

d. Premises with 120 volt 2-wire service, or meter locations which would make monthly meter readings unusually difficult to obtain, do not qualify for this NAW option.

** e. Participation shall be limited to 5,000 customers.

** f. Participation shall exclude customers with a net metering agreement.

** g. Service under the NAW option shall not be available after December 31, 2019.

5. RESIDENTIAL SERVICE RATE NOT APPLICABLE TO:

a. Service supplied through one meter (or more than one meter if the readings thereof are cumulated for billing purposes) to:

(1) Premises which consist of one or more dwelling units and a commercial unit or

(2) A residence or dwelling unit when any portion of such service is used in a commercial venture.

As used herein, the term "dwelling unit" shall mean that portion of a building which by appearance, design or arrangement is normally used for residential purposes by a single family, whether or not actually occupied, and the term "commercial unit" shall mean that portion of a building or premises which by appearance, design or arrangement is normally used for commercial purposes, whether or not actually so used.

b. Establishments in farming areas processing, distributing or selling farm or other products which do not originate through production on the premises served.

c. Separate buildings or other structures intended and/or used for recreational or group activities.

d. Nursing homes and/or retirement facilities licensed by the State of Missouri Department of Social Services Division of Aging.

e. Single-metered service supplied to multiple occupancy buildings for which a Commission variance, from the separate metering requirement contained in Section V.L. Rent Inclusion of the Company's rules and regulations, has been granted.

*Indicates Change. **Indicates Addition.

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	
Single Phase Service	$10.69
Three Phase Service	$21.38
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh	11.34¢
Energy Efficiency Program Charge – per kWh (3)	0.04¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	
Single Phase Service	$10.69
Three Phase Service	$21.38
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh	
Base Use	8.46¢
Seasonal Use(1)	4.87¢
Energy Efficiency Program Charge – per kWh (3)	0.03¢

Optional Time-of-Day Rate

Customer Charge - per month	
Single Phase Service	$21.43
Three Phase Service	$42.84
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh (2)	
Summer (June-September billing periods)	
All On Peak kWh	16.84¢
All Off Peak kWh	6.86¢
Winter (October-May billing periods)	
All On Peak kWh	11.09¢
All Off Peak kWh	5.09¢
Energy Efficiency Program Charge – per kWh (3)	
Summer (June-September billing periods)	0.04¢
Winter (October-May billing periods)	0.03¢

(1) The winter seasonal energy use shall be all kWh in excess of 1,000 kWh per month and in excess of the lesser of a) the kWh use during the preceding May billing period, or b) October billing period, or c) the maximum monthly kWh use during any preceding summer month.

(2) On-peak and Off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

(3) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

* Indicates Change.

SERVICE CLASSIFICATION NO. 3(M)
LARGE GENERAL SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$96.96
Low-Income Pilot Program Charge - per month	$ 0.50
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	10.86¢
Next 200 kWh per kW of Billing Demand	8.17¢
All Over 350 kWh per kW of Billing Demand	5.49¢
Demand Charge - per kW of Total Billing Demand	$ 5.07
Energy Efficiency Program Charge - per kWh (1)	0.08¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$96.96
Low-Income Pilot Program Charge - per month	$ 0.50
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	6.84¢
Next 200 kWh per kW of Base Demand	5.06¢
All Over 350 kWh per kW of Base Demand	3.97¢
Seasonal Energy Charge - Seasonal kWh	3.97¢
Demand Charge - per kW of Total Billing Demand	$ 1.88
Energy Efficiency Program Charge - per kWh (1)	0.05¢

(1) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $21.38 per month

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh(June-September billing periods)	+1.28¢	-0.72¢
Winter kWh(October-May billing periods)	+0.38¢	-0.22¢

(2) On-peak and off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

* Indicates Change.

SERVICE CLASSIFICATION NO. 4(M)
SMALL PRIMARY SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$328.50
Low-Income Pilot Program Charge - per month	$ 0.50
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	10.50¢
Next 200 kWh per kW of Billing Demand	7.92¢
All Over 350 kWh per kW of Billing Demand	5.30¢
Demand Charge - per kW of Total Billing Demand	$ 4.20
Reactive Charge - per kVar	38.00¢
Energy Efficiency Program Charge - per kWh (1)	0.09¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$328.50
Low-Income Pilot Program Charge - per month	$ 0.50
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	6.61¢
Next 200 kWh per kW of Base Demand	4.91¢
All Over 350 kWh per kW of Base Demand	3.84¢
Seasonal Energy Charge - Seasonal kWh	3.84¢
Demand Charge - per kW of Total Billing Demand	$ 1.53
Reactive Charge - per kVar	38.00¢
Energy Efficiency Program Charge - per kWh (1)	0.05¢

(1) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $21.38 per month

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh(June-September billing periods)	+0.93¢	-0.53¢
Winter kWh(October-May billing periods)	+0.35¢	-0.19¢

(2) On-peak and Off-peak hours applicable herein shall be as specified within this service classification.

* Indicates Change.

SERVICE CLASSIFICATION NO. 5(M)
STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED

***RATE PER UNIT PER MONTH LAMP AND FIXTURE**

A. Standard horizontal burning, enclosed luminaire on existing wood pole:

High Pressure Sodium		Mercury Vapor (1)	
Lumens	Rate	Lumens	Rate
9,500	$12.93	6,800	$12.93
25,500	$18.68	20,000	$18.68
50,000	$33.31	54,000	$33.31
		108,000	$66.63

B. Standard side mounted, hood with open bottom glassware on existing wood pole:

High Pressure Sodium		Mercury Vapor (1)	
Lumens	Rate	Lumens	Rate
5,800	$10.47	3,300	$10.47
9,500	$11.44	6,800	$11.44

C. Standard post-top luminaire including standard 17-foot post:

High Pressure Sodium		Mercury Vapor (1)	
Lumens	Rate	Lumens	Rate
9,500	$23.96	3,300	$22.64
		6,800	$23.96

D. Pole-mounted, direction flood luminaire; limited to installations accessible to Company basket truck:

High Pressure Sodium		Metal Halide		Mercury Vapor (1)	
Lumens	Rate	Lumens	Rate	Lumens	Rate
25,500	$23.72	34,000	$23.72	20,000	$23.72
50,000	$37.51	100,000	$74.98	54,000	$37.51

(1) Mercury Vapor lamps and fixtures are limited to customers served under contracts initiated prior to September 27, 1988. Company will continue to maintain these lamps and fixtures so long as parts are economically available.

* Indicates Change.

SERVICE CLASSIFICATION NO. 5(M)
STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)

E. All poles and cable, where required to provide lighting service:

The installation of all standard poles and cables shall be paid for in advance by customer, with all subsequent replacements of said facilities provided by Company.

*F. Incandescent lamps provided under contracts initiated prior to September 30, 1963, which facilities will not be maintained by Company after June 30, 1981:

Lamp and Fixture	Per Unit Monthly Rate
1,000 Lumens	$12.39
2,500 "	$16.72
4,000 "	$19.30
6,000 "	$21.42
10,000 "	$29.09

* Indicates Change.

SERVICE CLASSIFICATION NO. 5(M)
STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)

G. Former Subsidiary Company lighting units provided under contracts initiated prior to April 9, 1986, which facilities will only be maintained by Company so long as parts are available in Company's present stock:

Lamp and Fixture	*Per Unit Monthly Rate
11,000 Lumens, Mercury Vapor, Post-Top	$23.96
11,000 Lumens, Mercury Vapor, Open Bottom	$11.44
11,000 Lumens, Mercury Vapor, Horizontal Enclosed	$12.93
42,000 Lumens, Mercury Vapor, Horizontal Enclosed	$33.31
16,000 Lumens, H.P. Sodium, Horizontal Enclosed	$12.93
34,200 Lumens, H.P. Sodium, Directional(2)	$23.72
140,000 Lumens, H.P. Sodium, Directional	$74.98
20,000 Lumens, Metal Halide, Directional	$23.72

(2) This lamp represents a mercury vapor fixture with H.P. Sodium lamp.

Term of Contract Minimum term of three (3) years where only standard facilities are installed; ten (10) years where post-top luminaires are installed.

Discount for Franchised Municipal Customers A 10% discount will be applied to bills rendered for lighting facilities served under the above rates and currently contracted for by municipalities with whom the Company has an ordinance granted electric franchise as of September 27, 1988. The above discount shall only apply for the duration of said franchise. Thereafter, the above discount shall apply only when the following two conditions are met: 1) any initial or subsequent ordinance granted electric franchise must be for a minimum term of twenty (20) years and 2) Company must have a contract for all lighting facilities for municipal lighting service provided by Company in effect.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

SERVICE CLASSIFICATION NO. 6(M)
STREET AND OUTDOOR AREA LIGHTING – CUSTOMER-OWNED

***MONTHLY RATE FOR METERED SERVICE**

Customer Charge Per Meter	$7.00 per month
Energy Charge	4.73¢ per kWh

***RATE PER UNIT PER MONTH FOR UNMETERED SERVICE**

Customer Charge per account $7.00 per month

H.P. Sodium	Energy & Maintenance(1)	Energy Only(2)
9,500 Lumens, Standard	$ 3.76	$ 1.82
16,000 Lumens, Standard	N/A	$ 3.10
25,500 Lumens, Standard	$ 6.55	$ 4.66
50,000 Lumens, Standard	$ 9.45	$ 7.32
Metal Halide		
5,500 Lumens, Standard	$ 5.44	N/A
12,900 Lumens, Standard	$ 6.51	N/A
Mercury Vapor	(3)	
3,300 Lumens, Standard	$ 3.76	$ 1.93
6,800 Lumens, Standard	$ 4.90	$ 3.14
11,000 Lumens, Standard	$ 6.62	$ 4.47
20,000 Lumens, Standard	$ 8.78	$ 6.90
42,000 Lumens, Standard	N/A	$11.49
54,000 Lumens, Standard	$18.76	$16.41

Light Emitting Diodes (LED)	Energy Only
2,500 Lumens, 40 W	$0.62
5,000 Lumens, 70 W	$1.11
4,250 Lumens, 85 W Post Top	$1.34
12,500 Lumens, 180 W	$2.84
19,000 Lumens, 260 W	$4.10

(1) Company will furnish electric energy, furnish and replace lamps, and adjust and replace control mechanisms, as required.

(2) Limited to lamps served under contracts initiated prior to September 27, 1988.

(3) Maintenance of lamps and fixtures limited to customers served under contracts prior to November 15, 1991.

N/A Not Available.

Term of Contract One (1) year, terminable thereafter on three (3) days' notice.

Discount For Franchised Municipal Customers A 10% discount will be applied to bills rendered for lighting facilities served under the above rates and currently contracted for by municipalities with whom the Company has an ordinance granted electric franchise as of September 27, 1988. The above discount shall only apply for the duration of said franchise.

* Indicates Change.

SERVICE CLASSIFICATION NO. 7(M)
MUNICIPAL STREET LIGHTING – INCANDESCENT
RATE OF LIMITED APPLICATION

***RATE PER LAMP PER MONTH**

	Incandescent				
	1,000 Lumen	2,500 Lumen	4,000 Lumen	6,000 Lumen	10,000 Lumen
Wood Pole Rates	$4.75	$7.23	$9.86	$13.09	$17.93
Ornamental Pole	Add $7.80 per month per pole to above Wood Pole rates.				

*Customer-Owned Street Lighting Facilities

Where customer furnishes, installs and owns all street lighting facilities, service will be supplied as follows:

For Metered Service:
Customer Charge per Meter $16.29 per month
1) Secondary Service 4.75¢ per kWh
2) Primary Service - Rider C shall be applied.

Customer shall install suitable switching and protective equipment, meter loop, space and mounting facilities for Company metering devices.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

Payments Bills are due and payable within ten (10) days from date of bill.

Term of Contract Ten (10) years. Customer, if not legally authorized to contract for all of an initial or succeeding ten-year contract term at one time, may sign an agreement for the maximum period for which it is legally authorized to contract, and said agreement will continue in force thereafter for successive one-year periods unless terminated by either party by written notice given not less than sixty (60) days prior to any annual termination date.

* Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$328.50
Low-Income Pilot Program Charge – per month	$ 50.00
Energy Charge – per kWh	3.55¢
Demand Charge - per kW of Billing Demand	$ 21.25
Reactive Charge - per kVar	38.00¢
Energy Efficiency Program Charge – per kWh (1)	0.04¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$328.50
Low-Income Pilot Program Charge – per month	$ 50.00
Energy Charge – per kWh	3.15¢
Demand Charge - per kW of Billing Demand	$ 9.65
Reactive Charge - per kVar	38.00¢
Energy Efficiency Program Charge – per kWh (1)	0.02¢

(1) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Optional Time-of-Day Adjustments

Additional Customer Charge - per month $21.38 per month

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh(June-September billing periods)	+0.69¢	-0.38¢
Winter kWh(October-May billing periods)	+0.32¢	-0.16¢

(2) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

* Indicates Change.

SERVICE CLASSIFICATION NO. 12(M)
LARGE TRANSMISSION SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during four (4) monthly billing periods of June through September)

Customer Charge – per month	$328.50
Low-Income Pilot Program Charge – per month	$1,500.00
Demand Charge – per kW of Billing Demand	$15.68
Energy Charge – per kWh	2.977¢
Reactive Charge – per kVar	38.000¢

Winter Rate (Applicable during eight (8) monthly billing periods of October through May)

Customer Charge – per month	$328.50
Low-Income Pilot Program Charge – per month	$1,500.00
Demand Charge – per kW of Billing Demand	$5.99
Energy Charge – per kWh	2.621¢
Reactive Charge – per kVar	38.000¢

Optional Time-of-Day Adjustments

Additional Customer Charge – per month	$21.38

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh (June-September Billing Periods)	+0.60¢	-0.34¢
Winter kWh (October-May Billing Periods)	+0.27¢	-0.15¢

(1) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC) Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

*Energy Line Loss Rate Compensation for customer's energy line losses from use of the transmission system(s) outside Company's control area shall be in the form of energy solely supplied by Company to the transmission owner(s) and compensated by payment at a monthly rate of $0.0402 per kWh after appropriate Rider C adjustment of meter readings.

* Indicates Change.

MISCELLANEOUS CHARGES

A. Reconnection Charges per Connection Point

Sheet No. 79, Par. B-3 (Annually Recurring Service)	$30.00
Sheet No. 145, Par. I (Reconnection of Service)	$30.00

*B. Supplementary Service Minimum Monthly Charges

Sheet No. 78, Par. C-3

Charges applicable during 4 monthly billing periods of June through September	Primary Service Rate
Customer Charge per month, plus	$328.50
Low-Income Pilot Program Charge – per month	$50.00
All kW @	$21.25

Charges applicable during 8 monthly billing periods of October through May	Primary Service Rate
Customer Charge per month, plus	$328.50
Low-Income Pilot Program Charge – per month	$50.00
All kW @	$9.65

C. Service Call Charge

Customer’s reporting service problems may be charged a $50.00 fee for a service call, if it is determined the problem is within the customer’s electrical system.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

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.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

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

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

1. For fossil fuel plants:
   A. the following costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account 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

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

   *C. the following costs and revenues reflected in FERC Account 547, excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center. Such costs and revenues include 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; and

2. Costs and revenues in FERC Account 518 (Nuclear Fuel Expense), including nuclear fuel commodity and waste disposal expense, and nuclear fuel hedging costs.

PP = Purchased power costs and revenues and consists of the following:

1. Costs and revenues for purchased power reflected in FERC Accounts 555 and 575, excluding all charges under Midwest Independent Transmission System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and excluding generation capacity charges for contracts with terms in excess of one (1) year. Such costs and revenues include:

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

A. MISO costs or revenues for MISO's energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:
   i. Energy;
   ii. Losses;
   iii. Congestion management including:
      a. Congestion;
      b. Financial Transmission Rights; and
      c. Auction Revenue Rights;
   iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;
   v. Revenue sufficiency guarantees;
   vi. Revenue neutrality uplift;
   vii. Net inadvertent energy distribution amounts;
   viii. Ancillary Services, including:
      a. Regulating reserve service (MISO Schedule 3, or its successor);
      b. Energy imbalance service (MISO Schedule 4, or its successor);
      c. Spinning reserve service (MISO Schedule 5, or its successor);and
      d. Supplemental reserve service (MISO Schedule 6, or its successor); and
   ix. Demand response, including:
      a. Demand response allocation uplift; and
      b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;
   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

2. Insurance premiums in FERC Account 924 for replacement power insurance. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles; and

3. All transmission service costs reflected in FERC Account 565 and all transmission service revenues reflected in FERC Account 456.1. Such transmission service costs and revenues include:
   A. MISO costs and revenues associated with:
      i. network transmission service (MISO Schedule 9 or its successor);
      ii. point-to-point transmission service (MISO Schedules 7 and 8 or their successors);
      iii. System control and dispatch, (MISO Schedule 1 or its successor);
      iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);
      v. MISO Schedule 11 or its successor;
      vi. MISO Schedules 26, 26A, 37 and 38 or their successors; and
      vii. MISO Schedule 33;
   B. Non-MISO costs associated with:
      i. network transmission service;
      ii. point-to-point transmission service;
      iii. System control and dispatch; and
      iv. Reactive supply and voltage control.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

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

OSSR = Costs and revenues in FERC Account 447 for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   A. Regulating reserve service (MISO Schedule 3, or its successor);
   B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   C. Spinning reserve service (MISO Schedule 5, or its successor); and
   D. Supplemental reserve service (MISO Schedule 6, or its successor);
4. Make-whole payments, including:
   A. Price volatility; and
   B. Revenue sufficiency guarantee; and
5. Hedging.

*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-2014-0258, 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-2014-0258.

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

For purposes of factors FC, 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, off-system sales 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.

Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which MISO or another centrally administered market (e.g., PJM or SPP) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the MISO or another centrally administered market (e.g. PJM or SPP) implement a market settlement charge type not listed in Exhibit H of the Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues And Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets approved in Case No. ER-2012-0166 (a "new charge type"):

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to another party's right to challenge the inclusion (or failure to include) as outlined in E. below;

B. The Company will include in its monthly reports required by the Commission's fuel adjustment clause rules notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such notice shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

E. If the Company includes a new charge type cost or revenue in a FAR filing and a party challenges the inclusion (or if the Company does not include a new charge type cost or revenue and a party challenges the failure to include it), such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. To challenge the failure to include a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should have been included, because they do possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. In the event of a challenge, the Company shall bear the burden of proof to support its decision to include or exclude or its failure to include or exclude a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

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, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

$B = BF \times S_{AP}$

*BF = The Base Factor, which 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 $0.01828 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01779 per kWh.

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

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 generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

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 generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

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.

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

T = True-up amount 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 Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

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

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On XXXXXXX X, 201X And Thereafter)

FAR DETERMINATION (Cont'd.)

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.

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.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Calculation of Fuel Adjustment Rate for the Billing Months of XXXX 201X through XXXXXXXXX 201X)

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending:

1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$	
2.	Net Base Energy Cost (B)	-	$	
	2.1 Base Factor (BF)	x	$	
	2.2 Accumulation Period Sales (S_{AP})			kWh
3.	Total Company Fuel and Purchased Power Difference	=	$	
	3.1 Customer Responsibility	x	95%	
4.	Fuel and 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.

RIDER B

DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP

Where a customer served under rate schedules 4(M) or 11 (M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:

*1. A monthly credit of $1.25/kW of billing demand for customers taking service at 34.5 or 69kV

*2. A monthly credit of $1.48/kW of billing demand for customers taking service at 115kV or higher

* Indicates Change.

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GENERAL RULES & REGULATIONS

*Indicates Addition.

GENERAL RULES AND REGULATIONS

I. GENERAL PROVISIONS (Cont'd.)

K. REGULATORY AUTHORITIES (Cont'd.)

Because Commission jurisdiction constitutes a legislative recognition that the public interest in proper regulation of public utilities transcends municipal or county lines, and that a centralized control must be entrusted to an agency whose continually developing expertise will assure uniformly safe, proper and adequate service by the Company, no regulations or ordinances of local governments shall be permitted to impose any requirements on the Company's provision of electric service (excepting local permit requirements for excavation and restoration of public rights-of-way, and except in specific instances where the providing of such service will itself cause a substantial and direct threat of injury to persons or property), which are different from or in addition to such Standard Rules and Regulations and the Commission's regulations, unless such requirements are approved by the Commission for uniform application throughout the Company's service area.

*L. REIMBURSEMANT OF COSTS NECESSITATED BY NEGLIGENCE

Where Company seeks to recover the cost to repair, replace, reroute, or relocate any Company facilities necessitated by another party’s negligence, the charge will include the total cost of all labor and materials, easements, licenses, permits, cleared right-of-way, and all other incidental costs, including indirect costs. The indirect costs will include, where applicable, the cost of engineering, supervision, inspection, insurance, payments for injury and damage awards, taxes, AFUDC (Allowance for Funds Used During Construction), legal and administrative and general expenses associated with the affected facilities. The percentage used for indirect costs reflects the Company's historical indirect cost experience.

*Indicates Addition.

AMEREN MISSOURI
RESIDENTIAL SERVICE CLASSIFICATION NO. 1(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
ID EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWEI
ADJUSTMENT CLAUSE

kWh	AVERAGE MONTHLY BILL
100	$18.95
150	$24.03
200	$29.11
250	$34.18
300	$39.26
350	$44.34
400	$49.41
450	$54.49
500	$59.57
550	$64.64
600	$69.72
650	$74.80
700	$79.87
750	$84.95
800	$89.04
850	$93.13
900	$97.22
950	$101.31
1000	$105.40
1100	$113.58
1200	$121.76
1300	$129.94
1400	$138.12
1500	$146.30
1600	$154.48
1700	$162.66
1800	$170.84
1900	$179.02
2000	$187.20
2500	$228.10
3000	$269.00
3500	$309.90
4000	$350.80
4500	$391.70
5000	$432.60

AMEREN MISSOURI
SMALL GENERAL SERVICE CLASSIFICATION NO. 2(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
ID EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWER
ADJUSTMENT CLAUSE
SINGLE-PHASE SERVICE

kWh	AVERAGE MONTHLY BILL
0	$10.74
50	$15.47
100	$20.19
300	$39.10
400	$48.55
500	$58.01
600	$67.46
700	$76.91
800	$86.37
900	$95.82
1000	$105.27
2,000	$199.81
3,000	$294.34
4,000	$388.87
5,000	$483.41
6,000	$577.94
7,000	$672.47
8,000	$767.01
9,000	$861.54
10,000	$956.07
11,000	$1,050.61
12,000	$1,145.14
13,000	$1,239.67
14,000	$1,334.21
15,000	$1,428.74
16,000	$1,523.27
17,000	$1,617.81
18,000	$1,712.34
19,000	$1,806.87
20,000	$1,901.41
21,000	$1,995.94
22,000	$2,090.47
23,000	$2,185.01
24,000	$2,279.54
25,000	$2,374.07
30,000	$2,846.74
35,000	$3,319.41
40,000	$3,792.07
45,000	$4,264.74
50,000	$4,737.41

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

AMEREN MISSOURI
SMALL GENERAL SERVICE CLASSIFICATION NO. 2(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
ND EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWER
ADJUSTMENT CLAUSE
THREE-PHASE SERVICE

kWh	AVERAGE MONTHLY BILL
0	$21.43
50	$26.16
100	$30.88
300	$49.79
400	$59.24
500	$68.70
600	$78.15
700	$87.60
800	$97.06
900	$106.51
1000	$115.96
2,000	$210.50
3,000	$305.03
4,000	$399.56
5,000	$494.10
6,000	$588.63
7,000	$683.16
8,000	$777.70
9,000	$872.23
10,000	$966.76
11,000	$1,061.30
12,000	$1,155.83
13,000	$1,250.36
14,000	$1,344.90
15,000	$1,439.43
16,000	$1,533.96
17,000	$1,628.50
18,000	$1,723.03
19,000	$1,817.56
20,000	$1,912.10
21,000	$2,006.63
22,000	$2,101.16
23,000	$2,195.70
24,000	$2,290.23
25,000	$2,384.76
30,000	$2,857.43
35,000	$3,330.10
40,000	$3,802.76
45,000	$4,275.43
50,000	$4,748.10

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

AMEREN MISSOURI
LARGE GENERAL SERVICE CLASSIFICATION NO. 3(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
AND EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWER
ADJUSTMENT CLAUSE

kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
100	100	10,000	$1,215.79
	200	20,000	$1,935.63
	300	30,000	$2,551.29
	400	40,000	$3,085.96
	500	50,000	$3,539.63
	600	60,000	$3,993.29
	700	70,000	$4,446.96
500	100	50,000	$5,689.13
	200	100,000	$9,288.29
	300	150,000	$12,366.63
	400	200,000	$15,039.96
	500	250,000	$17,308.29
	600	300,000	$19,576.63
	700	350,000	$21,844.96
1000	100	100,000	$11,280.79
	200	200,000	$18,479.13
	300	300,000	$24,635.79
	400	400,000	$29,982.46
	500	500,000	$34,519.13
	600	600,000	$39,055.79
	700	700,000	$43,592.46
2,000	100	200,000	$22,464.13
	200	400,000	$36,860.79
	300	600,000	$49,174.13
	400	800,000	$59,867.46
	500	1,000,000	$68,940.79
	600	1,200,000	$78,014.13
	700	1,400,000	$87,087.46
3,000	100	300,000	$33,647.46
	200	600,000	$55,242.46
	300	900,000	$73,712.46
	400	1,200,000	$89,752.46
	500	1,500,000	$103,362.46
	600	1,800,000	$116,972.46
	700	2,100,000	$130,582.46
5,000	100	500,000	$56,014.13
	200	1,000,000	$92,005.79
	300	1,500,000	$122,789.13
	400	2,000,000	$149,522.46
	500	2,500,000	$172,205.79
	600	3,000,000	$194,889.13
	700	3,500,000	$217,572.46

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

AMEREN MISSOURI
SMALL PRIMARY SERVICE CLASSIFICATION NO. 4(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
AND EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWER
ADJUSTMENT CLAUSE

kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
100	100	10,000	$1,368.00
	200	20,000	$2,065.33
	300	30,000	$2,663.00
	400	40,000	$3,181.33
	500	50,000	$3,620.33
	600	60,000	$4,059.33
	700	70,000	$4,498.33
500	100	50,000	$5,524.00
	200	100,000	$9,010.67
	300	150,000	$11,999.00
	400	200,000	$14,590.67
	500	250,000	$16,785.67
	600	300,000	$18,980.67
	700	350,000	$21,175.67
1000	100	100,000	$10,719.00
	200	200,000	$17,692.33
	300	300,000	$23,669.00
	400	400,000	$28,852.33
	500	500,000	$33,242.33
	600	600,000	$37,632.33
	700	700,000	$42,022.33
2,000	100	200,000	$21,109.00
	200	400,000	$35,055.67
	300	600,000	$47,009.00
	400	800,000	$57,375.67
	500	1,000,000	$66,155.67
	600	1,200,000	$74,935.67
	700	1,400,000	$83,715.67
3,000	100	300,000	$31,499.00
	200	600,000	$52,419.00
	300	900,000	$70,349.00
	400	1,200,000	$85,899.00
	500	1,500,000	$99,069.00
	600	1,800,000	$112,239.00
	700	2,100,000	$125,409.00
5,000	100	500,000	$52,279.00
	200	1,000,000	$87,145.67
	300	1,500,000	$117,029.00
	400	2,000,000	$142,945.67
	500	2,500,000	$164,895.67
	600	3,000,000	$186,845.67
	700	3,500,000	$208,795.67

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

AMEREN MISSOURI
LARGE PRIMARY SERVICE CLASSIFICATION NO. 11(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
AND EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWER
ADJUSTMENT CLAUSE

	kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
*	4,000	300	1,200,000	$107,681.83
		400	1,600,000	$120,921.83
		500	2,000,000	$134,161.83
		600	2,400,000	$147,401.83
		700	2,800,000	$160,641.83
	5,000	300	1,500,000	$117,611.83
		400	2,000,000	$134,161.83
		500	2,500,000	$150,711.83
		600	3,000,000	$167,261.83
		700	3,500,000	$183,811.83
	10,000	300	3,000,000	$234,845.17
		400	4,000,000	$267,945.17
		500	5,000,000	$301,045.17
		600	6,000,000	$334,145.17
		700	7,000,000	$367,245.17
	20,000	300	6,000,000	$469,311.83
		400	8,000,000	$535,511.83
		500	10,000,000	$601,711.83
		600	12,000,000	$667,911.83
		700	14,000,000	$734,111.83
	30,000	300	9,000,000	$703,778.50
		400	12,000,000	$803,078.50
		500	15,000,000	$902,378.50
		600	18,000,000	$1,001,678.50
		700	21,000,000	$1,100,978.50
	50,000	300	15,000,000	$1,172,711.83
		400	20,000,000	$1,338,211.83
		500	25,000,000	$1,503,711.83
		600	30,000,000	$1,669,211.83
		700	35,000,000	$1,834,711.83
	100,000	300	30,000,000	$2,345,045.17
		400	40,000,000	$2,676,045.17
		500	50,000,000	$3,007,045.17
		600	60,000,000	$3,338,045.17
		700	70,000,000	$3,669,045.17

* - BILLS REFLECT MINIMUM BILLING DEMAND OF 5,000 kW.

AMEREN MISSOURI
LARGE TRANSMISSION SERVICE CLASSIFICATION NO. 12(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
AND EXCLUDING THE COMPANY'S RIDER FAC - FUEL AND PURCHASED POWER
ADJUSTMENT CLAUSE

	kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
*	4,000	300	1,200,000	$80,805.00
		400	1,600,000	$91,763.67
		500	2,000,000	$102,722.33
		600	2,400,000	$113,681.00
		700	2,800,000	$124,639.67
	5,000	300	1,500,000	$89,024.00
		400	2,000,000	$102,722.33
		500	2,500,000	$116,420.67
		600	3,000,000	$130,119.00
		700	3,500,000	$143,817.33
	10,000	300	3,000,000	$176,219.00
		400	4,000,000	$203,615.67
		500	5,000,000	$231,012.33
		600	6,000,000	$258,409.00
		700	7,000,000	$285,805.67
	20,000	300	6,000,000	$350,609.00
		400	8,000,000	$405,402.33
		500	10,000,000	$460,195.67
		600	12,000,000	$514,989.00
		700	14,000,000	$569,782.33
	30,000	300	9,000,000	$524,999.00
		400	12,000,000	$607,189.00
		500	15,000,000	$689,379.00
		600	18,000,000	$771,569.00
		700	21,000,000	$853,759.00
	50,000	300	15,000,000	$873,779.00
		400	20,000,000	$1,010,762.33
		500	25,000,000	$1,147,745.67
		600	30,000,000	$1,284,729.00
		700	35,000,000	$1,421,712.33
	100,000	300	30,000,000	$1,745,729.00
		400	40,000,000	$2,019,695.67
		500	50,000,000	$2,293,662.33
		600	60,000,000	$2,567,629.00
		700	70,000,000	$2,841,595.67

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE
For MEEIA CYCLE 1 Plan

APPLICABILITY

This Rider EEIC – Energy Efficiency Investment Charge(Rider EEIC) is applicable to all kilowatt-hours (kWh) of energy supplied to customers served by Ameren Missouri (Company) under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 11(M), and 12(M), excluding kWh of energy supplied to "opt-out" or "low-income" customers.

Charges passed through this Rider EEIC reflect the charges approved to be collected from the implementation of the MEEIA Cycle 1 Plan. Those charges include: 1) projected Program Costs, projected Ameren Missouri's TD-NSB Share and Performance Incentive Award (if any) for each Effective Period, 2) Reconciliations, with interest, to true-up for differences between the revenues billed under this Rider EEIC and total actual monthly amounts for: i) Program Costs incurred, ii) Ameren Missouri's TD-NSB Share incurred, and iii)amortization of any Performance Incentive Award ordered by the Missouri Public Service Commission (Commission) and 3)any Ordered Adjustments. Charges under this Rider EEIC shall continue after the anticipated December 31, 2015 end of MEEIA Cycle 1 Plan until such time as the charges described in items 1), 2) and 3) in the immediately preceding sentence have been billed. Charges arising from the MEEIA Cycle 1 Plan that are the subject of this Rider EEIC shall be reflected in one "Energy Efficiency Invest Chg" on customers' bills in combination with any charges arising from a rider that is applicable to post-MEEIA Cycle 1 Plan demand-side management programs approved under the Missouri Energy Efficiency Investment Act.

DEFINITIONS

As used in this Rider EEIC, the following definitions shall apply:

"Ameren Missouri's TD-NSB Share" means 26.34% of the TD-NSB multiplied by the Time-Value Adjustment Factor.

"Effective Period" (EP) means the twelve (12) billing months beginning with the February billing month and ending with the January billing month. Where an additional EEIC filing is made during a calendar year, the Effective Period for such a filing shall begin with the June or October billing month and end with the subsequent January billing month.

"Evaluation Measurement & Verification - Net Shared Benefits" (EM&V-NSB) means the 2013 present value of the lifetime avoided costs (i.e., avoided energy, capacity, transmission and distribution, and probable environmental compliance costs) for the MEEIA Cycle 1 Plan using the EM&V results described in paragraph 11 of the Stipulation less the 2013 present value of Program Costs. Paragraphs 5.b.ii and 6. c. of the Stipulation provide further description of the EM&V-NSB.

"MEEIA Cycle 1 Plan" has the same meaning as the defined term "Plan" provided for in paragraph 4 of the Stipulation, as it may be hereafter amended by Commission-approved amendments to the Stipulation.

"MWH Target" has the meaning provided for in paragraph 5.b.ii and Appendix B of the Stipulation.

"Program Costs" means program expenditures, including such items as program design, administration, delivery, end-use measures and incentive payments, evaluation, measurement and verification, market potential studies and work on the Technical Resource Manual (TRM).

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA CYCLE 1 Plan

DEFINITIONS (Cont'd.)

"Low-Income" customers means those Service Classification 1(M)-Residential customers eligible for the low income exemption provisions contained in Section 393.1075.7, RSMo. As approved in File No. ER-2014-0258, customers eligible under this definition will be exempt from Rider EEIC charges for 12 months following assistance received from either Missouri Energy Assistance (a.k.a. Low Income Home Energy Assistance Program or LIHEAP), Winter Energy Crisis Intervention Program, Summer Energy Crisis Intervention Program, the Company's Keeping Current Low Income Pilot Program, and/or the Company's Keeping Cool Low Income Pilot Program.

"Performance Incentive Award" means the sum of a two-year annuity (using 6.95% as a discount rate and not discounting the first period) of a percentage of EM&V-NSB as described below and further described in paragraph 5.b.ii and Appendix B of the Stipulation:

Percent of MWH Target	Percent of EM&V-NSB*
<70	0.00%
70	4.60%
80	4.78%
90	4.92%
100	5.03%
110	5.49%
120	5.87%
130	6.19%
>130	6.19%

*Includes income taxes (i.e. results in revenue requirement without adding income taxes). The percentages are interpolated linearly between the performance levels.

"Stipulation" means the Stipulation and Agreement approved by the Commission in its order effective August 11, 2012, as amended by order effective December 29, 2012, in File No. EO-2012-0142, as it may be amended further by subsequent Commission orders.

"Throughput Disincentive - Net Shared Benefits" (TD-NSB)means the 2013 present value of the lifetime avoided costs (i.e., avoided energy, capacity, transmission and distribution, and probable environmental compliance costs) for the MEEIA Cycle 1 Plan using the deemed values in the TRM, less the 2013 present value of Program Costs as further described in paragraphs 5.b.i and 6. b. of the Stipulation.

"Time-Value Adjustment Factor" means the factor used each month to convert Ameren Missouri's TD-NSB Share from a present value into a nominal revenue requirement. The factor is [1.0695 ^ (Calendar Year – 2013)].

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA CYCLE 1 Plan

ENERGY EFFICIENCY INVESTMENT RATE (EEIR) DETERMINATION

The EEIR during each applicable EP is a dollar per kWh rate for each Service Classification calculated as follows:

$$EEIR = [NPC + NTD + NPI + NOA]/PE$$

Where:

NPC = Net Program Costs for the applicable EP as defined below,

$$NPC = PPC + PCR$$

PPC = Projected Program Costs is an amount equal to Program Costs projected by the Company to be incurred during the applicable EP.

PCR = Program Costs Reconciliation is equal to the cumulative difference, if any, between the PPC revenues billed resulting from the application of the EEIR and the actual Program Costs incurred through the end of the previous EP (which will reflect projections through the end of the previous EP due to timing of adjustments). Such amounts shall include monthly interest charged at the Company's monthly short-term borrowing rate.

NTD = Net Throughput Disincentive for the applicable EP as defined below,

$$NTD = PTD + TDR$$

PTD = Projected Throughput Disincentive is 90% of Ameren Missouri's TD-NSB Share projected by the Company to be incurred during the applicable EP.

TDR = Throughput Disincentive Reconciliation is equal to the cumulative difference, if any, between the PTD revenues billed resulting from the application of the EEIR and 100% of Ameren Missouri's TD-NSB Share through the end of the previous EP as adjusted for the inputs described in paragraph 6.b. of the Stipulation, (which will reflect projections through the end of the previous EP due to timing of adjustments). Prior to the beginning of the February 2014 billing month, such amounts shall include monthly interest charged at the Company's monthly Allowance for Funds Used During Construction (AFUDC) rate. Beginning with the start of the February 2014 billing month, any cumulative difference and all subsequent amounts shall include monthly interest charged at the Company's monthly short-term borrowing rate.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA CYCLE 1 Plan

EEIR DETERMINATION (Cont'd.)

NPI = Net Performance Incentive for the applicable EP as defined below,

$$NPI = PI + PIR$$

PI = Performance Incentive is equal to the Performance Incentive Award monthly amortization multiplied by the number of billing months in the applicable EP.

The monthly amortization shall be determined by dividing the Performance Incentive Award by the number of available billing months between the first billing month of the first EEIR filing after the determination of the Performance Incentive Award and 24 calendar months following the end of the annual period in which the Performance Incentive Award is determined.

The number of applicable billing months in the EP shall be the number of applicable billing months less the number of months including Performance Incentive Award amortization from previous EPs.

PIR = Performance Incentive Reconciliation is equal to the cumulative difference, if any, between the PI revenues billed resulting from the application of the EEIR and the monthly amortization of the Performance Incentive Award through the end of the previous EP (which will reflect projections through the end of the previous EP due to timing of adjustments). Such amounts shall include monthly interest charged at the Company's monthly short-term borrowing rate.

NOA = Net Ordered Adjustment for the applicable EP as defined below,

$$NOA = OA + OAR$$

OA = Ordered Adjustment is the amount of any adjustment to the EEIC ordered by the Commission as a result of prudence reviews and/or corrections under this Rider EEIC. Such amounts shall include monthly interest at the Company's monthly short-term borrowing rate.

OAR = Ordered Adjustment Reconciliation is equal to the cumulative difference, if any, between the OA revenues billed resulting from the application of the EEIR and the actual OA ordered by the Commission through the end of the previous EP (which will reflect projections through the end of the previous EP due to timing of adjustments). Such amounts shall include monthly interest charged at the Company's monthly short-term borrowing rate.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA CYCLE 1 Plan

EEIR DETERMINATION (Cont'd.)

PE = Projected Energy, in kWh, forecasted to be delivered to the customers to which the Rider EEIC applies during the applicable EP.

The EEIR components and Total EEIR applicable to the individual Service Classifications shall be rounded to the nearest $0.000001.

Allocations of charges for each Service Classification for the MEEIA Cycle 1 Plan will be made in accordance with the Stipulation.

This Rider EEIC shall not be applicable to customers that have satisfied the opt-out or the low-income exemption provisions contained in Section 393.1075.7, RSMo.

FILING

The Company shall make an EEIC filing each calendar year to be effective for the subsequent calendar year's February billing month. The Company is allowed or may be ordered by the Commission to make one other EEIC filing in each calendar year with such subsequent filing to be effective beginning with either the June or October billing month. Rider EEIC filings shall be made at least sixty (60) days prior to their effective dates.

PRUDENCE REVIEWS

A prudence review shall be conducted no less frequently than at twenty-four (24) month intervals in accordance with 4 CSR 240-20.093(10). Any costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this Rider EEIC shall be addressed through an adjustment in the next EEIR determination and reflected in factor OA above.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA CYCLE 1 Plan
(Applicable To Determination of EEIR for the Billing Months of February 2014 through January 2015)

EEIR Components and Total EEIR

Service Class	NPC/PE ($/kWh)	NTD/PE ($/kWh)	NPI/PE ($/kWh)	NOA/PE ($/kWh)	Total EEIR ($/kWh)
1(M)-Residential Service	$0.001447	$0.002025	$0.000000	$0.000000	**$0.003472**
2(M)-Small General Service	$0.000920	$0.001035	$0.000000	$0.000000	**$0.001955**
3(M)-Large General Service	$0.000933	$0.001439	$0.000000	$0.000000	**$0.002372**
4(M)-Small Primary Service	$0.000936	$0.001087	$0.000000	$0.000000	**$0.002023**
11(M)-Large Primary Service	$0.000809	$0.000886	$0.000000	$0.000000	**$0.001695**
12(M)-Large Transmission Service	$0.000000	$0.000000	$0.000000	$0.000000	**$0.000000**

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-2014-0258

AFFIDAVIT OF WILLIAM R. DAVIS

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

William Davis, being first duly sworn on his oath, states:

1. My name is William R. Davis. I am employed by Union Electric Company, d/b/a Ameren Missouri, as an Economic Analysis and Pricing Manager.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company, d/b/a Ameren Missouri, consisting of 30 pages and Schedule(s) WRD-1 through WRD-3, 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.

William R. Davis

Subscribed and sworn to before me this 3rd day of July, 2014.

Notary Public

My commission expires: 1/15/2017

Julie Irby - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #13753418
My Commission Expires 1/15/2017