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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

DIRECT TESTIMONY

OF

MICHAEL W. HARDING

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
July 2019

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DIRECT TESTIMONY

OF

MICHAEL W. HARDING

FILE NO. ER-2019-0335

I. INTRODUCTION

Q. Please state your name and business address.

A. Michael W. Harding, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am employed by Ameren Missouri as the Manager of Rates & Analysis.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Science in Business Finance from the University of Kansas in 2007. At the end of 2007, I accepted a Real-Time Trading Position with Union Electric Company, I was subsequently promoted to Term Trader in May 2008. At the beginning of 2014, I was named General Executive of Renewable Energy within Ameren Services Company. I was promoted to my current position in April 2017, where I lead a team responsible for the Company's class cost of service, rate design, tariff administration, and various other regulatory projects. Prior to my employment at Ameren, I was employed by Westar Energy (now Evergy) in various roles within their trading and asset management department.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to:

(a) Discuss the allocation of revenues to all classes and the design of the rates necessary to achieve the Company's Missouri jurisdictional revenue requirement.

(b) Describe the process used to develop the weather normalized billing units in this case. In addition to weather, this includes the annualization adjustments for taxes and energy efficiency.

(c) Describe the process Ameren Missouri used to weather normalize test year sales and net system output.

(d) Outline the revisions to various other tariff sheets filed as a part of this case

Q. Are you sponsoring any schedules for presentation to the Commission in this proceeding?

A. Yes. I am sponsoring four schedules. These are listed and summarized below:

- Schedule MWH-D1

  Consists of the tariff sheets which reflect the revised rates being proposed by the Company in this case. Such tariffs reflect a decrease in the Company's net Missouri jurisdictional test year revenues of approximately $-774,000 or -0.03% below current tariffs.

- Schedule MWH-D2

  Shows the distribution of the proposed net revenue requirement decrease to Company's various service classifications.

- Schedule MWH-D3

  Details the rate elements used to develop the normalized retail revenues by rate class.

- Schedule MWH-D4

  Details the allocation of revenues within each rate component to develop the proposed rates.

III. CLASS REVENUE PROPOSAL

Q. What would the base revenue requirement for each customer class be if rates were set based solely on the class cost of service study performed by Company witness Thomas Hickman?

A. The table below summarizes the class base revenue requirements necessary to give the Company an opportunity to achieve an equal rate of return from each of its customer classes, based upon test year figures with the pro forma adjustments made by Company witness Laura Moore. A more detailed summary can be found in Schedule TEH-D1 attached to the direct testimony of Thomas Hickman.

Table 1 – Cost-Based Revenue Requirements by Customer Class ($MM)

Customer Class	Base Revenue Requirement	Return on Rate Base
Residential Service	$1,382.8	7.359%
Small General Service	$293.8	7.359%
Large General & Small Primary Service	$721.5	7.359%
Large Primary Service	$186	7.359%

Company-Owned Lighting	$31.3	7.359%
Customer-Owned Lighting	$4.9	7.359%
Total	$2,620.4	7.359%

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

A. There are several reasons why reflecting equal rates of return for all customer classes is 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, a greater apportionment of cost onto a given customer class, above the equal return on rate base revenue requirement displayed in Table 1, results in subsidization between the classes. 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. If adhering strictly to the class cost of service, what would the required change from current rates looks like?

A. The table below shows the change that would be required for each class' revenue requirement to achieve an equal return on rate base compared to the currently effective rates.

Table 2 – Cost-Based Rate Changes by Customer Class

Customer Class	Cost of Service Change
Residential Service	8.21%
Small General Service	-0.44%
Large General & Small Primary Service	-10.44%
Large Primary Service	-8.31%
Company-Owned Lighting	-11.88%
Customer-Owned Lighting	44.7%
Total	**-0.03%**

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 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 decrease requested in this case?

A. The Company is proposing to use a two-step process similar to that used to set rates per the Commission's order from the Company's last electric rate case, with the only exception being the removal of the Pre-MEEIA allocation step as it is no longer necessary. In the last electric rate case, the Pre-MEEIA allocation step assigned the portion of the revenue increase/decrease that was attributable to Energy Efficiency ("EE") programs from pre-MEEIA program costs directly to applicable customer classes. The pre-

MEEIA program costs consisted of the program costs for increases/decreases in the revenue requirement associated with the amortization of pre-MEEIA program costs. The removal of the pre-MEEIA program cost is discussed in greater detail in Company witness Laura Moore's direct testimony in this case.

Step 1: Increase/decrease the current base retail revenue on a revenue-neutral basis to various classes of customers. The Company has not made any revenue neutral adjustments in this step given the very small proposed revenue decrease, however, in the event the Commission finds the revenue requirement should deviate substantially from what the Company has proposed, consideration should be given to making gradual revenue neutral adjustments toward class cost of service. For example, the Customer-owned lighting class rate is already significantly below its cost of service and will require gradual increases over time to better align its rates with the cost to serve. Further lowering the rates paid by this class would only exacerbate the distance between the cost to serve the class and the revenues received from the class. A detailed breakdown of the Lighting cost allocations between the Company and Customer-owned lighting classes is provided in Company witness Ryan Ryterski's direct testimony.

A detailed breakdown of the revenue allocations to the lighting class as a whole is presented in Thomas Hickman's direct testimony.

Step 2: Determine the amount of revenue increase/decrease and allocate to customer classes as an equal percent of current base revenues after making the adjustment in Step 1.

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

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

Table 3 – Proposed Rate Decrease by Customer Class

Customer Class	Normalized Retail Revenues	Proposed Base Revenue Requirement	Required Base Revenue Adjustment*	Percentage Increase
Residential Service	$1,278,256,444	$1,277,894,109	($362,334)	-0.03%
Small General Service	$295,121,638	$295,011,973	($109,665)	-0.04%
Large General Service	$562,423,013	$562,252,254	($170,759)	-0.03%
Small Primary Service	$243,422,690	$243,331,477	($91,213)	-0.04%
Large Primary Service	$202,942,497	$202,876,368	($66,129)	-0.03%
Company-Owned Lighting	$35,602,359	$35,594,684	($7,676)	-0.02%
Customer-Owned Lighting	$3,391,008	$3,387,812	($3,196)	-0.09%
Metropolitan Sewer District	$74,966	$74,922	($44)	-0.06%
Total	**$2,621,234,615**	**$2,620,423,599**	**($811,016)**	**-0.03%**

*Revenue include Low-Income Pilot Program Charges.
**Targeted decrease from Company witness Laura Moore is $-774,303; however rate rounding resulted in a difference of $-36,713.

Q. Please explain the Company's proposal to allocate the revenue decrease in this 2-step process rather than based solely on class cost of service study results.

A. While the results of a class cost of service study provide an important starting point in developing class revenue targets and rate design, other factors – such as revenue stability, rate stability, effectiveness in yielding total revenue requirements, public acceptance, and value of service – are also considered when determining class revenue requirements and designing rates. Those additional considerations drove the specific revenue neutral shifts included in the Company's two-step process proposal. For the

Lighting class, it is apparent that the Customer-Owned Lighting class has rates that are well below its cost of service, while the Company-Owned Lighting class has rates that are well above its cost of service. Starting a transition towards rates that more closely match the underlying costs is necessary for the Customer-Owned Lighting class, but such adjustments need to be gradual in order to avoid rate shock. Given the small change in revenue requirement in this case, an increase applied to the Customer-Owned Lighting class based on a reallocation of the proposed change would do little to close the cost of service gap; however, it is recommended that if the final ordered revenue requirement deviates from the Company proposed decrease, consideration should be given to adjustments within the Customer-Owned Lighting class. The need to move these classes toward their cost of service will continue to be addressed in future cases.

IV. RATE DESIGN

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 changes) 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 Small Primary Service ("SPS") and Large Primary Service ("LPS") rate classes). 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 normalized customer class electrical usage for the test year will result in the collection of the targeted annual revenue requirement of each of the Company's retail rate classes.

Q. Is the Company proposing any addition or elimination of customer classes?

A. Yes. The Company proposes to eliminate the 12(M) customer class rate schedule.

Q. Please explain the elimination of the 12(M) rate schedule.

A. The 12(M) tariffs and rates were created to serve a specific customer that is no longer taking service from the Company and doesn't anticipate taking service from the Company in the future. In fact, File No. ED-2019-0309 concerns the cancellation of the Certificate of Convenience and Necessity ("CCN") that was originally issued by the Commission in 2005 for Noranda Aluminum ("Noranda"). In late 2004, Ameren Missouri entered into an agreement with Noranda under which Ameren Missouri would provide regulated retail electric service for a term of 15 years, subject to obtaining the required CCN to expand Ameren Missouri's service territory to encompass the property that is now owned by current occupant M7M. Concurrently with the CCN, the Company had filed for approval of a new rate schedule, the Large Transmission Service (LTS or 12(M)) rate, the design of which was specifically created based on the cost to serve this particular customer. The interdependency of the former customer and the 12(M) rate and tariffs that were developed to serve that customer's specific needs, warrant their removal at this time.

Q. Is the Company proposing any changes to its rates structures?

A. Yes, the Company is proposing a suite of new Residential rate options along with the roll-out of automated metering infrastructure ("AMI") meters. The details of these new residential rates offerings are discussed in depth in Company witness Steven Wills' direct testimony.

Q. Please describe the Company's rate design proposals in this case as they apply to existing rates and schedules.

A. Generally, the Company is proposing to decrease the charges for each customer class by the same percentage. The significance of implementing a rate decrease in this fashion is that it ensures all customers within each respective class experience the same percentage rate decrease when compared to other classes. There are three exceptions to this proposed methodology:

1) The total Residential class revenue requirement will proportionately decrease along with the other classes, but a small percentage of the expenses allocated to the Residential class will shift a proportionate amount from the energy charge into the customer charge. The Company proposes to move from $9 to $11 for the Residential customer charge. This slight change in the Residential rate structure will move the required rates within the Residential class marginally toward cost of service. Currently, the Residential customer charge is approximately 300% below the Company's calculated class cost of service study as defined in greater detail within Mr. Hickman's direct testimony.

This makes it one of the individual rate components that is furthest from the Company's CCOSS, even after the proposed rate design adjustment in this case.

2) The incremental customer charge applied to the Small General Service ("SGS"), Large General Service ("LGS"), SPS, and LPS rate schedules for customers opting for Time-of-Day ("TOD") service has been reduced to equal the customer charge billed under non-TOD service for each respective rate class. As all customers begin receiving advanced metering, this incremental charge will no longer be applicable since the installation/removal of specially programmed meters will no longer be required upon customers opting into and out of the TOD rate options.

3) Certain non-residential charges require the same changes across comparable rate classes to maintain consistency. The three charges below need to remain consistent for SPS and LPS because these costs are effectively the same regardless of the customer class:

1) The monthly customer charge;

2) The Rider B credits (customer-owned substation discounts); and

3) The Reactive charge.

Q. Are there any other considerations with the rate design of the Non-Residential rate schedules?

A. Yes, the Company is currently looking into potentially lowering the 5,000 kW minimum monthly billing demand required under the 11(M) LPS rate schedule. A change has not been proposed in this initial filing; however, the Company would welcome any comments or concerns as the Company is considering filing modifications to this schedule in future cases or potentially including in settlement discussions. The threshold

of 5,000 kW that was originally set prior to the Company prohibiting the coinciding of loads, is likely, in many cases an unrealistic threshold at present given the realities of physical infrastructure requirements and customers' desires to connect at voltages high enough to qualify for LPS off of a single circuit. Many customers on the LPS rate had previously done so through the coinciding of multiple loads prior to this rule change taking effect. Additionally, adjusting this threshold down may benefit Customers with high load factors that would see a benefit from their inclusion into the LPS class if not for the minimum qualification.

V. DEVELOPMENT OF BILLING UNITS

Q. Please explain what is meant by the term "billing unit."

A. A billing unit is a quantity of customers (customer count), electric usage (kilowatt-hours), demand (kilowatts), or reactive demand (kilovar) data to which filed rates are applied in determining customers' bills. Depending on a customer's rate class, two or more of these components are used to bill virtually all customers.

Q. Did you conduct a billing unit analysis for this case?

A. Yes. I conducted a billing unit analysis using the proposed test year for this case, consisting of the twelve months ending December 31, 2018, as the study period.

Q. What was the result of the billing units analysis?

A. The analysis provides the normalized billing units to be used to develop proposed rates. The study shows that test year retail revenues should be reduced by $232,445,143 to reflect normalized conditions. The resulting normalized retail revenues

were utilized by Ms. Moore in her annual revenue requirement calculation and are summarized in the table below.

Table 4 – Normalized Billing Units

Customer Class	Calculated Revenues	Normalized Revenues	Total Adjustment
Residential Service	$1,428,200,180	$1,278,256,444	($149,943,736)
Small General Service	$322,929,455	$295,121,638	($27,807,817)
Large General Service	$601,651,056	$562,423,013	($39,228,044)
Small Primary Service	$246,886,789	$243,422,690	($3,464,099)
Large Primary Service	$213,018,865	$202,942,497	($10,076,368)
Company-Owned Lighting	$37,001,805	$35,602,359	($1,793,414)
Customer-Owned Lighting	$3,523,075	$3,391,008	($138,419)
Metropolitan Sewer District	$78,213	$74,966	($3,247)
Total	**$2,853,289,438**	**$2,621,234,615**	**($232,455,143)**

*Revenue includes Low-Income Pilot Program Charges.

Q. What adjustments is the Company making to normalize the billing units?

A. There are five primary adjustments:

1) A tax adjustment to normalize for the federal income tax reduction applied during the test year;
2) A weather normalization adjustment to reflect normal weather conditions;
3) A 365-day adjustment;
4) A growth adjustment to capture expected customer growth through December 2019; and
5) An EE adjustment to adjust for loss of load from customers who implemented Energy Efficiency measures throughout the year.

Table 5 – Billing Unit Adjustments

Customer Class	Tax Change Adjustment	Weather Adjustment	365-Day Adjustment	Growth Adjustment	EE Adjustment	Total Adjustment
Residential Service	($59,157,351)	($89,837,144)	($4,113,358)	$7,632,676	($4,468,559)	($149,943,736)
Small General Service	($13,211,727)	($11,050,541)	($1,436,882)	$1,160,174	($3,268,841)	($27,807,817)
Large General Service	($24,076,094)	($12,307,171)	($1,316,130)	$4,105,148	($5,633,797)	($39,228,044)
Small Primary Service	($9,823,306)	$9,309,580	($880,735)	($224,848)	($1,844,789)	($3,464,099)
Large Primary Service	($7,907,927)	($1,179,151)	($768,159)	$0	($221,130)	($10,076,368)
Company-Owned Lighting	($1,399,446)	$0	$0	($393,969)	$0	($1,793,414)
Customer-Owned Lighting	($132,067)	$0	$0	($6,351)	$0	($138,419)
Metropolitan Sewer District	($3,247)	$0	$0	$0	$0	($3,247)
TOTAL	**($115,711,166)**	**($105,064,428)**	**($8,515,264)**	**$12,272,830**	**($15,437,115)**	**($232,455,143)**

Q. What was the initial step you took in the development of the Company's billing units for each customer class?

A. I used Company reports containing aggregate kilowatt-hour sales and revenues on a monthly basis for the Residential, Small General Service, Large General Service, Small Primary Service, and Large Primary Service rate classes to develop a more detailed monthly report which provides the billing units that are applied to the Company's filed rates for calculating billed revenues. This report provides billing data both by revenue month, which is the month for which the data was reported, and the primary month, which

is the month the data should have been reflected in customer bills. I used this report to assemble the billing data in the proper primary month. I then applied to the rates in effect during the test year for each specific rate class to the billing units for each class. This results in the "Calculated Retail Revenues" for each class.

Q. Do the revenues calculated from this process exactly match the revenues indicated on the Company's books ("reported revenue") for the same time period?

A. While the comparison of calculated revenue and reported revenue match closely, there will always be some difference between the two. The difference results from billing adjustments made to a number of accounts each month for corrected billings, and initial and final pro-rated billings.

Q. Were all of the classes analyzed using the billing unit reports?

A. No, individual customer data was used for the Large Primary Service class. The billing unit reports were used for all other classes.

Q. Why was the Large Primary Service class' billing units analyzed by individual customer?

A. The Large Primary Service class contains approximately 64 customers who are generally the largest customers, which warrants thorough review of each customer's billing data.

Q. How were the billing units and revenues adjusted to reflect normal weather?

A. Weather adjustment ratios for each billing month were applied to adjust the monthly reported sales to weather normalized sales. An additional weather normalization step was taken for the Residential and Small General Service classes to normalize the percentage of kilowatt-hours billed in the first block of the winter declining block rates. For the other rate classes, the kilowatt-hours in all of the rate blocks were adjusted by the weather ratios and the resulting units were priced at the rates offset in File No. ER-2016-0179.

Q. How were the billing units and revenues adjusted to a 365-day test year?

A. The Company's billed sales for a given month do not necessarily represent all of the energy used within the calendar days of that month. This is because the Company's customers have their meters read in 21 groups (or cycles) each month according to a published schedule. So an August bill for one customer may be based on the period July 14 through August 13, while for another customer the August bill may include usage from July 26 through August 26. Groups of customers that have their meters read on the same date are referred to as sharing a "billing cycle." This schedule varies from year to year and from billing group to billing group. The effect of this is that groups of customers may be billed for slightly more or less than 365 days over the course of a test year. The Company compares calendarized test year sales to the billed test year sales. Because the calendarized test year sales cover 365 days, the difference from the billed test year allows the Company to adjust the billing units to a standard calendar year.

Q. How were the billing units adjusted for customer growth?

A. The weather normalized billing units were adjusted for customer growth by multiplying the monthly usage per customer by the customer counts as of June 2018, and then again using forecasted customer counts for June 2019 (to capture the proposed true-up period), to calculate the customer growth through December 2019. The resulting revenue, calculated from the 365-day adjustment and the growth adjusted billing units, was then used to adjust the normalized billing units to calculate to the total growth adjusted revenues. Sales are typically annualized for changes in customer counts during the test year. During the test year, customer counts are typically growing because of new customer connections exceeding the number of customers that disconnect from the system. During a recession or housing market slump, this is not always the case, but it is a fairly ordinary course of events historically speaking. In the process of developing normalized billing units, both the Company and Staff typically adjust the test year sales to produce a level of sales that would have occurred if every customer on the system at the end of the test year had been on the system for the entire test year. This has most often increased the billing units above the level of sales that actually occurred in the test year. It is no different to annualize energy consumption such that the consumption pattern of light bulbs (and various other program measures) that are in place at the end of the test year in fixtures that were utilized during the test year are reflected in the level of sales made throughout the test year.

Q. How were the billing units adjusted for the EE adjustment?

A. During the test year, Ameren Missouri spent significant sums of money on programs designed to help its customers use energy more efficiently. The natural result of

these programs is a decline in the sales made by the Company relative to the level of sales that would be made absent the programs. Because Ameren Missouri's programs were successful in generating significant customer energy savings, the impact of the efficient measures installed in the test year should be annualized to reflect the full impact that those measures have on the Company's sales. Energy efficiency measures that were implemented during the test year are annualized back through the test year to account for the reduction in kilowatt-hours ("kWh") prior to the month these measures were installed. Forward month adjustments would not be included as these load reductions would already be captured following the installation of the given energy efficient measure. The total of these annualized EE adjustments for each measure is then applied to the overall adjustment. This adjustment is contemplated by the Company's Commission-approved Missouri Energy Efficiency Investment Act ("MEEIA")a program, and appropriate adjustments to rebase the throughput disincentive mechanism to stop recovering those sales declines through that mechanism will also be made once these adjustments are reflected in rates.

Q. Were any other adjustments made to the class level loads besides the calculations listed above?

A. Yes, the annualization of the tax change impacts were also reflected in the normalized retail revenues.

Q. Does the Company intend to revise its billing units and associated test year revenue to reflect a more recent twelve-month period as this case progresses?

A. Yes. In the Company's last several general rate cases, both the Company and Commission Staff moved the test year billing units forward in order to reflect a more

current twelve-month period. The Company anticipates that rather than relying on the twelve-months ending December 2018 data, a more current period will be utilized to allow the most current usage information possible to be used to set rates in this case.

Q. What do you do with the final normalized billing unit numbers?

A. These are used in the development of the final rate design proposed in the case.

VI. WEATHER NORMALIZATION

Q. What is weather normalization, and why is it necessary?

A. Weather normalization is the process of determining the level of sales that the Company would be expected to have made in the test year if normal weather conditions had prevailed. When changing rates in a rate case, it is important to normalize sales for the impact of unusual weather. This is because the level of test year sales (cents/kWh) will become the denominator in the development of new electric rates. If the test year included weather-related decreases in sales that are not expected to persist from year to year, the denominator of the rate will be too small and the resulting rate will be too high. In this circumstance, the Company would be expected to recover more than its revenue requirement, all other things being equal. Conversely, if the weather-related sales are higher than normal, the resultant rate will be too low for the Company to have a reasonable opportunity to recover its revenue requirement. Adjusting sales to a normal level will help develop a final rate that is most likely to permit the Company to collect its revenue requirement accurately.

Q. Please outline the process of weather normalizing electric sales.

A. At a high level, there are three basic steps involved in the process, each with significant details involved in them. The first step is to define "normal" weather. The Company has used weather observations from the period 1981-2010 to develop its normal weather conditions. This is consistent with the National Oceanic and Atmospheric Administration ("NOAA") definition, which states that normal for a climatic element is equal to the arithmetic average of that element computed over three consecutive decades (currently 1981-2010). However, because of the unique nature of the problem of normalizing energy usage, a specific technique that is often referred to as the "rank and average" approach is applied to temperatures from these decades. Application of this procedure is necessary in order to produce realistic levels of normal energy sales later in the process. This method has been utilized routinely in electric rate cases by the Missouri Public Service Commission Staff ("Staff"), and was used by both the Company and Staff in the Company' most recent rate case (File No. ER-2016-0179). I will elaborate further on this methodology later in my testimony.

The second step in the weather normalization process is to develop load-temperature relationships. Accurate statistical models of the response of load to temperature are critical to developing a reasonable level of sales and net system output upon which to develop rates. Using a software package called MetrixND, daily loads at the rate and revenue class level are modeled statistically as a function of calendar and weather variables. These statistical relationships are the basis for the weather adjustments that are made to test year sales and will be discussed in more detail later in my testimony.

The final step in the weather normalization process is to bring together the actual and normal weather data with the statistical relationships of load and weather to calculate the adjustments necessary to bring test year sales to the level expected under normal conditions. This is the point at which we develop the level of sales that will ultimately produce rates that afford the best opportunity to generate revenues in line with the revenue requirement in the case. These calculations will also be described further below.

Q. What weather data do you use to perform weather normalization?

A. I use actual and normal two-day weighted mean temperatures for each day in the test year that apply to the Company's service territory.

Q. What is a two-day weighted mean temperature ("TDMT")?

A. The TDMT is a temperature measure that is calculated by first taking an average of the high and low temperature reported for each day. This value is referred to as the daily average or mean temperature. Then for each day, the daily mean temperature is averaged with the prior day's daily mean temperature with 2/3 weight on the current day and 1/3 weight on the prior day. This calculation is done because the TDMT is a better predictor of electric loads than the simple daily mean temperature, reflecting the fact that electric loads tend to be higher on each successive very hot day. This phenomenon is observable in load data and is largely attributed to heat build-up. When coming off of a very hot day, buildings' temperatures are higher than they otherwise would be. Therefore, air conditioning units must work harder to cool structures. The TDMT captures this effect by bringing forward the effect of the prior day's temperature into the value being used to explain the current day's electric usage.

Q. What weather station is used to describe the weather in the Company's service territory?

A. Weather readings taken at the NOAA station at the St. Louis International Airport ("Lambert Field") are used in the weather normalization process as representing the Company's service territory. As the St. Louis Metropolitan Area is home to a large majority of the Company's customer base and the entire load served by the Company is located in relatively nearby Missouri counties, this is appropriate.

Q. Are there any adjustments made to the temperatures before they are used in the weather normalization process?

A. Actual temperatures for the test year are used in the Company's calculations. However, in the calculation of normal weather, it is necessary to make adjustments to the historical readings to account for certain discontinuities in the data that have resulted from known changes made over time in the equipment used at Lambert Field and its location.

Q. Please describe the need to make adjustments to the weather data as mentioned above.

A. Over the time period from 1981-2010, there have been changes made to the weather station at Lambert Field where the temperature measurements are taken. The most significant of these changes occurred in May 1996, when Lambert Field was changed to an Automated Surface Observing System station. At this time, both the equipment used to record temperatures and the location of that equipment changed in order to introduce a system that records weather data continuously and automatically. The new equipment and

location resulted in readings that were lower than they would have been with the previous equipment and at the previous location.

The most important characteristic of the calculated normal temperature is that it must be accurate relative to the test year temperatures. The difference between the normal temperature and the actual temperature should represent climate variability, not artificial differences that can be introduced by changing observation practices. If the temperature readings from 1981-2010 have a known bias when compared with current readings from Lambert Field, the calculated normal temperatures that are based on those readings will not be applicable to the test year.

To illustrate this point, imagine two consecutive days that happen to have identical high and low temperature conditions. At midnight, assume that the weather station is disassembled and simultaneously reconstructed with new equipment some distance away from where it previously was located. The new equipment happens to read cooler than the equipment it replaced, since it is now in a grassy field instead of near blacktop pavement that absorbs heat. The temperature on the second day now reads more than one degree cooler than the first day. It would be inappropriate to use the temperature from the first day without any adjustment in a calculation that will be used on the second day. The adjustment process corrects this problem and allows us to fulfill the objective of having normal temperatures that are accurate relative to the test year temperatures.

Q. How are the magnitudes, direction, and timing of these adjustments determined?

A. The adjustments that the Company makes to the historical temperature data from Lambert Field are based on a collaborative analysis undertaken by Staff and the Company during File No. EM-96-149. Climatologists engaged by the Company and Staff used a statistical technique called "double-mass analysis" to determine the timing, direction, and magnitude of the necessary adjustments. In the course of this analysis, the climatologists used multiple reference weather stations in close geographic proximity to Lambert Field to identify and characterize the discontinuities in the data. These adjustments were agreed to in File No. EM-96-149 and were used again by both parties in at least the last six Ameren Missouri electric rate cases, and most recently in File No. ER-2016-0179.

Q. Now that you have described the source of and adjustments to the historical temperature data, please describe the process you use to develop daily normal temperatures for the test year.

A. First, daily TDMTs are calculated for the period from 1981-2010. Next, a technique referred to as "rank and average" is applied to the historical TDMTs in order to develop normal values to use in the test year. The rank and average technique is used so that the resultant normal temperatures produce appropriate levels of electric usage when applied to the statistical models that capture the relationship between load and temperature. The rank and average technique starts by ranking all of the days within a season or year for each year from the highest TDMT to the lowest. Then for that season or year, the warmest day of each of the 30 years is averaged, the second warmest day of each of the 30 years is averaged, and so on until the coolest day of each of the 30 years is averaged. Through this process we get a series of daily temperatures that represent the normal warmest day for the

season or year through the normal coolest day for the season or year. This result is desirable because it gives normal temperatures that also exhibit normal levels of extreme temperatures.

Q. Why is it important to have normal levels of extreme temperatures?

A. The response of load to temperature is non-linear. That means that a change in temperature of 1 degree from 40 to 41 degrees has a different impact than a change in temperature from 60 to 61 degrees, which in turn has a different impact than a change from 80 to 81 degrees. Because load behaves differently across the spectrum of possible temperatures, it is important to have a representative number of days in each part of the temperature range in order to reproduce the level of load that would be experienced across a year with normal temperature variability. The rank and average technique achieves this objective.

Q. How is the relationship between load and TDMT established?

A. As I previously mentioned, the Company uses a software package called MetrixND to develop statistical models that represent the relationship of load and temperature.

Q. What are the inputs to the MetrixND models?

A. Daily loads for each customer rate/revenue class combination to be weather normalized are input into MetrixND. In addition, calendar variables that describe the day of the week and season of the year are utilized. Finally, TDMTs for the time period being used to develop the model are input.

Q. How does the Company obtain daily load data by customer rate and revenue class to input into the model?

A. The Company develops hourly load data (which is aggregated into daily data) through its Load Research Program. Ameren Missouri maintains stratified random samples of customers from each rate class, for which it collects hourly load data. Using the hourly loads from the samples along with calendar month class sales, the Company uses a statistical technique called "ratio analysis" to generate hourly class level loads. In addition to the rate class level analysis, the Company uses another statistical technique called "domain analysis" to extract revenue class level data. Revenue classes include Residential, Commercial, and Industrial. By subdividing rate classes into revenue classes, more homogeneous customer groups are available to model.

As a part of the load research process, class level loads are aggregated, adjusted for transmission and distribution line losses, and then compared to the observed system load by hour. The system load is an actual hourly metered value, whereas the class loads are statistical estimates. The class level loads are calibrated so that they aggregate up to match the known system loads by hour. This ensures that the class level hourly data is consistent with the energy that was consumed on the system. The resultant calibrated loads by rate and revenue class are used in the MetrixND model and become an important input in the process used to normalize net system output and the class peaks used in the class cost of service study.

Q. Please discuss the modeling process that occurs in MetrixND.

A. In MetrixND, a scatter plot is created with daily TDMTs on the horizontal axis and load on the vertical axis. Using this graph, ranges are identified that have similar load responses to changes in temperature. These ranges become temperature groupings for the model. Additionally, seasons are analyzed graphically to see if the load-temperature response differs seasonally. Variables are then developed to reflect these temperature ranges and seasonal combinations that have similar load-temperature responses. These variables, along with day of week variables and month or season variables are combined in regression models to explain the variation in daily energy consumption by class.

Q. Please describe how these statistical models represent the load-temperature response.

A. Consider a model that is being fit for which no seasonal variations in the load-temperature response have been identified. Over the course of the year, both heating and cooling equipment may be used by the Company's customers. The model may determine that when the temperature is between 40 and 50 degrees, a particular customer class' usage may increase by 100 megawatt-hours ("MWhs") for each degree it gets colder. That means that when the TDMT falls from 42 to 41 degrees, space heating equipment works harder, resulting in 100 MWhs of increased usage. In this case the MetrixND model would have a coefficient of -100 for the variable or variables that represent that temperature range. This is similar to graphically drawing a line with a slope of -100 over the area between 40 and 50 degrees on the scatter plot that we started with. However, this same model may indicate that from 70 to 80 degrees, the same class' usage increases by 150 MWhs for each degree warmer that it gets. This is because as temperature increased,

heating equipment was switched off and air conditioning equipment was switched on. The coefficient of the model for the variable(s) that represents this temperature range will be 150, which is similar to including a line with a slope of 150 on the scatter plot over the load-temperature pairs between 70 and 80 degrees. The model establishes across all relevant temperature ranges what is expected to happen to customer loads as the temperature changes.

Q. How are these models used to normalize customer loads?

A. For each day, actual and normal TDMTs have been paired based on the normal weather calculations described above. For a given day, assume that the actual TDMT was 74 degrees and normal is determined to be 78 degrees. We will look to the statistical relationships developed in MetrixND, which may indicate that in this temperature range each additional degree causes usage to increase by 100 MWhs. So in order to normalize load, we will take the number of degrees that the actual temperature deviated from normal (78 degree normal – 74 degree actual = 4 degree adjustment from actual to normal) and multiply it by the usage per degree described by the model (4 degrees x 100 MWhs/degree = 400 MWhs). On that day, normal usage is 400 MWhs higher than the actual usage.

Q. Are there any other models developed in this fashion?

A. Yes, an identical process is followed to generate statistical models and normal values to represent each customer class' daily peak load. This is instrumental in developing the normalized net system output and class demands.

Q. Once you have normalized the energy from the daily loads that you developed in your load research process, how does this translate into normal sales for billing months?

A. In the weather normalization process, the Company is normalizing each billing cycle independently. We start with billed sales for each billing cycle (group of customers whose meters are read together) for each month. Since we know the dates the meters were read for each billing cycle, it is possible to estimate how much usage occurred on each day. Take for example a hypothetical billing cycle that began on July 14 and ended on August 13. A particular class of customers (e.g., Residential, Commercial Small General Service, etc.) may have been billed for 150,000 MWhs of usage in that period for the customers on that billing cycle. We then look at the total estimated class daily usage from load research for those dates, where we may find that the total class used 3,000,000 MWhs over the dates between July 14 and August 13. Perhaps the total class usage on July 14th was 100,000 MWhs. Therefore, 3.33% of the class' usage occurred that day (100,000 MWhs of class daily usage / 3,000,000 MWhs of class usage over the billing period = 3.33%) and that 3.33% is applied to the sales of the actual billing cycle that is being normalized (150,000 MWhs x 3.33% = 5,000 MWhs on July 14th). Using this methodology, the actual billed sales are estimated by day for each billing cycle. Then, for each day, the actual billed sales are adjusted based on the daily normalized loads produced by MetrixND. We know that the total class used 100,000 MWhs on July 14th, and through the MetrixND process the normal load for July 14th was determined to be 110,000 MWhs. So for that day, normal usage was 110% of actual (110,000 MWhs normal load / 100,000 MWhs actual

load = 110%). The billing cycle that used 5,000 MWhs on July 14th has a normal load for that day of 5,500 MWh (5,000 MWhs actual usage x 110% normal/actual ratio = 5,500 MWhs normal usage). For every customer class, month and billing cycle combination, this calculation is done for each day that falls between the applicable meter reading dates. The sum of the daily billed sales across all months and billing cycles ties to the Company's billings for the year for the customer class being normalized. The sum of the daily billed normal sales across all months and billing cycles is the normalized level of the Company's billings for the year.

Q. How are calendar month actual and normal sales estimated in this process?

A. When going through the calculations of actual and normal billed sales, daily actual and normal sales by billing cycle are developed as described above. These sales are then just aggregated according to the days within a calendar month rather than according to meter read schedule dates to develop calendar month sales.

Q. Please summarize the results of your analysis for the test year in this case.

A. The test year was significantly warmer than normal in the summer and slightly cooler than normal in the winter. Cooling Degree Days ("CDD"), a quantification of the weather that typically results in air conditioning load, were 37% greater than normal. Heating Degree Days ("HDD"), a quantification of the weather that typically results in heating load, were 4% greater than normal. Total retail sales for the weather sensitive classes were adjusted down by 3.51% in aggregate.

Q. How are the final weather normalized sales numbers used?

A. They are used in the development of the billing units for the case.

Q. What is net system output?

A. Net System Output ("NSO") is the term the Company uses to describe the total amount of energy generated or purchased to serve its retail load including the energy associated with distribution system line losses. Commission rule 4 CSR 240-3.190 requires electric utilities to submit monthly data reporting, among other things, Net System Input ("NSI"). The Company uses these two terms interchangeably. Both describe the amount of electric supply required to serve the utility's ultimate consumers including line losses. As long as they are measured at the same point, there is really no difference between the two. Since Ameren Missouri began operating as a part of the Midcontinent Independent System Operator ("MISO") Day 2 Energy market in April 2005, NSO has been measured at the transmission level (i.e. including distribution losses but excluding transmission losses). This is because, as described more fully below, Ameren Missouri is not responsible for the physical energy that is lost on the transmission system under MISO's market construct. Because the Company has normalized sales (and consequently test year revenues), it is also essential to normalize NSO. The NSO is the load that will drive the production cost model that determines the fuel and purchased power costs of the Company during the test year. This ensures we are treating revenues and expenses equivalently so that the true cost of service of our normalized level of load is reflected in the case in a manner that is consistent with the calculated normalized revenues.

Q. How is NSO normalized?

A. Much of the work is already done from the process of normalizing sales. We used calibrated load research data for each customer class to build statistical models of daily class energy. As mentioned when describing the sales normalization, models are simultaneously built to weather normalize the daily peak load for each class. From these models, it is possible to generate hourly weather normalized class loads.

Q. How does normalization of the daily energy and peak produce normal hourly class loads?

A. A technique called the "unitized hourly load calculation" is used that keeps the existing hourly pattern of loads that was experienced in the test year, but adjusts it to the targeted energy and peak levels from the daily weather response functions. This technique is detailed in the Staff's 1990 Draft Report titled "Weather Normalization of Electric Loads."

Q. Once you have computed normalized hourly class loads, how do you create the net system output on a normal basis?

A. We adjust the normalized class hourly loads for losses and sum across the classes to develop normalized net system output.

Q. Do the details of the load research process described earlier provide any benefits at this point in the process?

A. Yes, this is the reason it was important to point out the calibration process of our load research work. The load research was developed at the customer meter level, then adjusted for transmission and distribution line losses, and finally compared to the

actual observed system loads. Any variation between the sum of our class level estimates and the total system load was allocated to the various customer classes at that time. The sum of hourly class loads adjusted for losses is equal to the observed system load. All energy generated and purchased for load is necessarily accounted for in these values. Using the normalized version of these calibrated loads and adjusting for losses using the same loss rates as before ensures that the normalized net system output also accounts for all energy that would be generated or purchased to serve the normalized level of load from the test year.

Q. What are the advantages of the class-by-class, or "bottom-up" method of normalizing net system output?

A. There are at least three advantages of this method. First, the models that are normalizing the energy level of the net system output are the exact same models that are normalizing sales for revenue calculations. That helps build consistency between these adjustments. Second, the energy models at the rate class level can pick up differences in response to temperature by class and therefore incorporate more useful information about load into the calculation. The increased level of detail should provide a truer representation of the load-temperature relationship. Finally, it helps build consistency across filings to use the bottom-up approach, as the results of a class-by-class hourly weather normalization will be utilized in Integrated Resource Planning ("IRP") filings made by the Company. Using a similar approach to weather normalization of class and system loads in the rate case and IRP only makes sense. Again, it is worth reiterating that the calibration of the

original class level load research ensures consistency between the class level calculations and the system load calculations.

Q. Why does the estimate of transmission losses need to be based on MISO settlements, and why is it deducted from net system output?

A. When the Company interacts with MISO, transmission losses are settled financially. This means that the Company buys the energy needed to serve its load from MISO, but does not explicitly buy the associated energy to cover transmission losses (energy associated with distribution losses is purchased from MISO). The Company will be paid for all energy it generates by MISO and will pay for all energy it consumes from MISO. The difference between the generation sold and the load purchased is equal to off-system energy sales net of power purchases. Since transmission losses are not included in the load purchased from MISO, the load used for the net system output should not include those losses. That way the generation that went to serve transmission losses will appear as off-system sales in the production cost model, which is a reflection of how the Company truly transacts with MISO. Transmission losses are paid for through the Marginal Loss Component of the Locational Marginal Price paid for all load. In order to match this reality, the loss rate that matches MISO's loss estimates is used in the calculation.

Q. What is done with the normalized net system output number in the Company's filing?

A. The hourly net system output is used in production cost modeling along with the annual MWh of net system output in the calculation of the Net Base Fuel Cost ("NBFC") in the Fuel Adjustment Clause tariff.

Q. Please describe the class demand data that is presented in this case and its purpose.

A. The load research provides a key input to the class cost of service study. It provides the demand of each rate class that occurs coincident with the system peak demand. It also provides the class peak demand for the year on a non-coincident basis. Additionally, it provides the class non-coincident demands, which represent an aggregate of the estimated peak usage of each member of the class.

Q. How is this data utilized in the class cost of service study?

A. In summary, this weather normalized data is used to develop allocation factors to assign various costs to the customer classes responsible for causing them. The specific details are covered by Thomas Hickman in his Direct Testimony.

Q. What is the benefit of weather normalizing class demands?

A. Class demand data that has not been weather normalized can be influenced by extreme weather experienced in the test year. Absent weather normalization of the class demands, allocation factors could change from case to case based on nothing more than the prevailing weather conditions at the time of peak during the test year. Normalizing these demands will help produce more stable allocation factors that will only change when there is a true change in the usage characteristics of the various customer classes.

VII. MISCELLANEOUS TARIFF UPDATES

Q. Please describe the changes made to the non-standard service language in the tariffs on Sheet No. 110 in the Company's General Rules and Regulations.

A. The last sentence of the second paragraph in Section J of the Non-Standard Service has been removed. This language, which extends beyond what is required in 4 CSR 240-20.050, is no longer consequential and simply confuses Customers who are making decisions concerning the installation of metering for their property. The removal of this language will apply to all Customers regardless of date, and should provide developers with greater flexibility in redeveloping buildings constructed prior to June 1, 1981.

Q. Please describe the addition of the returned check fee on Sheet No. 63 in the tariffs.

A. The Company currently charges a returned check fee per Section 570.120.6, RSMo. The Miscellaneous Charges Sheet No. 63 is being updated to align with that statute.

Q. Please describe the modifications to the "additional charge" fees as they apply throughout the Company's tariffs.

A. Additional customer charges present in rate schedules 2(M), 3(M), 4(M), and 11(M) that were applied to customers with optional Time-of-Day rates who required a specially programmed meter, have been reduced and aligned with the standard customer charge that applies for each respective rate class. Time differentiated cost adders under Rider QF have also been eliminated, and language concerning additional metering fees in Rider I have been updated to account for the installation of advanced metering. Customers that request service under Rider I prior to the installation of advanced metering will still be required to pay the existing incremental charges that may apply under the provisions of Rider I.

Q. Briefly describe Rider M and explain the reason for its removal.

A. Rider M is the Option Based Curtailment Rider, whose purpose was to provide customers the option to allow the Company to curtail a certain level of power in exchange for an option premium. The language contained in Rider M is long outdated, even the concept of the Rider itself, which predated the creation of the Midwest Independent System Operator model, essentially became unnecessary and uneconomical with the evolution of the current market constructs. Over the past 15 years, the Rider has not provided any economic benefit for either customers or the Company, and no customers have taken service under Rider M.

Q. Briefly describe Rider SP and explain the reason for its removal.

A. Rider SP (Solar Renewable Energy Credit ("SREC") Purchase) was implemented to provide a mechanism for eligible customers to sell, and Company to purchase, the Renewable Energy Credits associated with energy generated by solar electric systems. This Rider expired December 31, 2014, and operated primarily during the years 2011-2013. It provided a supplement to solar rebates provided through Rider SR and provided a mechanism for Ameren Missouri to acquire solar RECs for compliance with Missouri's Renewable Energy Standard. This Rider has not been available for new solar installations since the Missouri Renewable Energy Standard was modified in 2013.

Q. Please describe the language addition in Measurement of Service under the Remote Meter Reading Opt-Out section on tariff Sheet No. 129.

A. This language has been added to support the installation of advanced meters throughout the Company's service area. To summarize, the language addition on Sheet No. 129 simply states that customers who deny Ameren Missouri access, refuse the installation

of advanced metering, or make threats that may compromise the safety of the workers performing the installation, will receive the monthly $45.00 Non-Standard Meter Charge, which is similar to a customer who opts out and requests non-standard metering service. The charges have been listed on Sheet No. 63, Miscellaneous Charges.

Q. Please describe the language changes proposed for the 2(M) rate class on tariff Sheet No. 55.2.

A. Should a Customer exceed the 100kW demand threshold, the presence of an advanced meter will make the delayed two-month billing period required to install a new meter for monitoring demand unnecessary. Customers with advanced metering who exceed the 100kW demand threshold will be automatically moved onto the 3(M) rate class with their next billing month. Language in the tariff has been updated to reflect the capabilities of the AMI metering system once in place and to address Automated Meter Reading ("AMR") meters through the transition period.

Q. Please describe the addition of Paperless Billing language on tariff Sheet No. 63, Miscellaneous Charges, and Sheet No. 138.

A. These additions support the Paperless Billing Incentive described in greater detail within Company witness Mark Birk's direct testimony. The credit is added to the Miscellaneous Charges sheet, along with language defining the terms on Sheet No. 138, section N within the Billing Practices section of the Company's Rules and Regulations.

Q. Are there any other tariff modifications that should be considered in this case related to AMI deployment?

A. Yes. Ameren Missouri has filed a 60-day notice in File No. EE-2019-0382 to request a waiver of various tariff provisions and regulations to enable deployment of AMI meters in 2020. In that waiver request, the Company plans to address the current requirement to knock on customers' doors prior to disconnecting service. With AMI technology, the Company can reconnect and disconnect remotely, eliminating the expense of deploying a truck to the site for both restarting service and shutting off service. This expense however would still persist if the Company is required to deploy a truck to simply knock on a door or place a disconnection notice, and thus the $30 Reconnection Fee under Miscellaneous Charges would need to remain in place. Because the waiver request has not yet been filed or resolved though, modifications to the tariffs to effectuate that waiver have not been filed with this direct case. Specifically, no modifications are proposed to the tariffs in this direct case concerning Reconnection Fees, but the Company recommends modifying the tariffs with the compliance filing to include the following:

1) Eliminate the Reconnection Charges per Connection Point on Sheet No. 63, Miscellaneous Charges;

2) Eliminate the associated language on Sheet No. 145, Disconnection and Reconnection of Service, that refers to the Reconnection Charge on Sheet No. 63;

3) Update the language on Sheet No. 144, Residential Customer Contact and Notice of Disconnection, with a requirement for an email, text, phone message, or other

means of communication provided by the customer, in lieu of a physical notice attached to the door after disconnection.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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RATES

SERVICE CLASSIFICATION NO. 1(M) R-BASIC
BASIC RESIDENTIAL SERVICE

*AVAILABILITY

This rate is applicable to all residential Customers that are not receiving service under an optional residential rate, and that are supplied by the Company to individually metered residences or 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.

*DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use or demand (how much energy is used at one time).

**RATES

The monthly bill will consist of the following charges, plus adjustments:

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

Customer Charge - per month	$11.00
Low-Income Pilot Program Charge – per month	$0.04
Energy Charge - per kWh	11.51¢

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

Customer Charge - per month	$11.00
Low-Income Pilot Program Charge – per month	$0.04
Energy Charge - per kWh	
First 750 kWh	8.00¢
Over 750 kWh	5.51¢

*Indicates Addition. **Indicates Change.

SERVICE CLASSIFICATION NO. 1(M) R-BASIC
BASIC RESIDENTIAL SERVICE (Cont'd.)

ADJUSTMENTS

The bill will include the followings adjustments:

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.

Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM). Applicable to all metered kilowatt-hours (kWh) of energy.

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.

***SERVICE DETAILS**

1. Payments. Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.
2. Term of Use. Initial period one (1) year, terminable thereafter on three (3) days' notice.
3. 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 - 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.
4. Temporary Service. Temporary service requested for residential use will be supplied under the terms and conditions set forth under Rider D.
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.

*Indicates Reissue.

SERVICE CLASSIFICATION NO. 1(M) R-BASIC
BASIC RESIDENTIAL SERVICE (Cont'd.)

***SERVICE DETAILS (Cont'd.)**

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.

6. General Rules and Regulations. In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

*Indicates Reissued.

SERVICE CLASSIFICATION NO. 1(M) R-BASIC
BASIC RESIDENTIAL SERVICE (Cont'd.)

*GRANDFATHERED OPTIONAL TOD (TIME-OF-DAY) RATE PILOT

Service under the TOD pilot is no longer offered for new enrollees. Existing residential customers who are currently receiving service under the TOD pilot will continue to be eligible to receive TOD service until the installment of an advanced meter. Upon installation of an advanced meter, the Customer's service will transfer to the R-TOU rate schedule with the next applicable billing period, unless opting for an alternative residential rate option.

Customer Charge - per month	$11.00
Low-Income Pilot Program Charge – per month	$0.04
Energy Charge - per kWh (1)	
Summer (June-September billing periods)	
All On Peak kWh	28.82¢
All Off Peak kWh	7.20¢
Winter (October-May billing periods)	
First 750 kWh	8.00¢
Over 750 kWh	5.51¢

(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.

The Grandfathered Optional TOD (Time-Of-Day) Rate Pilot is subject to the following provisions:

a. Customer will be transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.
b. Any customer canceling this TOD option cannot thereafter resume billing under said option.
c. Participation shall exclude customers with a net metering agreement.

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

SERVICE CLASSIFICATION NO. 1(M) R-TOU
* RESIDENTIAL SMART SAVER SERVICE

AVAILABILITY

This optional rate is available at Customer's election to all residential Customers being served through an advanced meter and 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.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by the time of day that the energy is used (On-Peak,Intermediate, Off-Peak), and the season (Summer or Winter). This rate does not have a demand charge.

This rate has two options: year round service(Option A) and a summer seasonal service(Option B). Under Option B, a Customer will only be billed under R-TOU for the Summer billing period, the Winter season will be billed under the R-BASIC rate schedule.

RATES

The monthly bill will consist of the following charges, plus adjustments:

Customer Charge - per month	$11.00
Low-Income Pilot Program Charge – per month	$0.04
Energy Charge - per kWh	
Summer(June-September billing periods; Option A & B)	
On Peak kWh	32.14¢
Intermediate kWh	8.45¢
Off Peak kWh	5.37¢
Winter(October-May billing periods; Option A)	
On Peak kWh	16.36¢
Intermediate kWh	5.90¢
Off Peak kWh	4.78¢
Winter(October-May billing periods; Option B)	see R-BASIC

TIME PERIODS

On-peak and Off-peak hours applicable herein are:

Summer (June-September billing periods)

Peak hours - 3:00 P.M. to 7:00 P.M., Monday through Friday, excluding holidays(1)

Intermediate hours - 6:00 A.M. to 10:00 P.M., All days, excluding Peak hours

Off-Peak hours - 10:00 P.M. to 6:00 A.M., All days

*Indicates Addition.

SERVICE CLASSIFICATION NO. 1(M) R-TOU

* **RESIDENTIAL SMART SAVER SERVICE (Cont'd.)**

TIME PERIODS (Cont'd.)

Winter (October-May billing periods)

Peak hours - 6:00 A.M. to 8:00 A.M. and 6:00 P.M. to 8:00 P.M.
Monday through Friday, excluding holidays(1)

Intermediate hours - 6:00 A.M. to 10:00 P.M., All days, excluding Peak hours

Off-Peak hours - 10:00 P.M. to 6:00 A.M., All days

(1) Legal Holidays of New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Thanksgiving Friday, Christmas Eve Day, and Christmas Day.

ADJUSTMENTS

The bill will include the followings adjustments:

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.

Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM). Applicable to all metered kilowatt-hours (kWh) of energy.

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.

SERVICE DETAILS

1. Payments. Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.
2. Term of Use. Customers may transfer from this rate to another 1(M) residential rate schedule at any time, however, any customer transferring from this TOU option cannot thereafter resume billing under said option for a period of one year following the last billing period on the TOU option.
3. 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

DATE OF ISSUE July 3, 2019 — DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) — President (TITLE) — St. Louis, Missouri (ADDRESS)

SERVICE CLASSIFICATION NO. 1(M) R-TOU

* **RESIDENTIAL SMART SAVER SERVICE (Cont'd.)**

SERVICE DETAILS (Cont'd.)

customer will be provided, subject to the Company's approval, under the provisions of Section III - 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.

4. 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.

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

5. General Rules and Regulations. In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

SERVICE CLASSIFICATION NO. 1(M) R-TOUEV
RESIDENTIAL TIME-OF-USE EV SAVER SERVICE

AVAILABILITY

This optional rate is available at Customer's election to all residential Customers 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. Where Customers are not served through an advanced meter, an additional monthly service charge will apply.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

This rate has two options: a year round service(Option A) and a summer seasonal service(Option B). Under Option B, a Customer will only be billed under R-TOUEV for the Summer billing period, the Winter season will be billed under the R-BASIC rate schedule.

RATES

The monthly bill will consist of the following charges, plus adjustments:

Customer Charge - per month	$11.00
Non-AMI Meter Charge – per month	$1.50
Low-Income Pilot Program Charge – per month	$0.04
Energy Charge - per kWh	
Summer(June-September billing periods; option A & B)	
On Peak kWh	13.55¢
Off Peak kWh	5.39¢
Winter(October-May billing periods; option A)	
On Peak kWh	7.82¢
Off Peak kWh	4.77¢
Winter(October-May billing periods; option B)	see R-BASIC

TIME PERIODS

On-peak and Off-peak hours applicable herein are:

Summer (June-September billing periods)

Peak hours - 6:00 A.M. to 10:00 P.M., All days

Off-Peak hours - 10:00 P.M. to 6:00 A.M., All days

Winter (October-May billing periods)

Peak hours - 6:00 A.M. to 10:00 P.M., All days

Off-Peak hours - 10:00 P.M. to 6:00 A.M., All days

SERVICE CLASSIFICATION NO. 1(M) R-TOUEV
RESIDENTIAL TIME-OF-USE EV SAVER SERVICE (Cont'd.)

ADJUSTMENTS

The bill will include the followings adjustments:

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.

Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM). Applicable to all metered kilowatt-hours (kWh) of energy.

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.

SERVICE DETAILS

1. Payments. Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.
2. Term of Use. Customers may transfer from this rate to another 1(M) residential rate schedule at any time, however, any customer transferring from this TOU option cannot thereafter resume billing under said option for a period of one year following the last billing period on the TOU option.
3. 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 - 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.
4. 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.

SERVICE CLASSIFICATION NO. 1(M) R-TOUEV
RESIDENTIAL TIME-OF-USE EV SERVICE (Cont'd.)

SERVICE DETAILS (Cont'd.)

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.

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

5. General Rules and Regulations. In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

SERVICE CLASSIFICATION NO. 1(M) R-TOUUS
RESIDENTIAL ULTIMATE SAVER SERVICE

AVAILABILITY

This limited optional rate is available to residential Customers solicited for pilot participation by Company for 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.

DESCRIPTION

This rate has three parts: a basic service charge, an energy charge, and a demand charge. The energy charge will vary by the time of day that the energy is used (On-Peak or Off-Peak), and the season (Summer or Winter).

RATES

The monthly bill will consist of the following charges, plus adjustments:

Customer Charge - per month	$11.00
Low-Income Pilot Program Charge – per month	$0.04
Demand Charge - per monthly kW of billing demand	
Summer(June-September billing periods)	$6.86
Winter(October-May billing periods)	$2.93
Energy Charge - per kWh	
Summer(June-September billing periods)	
On Peak kWh	25.15¢
Off Peak kWh	4.27¢
Winter(October-May billing periods)	
On Peak kWh	14.05¢
Off Peak kWh	3.89¢

On-peak and Off-peak hours applicable herein are:

Summer (June-September billing periods)

Peak hours - 3:00 P.M. to 7:00 P.M., Monday through Friday, excluding holidays(1)

Off-Peak hours - All other hours

Winter (October-May billing periods)

Peak hours - 6:00 A.M. to 8:00 A.M. and 6:00 P.M. to 8:00 P.M. Monday through Friday, excluding holidays(1)

Off-Peak hours - All other hours

(1) Legal Holidays of New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Thanksgiving Friday, Christmas Eve Day, and Christmas Day.

SERVICE CLASSIFICATION NO. 1(M) R-TOUUS
RESIDENTIAL ULTIMATE SAVER SERVICE (Cont'd.)

ADJUSTMENTS

The bill will include the followings adjustments:

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.

Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM). Applicable to all metered kilowatt-hours (kWh) of energy.

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.

DEMAND BILLING

The Demand Charge will be assessed on the Customer's maximum usage measured over a one hour period between 6:00 A.M. and 10:00 P.M. on any day of the billing period.

SERVICE DETAILS

1. Payments. Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.
2. Term of Use. Initial (2) year pilot term will commence once pilot recruitment phase is complete. Participants will be notified prior to rate application beginning. Any customer may transfer from this rate to another 1(M) residential rate schedule at any time, however, customer cannot thereafter resume billing under this rate for the duration of this initial pilot period. At conclusion of the initial (2) year term, Customers will be transferred back to the R-Basic rate, unless opting for an alternative residential rate option.
3. 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 - 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.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

SERVICE CLASSIFICATION NO. 1(M) R-TOUUS
RESIDENTIAL ULTIMATE SAVER SERVICE (Cont'd.)

SERVICE DETAILS (Cont'd.)

4. 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.

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

5. General Rules and Regulations. In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

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	$11.31
Three Phase Service	$21.45
Limited Unmetered Service	$5.92
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh	10.47¢

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

Customer Charge - per month	
Single Phase Service	$11.31
Three Phase Service	$21.45
Limited Unmetered Service	$5.92
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh	
Base Use	7.82¢
Seasonal Use(1)	4.50¢

Optional Time-of-Day Rate

Customer Charge - per month	
Single Phase Service	$11.31
Three Phase Service	$21.45
Limited Unmetered Service	$5.92
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh (2)	
Summer (June-September billing periods)	
All On Peak kWh	15.56¢
All Off Peak kWh	6.34¢
Winter (October-May billing periods)	
All On Peak kWh	10.25¢
All Off Peak kWh	4.70¢

(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) the kWh use during the preceding 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.

*Indicates Change.

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SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE (Cont'd.)

1. RATE APPLICATION

This rate is applicable to all secondary service supplied by the Company in Missouri for general use which does not qualify for any other secondary rate.

2. CHARACTER OF SERVICE SUPPLIED

Company will specify and provide a standard single- and/or three-phase alternating current secondary service voltage.

3. CUMULATION OF SERVICES

Service provided through multiple meters to the same customer on the same premises and cumulated for billing purposes under this Service Classification, prior to May 5, 1990, may continue to receive such billing. Unless otherwise required for Company's engineering or other reasons, any additional services installed at customer's request and agreed to by Company on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

***4. DEMAND PROVISIONS**

Customer shall be transferred to the Company's Large General Service Rate 3(M) whenever customer's metered demand in any summer month exceeds 100 kW. For a customer being served through an advanced meter, they may be transferred to Large General Service Rate 3(M) as soon as the next billing period.

For customers remaining on Company's legacy automated meter reading system, when normal use of an existing customer or the estimated use of a new customer exceeds 25,000 kWh per month for two consecutive summer billing months, or Company has reason to believe that customer's summer demand exceeds 100 kW regardless of his kWh use, Company will install a demand meter for purposes of measuring customer's demand.

5. CUSTOMERS WITHOUT PRIOR BILLING DETERMINANTS

Customers on this rate who did not have sufficient use during preceding billing periods to establish their Base use for the winter billing season will be billed entirely on the Base rate unless electric heating supplies the customer's entire space heating requirements, in which case one-half of all use in excess of 1,000 kWh will be billed on the Base rate and one-half on the Seasonal energy rate. In either event, after subsequent billing periods are completed, the customer's billing during the preceding winter will be reviewed using the Base use determined from the following May billing period and a refund given if appropriate.

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE (Cont'd.)

***6. OPTIONAL TIME-OF-DAY (TOD) SERVICE**

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

a. If an advanced meter is not present, Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

b. Customer electing this TOD option, shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

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

7. LIMITED UNMETERED SERVICE

Where service is required for electrical loads which are constant over a predetermined operating schedule and can be reasonably estimated by Company, Company may at its sole discretion waive the metering requirement for the limited types of load referred to herein. In such instances Company would calculate monthly billing for these loads under Service Classification No. 2(M). Additionally, all other provisions of Service Classification 2(M) shall apply to these loads. Service supplied under the provisions of this paragraph is limited to loads of 5 kVA or less at any one service delivery point.

8. GENERAL RULES AND REGULATIONS

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

*Indicates Change.

*THIS SHEET RESERVED FOR FUTURE USE

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	$94.58
Low-Income Pilot Program Charge - per month	$ 0.56
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	9.95¢
Next 200 kWh per kW of Billing Demand	7.49¢
All Over 350 kWh per kW of Billing Demand	5.03¢
Demand Charge - per kW of Total Billing Demand	$ 5.08

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

Customer Charge - per month	$94.58
Low-Income Pilot Program Charge - per month	$ 0.56
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	6.25¢
Next 200 kWh per kW of Base Demand	4.65¢
All Over 350 kWh per kW of Base Demand	3.66¢
Seasonal Energy Charge - Seasonal kWh	3.66¢
Demand Charge - per kW of Total Billing Demand	$ 1.88

Optional Time-of-Day Adjustments

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh(June-September billing periods)	+1.18¢	-0.67¢
Winter kWh(October-May billing periods)	+0.36¢	-0.20¢

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

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

SERVICE CLASSIFICATION NO. 3(M)
LARGE GENERAL SERVICE RATE (Cont'd.)

4. DEMAND BILLING (Cont'd.)

e. Demand Meters

When normal use of an existing customer or the estimated use of a new customer exceeds 25,000 kWh per month for two consecutive summer billing months, or Company has reason to believe that customer's summer demand exceeds 100 kW regardless of his kWh use, Company will install a demand meter for purposes of measuring customer's demand.

***5. OPTIONAL TIME-OF-DAY (TOD) SERVICE**

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

a. If an advanced meter is not present, Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

b. Customer electing this TOD option shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

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

6. CUMULATION OF SERVICES

Service provided through multiple meters to the same customer on the same premises and cumulated for billing purposes under this Service Classification, prior to May 5, 1990, may continue to receive such billing. Unless otherwise required for Company's engineering or other reasons, any additional services installed at customer's request and agreed to by Company on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

7. GENERAL RULES AND REGULATIONS

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

*THIS SHEET RESERVED FOR FUTURE USE

*Indicate 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	$324.46
Low-Income Pilot Program Charge - per month	$ 0.56
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	9.62¢
Next 200 kWh per kW of Billing Demand	7.24¢
All Over 350 kWh per kW of Billing Demand	4.85¢
Demand Charge - per kW of Total Billing Demand	$ 4.38
Reactive Charge - per kVar	36.00¢

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

Customer Charge - per month	$324.46
Low-Income Pilot Program Charge - per month	$ 0.56
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	6.06¢
Next 200 kWh per kW of Base Demand	4.50¢
All Over 350 kWh per kW of Base Demand	3.52¢
Seasonal Energy Charge - Seasonal kWh	3.52¢
Demand Charge - per kW of Total Billing Demand	$ 1.59
Reactive Charge - per kVar	36.00¢

Optional Time-of-Day Adjustments

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh(June-September billing periods)	+0.86¢	-0.48¢
Winter kWh(October-May billing periods)	+0.32¢	-0.17¢

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

*Indicates Change.

SERVICE CLASSIFICATION NO. 4(M)
SMALL PRIMARY SERVICE RATE (Cont'd.)

6. REACTIVE CHARGE (Cont'd.)

Where in the Company's judgment application of the above formula would not be appropriate to full or partial self-generation customers, an alternative agreement, between Company and customers, for the payment of reactive supply facilities may be substituted for said formula.

7. OPTIONAL TIME-OF-DAY (TOD) SERVICE

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

*a. If an advanced meter is not present, Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

b. Customer electing this TOD option, shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

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

8. GENERAL RULES AND REGULATIONS

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

*Indicates Change.

*THIS SHEET RESERVED FOR FUTURE USE

*Indicates Change.

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

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

A. LED bracket mounted luminaire on existing wood pole:

Identification	Rate
100W Equivalent (1)	$10.03
250W Equivalent (1)	$16.19
400W Equivalent (1)	$29.76

(1) The equivalent wattage represents the rating of the high pressure sodium lamp that the LED replaces.

B. LED directional flood luminaire; limited to installations accessible to Company basket truck:

Identification	Rate
Directional - Small	$21.09
Directional - Medium	$33.81
Directional - Large	$67.40

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

Identification	Rate
All Styles	$22.28

The High Pressure Sodium and Mercury Vapor offerings under sections D. and E. below are no longer available. Company will replace these existing fixtures, upon failure, with an LED fixture under section A.

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

High Pressure Sodium		Mercury Vapor	
Lumens	Rate	Lumens	Rate
9,500	$12.21	6,800	$11.72
25,500	$16.89	20,000	$16.05
50,000	$30.47	54,000	$27.08

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

High Pressure Sodium		Mercury Vapor	
Lumens	Rate	Lumens	Rate
5,800	$10.04	3,300	$9.72
9,500	$10.73	6,800	$10.24

*Indicates Change.

SERVICE CLASSIFICATION NO. 5(M)

***STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)**

The High Pressure Sodium, Metal Halide and Mercury Vapor offerings under section F. below are no longer available for new installations. Company will replace these existing fixtures, upon failure, with an LED fixture under section B.

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

High Pressure Sodium		Metal Halide		Mercury Vapor	
Lumens	Rate	Lumens	Rate	Lumens	Rate
25,500	$21.91	34,000	$21.10	20,000	$21.07
50,000	$34.66	100,000	$68.52	54,000	$31.27

The High Pressure Sodium and Mercury Vapor offerings under sections G. below are no longer available for new installations.

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

High Pressure Sodium		Mercury Vapor (1)	
Lumens	Rate	Lumens	Rate
9,500	$22.97	3,300	$21.63
		6,800	$22.47

(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.

H. 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.

I. 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, Open Bottom	$9.74
140,000 Lumens, H.P. Sodium, Directional	$69.08

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

*Indicates Change.

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

4. CONVERSION OR MODIFICATION OF LAMPS (Cont'd.)

*Company will convert to LED up to 1,000 lights per year requested by customers. Customer requests for LED lights are now being accepted, and will be limited to twenty-five (25) lights per customer account per calendar year. Customer requests must be in writing and, at a minimum, identify the specific physical location and billing account number and service date requested of each light. In the event Company determines it cannot accommodate all requests for conversions in the timeframes requested, prioritization of the requests will be at Company's discretion.

5. CHANGE OR RELOCATION

Upon receipt of written request and authorization from customer, Company will, insofar as it may be practical and permissible, make any other change in or relocation of its facilities used in rendering service hereunder, provided customer pays in advance Company's estimated costs in connection therewith.

6. ADDITIONAL INSTALLATIONS

Customer may obtain the installation of additional lamps and the supply of service thereto under the existing contract for the remainder of the term thereof upon written application to the Company, provided, however, that if at any time during the term of the contract customer requires such additional lamps so as to cause the total number of lamps in service to exceed by 20% the lamps originally contracted for and then installed, the parties shall execute a new contract.

7. TERMINATION

If customer requests in writing the termination of all or a portion of any lighting service, not paid for in advance, within three years of the installation of the lamps being terminated, or within ten years of the installation of post top luminaires, wood poles or cable being terminated, customer shall pay in advance to Company $100.00 per lamp for both the removal costs associated therewith and the loss of the remaining life value of such facilities. If said request for termination of lighting service is made after the above three and ten year in-service periods, as applicable, and customer requests a new lighting installation within twelve months after the removal of the prior terminated lighting facilities, customer shall pay the amount specified earlier in this paragraph for all facilities previously removed prior to Company making any new lighting installation.

***Indicates Change.**

*THIS SHEET RESERVED FOR FUTURE USE

*Indicates Change.

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

***MONTHLY RATE FOR METERED SERVICE**

Customer Charge Per Meter	$6.97 per month
Energy Charge	4.40¢ per kWh

*RATE PER UNIT PER MONTH	Energy & Maintenance(1)	Energy Only(2)
H.P. Sodium		
9,500 Lumens, Standard	$ 3.67	$ 1.71
25,500 Lumens, Standard	$ 6.29	$ 4.44
50,000 Lumens, Standard	$ 9.03	$ 6.88
Metal Halide		
5,500 Lumens, Standard	$ 5.36	N/A
12,900 Lumens Standard	$ 6.35	N/A
Mercury Vapor	(3)	
3,300 Lumens, Standard	$ 3.67	$ 1.82
6,800 Lumens, Standard	$ 4.72	$ 2.95
11,000 Lumens, Standard	$ 6.38	$ 4.20
20,000 Lumens, Standard	$ 8.39	$ 6.48
54,000 Lumens, Standard	$17.79	$15.43
Light Emitting Diodes (LED)		Energy Only
Energy Charge – per rated wattage per month		1.48¢

(1) Company will furnish electric energy, furnish and replace lamps, and adjust and replace control mechanisms, as required. In conjunction with the Company's conversion of its Company-Owned lights to LED, Company anticipates eliminating 6(M) Energy & Maintenance service in the future but not prior to 6/1/2022. Customers remaining on Energy & Maintenance at that time will be transitioned to Energy Only service.

(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. 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.

*Indicates Change.

*THIS SHEET RESERVED FOR FUTURE USE

*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	$324.46
Low-Income Pilot Program Charge – per month	$ 61.10
Energy Charge – per kWh	3.33¢
Demand Charge - per kW of Billing Demand	$ 19.88
Reactive Charge - per kVar	36.00¢

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

Customer Charge - per month	$324.46
Low-Income Pilot Program Charge – per month	$ 61.10
Energy Charge – per kWh	2.95¢
Demand Charge - per kW of Billing Demand	$ 9.01
Reactive Charge - per kVar	36.00¢

Optional Time-of-Day Adjustments

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh(June-September billing periods)	+0.65¢	-0.36¢
Winter kWh(October-May billing periods)	+0.29¢	-0.17¢

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

*Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE (Cont'd.)

6. REACTIVE CHARGE

The charge specified in this rate shall be applicable to the kilovars by which the customer's average metered kilovars exceed the customer's kilovars at an average power factor of 90% lagging during the billing period. Such average kilovar billing units shall be determined in accordance with the following formula:

$$kVar = \left(\frac{kVarh}{kWh} - 0.4843\right)(kW)$$

where:

kVar = kilovar billing units
kVarh = metered kilovar-hours
kWh = metered kilowatt-hours
kW = metered kilowatts
0.4843 = kilovar requirement at 90% lagging power factor.

Where in the Company's judgment application of the above formula would not be appropriate to full or partial self-generation customers, an alternative agreement, between Company and customers, for the payment of reactive supply facilities may be substituted for said formula.

7. OPTIONAL TIME-OF-DAY (TOD) SERVICE

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

*a. If advanced metering is not present, Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

b. Customer electing this TOD option, shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

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

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

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Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2016-0179.

DATE OF ISSUE March 8, 2017 DATE EFFECTIVE April 1, 2017

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

MISCELLANEOUS CHARGES

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

*Supplementary Service Minimum Monthly Charges
Sheet No. 78, Section C-3

Charges applicable during 4 monthly billing periods of June through September	Primary Service Rate
Customer Charge per month, plus	$324.46
Low-Income Pilot Program Charge – per month	$61.10
All kW @	$19.88

Charges applicable during 8 monthly billing periods of October through May	Primary Service Rate
Customer Charge per month, plus	$324.46
Low-Income Pilot Program Charge – per month	$61.10
All kW @	$9.01

**Returned Check Fee	$25.00

**Opt-Out Charges
Sheet No. 129, Section E

One-time setup charge	$150.00
Non-Standard Meter Charge – per month	$45.00

**Paperless Billing Incentive (Credit to Customer)
Sheet No. 138, Section N

Paperless Billing Incentive – per month	$0.50

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.
**Indicates Addition.

TABLE OF CONTENTS

RIDERS

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet 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), and 11(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 calendar 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 day of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

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

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

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

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

Where:

* ANEC = FC + PP + T + E ± R – OSSR

* FC = Fuel costs and revenues associated with the Company's generating plants consisting of the following:

1. For fossil fuel plants:

*A. the following costs and revenues (including applicable taxes) arising from steam plant operations recorded in FERC Account 501: coal commodity, gas, alternative fuels, 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, fuel additive costs included in commodity or transportation costs, oil costs, ash disposal costs and revenues, and expenses resulting from fuel and transportation portfolio optimization activities;

**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 (including applicable taxes) arising from non-steam plant operations recorded in FERC Account 547: 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, but excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center; and

2. The following costs and revenues (including applicable taxes) arising from nuclear plant operations: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

*Indicates Change. **Indicates Addition.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

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

The following costs and revenues for purchased power reflected in FERC Account 555, excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, (b) all charges under Midcontinent Independent 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:

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:
      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:
      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:
      a. Demand response allocation uplift; and
      b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

*Indicates Change.

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

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

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.

*T =

*1) One hundred percent (100%) of transmission service costs reflected in FERC Account 565 to either:

a. transmit excess electric power sold to third parties to locations outside of MISO (off-system sales)(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule)or;

b. transmit electric power on a non-MISO system,

**2) One and 65/100 percent (1.65%) of transmission service costs reflected in FERC Account 565 directly attributable to Ameren Missouri's network transmission service (excluding (a) amounts associated with portions of Purchased Power Agreements dedicated to specific customers under the Renewable Choice Program tariff and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule),and

*Indicates Addition. **Indicates Change.

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*3) One and 65/100 percent (1.65%) of transmission revenues reflected in FERC Account 456.1(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule).

Such transmission service costs and revenues included in Factor T 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, 26C, 26D, 37 and 38 or their successors;
   vii. MISO Schedule 33; and
   viii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs and revenues associated with:
   i. Network transmission service;
   ii. Point-to-point transmission service;
   iii. System control and dispatch; and
   iv. Reactive supply and voltage control.

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.

R = Net insurance recoveries for costs/revenues included in this Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included in this Rider FAC.

* Indicates Change

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*OSSR = Costs and revenues in FERC Account 447 (excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff and (c) amounts associated with generation assets that began commercial operation after the date BF was determined and that were dedicated to specific customers under the Renewable Choice Program tariff when it began commercial operation) 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.

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.

* Indicates Change.

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*Costs and revenues not specifically detailed in Factors FC, PP, T, E, R or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, T 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, T or OSSR for the costs or revenues to be considered specifically detailed in Factors PP, T or OSSR; and provided further, should the MISO or another centrally administered market (e.g. PJM or SPP) implement a market settlement charge type or schedule not listed in the FAC Charge Type Table included in this rider (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, T or OSSR, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party’s right to challenge the inclusion as outlined in E. below;

*B. The Company will make a filing with the Commission giving the Commission 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 filing 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, T 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

* Indicates Change.

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*E. If the Company makes the filing provided for in B above and a party challenges the inclusion, 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, T or OSSR, as the case may be. A party wishing to challenge the inclusion of a charge type shall include in its filing the reasons why it believes the Company did not show that the new charge type possesses the characteristics of the costs or revenues listed in Factors PP, T or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

*F. A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, T or OSSR, as the case may be. The party's filing 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, T or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging 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, T or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues

*Indicates Change.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

listed in Factors PP, T or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be 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, T, 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, T, 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), plus transmission costs and revenues (constistent with term T), 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 $0.01266 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01208 per kWh.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the 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).

*Indicates Change.

Schedule MWH-D1
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RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

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 ("TUP") 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.

*TUP = 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 = The lower of (a) PFAR and (b) RAC.

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.

**PFAR = The Preliminary FAR, which is the sum of FAR_{RP} and $FAR_{(RP-1)}$

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}.

*Indicates Change. **Indicates Addition.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn President St. Louis, Missouri

NAME OF OFFICER TITLE ADDRESS

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

**RAC = Rate Adjustment Cap: applies to the FAR rate and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the baseline rate as determined under Section 393.1655.4 by the 2.85% Compound Annual Growth Rate compounded for the amount of time that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655, and dividing that result by the weighted average voltage adjustment factor 1.0476%.

*The Initial Rate Component For the Individual Service Classifications shall be determined by multiplying the FAR determined in accordance with the foregoing by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0570
Primary Voltage Service (VAF_{PRI})	1.0194

** Customers served by the Company under Service Classification No. 11(M), Large Primary Service, shall have their rate capped such that their FARLPS does not exceed RACLPS, where

** RAC_{LPS} = Rate Adjustment Cap Applicable to LPS Class: applies to the FAR rate applicable to customers in the LPS class and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the baseline class average overall rate as determined under Section 393.1655.6 by the 2.00% Compound Annual Growth Rate compounded for the amount of time that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the class average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655.

*Indicates Change. **Indicates Addition.

RIDER FAC

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

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*Where the Initial Rate Component for Primary Customers is greater than FAR_{LPS}, then a Per kWh FAR Shortfall Adder shall apply to each of the respective Initial Rate Components to be determined as follows:

*Per kWh FAR Shortfall Adder =
(((Initial Rate Component For Primary Customers– FARLPS) x SLPS) / (SRP – SRP-LPS))

*Where:
SLPS = Estimated Recovery Period LPS kWh sales at the retail meter
SRP-LPS = Estimated Recovery Period LPS kwh sales at the Company's MISO CP Node (AMMO.UE or successor node)

*The FAR Applicable to the Individual Service Classifications shall be determined as follows:

FARSEC = Initial Rate Component For Secondary Customers + (Per kWh FAR Shortfall Adder x VAFSEC)
FARPRI = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAFPRI)

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 TUP 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.

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*Indicates Addition. **Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

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.)
FAC CHARGE TYPE TABLE

***MISO Energy & Operating Reserve Market Settlement Charge Types and Capacity Market Charges and Credits**

DA Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;
DA Financial Bilateral Transaction Congestion Amount;
DA Financial Bilateral Transaction Loss Amount;
DA Loss Rebate on Carve-out GFA;
DA Loss Rebate on Option B GFA;
DA Non-Asset Energy Amount;
DA Ramp Capability Amount;
DA Regulation Amount;
DA Revenue Sufficiency Guarantee Distribution Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;
DA Spinning Reserve Amount;
DA Supplemental Reserve Amount;
DA Virtual Energy Amount;
FTR Annual Transaction Amount;
FTR ARR Revenue Amount;
FTR ARR Stage 2 Distribution;
FTR Full Funding Guarantee Amount;
FTR Guarantee Uplift Amount;
FTR Hourly Allocation Amount;
FTR Infeasible ARR Uplift Amount;
FTR Monthly Allocation Amount;
FTR Monthly Transaction Amount;
FTR Yearly Allocation Amount;
FTR Transaction Amount;
RT Asset Energy Amount;
RT Congestion Rebate on Carve-out GFA;
RT Contingency Reserve Deployment Failure Charge Amount;
RT Demand Response Allocation Uplift Charge;
RT Distribution of Losses Amount;
RT Excessive Energy Amount;
RT Excessive\Deficient Energy Deployment Charge Amount;
RT Financial Bilateral Transaction Congestion Amount;
RT Financial Bilateral Transaction Loss Amount;
RT Loss Rebate on Carve-out GFA;
RT Miscellaneous Amount;
RT Ramp Capability Amount;
Real Time MVP Distribution;
RT Net Inadvertent Distribution Amount;
RT Net Regulation Adjustment Amount;
RT Non-Asset Energy Amount;
RT Non-Excessive Energy Amount;
RT Price Volatility Make Whole Payment;
RT Regulation Amount;
RT Regulation Cost Distribution Amount;
RT Resource Adequacy Auction Amount;
RT Revenue Neutrality Uplift Amount;
RT Revenue Sufficiency Guarantee First Pass Dist Amount;
RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;

***MISO Transmission Service Settlement Schedules**

MISO Schedule 1 (System control & dispatch);
MISO Schedule 2 (Reactive supply & voltage control);
MISO Schedule 7 & 8 (point to point transmission service);
MISO Schedule 9 (network transmission service);
MISO Schedule 11 (Wholesale Distribution);
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);
MISO Schedules 26-C & 26-D - (TMEP Cost Recovery);
MISO Schedule 33 (Black Start Service);
MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

MISO Charge Types Which Appear On MISO Settlement Statements Represent Administrative Charges And Are Specifically Excluded From The FAC

DA Market Administration Amount;
DA Schedule 24 Allocation Amount;
FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;
RT Market Administration Amount;
RT Schedule 24 Allocation Amount;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

* Indicates Change.

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

PJM Market Settlement Charge Types

Auction Revenue Rights;
Balancing Operating Reserve;
Balancing Operating Reserve for Load Response;
Balancing Spot Market Energy;
Balancing Transmission Congestion;
Balancing Transmission Losses;
Capacity Resource Deficiency;
Capacity Transfer Rights;
Day-ahead Economic Load Response;
Day-Ahead Load Response Charge Allocation;
Day-ahead Operating Reserve;
Day-ahead Operating Reserve for Load Response;
Day-ahead Spot Market Energy;
Day-ahead Transmission Congestion;
Day-ahead Transmission Losses;
Demand Resource and ILR Compliance Penalty;
Emergency Energy;
Emergency Load Response;
Energy Imbalance Service;
Financial Transmission Rights Auction;
Generation Deactivation;
Generation Resource Rating Test Failure;
Inadvertent Interchange;
Incremental Capacity Transfer Rights;
Interruptible Load for Reliability;
Load Reconciliation for Inadvertent Interchange;
Load Reconciliation for Operating Reserve Charge;
Load Reconciliation for Regulation and Frequency Response Service;
Load Reconciliation for Spot Market Energy;
Load Reconciliation for Synchronized Reserve;
Load Reconciliation for Synchronous Condensing;
Load Reconciliation for Transmission Congestion;
Load Reconciliation for Transmission Losses;
Locational Reliability;
Miscellaneous Bilateral;
Non-Unit Specific Capacity Transaction;
Peak Season Maintenance Compliance Penalty;
Peak-Hour Period Availability;
PJM Customer Payment Default;
Planning Period Congestion Uplift;
Planning Period Excess Congestion;
Ramapo Phase Angle Regulators;
Real-time Economic Load Response;
Real-Time Load Response Charge Allocation;
Regulation and Frequency Response Service;
RPM Auction;
Station Power;
Synchronized Reserve;
Synchronous Condensing;
Transmission Congestion;
Transmission Losses;

*PJM Transmission Service Charge Types

Black Start Service;
Day-ahead Scheduling Reserve;
Direct Assignment Facilities;
Expansion Cost Recovery;
Firm Point-to-Point Transmission Service;
Internal Firm Point-to-Point Transmission Service;
Internal Non-Firm Point-to-Point Transmission Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;
Load Reconciliation for Reactive Services;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service;
Network Integration Transmission Service (exempt);
Network Integration Transmission Service Offset;
Non-Firm Point-to-Point Transmission Service;
Non-Zone Network Integration Transmission Service;
Other Supporting Facilities;
PJM Scheduling, System Control and Dispatch Service Refunds;
PJM Scheduling, System Control and Dispatch Services;
Qualifying Transmission Upgrade Compliance Penalty;
Reactive Supply and Voltage Control from Generation and Other Sources Service;
Transmission Enhancement;
Transmission Owner Scheduling, System Control and Dispatch Service;
Unscheduled Transmission Service;
Reactive Services;

*Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

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

PJM Charge Types Which Appear On The Settlement Statements Represent Administrative Charges Are Specifically Excluded From The FAC

Annual PJM Building Rent;
Annual PJM Cell Tower;
FERC Annual Charge Recovery;
Load Reconciliation for FERC Annual Charge Recovery;
Load Reconciliation for North American Electric Reliability Corporation (NERC);
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding;
Load Reconciliation for Reliability First Corporation (RFC);
Market Monitoring Unit (MMU) Funding;
Michigan - Ontario Interface Phase Angle Regulators;
North American Electric Reliability Corporation (NERC);
Organization of PJM States, Inc. (OPSI) Funding;
PJM Annual Membership Fee;
PJM Settlement, Inc.;
Reliability First Corporation (RFC);
RTO Start-up Cost Recovery;
Virginia Retail Administrative Fee;

***SPP Market Settlement Charge Types**

DA Asset Energy Amount;
DA Non-Asset Energy Amount;
DA Make-Whole Payment Distribution;
DA Make-Whole Payment;;
DA Virtual Energy;
DA Virtual Energy Transaction Fee;
DA Demand Reduction Amount;
DA Demand Reduction Distribution Amount;
DA GFA Carve-Out Daily Amount;
DA GFA Carve-Out Monthly Amount;
DA GFA Carve-Out Yearly Amount;
GFA Carve Out Distribution Daily Amount;
GFA Carve Out Distribution Monthly Amount;
GFA Carve Out Distribution Yearly Amount;
RT Asset Energy Amount
RT Over Collected Losse;s Distribution;
RT Miscellaneous Amount;
RT Non-Asset Energy;
RT Revenue Neutrality Uplift;
RT Joint Operating Agreement;
RUC Make Whole Payment Distribution;
RUC Make Whole Payment;
RT Virtual Energy Amount;
RT Demand Reduction Amount;
RT Demand Reduction Distribution Amount;
Transmission Congestion Rights Daily Uplift;
Transmission Congestion Rights Monthly Payback;
Transmission Congestion Rights Auction Transaction;
Transmission Congestion Rights Annual Payback;
Transmission Congestion Rights Funding;
Auction Revenue Rights Annual Closeout;
Auction Revenue Rights Funding;
Transmission Congestion Rights Annual Closeout
Auction Revenue Rights Uplift
Auction Revenue Rights Monthly Payback
Auction Revenue Rights Annual Payback
DA Regulation Up
DA Regulation Down
DA Regulation Up Distribution
DA Regulation Down Distribution
DA Spinning Reserve
DA Spinning Reserve Distribution
DA Supplemental Reserve
DA Supplemental Reserve Distribution
RT Regulation Up
RT Regulation Up Distribution
RT Regulation Down
RT Regulation Down Distribution
RT Regulation Out of Merit
RT Spinning Reserve Amount
RT Supplemental Reserve Amount
RT Spinning Reserve Cost Distribution Amount
RT Supplemental Reserve Distribution Amount
RT Regulation Non-Performance
RT Regulation Non-Performance Distribution
RT Regulation Deployment Adjustment;
RT Regulation Deployment Adjustment;
RT Contingency Reserve Deployment Failure Distribution;
RT Reserve Sharing Group;
RT Reserve Sharing Group Distribution;
RT Pseudo-Tie Congestion Amount;
RT Pseudo-Tie Losses Amount;
RT Unused Regulation -Up Mileage Make Whole Payment;
RT Unused Regulation -Down Mileage Make Whole Payment;

*Indicates Addition.

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

** **SPP Transmission Service Charge Types**

Schedule 1 – Scheduling, System Control & Dispatch Service;
Schedule 2 – Reactive Voltage;
Schedule 7 – Zonal Firm Point-to-Point;
Schedule 8 – Zonal Non-Firm Point-to-Point;
Schedule 11 – Base Plan Zonal and Regional;

** **SPP charge types representing administrative charges specifically excluded from the FAC**

Transmission Schedule 1A – Tariff Administrative Fee;
Transmission Schedule 12 – FERC Assessment;

** Indicates Addition.

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

(Applicable To Calculation of Fuel Adjustment Rate for the Calendar Months of XXXXXX through XXXXX)

*Calculation of Current Fuel Adjustment Rate (FAR):

	Accumulation Period Ending:		
* 1.	Actual Net Energy Cost = (ANEC) (FC+PP+E+R+T-OSSR)		$
2.	(B) = (BF x S_{AP})	-	$
2.1	Base Factor (BF)		$/kWh
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 (TUP)	+	$
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})	=	$0.00000/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$0.00000/kWh
** 9.	Preliminary Fuel Adjustment Rate (PFAR)	=	$0.00000/kWh
**10.	Rate Adjustment Cap (RAC)	=	$0.00000/kWh
*11.	Fuel Adjustment Rate (FAR, lesser of PFAR and RAC)	=	$0.00000/kWh
**__Initial Rate Component for the Individual Service Classifications__			
*12.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0570
13.	Initial Rate Component for Secondary Customers		$0.00000/kWh
*14.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0194
15.	Initial Rate Component for Primary Customers		$0.00000/kWh
**__FAR Applicable to the Individual Service Classifications__			
16.	RAC_{LPS}	=	$0.00000/kWh
17.	FAR for Large Primary Service (FARLPS, lesser of 15 and 16)	=	$0.00000/kWh
18.	Difference (Line 15 – Line 17)	=	$0.00000/kWh
19.	Estimated Recovery Period Metered Sales for LPS (SLPS)		kWh
20.	FAR Shortfall Adder (Line 18 x Line 19)		$
21.	Per kWh FAR Shortfall Adder (Line 20 / (Line 6 – SRP-LPS))	=	$0.00000/kWh
22.	FAR for Secondary Customers (FARSEC) (Line 13 + (Line 21 x Line 12))	=	$0.00000/kWh
23.	FAR for Primary Customers (FARPRI) (Line 15 + (Line 21 x Line 14))	=	$0.00000/kWh

*Indicates Change. **Indicates Addition.

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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 $1.15/kW of billing demand for customers taking service at 34.5 or 69kV.

*2. A monthly credit of $1.37/kW of billing demand for customers taking service at 115kV or higher.

*Indicates Change.

RIDER I

*SECONDARY SERVICE OFF-PEAK DEMAND PROVISIONS

A. The monthly billing demand of any non-residential customer who is taking secondary service shall, upon their request be determined as follows:

The billing demand in any month will be the highest demand established during peak hours or 50% of the highest demand established during off-peak hours, whichever is highest during the month, but in no event less than 100 kW.

Peak hours and off-peak hours are defined as follows:

Peak hours - 10:00 A.M. to 10:00 P.M., Monday through Friday.

Off-peak hours - 10:00 P.M. of Monday through Thursday to 10:00 A.M. of the following day, and from 10:00 P.M. Friday to 10:00 A.M. Monday.

- The entire 24 hours of the following days:

New Year's Day	Thanksgiving Day
Good Friday	Thanksgiving Friday
Memorial Day	Christmas Eve Day
Independence Day	Christmas Day
Labor Day	

All times stated above apply to the local effective time.

B. If advanced metering is not installed, Customer shall pay for all metering equipment necessary for the application of the provisions of this Rider at the charges specified in Section IV.B - Additional Metering.

C. This Rider, if requested by customer without advanced metering, shall remain in effect for an initial period of three (3) years and shall be terminable thereafter on three (3) days' notice.

D. Customers with advanced metering installed will automatically have the provisions under Rider I applied without request.

* Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

*THIS SHEET RESERVED FOR FUTURE USE

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RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA 2019-21 Plan

***TD DETERMINATION (Cont'd.)**

NMR = Net Margin Revenue. NMR values for each applicable Service Classification and by End Use Category where applicable are as follows:

	Service Classifications	
Month	1(M)Res $/kWh	2(M)SGS $/kWh
January	0.045970	0.054094
February	0.047182	0.055695
March	0.048770	0.058252
April	0.049164	0.058984
May	0.051328	0.061717
June	0.102387	0.091987
July	0.102387	0.091987
August	0.102387	0.091987
September	0.102387	0.091987
October	0.048519	0.059548
November	0.050931	0.061122
December	0.047630	0.057174

	MISC./AIR COMP./ PROCESS/MOTORS			COOLING			EXT LIGHTING		
Month	3M	4M	11M	3M	4M	11M	3M	4M	11M
January	0.034932	0.034820	0.028014	0.026852	0.024126	0.017801	0.026876	0.025785	0.019520
February	0.036218	0.035344	0.028937	0.027555	0.024249	0.017801	0.027573	0.024269	0.019641
March	0.034636	0.035974	0.024975	0.026969	0.024408	0.025599	0.026986	0.024648	0.014413
April	0.035484	0.035351	0.027612	0.040424	0.037743	0.028646	0.029288	0.025693	0.019334
May	0.038468	0.037884	0.031736	0.065052	0.072675	0.057859	0.029427	0.024981	0.018097
June	0.069651	0.068766	0.055541	0.090783	0.096082	0.082689	0.046796	0.039195	0.021687
July	0.067181	0.067093	0.054226	0.084321	0.089348	0.077258	0.045451	0.039119	0.021116
August	0.069209	0.067769	0.052677	0.088398	0.092037	0.076688	0.046561	0.039227	0.021749
September	0.067299	0.066441	0.053193	0.107381	0.118992	0.104595	0.046719	0.039497	0.021718
October	0.037557	0.036834	0.032864	0.040965	0.037612	0.031694	0.028217	0.024701	0.018033
November	0.038333	0.037081	0.031745	0.028785	0.024532	0.030716	0.028940	0.024692	0.017828
December	0.035483	0.033275	0.029189	0.027621	0.024294	0.017801	0.027804	0.024316	0.018008

* Indicates Change.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA 2019-21 Plan

***TD DETERMINATION (Cont'd.)**

	HVAC/BUILDING SHELL			LIGHTING			REFRIG.		
Month	3M	4M	11M	3M	4M	11M	3M	4M	11M
January	0.040551	0.041901	0.034294	0.037201	0.037476	0.030465	0.034217	0.033691	0.025364
February	0.042717	0.043201	0.036007	0.038064	0.037322	0.030830	0.035502	0.034232	0.025839
March	0.042208	0.048769	0.035241	0.035394	0.037740	0.026484	0.033781	0.035284	0.023561
April	0.053065	0.060407	0.045764	0.038074	0.038567	0.030252	0.035710	0.035272	0.027220
May	0.053863	0.057529	0.048371	0.041612	0.041104	0.034807	0.038107	0.036540	0.029826
June	0.089856	0.094878	0.081592	0.073714	0.074006	0.061017	0.067376	0.058390	0.052347
July	0.083898	0.088795	0.076722	0.071016	0.072038	0.059642	0.064887	0.064214	0.046595
August	0.087832	0.091320	0.076000	0.073147	0.072730	0.057856	0.066972	0.065043	0.047707
September	0.102189	0.112145	0.098724	0.069665	0.069533	0.056567	0.065198	0.063795	0.049044
October	0.056929	0.060244	0.056117	0.040653	0.039926	0.036254	0.036958	0.035439	0.030860
November	0.050998	0.052568	0.045587	0.040536	0.039313	0.034014	0.037676	0.035836	0.028643
December	0.041327	0.039171	0.035957	0.036840	0.034246	0.030356	0.035011	0.032369	0.027579

	COOK.			DHW			HEAT.		
Month	3M	4M	11M	3M	4M	11M	3M	4M	11M
January	0.035379	0.033269	0.026580	0.034976	0.031906	0.025317	0.040551	0.039373	0.032154
February	0.035715	0.034373	0.027116	0.034976	0.033448	0.025809	0.042740	0.038339	0.032526
March	0.034206	0.037395	0.026481	0.033138	0.036611	0.025653	0.042814	0.039810	0.027066
April	0.038695	0.039247	0.030959	0.038030	0.038396	0.030201	0.061314	0.037621	0.031209
May	0.041043	0.040344	0.034101	0.040620	0.039779	0.033565	0.042512	0.036145	0.030017
June	0.074707	0.075287	0.062601	0.074627	0.075184	0.064594	0.046371	0.038689	0.021040
July	0.071821	0.072213	0.052249	0.071822	0.071124	0.049686	0.045041	0.038607	0.021040
August	0.074219	0.074080	0.055500	0.074153	0.073998	0.054746	0.046155	0.038740	0.021040
September	0.071240	0.071592	0.058809	0.070330	0.070402	0.057513	0.075759	0.068954	0.055936
October	0.039943	0.039053	0.035698	0.039530	0.038547	0.035667	0.065420	0.039550	0.034292
November	0.039459	0.039444	0.031053	0.039320	0.038898	0.029876	0.052109	0.036413	0.039550
December	0.036494	0.032774	0.031150	0.036385	0.032006	0.030710	0.041334	0.035937	0.028057

	OFFICE			VENT		
Month	3M	4M	11M	3M	4M	11M
January	0.034974	0.034139	0.027384	0.033213	0.032560	0.025923
February	0.035430	0.034017	0.027370	0.033842	0.032034	0.025890
March	0.033907	0.034617	0.023689	0.032546	0.032960	0.022242
April	0.035765	0.035315	0.027541	0.035419	0.034766	0.027135
May	0.039021	0.037646	0.031501	0.038047	0.036350	0.030220
June	0.068077	0.066731	0.053201	0.066342	0.064488	0.050927
July	0.065733	0.065158	0.051414	0.064488	0.063633	0.049483
August	0.067685	0.065850	0.050427	0.066417	0.064255	0.048974
September	0.064771	0.063139	0.049541	0.063943	0.062059	0.048328
October	0.038028	0.036709	0.032718	0.037002	0.035454	0.031273
November	0.038016	0.036212	0.030587	0.035892	0.033417	0.028084
December	0.034872	0.032005	0.027853	0.034507	0.031896	0.027326

* Indicates Change.

RIDER SSR

STANDBY SERVICE RIDER (Cont'd.)

*STANDBY RATE	Large General Service	Small Primary Service	Large Primary Service
Standby Fixed Charges			
Administrative Charge	$187.00/month	$187.00/month	$187.00/month
Generation and Transmission Access Charge per month per kW of Contracted Standby Demand	$0.64/kW	$0.64/kW	$0.77/kW
Facilities Charge per month per kW of Contracted Standby Demand:			
Summer	$3.84/kW	$3.14/kW	$3.14/kW
Winter	$0.94/kW	$0.65/kW	$0.65/kW
Daily Standby Demand Rate – Summer			
Per kW of Daily Standby Service Demand:			
Back-Up	$0.04/kW	$0.04/kW	$1.06/kW
Maintenance	$0.02/kW	$0.02/kW	$0.53/kW
Daily Standby Demand Rate - Winter			
Per kW of Daily Standby Service Demand:			
Back-Up	$0.02/kW	$0.02/kW	$0.51/kW
Maintenance	$0.01/kW	$0.01/kW	$0.25/kW
Back-Up Energy Charges – Summer			
kWh in excess of Supplemental Contract Capacity			
Energy(1)	9.95¢/kWh	9.62¢/kWh	3.33¢/kWh
On-Peak Energy(2)	11.13¢/kWh	10.48¢/kWh	3.98¢/kWh
Off-Peak Energy(2)	9.28¢/kWh	9.14¢/kWh	2.97¢/kWh
Back-Up Energy Charges – Winter			
kWh in excess of Supplemental Contract Capacity			
Energy(1)	6.25¢/kWh	6.06¢/kWh	2.95¢/kWh
On-Peak Energy(2)	6.61¢/kWh	6.38¢/kWh	3.24¢/kWh
Off-Peak Energy(2)	6.05¢/kWh	5.89¢/kWh	2.78¢/kWh
High Voltage Facilities Charge Discount			
Facilities Charge Credit per month per kW of Contracted Standby Demand			
@ 34.5 or 69kV	N/A	$1.15/kW	$1.15/kW
@ 115kV or higher	N/A	$1.37/kW	$1.37/kW

(1) Applicable to customers not on TOD rates.
(2) Applicable to customers on TOD rates for its non-back-up energy charges.

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*Indicates Change.

GENERAL RULES AND REGULATIONS

II. CHARACTERISTICS OF SERVICE SUPPLIED (Cont'd.)

I. SERVICE TO DOWNTOWN ST. LOUIS UNDERGROUND DISTRICT (Cont'd.)

Where in Company's judgement it is impractical or inadvisable to supply a customer's new or increased load from the gridded or spot networks, customer will be required to provide at no cost to the Company an indoor substation room at or one level below grade, constructed in accordance with Company's specifications, and transfer all electrical load to the new connection point. In such instances requiring an indoor substation, customer may, with the Company's approval, accept responsibility for all excess costs incurred by Company in continuing to provide all or a portion of customer's service from the gridded network solely for customer's benefit.

*J. NON-STANDARD SERVICE

Changes in business practices and regulatory and legal requirements will, from time to time, result in the Company serving or billing a limited number of customers in a manner that is currently considered a non-standard form of service. Such non-standard service includes, but is not limited to, voltages, frequencies, metering equipment, metering locations, electrical distribution system supply facilities and configurations, and master and cumulated meter billing situations that are prohibited by current Commission rules and Company tariffs for application to new customers. The continued provision of such non-standard service and billing is limited to the premises presently served by such facilities. These facilities may only be relocated, expanded or enhanced for Company's engineering reasons.

In order to minimize and phase out the number of non-standard service installations and billing applications on its system, Company will, unless otherwise provided for above, discontinue providing any such non-standard service to a premises when a) the premises is remodeled or rehabilitated in any such manner that requires new, modified, enhanced or relocated electrical distribution supply facilities from the Company, or b) the premises become an inactive account for a consecutive period of six (6) months or more.

* Indicates Change.

GENERAL RULES AND REGULATIONS

IV. MEASUREMENT OF SERVICE (Cont'd.)

C. MULTIPLE METERED ACCOUNT BILLING

Where more than one meter is installed for metering the premises of an individual account in accordance with paragraphs A and B above, the sum of each watthour meter's kilowatt-hour usage and each demand meter's individual maximum non-simultaneous kilowatt demand will be used for billing purposes. Under all circumstances involving multiple metered accounts, any alternating current watthour meter registering zero usage in a given billing month shall be subject to the monthly charge for three phase meters, specified in paragraph B of this Section IV, during each month of zero usage.

D. METER INSPECTIONS AND TESTING

Company's meters shall be inspected and tested for accuracy in accordance with applicable Missouri Public Service Commission Rules. If customer requests a meter test within 12 months of any previous testing of such meter, a standard charge based on meter type will be assessed for meters found to have an average meter error of 2 percent or less.

* E. REMOTE METER READING OPT-OUT

Customers receiving Residential Service have the option of refusing the installation of remotely read metering or requesting the removal of previously installed remotely read metering. In such instances, non-standard metering equipment will be installed that requires a manual meter read. Customers requesting non-standard metering service after April 1, 2017 will be charged a one-time setup charge and a monthly recurring Non-Standard Meter Charge. Charges are listed on Sheet No. 63, Miscellaneous Charges.

In the normal course of business, Company replacement of meters may occur. To the extent that a customer denies, either through physical impediments, verbal denial or threats of violence, access to property or metering installation, or fails to establish a suitable time for access, customer will be notified, in writing, that failure to provide access will result in customer being considered an opt-out customer not sooner than 30 days after Company's notice. Company's notification will include information for the customer to understand the financial impact of opt-out status.

* Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

GENERAL RULES AND REGULATIONS

V. BILLING PRACTICES (Cont'd.)

M. PARTIAL PAYMENTS

If a partial payment is made on a billing including only current charges, the Company shall first credit the payment to the balance outstanding for utility charges before crediting a deposit. If a partial payment is made on a billing which includes a previous balance, the Company will credit the payment first to previous utility charges, then to previous deposit requirements before applying any payment to current charges. No portion of any payment will be applied to special charges until all utility charges are paid in full and all required deposits have been made. (This section reflects a variance from Rule 4 CSR 240-13.020(11) granted by the Commission in Case No. EO-98-263.)

***N. PAPERLESS BILLING**

Residential customers who enroll in paperless billing for the first time, are not currently enrolled in paperless billing, and have not received paperless billing in the past, will receive credit on their monthly bill for a term not to exceed a one-year period. Upon enrollment, the credit will be applied beginning with the Customer's next available billing month. The available monthly credit for qualifying enrollees is listed on Sheet No. 63, Miscellaneous Charges.

* Indicates Change.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

ELECTRIC POWER PURCHASES

ELECTRIC POWER PURCHASES FROM QUALIFYING FACILITIES

1. STANDARD RATES FOR PURCHASE

The standard rates for purchase from a customer with a design capacity of 500 kW or less are as follows:

a. Non-Time - Differentiated Energy Rate

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

Summer	3.15¢ per kWh

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

Winter	2.90¢ per kWh

b. Time-Differentiated Energy Rate

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

Weekday (10 AM - 10 PM)	3.99¢ per kWh
Weekday (10 PM - 10 AM)	2.53¢ per kWh
Saturday, Sunday, Holiday (1)	2.91¢ per kWh

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

Weekday (10 AM - 10 PM)	3.18¢ per kWh
Weekday (10 PM - 10 AM)	2.79¢ per kWh
Saturday, Sunday, Holiday (1)	2.71¢ per kWh

(1) Legal Holidays of New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Thanksgiving Friday, Christmas Eve Day, and Christmas Day.

DATE OF ISSUE July 3, 2019 DATE EFFECTIVE August 2, 2019

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

Mo Electric
12 Months Ending Dec 2018 with Growth to Dec 2019

	Total Revenue	Adjustment Amount	Target Revenue	Actual Revenues*	Variation	Revenue Decrease
Residential	$1,278,256,444	($377,525)	$1,277,878,919	$1,277,894,109	$15,191	-0.03%
Small General Service	$295,121,638	($87,290)	$295,034,348	$295,011,973	($22,376)	-0.03%
Large General Service	$562,423,013	($166,027)	$562,256,986	$562,252,254	($4,732)	-0.03%
Small Primary Service	$243,422,690	($71,844)	$243,350,846	$243,331,477	($19,369)	-0.03%
Large Primary Service	$202,942,497	($60,046)	$202,882,451	$202,876,368	($6,083)	-0.03%
Lighting Company Owned	$35,602,359	($10,545)	$35,591,814	$35,588,541	($3,273)	-0.03%
Lighting Customer Owned	$3,391,008	($1,004)	$3,390,004	$3,387,812	($2,192)	-0.03%
MSD	$74,966	($22)	$74,944	$74,922	($22)	-0.03%
Total Revenue	$2,621,234,615	($774,303)	$2,620,460,312	$2,620,417,457	($42,855)	-0.03%

*Actual Revenues adjusts for rounding in the final rates

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Residential Class

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills	4,265,511	$9.00	$38,389,602
Winter Bills	8,535,546	$9.00	$76,819,910
TOD Bills	1,082	$9.00	$9,742
Low Income Charge	12,802,139	$0.04	$512,086
Total Bills	12,802,139		
Energy Charge			
Summer kWh	4,703,625,375	$0.1258	$591,716,072
On-peak	74,477	$0.3150	$23,460
Off-peak	423,574	$0.0787	$33,335
Energy Eff kwh	4,704,119,520	$0.0003	$1,411,236
Tax Credit	4,704,123,426	-$0.0062	-$29,212,606
Winter kWh			
First 750 kWh	4,817,304,105	$0.0876	$421,995,840
Over 750 kWh	3,806,441,387	$0.0600	$228,386,483
On-peak			
Off-peak			
Energy Eff Charge	8,623,717,675	$0.0002	$1,724,744
Tax Credit	8,623,745,493	-$0.0062	-$53,553,460
Total kWh	13,327,868,918		
		Total	**$1,278,256,444**

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Small General Service Class

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills			
One-phase	373,368	$11.19	$4,177,984
Three-phase	153,599	$21.38	$3,283,951
Winter Bills			
One-phase	744,892	$11.19	$8,335,344
Three-phase	307,367	$21.38	$6,571,508
TOD Bills			
Limited Unmetered Service	81,050	$5.92	$479,817
One-phase	12,758	$21.43	$273,395
Three-phase	1,499	$41.84	$62,711
6M		$6.71	$0
Low Income Charge	1,674,533	$0.05	$83,727
Total Bills	1,674,533		
Energy Charge			
Summer kWh	1,119,061,653	$0.1120	$125,334,905
On-peak	12,503,276	$0.1664	$2,080,545
Off-peak	21,855,829	$0.0678	$1,481,825
Energy Eff Charge	1,152,136,146	$0.0001	$115,214
Summer kWh to Lighting Rate	646,859	$0.0472	$30,532
Tax Credit	1,154,067,616	-$0.0058	-$6,705,133
Winter kWh			
Base	1,621,128,084	$0.0836	$135,526,308
Seasonal	447,093,961	$0.0482	$21,549,929
On-peak	22,725,355	$0.1096	$2,490,699
Off-peak	41,113,895	$0.0503	$2,068,029
Energy Eff Charge	2,128,653,581	$0.0001	$212,865
Winter kWh to Lighting Rate	1,323,003	$0.0472	$62,446
Tax Credit	2,133,384,298	-$0.0058	-$12,394,963
Total kWh	3,285,482,052	Total	**$295,121,638**

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Large General Service

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills	42,869	$94.51	$4,051,530
Winter Bills	85,588	$94.51	$8,088,876
TOD Bills	422	$115.59	$48,785
Low Income Charge	128,878	$0.56	$72,172
Demand Charge (kW)			
Summer	8,415,461	$5.40	$45,443,490
Winter	15,841,921	$2.00	$31,683,842
Energy Charge			
Summer kWh			
First 150HU	1,088,670,145	$0.1058	$115,181,301
Next 200HU	1,227,101,130	$0.0796	$97,677,250
Over 350HU	544,941,909	$0.0535	$29,154,392
On-peak	5,132,746	$0.0125	$64,159
Off-peak	10,161,490	-$0.0071	-$72,147
Energy Eff Charge	2,773,513,936	$0.0003	$832,054
Tax Credit	2,860,713,184	-$0.0046	-$13,216,495
Winter kWh			
Base Energy Charge			
First 150HU	1,806,780,968	$0.0665	$120,150,934
Next 200HU	1,967,603,188	$0.0494	$97,199,597
Over 350HU	815,554,369	$0.0389	$31,725,065
Seasonal Energy	425,124,456	$0.0389	$16,537,341
On-peak	8,172,589	$0.0038	$31,056
Off-peak	16,914,385	-$0.0021	-$35,520
Energy Eff Charge	4,874,601,891	$0.0002	$974,920
Tax Credit	5,015,062,981	-$0.0046	-$23,169,591
Total kWh	7,875,776,165		**$562,423,013**

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Small Primary Service

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills	2,594	$323.82	$839,867
Winter Bills	5,184	$323.82	$1,678,763
TOD Bills	204	$344.90	$70,295
Low Income Charge	7,982	$0.56	$4,470
Demand Charge (kW)			
Summer	2,952,991.85	$4.66	$13,760,942
Winter	5,383,656.65	$1.69	$9,098,380
Energy Charge			
Summer kWh			
First 150HU	445,470,612	$0.1023	$45,571,644
Next 200HU	546,944,101	$0.0770	$42,114,696
Over 350HU	420,351,651	$0.0516	$21,690,145
On-peak	14,388,590	$0.0091	$130,936
Off-peak	30,109,489	-$0.0051	-$153,558
Energy Eff Charge	1,305,635,432	$0.0003	$391,691
Tax Credit	1,412,766,364	-$0.0040	-$5,707,576
Winter kWh			
First 150HU	745,793,217	$0.0644	$48,029,083
Next 200HU	920,390,284	$0.0478	$43,994,656
Over 350HU	673,232,614	$0.0374	$25,178,900
Seasonal Energy	190,479,780	$0.0374	$7,123,944
On-peak	27,009,248	$0.0034	$91,831
Off-peak	54,198,316	-$0.0018	-$97,557
Energy Eff Charge	2,325,628,264	$0.0002	$465,126
Tax Credit	2,529,895,894	-$0.0040	-$10,220,779
Total kWh	3,942,662,259		
Reactive Charge	1,336,133	$0.38	$507,730
Rider b			
115 kV	4,726.77	-$1.46	-$6,901
69 kV	921,980.18	-$1.23	-$1,134,036
			$243,422,690

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Large Primary Service

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Bills	708	$323.82	$229,265
TOD	60	$344.90	$20,694
Low Income Charge	768	61.1	$46,925
Demand Charge (kW)			
Summer	2,476,210.20	$21.16	$52,396,608
Winter	4,381,032.00	$9.61	$42,101,718
Energy Charge			
Summer kWh			
Energy	1,374,713,222	$0.0354	$48,664,848
On Peak	43,526,096	$0.0069	$300,330
Off-Peak	89,422,378	-$0.0038	-$339,805
Energy Eff Charge	618,013,111	$0.0001	$61,801
Tax Credit	1,374,713,222	-$0.0035	-$4,784,002
Winter kWh			
Energy	2,408,187,684	$0.0314	$75,617,093
On Peak	78,372,276	$0.0031	$242,954
Off-Peak	156,986,708	-$0.0018	-$282,576
Energy Eff Charge	1,055,855,128	$0.0001	$105,586
Tax Credit	2,408,187,684	-$0.0035	-$8,380,493
Total kWh	3,782,900,907		
Reactive Charge	376,499	$0.38	$143,070
Rider b			
115 kV	612,583.30	-$1.46	-$894,372
69 kV	1,875,728.50	-$1.23	-$2,307,146
			$202,942,497

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Company Owned Lighting 5M

Description CSS Code	Count	Present Rates	Present Revenue
LED 100 W EQ Bracket	51,955	$10.31	$6,427,873
LED 250 W EQ Bracket	7,475	$16.70	$1,497,990
LED 400 W EQ Bracket	1,453	$30.89	$538,598
	0		
9500 HPS Enclosed	7,398	$12.89	$1,144,323
25500 HPS Enclosed	8,222	$18.63	$1,838,110
50000 HPS Enclosed	1,658	$33.21	$660,746
6800 MV Enclosed	4,157	$12.89	$643,005
20000 MV Enclosed	2,296	$18.63	$513,294
54000 MV Enclosed	74	$33.21	$29,490
	0		
LED Direct-Small	1,085	$21.61	$281,362
LED Direct-Medium	1,577	$34.69	$656,474
LED Direct-Large	270	$69.13	$223,981
LED Post Top - All	3,216	$22.59	$871,793
	0		
	0		
5800 HPS Open Btm	88	$10.44	$11,025
9500 HPS Open Btm	27,379	$11.41	$3,748,733
3300 MV Open Btm	1,594	$10.44	$199,696
6800 MV Open Btm	8,714	$11.41	$1,193,121
	0		
9500 HPS Post Top	41,701	$23.65	$11,834,744
3300 MV Post Top	102	$22.35	$27,356
6800 MV Post Top	8,233	$23.65	$2,336,525
	0		
25500 HPS Direct	2,986	$23.65	$847,427
50000 HPS Direct	3,124	$37.40	$1,402,051
34000 MH Direct	4,334	$23.65	$1,229,989
100000 MH Direct	690	$74.76	$619,013
20000 MV Direct	237	$23.65	$67,261
54000 MV Direct	24	$37.40	$10,771
	0		
	0		
11000 MV Open Btm	84	$11.41	$11,501
140000 HPS Direct	11	$74.76	$9,868
			$38,876,121
		Tax Credit	-$1,873,064
		Realized Municpal Discount	0.03785
			$35,602,359

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Customer Owned Lighting 6M

Description CSS Code	Count	Present Rates	Present Revenue
Metered service (cust charge per m	1,610	$6.97	$134,660
Energy charge (per kWh)	55,769,535	$0.0472	$2,632,322
		$0.0441	
Unmetered service (cust charge pe	0	$6.9700	$0
		$0.0000	
9500 HPS Enrg&Maint	11,544	$3.8000	$526,406
25500 HPS Enrg&Maint	762	$6.6100	$60,442
50000 HPS Enrg&Maint	70	$9.5400	$8,014
5500 MH Enrg&Maint	169	$5.4900	$11,134
12900 MH Enrg&Maint	53	$6.5700	$4,179
3300 MV Enrg&Maint	5	$3.8000	$228
6800 MV Enrg&Maint	2,077	$4.9400	$123,125
11000 MV Enrg&Maint	86	$6.6900	$6,904
20000 MV Enrg&Maint	38	$8.8700	$4,045
54000 MV Enrg&Maint	4	$18.9300	$909
		$0.0000	$0
9500 HPS Enrgy Only	184	$1.8400	$4,063
25500 HPS Enrgy Only	0	$4.7000	$0
50000 HPS Enrgy Only	1	$7.3900	$89
3300 MV Enrgy Only	86	$1.9500	$2,012
6800 MV Enrgy Only	122	$3.1700	$4,641
11000 MV Energy Only	24	$4.5100	$1,299
20000 MV Energy Only	88	$6.9600	$7,350
54000 MV Energy Only	18	$16.5700	$3,579
2500 LED Energy Only	0	$0.6000	$0
5000 LED Energy Only	0	$1.0600	$0
4250 LED Energy Only	0	$1.2800	$0
12500 LED Energy Only	0	$2.7300	$0
19000 LED Energy Only	0	$3.9400	$0
100W LED Energy Only	29	$1.5900	$553
180W LED Energy Only	2	$2.8600	$69
25W LED Energy Only	2	$0.4000	$10
36W LED Energy Only	21	$0.5700	$144
40W LED Energy Only	69	$0.6400	$530
57W LED Energy Only	7	$0.9100	$76
70W LED Energy Only	13	$1.1100	$173
75W LED Energy Only	546	$1.1900	$7,797
76W LED Energy Only	0	$1.2100	$0
85W LED Energy Only	51	$1.3500	$826
6M Ltd LED 100 W EQ	5,771	$3.5200	$243,767
6M Ltd LED 250 W EQ	97	$4.9800	$5,797
			$3,795,141
		Tax Credit	-$208,764
		Realized Municpal Discount	0.0544751
			$3,391,008

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

MSD Horsepower Service

Connected Horsepower	Current Rate	Amount of Bill at .1735 per Horsepower Per Month	Annual
36,900.0	0.1735	$6,402	**$76,826**

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Residential Class

	Billing Units	Rounded Proposed Rates	Target Revenue
Customer Charge			
Summer Bills	4,265,511	$11.00	$46,920,625
Winter Bills	8,535,546	$11.00	$93,891,001
TOD Bills	1,082	$11.00	$11,907
Low Income Charge	12,802,139	$0.04	$512,086
Total Bills	12,802,139		
Energy Charge			
Summer kWh	4,703,625,375	$0.1151	$541,387,281
On-peak	74,477	$0.2882	$21,464
Off-peak	423,574	$0.0720	$30,497
Winter kWh			
First 750 kWh	4,817,304,105	$0.0800	$385,384,328
Over 750 kWh	3,806,441,387	$0.0551	$209,734,920
On-peak			
Off-peak			
Total kWh	13,327,868,918		
		Total	**$1,277,894,109**

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Page 1 of 8

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Small General Service Class

	Billing Units	Rounded Proposed Rates	Target Revenue
Customer Charge			
Summer Bills			
One-phase	373,368	$11.31	$4,222,789
Three-phase	153,599	$21.45	$3,294,703
Winter Bills			
One-phase	744,892	$11.31	$8,424,731
Three-phase	307,367	$21.45	$6,593,024
TOD Bills			
Limited Unmetered Service	81,050	$5.92	$479,817
One-phase	12,758	$11.31	$144,288
Three-phase	1,499	$21.45	$32,150
Low Income Charge	1,674,533	$0.05	$83,727
Total Bills	1,674,533		
Energy Charge			
Summer kWh	1,119,061,653	$0.1047	$117,165,755
On-peak	12,503,276	$0.1556	$1,945,510
Off-peak	21,855,829	$0.0634	$1,385,660
Summer kWh to Lighting Rate	646,859	$0.0440	$28,462
Winter kWh			
Base	1,621,128,084	$0.0782	$126,772,216
Seasonal	447,093,961	$0.0450	$20,119,228
On-peak	22,725,355	$0.1025	$2,329,349
Off-peak	41,113,895	$0.0470	$1,932,353
Winter kWh to Lighting Rate	1,323,003	$0.0440	$58,212
Total kWh	3,285,482,052	Total	**$295,011,973**

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Large General Service

	Billing Units	Rounded Proposed Rates	Target Revenue
Customer Charge			
Summer Bills	42,869	$94.58	$4,054,531
Winter Bills	85,588	$94.58	$8,094,867
TOD Bills	422	$94.58	$39,917
Low Income Charge	128,878	$0.56	$72,172
Demand Charge (kW)			
Summer	8,415,461	$5.08	$42,750,542
Winter	15,841,921	$1.88	$29,782,812
Energy Charge			
Summer kWh			
First 150HU	1,088,670,145	$0.0995	$108,322,679
Next 200HU	1,227,101,130	$0.0749	$91,909,875
Over 350HU	544,941,909	$0.0503	$27,410,578
On-peak	5,132,746	$0.0118	$60,566
Off-peak	10,161,490	-$0.0067	-$68,082
Winter kWh			
Base Energy Charge			
First 150HU	1,806,780,968	$0.0625	$112,923,810
Next 200HU	1,967,603,188	$0.0465	$91,493,548
Over 350HU	815,554,369	$0.0366	$29,849,290
Seasonal Energy	425,124,456	$0.0366	$15,559,555
On-peak	8,172,589	$0.0036	$29,421
Off-peak	16,914,385	-$0.0020	-$33,829
Total kWh	7,875,776,165		**$562,252,254**

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Small Primary Service

	Billing Units	Rounded Proposed Rates	Target Revenue
Customer Charge			
Summer Bills	2,594	$324.46	$841,527
Winter Bills	5,184	$324.46	$1,682,081
TOD Bills	204	$324.46	$66,129
Low Income Charge	7,982	$0.56	$4,470
Demand Charge (kW)			
Summer	2,952,991.85	$4.38	$12,934,104
Winter	5,383,656.65	$1.59	$8,560,014
Energy Charge			
Summer kWh			
First 150HU	445,470,612	$0.0962	$42,854,273
Next 200HU	546,944,101	$0.0724	$39,598,753
Over 350HU	420,351,651	$0.0485	$20,387,055
On-peak	14,388,590	$0.0086	$123,742
Off-peak	30,109,489	-$0.0048	-$144,526
Winter kWh			
First 150HU	745,793,217	$0.0606	$45,195,069
Next 200HU	920,390,284	$0.0450	$41,417,563
Over 350HU	673,232,614	$0.0352	$23,697,788
Seasonal Energy	190,479,780	$0.0352	$6,704,888
On-peak	27,009,248	$0.0032	$86,430
Off-peak	54,198,316	-$0.0017	-$92,137
Total kWh	3,942,662,259		
Reactive Charge	1,336,133	$0.36	$481,008
Rider b			
115 kV	4,726.77	-$1.37	-$6,476
69 kV	921,980.18	-$1.15	-$1,060,277
			$243,331,477

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Large Primary Service

	Billing Units	Rounded Proposed Rates	Target Revenue
Customer Charge			
Bills	708	$324.46	$229,718
TOD	60	$324.46	$19,468
Low Income Charge	768	61.1	$46,925
Demand Charge (kW)			
Summer	2,476,210.20	$19.88	$49,227,059
Winter	4,381,032.00	$9.01	$39,473,098
Energy Charge			
Summer kWh			
Energy	1,374,713,222	$0.0333	$45,777,950
On Peak	43,526,096	$0.0065	$282,920
Off-Peak	89,422,378	-$0.0036	-$321,921
Winter kWh			
Energy	2,408,187,684	$0.0295	$71,041,537
On Peak	78,372,276	$0.0029	$227,280
Off-Peak	156,986,708	-$0.0017	-$266,877
Total kWh	3,782,900,907		
Reactive Charge	376,499	$0.36	$135,540
Rider b			
115 kV	612,583.30	-$1.37	-$839,239
69 kV	1,875,728.50	-$1.15	-$2,157,088
			$202,876,368

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Company Owned Lighting 5M

Description CSS Code	Count	Rounded Proposed Rates	Target Revenue
LED 100 W EQ Bracket	51,955	$10.03	$6,253,304
LED 250 W EQ Bracket	7,475	$16.19	$1,452,243
LED 400 W EQ Bracket	1,453	$29.76	$518,895
9500 HPS Enclosed	7,398	$12.21	$1,083,955
25500 HPS Enclosed	8,222	$16.89	$1,666,435
50000 HPS Enclosed	1,658	$30.47	$606,231
6800 MV Enclosed	4,157	$11.72	$584,640
20000 MV Enclosed	2,296	$16.05	$442,210
54000 MV Enclosed	74	$27.08	$24,047
LED Direct-Small	1,085	$21.09	$274,592
LED Direct-Medium	1,577	$33.81	$639,820
LED Direct-Large	270	$67.40	$218,376
LED Post Top - All	3,216	$22.28	$859,830
5800 HPS Open Btm	88	$10.04	$10,602
9500 HPS Open Btm	27,379	$10.73	$3,525,320
3300 MV Open Btm	1,594	$9.72	$185,924
6800 MV Open Btm	8,714	$10.24	$1,070,776
9500 HPS Post Top	41,701	$22.97	$11,494,464
3300 MV Post Top	102	$21.63	$26,475
6800 MV Post Top	8,233	$22.47	$2,219,946
25500 HPS Direct	2,986	$21.91	$785,079
50000 HPS Direct	3,124	$34.66	$1,299,334
34000 MH Direct	4,334	$21.10	$1,097,369
100000 MH Direct	690	$68.52	$567,346
20000 MV Direct	237	$21.07	$59,923
54000 MV Direct	24	$31.27	$9,006
11000 MV Open Btm	84	$9.74	$9,818
140000 HPS Direct	11	$69.08	$9,119
			$36,995,079
		Realized Municpal Discount	0.03785
			$35,594,683.56

Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

Customer Owned Lighting 6M

Description CSS Code	Count	Rounded Proposed Rates	Target Revenue
Metered service (cust charge per m	1,610	$6.97	$134,660
Energy charge (per kWh)	55,769,535	$0.0440	$2,453,860
9500 HPS Enrg&Maint	11,544	$3.6700	$508,398
25500 HPS Enrg&Maint	762	$6.2900	$57,516
50000 HPS Enrg&Maint	70	$9.0300	$7,585
5500 MH Enrg&Maint	169	$5.3600	$10,870
12900 MH Enrg&Maint	53	$6.3500	$4,039
3300 MV Enrg&Maint	5	$3.6700	$220
6800 MV Enrg&Maint	2,077	$4.7200	$117,641
11000 MV Enrg&Maint	86	$6.3800	$6,584
20000 MV Enrg&Maint	38	$8.3900	$3,826
54000 MV Enrg&Maint	4	$17.7900	$854
9500 HPS Enrgy Only	184	$1.7100	$3,776
25500 HPS Enrgy Only	0	$4.4401	$0
50000 HPS Enrgy Only	1	$6.8800	$83
3300 MV Enrgy Only	86	$1.8200	$1,878
6800 MV Enrgy Only	122	$2.9500	$4,319
11000 MV Energy Only	24	$4.2000	$1,210
20000 MV Energy Only	88	$6.4800	$6,843
54000 MV Energy Only	18	$15.4300	$3,333
2500 LED Energy Only	0	$0.0000	$0
5000 LED Energy Only	0	$0.0000	$0
4250 LED Energy Only	0	$0.0000	$0
12500 LED Energy Only	0	$0.0000	$0
19000 LED Energy Only	0	$0.0000	$0
100W LED Energy Only	29	$1.5900	$553
180W LED Energy Only	2	$2.8600	$69
25W LED Energy Only	2	$0.4000	$10
36W LED Energy Only	21	$0.5700	$144
40W LED Energy Only	69	$0.6400	$530
57W LED Energy Only	7	$0.9100	$76
70W LED Energy Only	13	$1.1100	$173
75W LED Energy Only	546	$1.1900	$7,797
76W LED Energy Only	0	$1.2100	$0
85W LED Energy Only	51	$1.3500	$826
6M Ltd LED 100 W EQ	5,771	$3.5200	$243,767
6M Ltd LED 250 W EQ	97	$4.9800	$5,797
			$3,582,996
		Realized Municpal Discount	0.0544751
			$3,387,811.83

Schedule MWH-D4
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Weather Normalized-12 months ending December 2018
Projected Growth to December 2019

MSD Horsepower Service

Connected Horsepower	Proposed Rate	Amount of Bill at .1692 per Horsepower Per Month	Annual
36,900.0	0.1692	$6,243	**$74,922**

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 Decrease Its Revenues for Electric Service.	)))	File No. ER-2019-0335

AFFIDAVIT OF MICHAEL W. HARDING

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

Michael W. Harding, being first duly sworn on his oath, states:

1. My name is Michael W. Harding. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Manager, Rates and Analysis.

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 40 pages and Schedule(s) MWH-D1 to MWH-D4, 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.

Michael W. Harding

Subscribed and sworn to before me this 27th day of June, 2019.

Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2022
Commission Number: 14839811