Exhibit No. 28

Ameren – Exhibit 28
Nicholas Bowden, Ph.D.
Direct Testimony
File No. ER-2022-0337

Exhibit No.:	
Issue(s):	Billing Units
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

NICHOLAS BOWDEN, Ph.D.

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
August, 2022

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DIRECT TESTIMONY

OF

NICHOLAS BOWDEN, Ph.D.

FILE NO. ER-2022-0337

I. INTRODUCTION

Q. Please state your name and business address.

A. Nicholas Bowden, 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 a Regulatory Consultant.

Q. Please describe your educational background and employment experience.

A. I earned a Bachelor of Science in Economics from Bradley University in 2006, a Master of Science in Electricity, Natural Gas, and Telecommunications Economics from Illinois State University in 2008, and a Doctor of Philosophy in Energy Systems from the University of California, Davis in 2021. I was employed as an economic analyst with the Illinois Commerce Commission's ("ICC") Federal Energy Program from 2008 until 2012. My work at the ICC primarily involved interventions in Federal Energy Regulatory Commission dockets, but also included support for state jurisdictional policy and regulation. I was employed as a lecturer in the Department of Economics and a research associate with the Institute for Regulatory Policy Studies ("IRPS") at Illinois State University between 2011 and 2014. My work with the IRPS centered on the development of a national database of utility rates for the US Department of Energy. I joined Ameren Missouri in August of 2020 as a Regulatory Rate Specialist in the Rates and Analysis group, and was promoted to Regulatory Consultant in February of 2022.

Q. Have you sponsored testimony in other Missouri Public Service Commission ("Commission") proceedings?

A. Yes, I sponsored testimony in the Company's last request for review of electric general rates, File No. ER-2021-0240. In that proceeding my testimony included the development of normalized billing units and revenues at current rates, the evaluation of Rider EDI realized rates, the proposal for Rider CSP, and other miscellaneous tariff revisions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to:

1. Discuss the process used to develop normalized test year billing units and normalized revenues at current rates;

2. Discuss the rate analysis described in the Company's Rider EDI;

3. Provide updated Rider EEIC Net Margin Revenue values;

4. Discuss the interaction between RESRAM and this case, and;

5. Discuss the analysis of the SB564 Rate Caps.

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

A. Yes, I am sponsoring three Schedules.

Schedule NSB-D1 details the normalized billing units used to determine the normalized retail revenues and develop rates.

Schedule NSB-D2 provides the results of the Rider EDI rate analysis.

Schedule NSB-D3 provides an illustrative RESRAM rate sheet.

III. DEVELOPMENT OF NORMALIZED BILLING UNITS

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

A. Yes, I conducted the billing unit analysis for this case.

Q. What period of time does the billing unit analysis cover?

A. The billing unit analysis was conducted using the twelve months ending March 31, 2022, as the period of study, the proposed test year for this case.

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

A. A billing unit is a measurable phenomenon which drives electric power system cost and can be used in conjunction with filed rates to calculate customer bills. Billing units include, but are not limited to, electrical service connections (customer count), electrical energy consumption (kilowatt-hours or kWh), electrical power demand (kilowatts or kW), and reactive power demand (kilovolt-ampere reactive or kVar). The billing units used to calculate a customer's bill depend on a customer's rate class, but virtually all customers' bills are determined by more than one billing unit. Billing units are typically normalized when rates are set.

Q. Why are billing units normalized?

A. Billing units are normalized for two related reasons. First, billing units are normalized in order to calculate the normalized revenue, the revenue the Company expects to earn under normal conditions at current rates. Second, normalized billing units are used to develop the rates proposed in this proceeding; rates that allow the Company to collect its revenue requirement under normal conditions.

Q. What is the result of the billing unit analysis?

A. The billing unit analysis results in the normalized test year billing units, and when applied to current rates, the Company's normalized revenue. The normalized test year billing units are detailed in Schedule NSB-D1. The Company's normalized revenue in this case is $2,717,584,895. The Company's actual test year revenue, total revenue adjustments, and normalized revenue are summarized by customer class in Table 1.

Table 1. Normalized Revenue By Class

Customer Class	Actual Revenues (in Dollars)	Total Adjustments (in Dollars)	Normalized Revenue (in Dollars)
1M	1,283,073,684	89,936,186	1,373,009,870
2M	280,098,558	25,143,187	305,241,746
3M	518,368,772	38,234,478	556,603,249
4M	221,898,096	12,985,812	234,883,908
11M	189,972,337	15,848,325	205,820,662
Lighting	41,086,752	857,144	41,943,896
MSD	75,516	6,048	81,564
*Total	2,534,573,715	183,011,180	2,717,584,895

**Total may differ from sum of rows due to rounding.*

The difference between the Company's total revenue requirement, as calculated by Company witness Mitchell Lansford, and normalized revenue is the difference between the Company's cost of providing electrical service to its customers and the revenue that the Company expects to earn in a normal year at current rates. Normalized billing units are used in conjunction with this difference to propose rates that fully cover the Company's costs under normal conditions.

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

A. The Company is making five adjustments to normalize billing units and consequently normalize revenues. The Company is also making three adjustments that do not impact billing units but result in direct adjustments to revenue. The five billing unit adjustments are as follows:

1. A weather normalization adjustment;
2. A days adjustment;
3. An energy efficiency adjustment;
4. A customer-owned solar adjustment; and
5. A growth adjustment.

The three direct revenue adjustments are as follows:

1. A rate annualization adjustment;
2. An economic development incentive adjustment; and
3. A Community Solar adjustment.

The revenue value of each billing unit adjustment is shown in Table 2 by customer class.

Table 2. Billing Unit Revenue Adjustments

Customer Class	Weather Adjustment (in Dollars)	Days Adjustment (in Dollars)	Energy Efficiency Adjustment (in Dollars)	Solar Adjustment (in Dollars)	Growth Adjustment (in Dollars)
1M	-22,800,707	7,187,706	-7,750,260	-660,131	2,730,326
2M	-2,759,724	1,258,421	-1,375,367	-135,526	3,949,127
3M	-1,803,829	1,346,576	-5,416,250	-79,215	87,804
4M	-1,164,553	-964,401	-742,677	-6,457	-2,688,151
11M	-655,698	-261,162	-53,141	-6,334	956,598
Lighting	0	0	0	0	857,144
MSD	0	0	0	0	0
*Total	-29,184,511	8,567,139	-15,337,695	-887,663	5,892,848
**Total may differ from sum of rows due to rounding.*					

The value of each non-billing unit revenue adjustment is shown in Table 3 by customer class.

Table 3. Non-Billing Unit Revenue Adjustments

Customer Class	Rate Annualization Adjustment (in Dollars)	Economic Development Adjustment (in Dollars)	Community Solar Adjustment (in Dollars)
1M	111,008,204	0	221,049
2M	24,206,066	0	189
3M	44,528,622	-429,230	0
4M	18,729,967	-177,915	0
11M	15,937,258	-69,196	0
Lighting	0	0	0
MSD	6,048	0	0
*Total	214,416,165	-676,341	221,238
**Total may differ from sum of rows due to rounding.*			

Q. What is the starting point for the process of normalizing billing units?

A. The process of normalizing billing units starts with the actual metered and billed test year billing units. The test year billing units are extracted directly from the Company's billing system at the customer level by month. The customer level billing units are then aggregated across customers by rate class.

Q. Are there any notable changes to the structure or form of billing units since the Company's last electric rate review?

A. Yes, starting in June 2021, the Company began seasonally prorating billing units on customer bills.[1]

- Historical: Prior to June 2021, the Company billed customers on a primary month basis. Under the primary month billing method, the rates applied to

[1] The Company's billing processes, as reflected in its tariffs, were updated to feature proration of seasonal rates as a result of the settlement of the Company's 2019 electric rate case, File No. ER-2019-0335.

a customer's billing units are determined by the value of a customer's primary month variable stored in the billing system. If the value of a customer's primary month variable was 6, 7, 8, or 9 (representing the primary months of June through September) for a given billing period, then the billing system would apply summer rates to all of the customer's billing units in that billing period. On the other hand, if the primary month variable value was 1, 2, 3, 4, 5, 10, 11, of 12, then the billing system would apply winter rates. However, there is not a one-to-one correspondence between the primary month variable and the actual calendar month. This lack of one-to-one correspondence is a result of the staggered nature of meter reading and billing dates. For instance, a customer could have their meter read on the 15th day of June for a billing period beginning on the 16th day of May. If, under the primary month billing method, the value of the customer's primary month variable was 6, then summer rates would be applied to all of their billing units for that period, although half of the days in the period were in May, a winter month.

- <u>Change</u>: Starting in June 2021, this practice changed. Instead of billing based on the value of the primary month variable, the billing system was redesigned to calculate the proportion of days in the winter and summer seasons during any given billing period (which still has an associated primary month value). Those proportions are now used to allocate billing units to winter and summer billing units, so that both winter and summer rates can be applied during a billing period where appropriate. This new practice has been generally referred to as "seasonal proration." In the context of billing unit normalization and the calculation of normalized revenues, the result is seasonally-prorated, primary-month billing units. Therefore, in the workpapers used to normalize billing units and calculate normalized revenue, billing units are organized by primary month, but any primary month may have both winter and summer billing units.

Q. How are the aggregate monthly billing units used in your analysis?

A. First, the actual aggregate monthly billing units are used in conjunction with historical rates applicable during the test year to calculate the actual revenues earned in the test year. Separate calculations are made for base rate revenue and rider revenue. Riders for the test year include the fuel adjustment clause ("FAC"), energy efficiency investment charge ("EEIC"), and the renewable energy standard rate adjustment mechanism ("RESRAM"). The calculated base rate revenue is compared to the Company's recorded revenue minus the calculated rider revenue to check for data entry or aggregation errors. Ideally, the difference between the calculated base revenue and the recorded minus calculated rider revenue would be zero. However, there are a handful of practical reasons why the difference is unlikely to be zero. For example, the recorded revenue is the sum of revenues generated from individual customer bills, while normalized revenue is calculated using the sum of individual customer billing units. On each customer bill, there are several charges, and each charge is rounded to the nearest penny. In the normalized revenue calculation, the single sum of billing units across customers is multiplied by applicable rates and only that single result is rounded. Mathematical theory tells us that rounding individual customer level charges up and down should cancel out as the number of customers increases, but it is also true that in any given instance we could experience a large deviation from that expectation.

Another source of deviation in practice comes from the timing of rate changes, both rider rate and base rate changes. Despite the billing practice improvements associated with seasonal proration, our billing units are still defined as seasonally prorated primary month data and are not calendar month data. Rider and base rate changes, however, happen on specific calendar dates, and have always been applied on a prorated basis based on days before and after the rate change in each specific customer's billing period. Seasonally prorated billing units give us a way to estimate the proportion of billing units billed on either side of the first of each month, which we can use to prorate rate changes for a given primary month, but this estimate is based on observations of months that cross over the winter-summer seasonal boundary, and the proportion certainly changes across time. In addition to the deviations caused by the proration of intra-billing-period rate changes on customers' bills, deviations are also caused by the proration of first and final bills. On first and final bills, customer charges and block sizes are prorated by the number of days billed over thirty days. The entering and exiting of customers within months is not captured in the calculation of revenues at this initial stage.

Once the historical billing units are assembled and verified, the process of making billing unit adjustments/normalizations begins. The combined effect of adjustments determines the normalized billing units. The combination of normalized billing units and currents rates yields the Company's normalized revenue. Each adjustment is outlined in detail below.

Q. Are all billing units presented as class level aggregates?

A. Yes, but in two instances, large primary service and lighting service, greater detail is also provided. Large primary service billing units are provided at the customer account level and lighting service is provided at the lighting-fixture-type level.

Q. What is the purpose of conducting the large primary service billing unit analysis at the customer account level?

A. We conduct the large primary service billing unit analysis at the customer account level given three related facts. First, the number of customers is small enough to make the account level analysis feasible. Second, the Company regularly communicates with these customers about their historic and future usage, and therefore has customer-specific information that can be used to inform the analysis. Third, each customer has significant electrical loads, such that changes in a single customer's electrical demand or energy consumption can have a non-negligible impact on the Company's electrical system and normalized revenues. In combination, these three facts allow the Company to make reasonable customer-specific adjustments to normalize billing units when appropriate.

Q. What is the purpose of conducting the lighting service billing unit analysis at the lighting fixture level?

A. Unlike all other retail electric base rates, retail rates for unmetered lighting service are defined on a dollar per fixture per month basis, and more than 90% of the Company's lighting service revenue comes from unmetered customers. While we can observe customer counts, implied kWh (rated watts × lighting hours × 1/1000), and recorded revenues at the class level using aggregate monthly data, we cannot calculate revenue using these monthly aggregates. We cannot make this calculation, because revenue is determined by the monthly rate per fixture and the fixture count. Technically, fixture counts are the billing units for unmetered lighting service. Therefore, we retrieve monthly fixture counts in order to conduct the lighting service billing unit analysis. The fixture level data also allows us to embed the ongoing LED conversion of lighting fixtures in a pro-forma growth adjustment. Fixture counts are projected out to December 2022 using the fixture specific trends during the test year. Those trends capture absolute growth in total fixture counts and the conversion of historic fixture types to LED fixtures. Generally speaking, we observe declines in the historic fixture types and offsetting increases in LED fixture types.

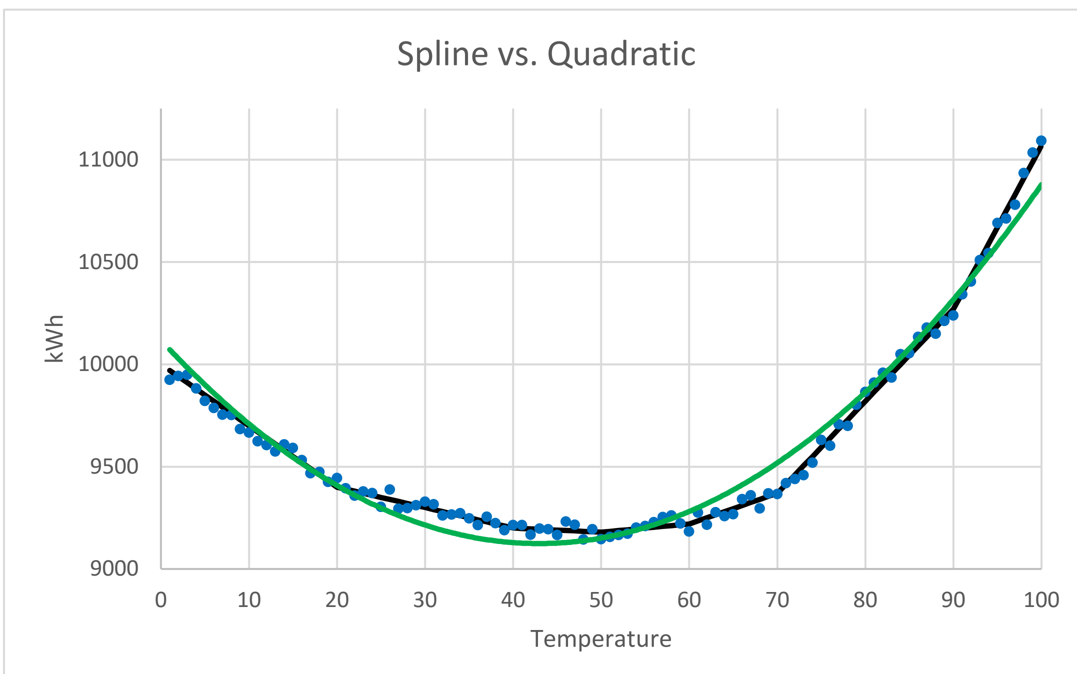
A. Billing Unit Revenue Adjustments

Q. How and why was the weather adjustment made?

A. The weather adjustment, or weather normalization, is made to remove the impact that test-year-specific weather conditions have on revenues through weather's impact on billing units. The weather normalized billing units are a statistical estimate of the billing units that would have occurred during the test year under normal weather conditions. A thirty-year average (1992 to 2021) temperature is used to define normal daily weather conditions. The weather normalization adjustment exists when weather in the test year deviates from normal weather. It is possible for test year weather to be equivalent to normal weather, but given the degree of variation in weather from year to year, the possibility is highly improbable. The direction and magnitude of the adjustment is a function of the direction and magnitude of the monthly deviations between test year weather and normal weather and the way different customer class consumption responds to variation in weather at different times of the year. The weather adjustments are made using customer class- and month-specific weather adjustment ratios. The ratios are defined as the ratio of normal kWh to actual billed kWh for each class in each month. The class- and month-specific weather adjustment ratios are multiplied by actual kWh billing units for that class and month to produce weather adjusted kWh billing units.

Actual billed kWh are observed and normal kWh are estimated for each class using statistical models of the relationship between weather and kWh. First, the relationship between daily weather and daily kWh is estimated using actual observed daily weather and kWh. Then, that relationship is used to adjust observed daily kWh based on the difference between actual and normal daily weather conditions. The actual and normalized daily kWh are then aggregated to the monthly level to define the adjustment ratios described above. Our class-specific statistical models of the relationship between daily weather and daily kWh usage are estimated by ordinary least squares using day-of-week and month fixed effects and a temperature spline. The day-of-week and month fixed effects capture the predictable level differences in kWh usage that exist along these dimensions of time, and that are not related to variation in daily temperature. For instance, there is a predictable difference between the level of kWh used on Saturdays and Sundays and the level of kWh used during the weekdays at an office building that is not related to the variation in daily temperature. Monthly fixed effects capture predictable variations in the level of kWh usage associated with environmental and behavior factors that are seasonal, but independent of variation in daily temperature. For instance, the level of kWh used during winter months, that is not related to the variation in daily temperature, is greater than spring or summer due to the increased hours of lighting. In addition to these level effects, we observe a predictable non-linear relationship between daily temperature and daily kWh usage. The relationship might generally be characterized as parabolic with the parabola opening upward, i.e. greater kWh usage at higher and lower temperatures and lower kWh usage in the middle of the range of temperatures, but the relationship is not symmetric around the minimum, so it is not technically parabolic. A temperature spline is our preferred modeling choice because it captures the non-linear nature of the relationship between temperature and kWh usage using a piecewise linear approximation rather than quadratic approximation that would force symmetry on either side of the parabola's minimum. Figure 1 provides a stylistic illustration of the superiority of modeling a relationship with a piecewise linear spline relative to a quadratic when the data might generally be described as parabolic, but is, in fact, not symmetric around the minimum.

Figure 1. Regression Spline



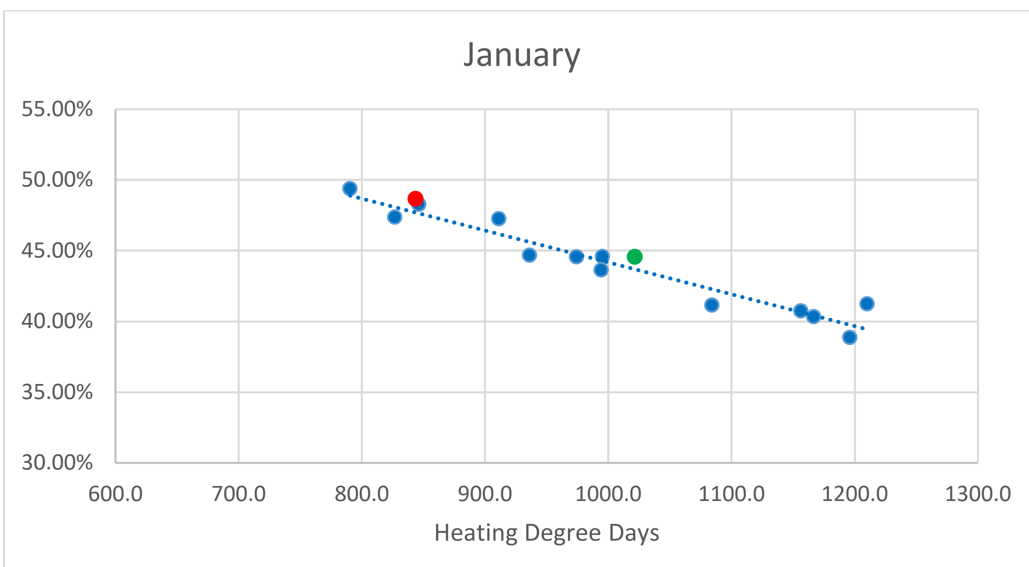
In Figure 1, the black line is a piecewise linear spline approximation of the blue points, which represent the observed relationship between the **X** and **Y** variables (temperature and kWh usage). The green line in Figure 1 is a quadratic approximation of the data. It is clear in this illustration that the quadratic function systematically underestimates **Y** along some portions of the range of **X** and overestimates **Y** along other portions of **X**. On the other hand, the piecewise linear spline does not systematically underestimate or overestimate **Y** at any point along **X**. The class specific ordinary least squares models are estimated using two years of daily temperature values and kWh usage, and produce parameters that describe the relationship between temperature and kWh usage, holding the day-of-week and month constant. The parameter values can then be used to estimate the kWh usage that would have occurred under normal weather conditions. Effectively, we hold kWh usage associated with each specific month and day-of-week combination constant and replace the observed quantity of kWh used associated with the test year temperature with the quantity of kWh associated with normal weather.

In addition to weather normalizing the total kWh billing unit using customer class- and month-specific weather adjustment ratios, we weather normalize the proportion of kWh consumed within block 1 and block 2 of the residential and small general service classes for each winter month.[2] We normalize the block 1 and block 2 proportions using a regression method subject to one additional logical constraint. First, historic data on the proportions of kWh consumed in block 1 is regressed on historic temperature data by month to develop a month-specific relationship between the proportion of kWh consumed in block 1 and temperature. The month-specific relationship and the difference between the monthly test year and normal temperature are then used to normalize the proportion of kWh consumed in block 1. The month-specific normalized proportion is then used to normalize the actual kWh within block 1 and by consequence block 2. Figure 2 illustrates how the

[2] The block normalization applies to most residential rates. Specifically, Anytime Service, Anytime TOD, Evening Morning Savers, Overnight Savers Option B, and Smart Savers Option B.

regression method is used to normalize the proportion of kWh consumed in block 1. The proportion along the vertical axis in Figure 2 measures the percent of the total kWh consumed in block 1 and the horizontal axis measures heating degree days, an aggregate measure of weather in the month. The blue points represent historic data, and the red point represents the test year observation. The slope of the dotted blue line represents the estimate of the historic relationship between temperature (heating degree days) and the proportion of kWh consumed within block 1 in January. The green point represents the weather normalized proportion of kWh consumed in block 1 during January of the test year. The horizontal position of the green point is the normal temperature. The process of normalizing the proportion of kWh which are consumed within block 1 moves the proportion parallel with the line (but not exactly on to it) until it reaches the normal temperature.

Figure 2. Residential and Small General Service Block Normalization



The normalization based on the outcome of the regression is subject to one additional logical constraint. The logical constraint has the potential to mitigate the size of the block normalization adjustment (the vertical distance between the red and green dots) prescribed by the regression. The logical constraint is as follows: the absolute value of kWh (not the proportion) in both blocks must move in the same direction as the total kWh did when it was weather normalized. For instance, if the total kWh increases because of weather normalization, then the absolute value of kWh in each block must also increase. The change in proportion in block 1 will be determined by which block increases by more. In some instances, the result prescribed by the regression could require one block to decrease in order to allow the other block to increase by enough given the value of total weather normalized kWh. Table 4 illustrates the effect of the constraint when it binds the regression result.

Table 4. Block Normalization Logical Constraint

	January 2022	February 2022
Total WN direction	+	-
Block 1 Adj	0	0
Block 2 Adj	90,383,454	-29,884,066
Regression based Adj	-0.0438	0.0247
Constrained Adj	-0.0338	0.0106

In January 2022, weather normalization resulted in an increase (+) in the total kWh. The regression-based normalization of block 1 indicates that the proportion of kWh in block 1 decreases by 4.38%. However, block 1 kWh would need to decrease for the proportion to decrease by that magnitude. The constraint causes the block 1 kWh to move in the same direction (or at least not move in the opposite direction) as the total adjustment, i.e., the change in block 1 kWh is 0. As a result, the constrained adjustment to the block 1 proportion is a decrease of 3.38% rather than a decrease of 4.38%. Similarly in February

2022, the constraint results in a 1.06% increase in the proportion rather than the 2.47% increase prescribed by the regression alone.

Q. What is the result of the weather adjustment?

A. In aggregate across the test year, the weather adjustment decreases billing units and therefore decreases normalized revenues. The weather adjustment results in a total decrease in revenue of $29,184,511 as shown in Table 2.

Q. How and why was the days adjustment made?

A. The Company's actual billing units for a given primary month do not necessarily represent kWh and kW that occurred exclusively during the similarly named calendar month. In fact, it is rare that a customer's primary month corresponds precisely to the calendar month with the same name. The lack of correspondence between primary month and calendar month is a result of the staggered reading of groups of meters, i.e., different customers have different billing cycles. Therefore, customers whose billing cycle straddles two calendar months will have billing units assigned to a single primary month by the Company's billing system, but truly have billing units which occurred in two different calendar months. The lack of correspondence between primary months and calendar months can result in customers whose billing year is more or less than a 365-day calendar year. Therefore, these customers' billing units need to be decreased or increased to reflect a normal 365-day year. The billing unit adjustment achieves this desired outcome.

Q. What is the result of the days adjustment?

A. In the proposed test year, the days adjustment increases billing units for some classes and decreases them for other. In aggregate, the days adjustment increases revenue by $8,567,139 as shown in Table 2.

Q. How and why was the energy efficiency adjustment made?

A. The energy efficiency adjustment was made to annualize the impact of energy efficiency measures implemented throughout the test year. The energy efficiency adjustment is explicitly required by the terms of the Company's Demand Side Investment Mechanism that was approved by the Commission pursuant to the Missouri Energy Efficiency Investment Act ("MEEIA") and compensates the Company for the decrease in billing units and associated revenue that result from energy efficiency measures implemented during the test year through the Company's MEEIA programs. The energy efficiency annualization adjustment is calculated using the energy efficiency measures installed during in the test year. First, the energy efficiency measures installed in the test year are used along with the measure-specific average kWh savings profiles to estimate the number of kWh saved during each month of the test year, inclusive of the month each measure was installed. A half month convention is used to estimate the savings in the month of installation. The half month convention is an assumption that all energy efficiency capacity was installed at the halfway point between the beginning and end of month and is mathematically equivalent to assuming that the investments were made uniformly across the month. This estimate reflects actual test year energy efficiency savings that are already embedded in the test year kWh billing unit data, because the estimate reflects the savings that occurred and were not metered or billed during the test year. Next, the level of savings that would have been realized during the test year, assuming all measures were installed on April 1, 2021, is estimated for each month of the test year. This second estimate reflects the kWh billing units that the Company will not meter or bill going forward as a result of the energy efficiency measures installed in the test year, the annual energy efficiency savings. The positive monthly difference (annual – actual test year savings) between these two estimates is subtracted from the actual billing units so that normalized billing units reflect the total annual reductions in billing units that resulted from the energy efficiency measures installed in the test year. This monthly difference is the primary component of the energy efficiency annualization adjustment, but the adjustment also includes another, smaller component, the Demand Response Event Net Energy ("DRENE") component. DRENE kWh result when demand response events are called by the Company, and participating customers reduce kWh consumption to provide system benefits. The kWh reductions that result from these events are reflected in billing units, but are not permanent energy savings like those that result from investments in energy efficiency measures. Therefore, DRENE kWh are added back to the test year billing units to reflect normal conditions. The DRENE kWh are added by reducing the annualized energy efficiency reductions as follows:

$$Energy\ Efficiency\ Adjustment = Annual\ Energy\ Efficiency\ Savings - Test\ Year\ Energy\ Efficiency\ Savings - DRENE\ kWh$$

Q. What is the result of the energy efficiency adjustment?

A. The energy efficiency adjustment decreases kWh billing units for every class, because the energy efficiency component unambiguously reduced billing units and is large relative to the DRENE component. In total, the energy efficiency adjustment reduced kWh billing units by 167,101,039 kWh. The energy efficiency adjustment decreases the Company's revenue by $15,337,695 as shown in Table 2.

Q. How and why was the customer-owned solar adjustment made?

A. The customer-owned solar adjustment was made to annualize the impact of behind-the-meter solar installations made throughout the test year by the Company's customers, the majority of which were incentivized by the Company pursuant to Section 393.1670, RSMo. The solar adjustment reflects the decrease in billing units and associated revenue that occur because of such customer solar generation installations during the test year. The solar adjustment is calculated using the behind-the-meter capacity installed during each month of the test year. First, the number of kWh generated by each solar installation, given their installation month and installed capacity, is estimated for each month of the test year. This estimate reflects actual test year behind-the-meter generation already embedded in the test year kWh billing unit data, because the estimate reflects the generation that occurred and displaces system-supplied energy that as a result was not metered or billed during the test year. Next, the number of kWh that would have been generated during the test year assuming all capacity was installed on April 1, 2021 is estimated for each month of the test year. The monthly difference between these two estimates is the preliminary estimate of the solar adjustment. This preliminary estimate of the solar adjustment is then further adjusted to reflect the fact that not all behind-the-meter solar generation will net against retail load, but rather some number of the kWh generated will be sold to the Company at its avoided cost rate under the Electric Power Purchases from Qualifying Net Metering Units tariff (Sheet No. 171). In order to reflect these sales in the solar adjustment, we estimate the probability that any kWh of behind-the-meter solar generation will be sold to the Company at avoided cost. We estimate this probability monthly using the ratio of total behind-the-meter generation sold at avoided cost to the total behind-the-meter generation. The preliminary adjustment is multiplied by one minus this probability to determine the final solar adjustment.

Q. What is the result of the solar adjustment?

A. The solar adjustment unambiguously decreases kWh billing units for customer classes which have non-zero behind-the-meter solar capacity installed during the test year. The total solar adjustment for all classes of customers is 9,229,081 kWh for the test year, and decreases the Company's revenue by $887,663.

Q. How and why was the growth adjustment made?

A. The growth adjustment was made to adjust billing units to the level we expect to observe at the time of true-up, December 31, 2022, in order to minimize the change in normalized revenues that will occur upon the true-up. Class-specific growth adjustments may be made using two component parts. The two components of the growth adjustment are the pure customer count growth and inter-class class switching.

The pure growth component of the adjustment is made according to the following procedure for all but the large primary service class. First, a class-specific customer count forecast is made for December 31, 2022. Second, the difference between the forecasted customer count value and the test year customer count is calculated for each month. Third, the difference, or change, in customer count in each class is multiplied by the class average billing unit values and that product is added to the test year billing unit values. For the large primary service class, growth adjustments include the addition or subtraction of specific customer loads, based on knowledge of customer-specific entry or exit from the system.

The switching component of the adjustment is made using different methods for different classes. In the past, switching was primarily focused on switching between the large primary service and small primary service customer classes. Switching between the large primary service and small primary service customer classes is done using customer-specific loads for customers who are known to have switched within the test year or whose intent to switch prior to December 31, 2022, is known. In this specific case, residential switching was included in the determination of billing units and normalized revenue. Residential switching became significant in the proposed test year for two reasons. First, an increased number of residential customers began adopting advanced time-of-use rate options. Second, the Company began to implement an updated default residential rate policy whereby residential customers are switched to the Evening Morning Savers rate six months after receiving their advanced meter, unless they elect another rate option. For the residential class, the switching component is implemented prior to the pure growth component. The switching component is implemented by calculating the difference between the customer counts in each of the first eleven months of the test year and the customer count from the last month of the test year, March 2022. This difference is multiplied by the class average billing units and the product is added to the test year billing units. The switching component of the residential growth adjustment effectively normalizes the distribution of residential customers across the residential rate options to reflect distribution in the final month of the test year. After this normalization, the pure growth component is implemented.

Q. What is the result of the growth adjustment?

A. The growth adjustment resulted in increases in residential, small general service, large general service, large primary service, and lighting revenues. The growth adjustment decreased small primary service revenues. In March 2022, one large primary service customer switched to small primary service. This customer's billing units for the year were switched from the large primary to the small primary class. In addition to that customer-specific adjustment, two other customer-specific adjustments were made. First, one large primary service customer's billing units were removed from the test year, because that customer is shutting down operations. Second, the billing units for one small primary customer with three accounts were moved from the small primary to the large primary service class. This customer is in the process of switching as a result of the meter aggregation policy approved in File No. ER-2021-0240. In total, the growth adjustment increases the Company's revenue by $5,892,848.

B. Non-Billing Unit Revenue Adjustments

Q. How and why was the rate annualization adjustment made?

A. The rate annualization adjustment was made because portions of the test year were not subject to current rates. In fact, the current rates did not go into effect until the end of February 2022, the eleventh month of the test year. The rate annualization adjustment was made to quantify the revenue impact of this change in rates and determine revenues that would have been expected had the rates that were effective on February 28, 2022 been in effect since April 1, 2021. This adjustment had no impact on billing units. The adjustment was made by first calculating base revenues at historic rates, and then calculating base revenues as if current rates were in effect for the entire test year. The difference between these two revenues is the annualization adjustment.

Q. What is the result of the annualization adjustment?

A. The result of the annualization adjustment is an increase in revenue. In total, the annualization adjustment resulted in a $214,416,165 increase in revenues.

Q. How and why was the economic development incentive adjustment made?

A. The economic development incentive adjustment was made to account for base rate revenues that were not collected, because of discounts on base rates that were granted under the Company's economic development incentive provisions (Rider EDI at Sheet Nos. 86-86.5). Rider EDI was originally approved in compliance with Section 393.1640, RSMo. Section 393.1640, until amended effective August 28, 2022 under Senate Bill 745 (2022), allows customers meeting specific economic development criteria to receive a percentage discount on base rates for a period up to five years. The annual discount may vary between thirty and fifty percent of base rates in any given year, but must be forty percent on average over the five-year period. The value of the EDI discount is calculated as part of each applicable customer's monthly billing process, and therefore, the individual monthly value of the discount for each applicable customer can be retrieved from the Company's billing system. The value of the individual monthly discounts are aggregated across customers to determine the total value of base revenues that the Company did not collect as a result of the economic development incentive discounts. That total value is the economic development incentive adjustment.

Q. What is the result of the economic development incentive adjustment?

A. The economic development incentive adjustment decreases the Company's revenue by $676,341. The reduced level of revenues, $676,341, is allocated to each of the Company's customer classes through the application of a uniform percentage adjustment to the revenue requirement responsibility of each customer class as required by Section

393.1640. The uniform percentage adjustment to the revenue requirement responsibility is outlined further by Company witness Michael Harding.

Q. How and why was the Community Solar adjustment made?

A. The Community Solar adjustment was made to account for the Community Solar Pilot Program revenues that were collected by the Company. Community Solar Pilot Program customers subscribe to 100-kWh blocks of solar energy and pay the Community Solar Pilot Program's Total Solar Block Charge for each block of solar energy. The Community Solar adjustment is equal to the total number of 100-kWh blocks sold multiplied by the Total Solar Block Charge, i.e., total Community Solar Pilot Program revenue. The adjustment is equal to the total revenue because kWh that were metered, but not billed at base rates due to solar block subscriptions, were removed from the billing units used to calculate normalized revenue.

The total Solar Block Charge consists of two parts, the Solar Generation Charge and the Facilities Charge. The Solar Generation Charge is designed to cover the cost of the Community Solar Pilot Program solar generation resources. The Facilities Charge is designed to cover the cost of other Company assets beyond the solar generation resource needed to serve Community Solar Pilot Program customers. The revenues associated with each of the charges will receive different treatment in the design of proposed rates as discussed further by Company witness Michael Harding.

Q. What is the result of the Community Solar adjustment?

A. A total of 15,592 100-kWh blocks were sold at the Total Solar Block Charge during the test year, 15,578 to residential customers and 14 to small general service customers. The Total Solar Block Charge during the test year equals $14.19 and $13.26

per block for residential and small general service customers, respectively. Therefore, the community solar adjustment increases the Company's revenue by $221,238. The portion of the adjustment associated with the Solar Generation Charge will be excluded from the general base rate adjustment and distributed to all customer classes pro rata to offset revenue changes needed in base rates. The portion of revenue associated with the Facilities Charge will be subject to the general base rate adjustment so the Facilities Charge adjustment prescribed under the stipulations and agreements in File No. EA-2016-0207 will be realized. This process will be described in more detail by Company Witness Michael Harding.

IV. ECONOMIC DEVELOPMENT INCENTIVE

Q. Please describe the Rider EDI realized rates analysis.

A. On June 1, 2018, Senate Bill 564 was signed into law as Section 393.1640, RSMo. Section 393.1640 required the Company to make discounted rates available to qualifying customers for up to five years. The average of the discount over five years must be 40 percent under the law. The economic development incentive adjustment discussed above reflects that fact that qualified customers applied for and were granted discounted rates in compliance with Section 393.1640. The law also requires the realized rate paid by customers receiving the discount to be greater than the variable cost of providing service to customers receiving the discount in aggregate, and therefore also contribute to covering fixed costs.

Section 393.1640 and therefore Rider EDI grants qualifying customers an average discount on base rates of 40 percent over the five-year term of the discount, but allows customers to choose discounts of 30, 40, or 50 percent in any given year of the five-year term. We compute the realized rate across all Rider EDI customers using current rates and assuming a 40 percent discount to determine if the realized rates are greater than the Company's variable cost to serve the customers in aggregate, and therefore contribute to fixed costs.

Q. Were any improvements made to the Rider EDI analysis method presented in File No. ER-2021-0240?

A. Yes, several improvements were made to the Rider EDI analysis method relative to analysis performed in File No. ER-2021-0240. First, the analysis was performed separately for customers with 12 months or more of discounts and those with less than 12 months of discounts. In general, the revenue and cost "picture" is more complete for customers with at least 12 months of Rider EDI billing data. Even the first 12 months of Rider EDI billing data may not provide a complete and accurate picture of the revenues and costs that will be realized for a Rider EDI customer, because of the nature of Rider EDI customers. Rider EDI is designed to support significant new or incremental loads that generally take some time to ramp up to full demand and energy levels. Furthermore, the analysis includes capacity costs that are assessed on an annual basis, and a customer with less than 12 months of Rider EDI billing data may not have the specific demand value needed to appropriately estimate capacity costs. This final point is outlined in greater detail in my Rider EDI workpaper. Second, the calculation of capacity costs used in the analysis was improved. The Company's capacity cost is determined by the Company's system peak load. Therefore, the capacity cost associated with any individual customer is determined by the customer's demand at the time of the system peak. In the previous analysis in File No. ER-2021-0240, a customer's capacity cost was calculated using the customer's maximum billing demand regardless of month and without consideration for how that peak demand was correlated with the system peak. In this case, each customer's demand associated with capacity costs was determined by the following process: 1) the month of the Company's system peak was determined; 2) each customer's peak demand for that month was determined; 3) class specific diversity factors were calculated;[3] 4) each customer's peak demand during the peak months is divided by their class's specific diversity factor to yield the customer's contribution to system peak demand and therefore the Company's capacity cost. Third, an estimate of Renewable Energy Standard ("RES") compliance costs were added to the cost side of the analysis.

Q. What is the result of the Rider EDI realized rate analysis?

A. The realized rate paid by Rider EDI customers with 12 or more months of Rider EDI bills is $0.0421/kWh, and the variable cost to serve these same customers is $0.0351/kWh. Therefore, the realized rate paid by Rider EDI customers is greater than the variable cost to serve those customers, and these customers make a positive contribution to fixed cost. See confidential Schedule NSB-D2 for more on the analysis.

V. EEIC NET MARGIN REVENUE

Q. Were Rider EEIC Net Margin Revenue values updated to reflect rates proposed in the Company's filing?

A. Yes, the Rider EEIC Net Margin Revenue values were updated to reflect the rates proposed in the Company's filing.

[3] The diversity factor is defined as the sum of individual customers peak demands divided by the system (or class) peak demand. If each customer's peak is multiplied by the diversity factor, and then those products are summed, so that the result would be the system (or class) peak. In that sense, the diversity factor (or one over it) represents the average customer's contribution to the peak.

VI. RIDER RESRAM REBASING

Q. Why is Rider RESRAM, which is a rider mechanism that establishes a rate outside of general rate cases, to be rebased in this case?

A. Rider RESRAM is designed to recover costs and distribute benefits associated with RES compliance. Rider RESRAM captures costs and benefits that occur between rate cases to ensure the Company and its customers are both made whole given the costs and benefits of RES compliance. The RESRAM is designed to be rebased in general rate proceedings. Rebasing moves RES costs and benefits currently included in the RESRAM rate into base rates.

Rebasing RESRAM may include two changes that impact the RESRAM rate: 1) the transfer of RESRAM eligible costs and benefits out of the RESRAM rate and into base rates, and 2) the establishment of values for the RBA and MBA components of the RESRAM rate. The values of RBA and MBA represent amounts of RESRAM eligible costs and benefits reflected in the RESRAM rate and base rates respectively.

Q. Did you submit a tariff sheet that rebases RESRAM filed in the direct case?

A. No. The timing of annual RESRAM filings and the timing of a general rate proceedings make filing a tariff sheet rebasing RESRAM with the direct case impractical. The RESRAM rate is revised through an annual filing made by October 1st of each year. The annual filing has a four-month review period before the revised RESRAM rate takes effect on February 1st. Therefore, the RESRAM rate needs to be reset between the time this case is filed (August 1, 2022) and the time the resulting rates take effect (expected to be on or before July 1, 2023). Modifications to Rider RESRAM needed for rebasing cannot be filed with the other tariff sheet modifications initiating this case because, as is typical with general rate review filings, we expect all filed tariff sheets to be suspended. Suspension of the RESRAM tariff sheet would prevent the normal annual Rider RESRAM filing from occurring pursuant to its own schedule. Therefore, I have attached Schedule NSB-D3 to my testimony, an illustrative RESRAM rate sheet that shows the establishment of a new MBA based on the amount of RESRAM eligible costs and benefits reflected in the revenue requirement in the Company's direct filed case. When this case is resolved by Commission order, the Company will file the RESRAM rate sheet with an updated MBA, and an adjusted RBA and RESRAM rate consistent with the Commission's final order in this case as part of the compliance tariffs.

Q. What adjustment to the RESRAM rate and RBA will be required at the conclusion of this case?

A. The actual magnitude of the adjustments to the RESRAM rate and RESRAM RBA are not known at this time. In the anticipated October 2022 RESRAM rate filing, over- and under-recoveries and annual ongoing revenue requirements accumulated through July 2022 will be reflected in the RESRAM rate. The level of ongoing RESRAM revenue requirement included in the RESRAM rate and RBA as a result of that October 2022 filing, which is subsequently reflected in the base rate revenue requirement and MBA established by the Commission in this case, will need to be removed from the RESRAM rate and RBA in the compliance tariffs filed to implement the Commission's decision in this case.

Q. Will the RESRAM rate be zero when this rebasing occurs?

A. No. The portion of the RESRAM rate related to recovery of the ongoing revenue requirement associated with eligible RES investments and activities will be set to zero (assuming these costs and benefits are reflected in this case's base rate revenue requirement). The portion of the RESRAM rate that reflects historical over- or under-recoveries from the previous Accumulation Period, ROUR, will remain in effect. Therefore, compliance tariffs would include a non-zero rate consistent with the recovery of ROUR from the Accumulation Period that ends in July of 2022.

VII. SB 564 RATE CAP ANALYSIS

Q. Please describe the Senate Bill 564 rate caps that the Company is operating under as a result of its election to utilize Plant In Service Accounting ("PISA").

A. The Company's election of PISA under SB 564 (2018) subjects it to a rate cap provision that requires that average rates not increase more than a 2.85% Compound Annual Growth Rate ("CAGR") from a baseline established prior to that election. Further, the Company's large power service classification (Rate 11(M) – Large Primary Service for Ameren Missouri) may not exceed a 2% CAGR from the baseline. The average rate is calculated including all riders except for those arising from energy efficiency programs approved under the MEEIA. In the Company's case, the rate subject to the cap therefore includes the FAC and RESRAM.

Q. How is the baseline rate for the rate cap test established?

A. The rate cap baseline rate is based on the rates made effective by the most recent rate case prior to the utility's election of PISA, assuming the utility was not involved in ongoing rate case when the law became effective. The Company was not involved in an ongoing rate case at that time and therefore the relevant rates took effect on April 1, 2017, as a result of File No. ER-2016-0179. The average base rate from that case is determined by dividing the authorized retail revenue requirement from that case by the total annual kWh reflected in the billing units used to establish rates in that case. The average rider rate for that date is also established based on the weighted average FAC rate that was in effect on April 1, 2017. The baseline rate must also factor in one-half of the rate reduction that was associated with law's requirement to reflect the reduced income tax expense that arose from the 2017 Tax Cut and Jobs Act ("TCJA"). On August 1, 2018, the Company's rates were reduced consistent with this provision of SB 564. The average rate from the TCJA related rate reduction is calculated similarly to the average rate resulting from the 2016 rate case. The baseline average rate is $0.0852/kWh, the average of the average rate from the 2016 rate case (plus then-current FAC) and the 2018 rate reduction case (plus then current FAC). This baseline is fixed for the duration of the Company's PISA election and has been included in the Company's workpapers associated with numerous FAC and RESRAM rider filings in recent years.

Q. How is the baseline rate used to set a cap for rates in this case?

A. The 2.85% CAGR is applied to the baseline average rate of $0.0852/kWh. The legislated rate cap growth rate is compounded for the number of years that have passed since the rate case that established the starting point of the calculation – File No. ER-2016-0179. Six and one-quarter years will have passed by the time rates from this case are expected to take effect on or before July 1, 2023. The 2.85% CAGR compounded for 6.25

years allows for an increase in the average rate of 19.2% from the baseline, or an average rate of up to $0.10151 per kWh.

Q. If the Commission were to approve the requested increase in this case, what would the average rate be when rates take effect, and would that comply with the cap?

A. If the Commission were to approve the requested increase in this case, the average rate would be $0.0982 per kWh, i.e., below the SB 564 rate cap. The kWh, and revenues used in the calculation of the proposed rate increase are shown in Table 5.

Table 5. Proposed Revenues and Rates with Currently Effective FAC and RESRAM

	Proposed Billing Units (ER-2022-0337)	Proposed Base Rev. Req. (ER-2022-0337)	FAC Revenues	RESRAM Revenues	Total Revenues
Residential	13,227,655,037	$1,530,839,059	$5,423,339	-$6,563,640	$1,529,698,758
SGS	3,159,125,697	$340,468,201	$1,295,242	-$1,567,577	$340,195,866
LGS	7,237,757,535	$621,263,333	$2,967,481	-$3,591,418	$620,639,396
SPS	3,526,793,546	$262,140,008	$1,410,717	-$1,750,016	$261,800,709
LPS	3,556,017,655	$229,584,351	$1,422,407	-$1,764,517	$229,242,242
Lighting 5M	88,303,972	$43,492,351	$36,205	-$43,817	$43,484,738
Lighting 6M	49,483,044	$3,341,139	$20,288	-$24,554	$3,336,873
MSD	172,186	$91,084	$71	-$85	$91,069
Total	30,845,308,671	3,031,219,526	$12,575,748	-$15,305,623	$3,028,489,651
	Rate per kWh	$0.0983	$0.00041	-$0.0005	$0.0982

Q. Please discuss the sub-cap applicable to the large primary service class.

A. In addition to the rate cap applicable to the Company's total revenue and all customer kWh, there is a sub-cap applicable to the large primary service class. The LPS cap is calculated in a manner similar to the company-wide cap, but is confined to large primary service customer kWh and revenues. In addition to the targeted focus on the average large primary service rate, the sub-cap also applies a different CAGR to the baseline rate. The CAGR applied to the large primary service baseline rate of $0.0571 per kWh is 2.0%. The application of the 2.0% CAGR to the base of $0.0571 over 6.25 years yields a large primary service sub-cap of $0.06461 per kWh. If the Commission were to approve the requested increase and rate design in this case, the average large primary service rate would be $0.06447 per kWh, i.e., below the SB 564 rate cap.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Residential - Anytime Users	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	9,954,036	9.00	89,586,324
Low Income Charge	9,954,036	0.14	1,393,565
Energy Charge			
Summer kWh	3,660,879,383	0.1296	474,449,968
Winter kWh			
First 750 kWh	3,785,376,775	0.0881	333,491,694
Over 750 kWh	3,004,106,797	0.0591	177,542,712
Total Anytime Users kWh	10,450,362,955		
Total Anytime Users Revenue			1,076,464,263

Residential - Anytime TOD	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	600	9.00	5,400
Low Income Charge	600	0.14	84
Energy Charge			
Summer kWh			
Off Peak	306,369	0.0786	24,081
On Peak	58,125	0.3346	19,449
Winter kWh			
First 750 kWh	366,873	0.0881	32,321
Over 750 kWh	271,094	0.0591	16,022
Total kWh	1,002,461		
Total Anytime TOD Revenue			97,356

Residential - Evening Morning Savers			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	3,044,844	9.00	27,403,596
Low Income Charge	3,044,844	0.14	426,278
Energy Charge			
Summer kWh	1,080,351,268	0.1263	136,448,365
Summer Peak kWh	687,214,669	0.005	3,436,073
Winter kWh			
First 750 kWh	968,749,892	0.0867	83,990,616
Over 750 kWh	718,980,506	0.0578	41,557,073
Winter Peak kWh	850,952,218	0.0025	2,127,381
Total kWh	2,768,081,666		
Total Anytime TOD Revenue			295,389,382

Residential - Overnight Savers			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	4,188	9.00	37,692
Low Income Charge	4,188	0.14	586
Energy Charge			
Summer kWh			
Off Peak	529,237	0.0608	32,178
On Peak	1,033,756	0.1525	157,648
Winter kWh			
Off Peak	764,535	0.0524	40,062
On Peak	1,409,379	0.0858	120,925
First 750 kWh	121,353	0.0881	10,691
Over 750 kWh	77,520	0.0591	4,581
Total kWh	3,935,779		
Total R-TOU2 Revenue			404,363

Residential - Smart Savers			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	2,448	9.00	22,032
Low Income Charge	2,448	0.14	343
Energy Charge			
Summer kWh			
Off Peak	263,132	0.0637	16,761
Intermediate Peak	466,119	0.1008	46,985
On Peak	126,148	0.3359	42,373
Winter kWh			
Off Peak	321,662	0.0526	16,919
Intermediate Peak	546,326	0.0645	35,238
On Peak	107,252	0.1798	19,284
First 750 kWh	207,014	0.0881	18,238
Over 750 kWh	121,244	0.0591	7,166
Total kWh	2,158,898		
Total R-SmartSavers Revenue			225,339

Residential - Ultimate Savers			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	2,124	9.00	19,116
Low Income Charge	2,124	0.14	297
Energy Charge			
Summer kWh			
Off Peak	779,916	0.0479	37,358
On Peak	109,096	0.2831	30,885
Winter kWh			
Off Peak	1,088,514	0.0423	46,044
On Peak	135,752	0.1539	20,892
Demand Charge			
Summer Demand	3,811	7.71	29,383
Winter Demand	7,592	3.18	24,143
Total kWh	2,113,279		
Total kW	11,403		
Total R-SmartSavers Revenue			208,119

Community Solar Revenue	221,049
Total Residential Revenue	1,373,009,870

Small General Service Class			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
One-phase	1,159,732	11.33	13,139,763
Three-phase	470,409	21.68	10,198,468
Limited Unmetered Service	86,410	6.01	519,321
TOD Bills			
One-phase	17,259	21.72	374,863
Three-phase	1,903	42.42	80,716
Low Income Charge	1,735,712	0.18	312,428
Total Bills	1,735,712		
Energy Charge			
Summer kWh	1,077,841,333	0.1135	122,334,991
Off Peak	27,044,761	0.0688	1,860,680
On Peak	15,504,866	0.1687	2,615,671
Winter kWh			
Base	1,454,197,437	0.0848	123,315,943
Seasonal	497,608,264	0.0488	24,283,283
Off Peak	54,771,506	0.0507	2,776,915
On Peak	29,835,678	0.1111	3,314,744
kWh Lighting Rate	2,321,846	0.0490	113,770
Total kWh	3,159,125,691		
Total Revenue			305,241,556

Community Solar Revenue	189
Total SGS Revenue	305,241,746

Large General Service			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Standard Bills	128,376	102.80	13,197,053
TOD Bills	588	21.08	12,395
Low Income Charge	128,376	2.06	264,455
Demand Charge (kW)			
Summer	7,902,810	5.87	46,389,494
Winter	14,606,317	2.18	31,841,771
Energy Charge			
Summer kWh			
First 150HU	1,032,265,372	0.1054	108,800,770
Next 200HU	1,122,776,418	0.0793	89,036,170
Over 350HU	468,278,551	0.0534	25,006,075
Off Peak	12,340,030	-0.0065	-80,210
On Peak	6,755,603	0.0114	77,014
Winter kWh			
Base Energy Charge			
First 150HU	1,654,427,602	0.0662	109,523,107
Next 200HU	1,753,843,635	0.0492	86,289,107
Over 350HU	731,482,950	0.0387	28,308,390
Seasonal Energy	474,683,007	0.0387	18,370,232
Off Peak	24,158,992	-0.0019	-45,902
On Peak	12,159,941	0.0035	42,560
Total kWh	7,293,172,101		
Total EDI Discount			-429,230
Total Revenue			556,603,249

Small Primary Service			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Standard Bills	7,980	352.19	2,810,476
TOD Bills	212	21.08	4,469
Low Income Charge	7,980	2.06	16,439
Demand Charge (kW)			
Summer	2,821,207	5.06	14,275,306
Winter	5,099,765	1.84	9,383,568
Energy Charge			
Summer kWh			
First 150HU	407,964,922	0.1023	41,734,811
Next 200HU	490,765,290	0.0769	37,739,851
Over 350HU	369,958,303	0.0517	19,126,844
Off Peak	1,868,929	-0.0048	-8,971
On Peak	1,014,139	0.0084	8,519
Winter kWh			
Base Energy Charge			
First 150HU	656,710,366	0.0644	42,292,148
Next 200HU	794,119,585	0.0479	38,038,328
Over 350HU	598,327,588	0.0374	22,377,452
Seasonal Energy	208,947,493	0.0374	7,814,636
Off Peak	3,574,293	-0.0018	-6,434
On Peak	1,898,010	0.0031	5,884
Reactive Power (kvar)	1,280,800	0.38	486,704
Rider B 34.5/69 kV Discount	830,239	-1.24	-1,029,497
Rider B 138 kV Discount	5,926	-1.47	-8,711
Total kWh	3,535,148,917		
Total EDI Discount			-177,915
Total Revenue			234,883,908

Large Primary Service			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Standard Bills	756	352.19	266,256
TOD	60	21.08	1,265
Low Income Charge	756	220.99	167,068
Demand Charge (kW)			
Summer	2,312,245	21.00	48,557,137
Winter	4,270,692	9.34	39,888,259
Energy Charge			
Summer kWh			
Energy	1,276,221,362	0.0357	45,561,103
Off Peak	85,081,406	-0.0035	-297,785
On Peak	42,073,854	0.0064	269,273
Winter kWh			
Energy	2,279,796,293	0.0326	74,321,359
Off Peak	140,364,801	-0.0018	-252,657
On Peak	70,591,292	0.0029	204,715
Reactive Power (kvar)	293,781	0.38	111,637
Rider B 34.5/69 kV Discount	1,568,434	-1.24	-1,944,859
Rider B 138 kV Discount	655,042	-1.47	-962,912
Total kWh	3,556,017,655		
Total EDI Discount			-69,196
Total Revenue			205,820,662

Company Owned Lighting 5M	Billing Units	Current Rates	Current Revenue
100000 MH Direct	324	74.26	288,723
11000 MV Open Btm	82	10.56	10,391
140000 HPS Direct	3	74.88	2,696
20000 MV Direct	192	22.83	52,600
20000 MV Enclosed	1,594	17.39	332,636
25500 HPS Direct	2,190	23.75	624,150
25500 HPS Enclosed	3,938	18.29	864,312
27500 HP Enclosed	226	18.29	49,602
3300 MV Open Btm	967	10.54	122,306
3300 MV Post Top	77	23.39	21,612
34000 MH Direct	582	22.87	159,724
34200 HPS Direct	3	23.75	855
36000 MH Direct	1,987	22.87	545,312
47000 HPS Direct	75	37.58	33,822
50000 HPS Direct	2,168	37.58	977,681
50000 HPS Enclosed	1,077	33.04	427,009
54000 MV Direct	6	33.89	2,440
54000 MV Enclosed	42	29.35	14,792
5800 HPS Open Btm	43	10.89	5,619
6800 MV Enclosed	3,190	12.7	486,156
6800 MV Open Btm	5,203	11.09	692,415
6800 MV Post Top	6,432	24.3	1,875,571
9500 HPS Enclosed	4,057	13.23	644,089
9500 HPS Open Btm	10,124	11.62	1,411,691
9500 HPS Post Top	33,942	24.84	10,117,431
LED 100 W EQ Bracket	81,507	10.68	10,445,937
LED 250 W EQ Bracket	12,435	17.24	2,572,553
LED 400 W EQ Bracket	2,050	31.67	779,082
LED Direct-Large	573	71.72	493,147
LED Direct-Medium	3,645	35.98	1,573,765
LED Direct-Small	3,093	22.44	832,883
LED Post Top - All	14,556	23.71	4,141,473
Municipal Discount		-0.0392	-1,591,682
Total Revenue			39,010,796

Customer Owned Lighting 6M	Billing Units	Current Rates	Current Revenue
100W LED Energy Only	46	1.66	916
11000 MV Energy Only	24	4.67	1,345
11000 MV Enrg&Maint	26	7.1	2,215
12900 MH Enrg&Maint	53	7.06	4,490
162W LED Energy Only	8	2.6892	258
180W LED Energy Only	9	2.988	323
196W LED Energy Only	28	3.2536	1,093
20000 MV Energy Only	90	7.21	7,787
20000 MV Enrg&Maint	38	9.33	4,254
25500 HPS Enrg&Maint	676	7	56,784
25500 HPS Enrgy Only	26	4.87	1,519
25W LED Energy Only	2	0.415	10
26W LED Energy Only	39	0.4316	202
27W LED Energy Only	10	0.4482	54
3300 MV Enrg&Maint	3	4.08	147
3300 MV Enrgy Only	84	2.02	2,036
36W LED Energy Only	43	0.5976	308
40W LED Energy Only	25	0.664	199
44W LED Energy Only	1	0.7304	9
45W LED Energy Only	47	0.747	421
50000 HPS Enrg&Maint	63	10.04	7,590
50000 HPS Enrgy Only	1	7.65	92
54000 MV Energy Only	11	17.17	2,266
54000 MV Enrg&Maint	4	19.8	950
54W LED Energy Only	33	0.8964	355
5500 MH Enrg&Maint	169	5.96	12,087
57W LED Energy Only	7	0.9462	79
60W LED Energy Only	4	0.996	48
6800 MV Enrg&Maint	1,385	5.25	87,255
6800 MV Enrgy Only	121	3.28	4,763
6M Ltd LED 100 W EQ	9,781	3.07	360,332
6M Ltd LED 250 W EQ	106	3.98	5,063
6M Ltd LED 400 W EQ	9	7.03	759
70W LED Energy Only	13	1.162	181
72W LED Energy Only	19	1.1952	273
75W LED Energy Only	182	1.245	2,719
85W LED Energy Only	50	1.411	847
9500 HPS Enrg&Maint	8,264	4.08	404,605
9500 HPS Enrgy Only	116	1.9	2,645
Fixture Revenue			977,281
Municipal Discount		-0.0392	-38,311
Total Revenue			938,970

Customer Owned Lighting 6M Metered			
	Billing Units	**Current Rates**	**Current Revenue**
Bills	18,977	7.75	147,072
Energy	40,612,468	0.049	1,990,011
Billed Revenue			2,137,083
Municipal Discount		-0.0669	-142,953
Total Revenue			1,994,130

Total Lighting Revenue	41,943,896

MSD Horsepower Service			
	Billing Units	**Current Rates**	**Current Revenue**
	36,900	0.1842	81,564

Contracts which billed all months of the test year

RES = $5 per REC

Actual EDI Incremental Data (above Baseline at Historic Rates)											Expected Base Rate Bills at		Marginal Cost of Service (ER-2021-			Total Variable Cost and Average Variable Cost				
Contract	Effective Date	Rate	Baseline Applicable	Discount %	Test Year Months	- Undiscounted Base Rate $ less Baseline	Rider EDI Discounts	Demand (kW) (1)	Energy (kWh)	Discounted Bills	Projected Rider EDI Discount	Projected Bills	Annual Capacity ($/KW)	Energy ($/kWh)	N&I Support	Capacity (3)	Energy	RES	N&I Support	Variable Cost
1	1/9/20	3M RI	Yes	50% & 40%	12	$ 180,503	$ (87,880)	566	2,937,600	$ 92,623	$ (78,394)	$ 117,591	$ 1.80	$ 0.02682	11.61%	$ 772	$ 78,792	$ 2,203	$ 20,956	$ 102,723
2	3/31/20	4M	No	40%	12	$ 299,438	$ (118,016)	947	4,718,694	$ 181,423	$ (128,336)	$ 197,290	$ 1.74	$ 0.02601	11.61%	$ 1,220	$ 122,733	$ 3,539	$ 34,765	$ 162,257
3	4/27/20	3M	No	30%	12	$ 92,000	$ (28,962)	352	1,260,480	$ 63,038	$ (40,613)	$ 59,168	$ 1.80	$ 0.02682	11.61%	$ 480	$ 33,808	$ 945	$ 10,681	$ 45,915
4	7/21/20	3M RI	No	50%	12	$ 157,158	$ (78,579)	461	2,469,519	$ 78,579	$ (69,349)	$ 100,805	$ 1.80	$ 0.02682	11.61%	$ 628	$ 66,237	$ 1,852	$ 18,246	$ 86,963
5	3/3/21	3M RI	No	40%	12	$ 205,372	$ (82,075)	542	3,371,520	$ 123,296	$ (89,228)	$ 134,041	$ 1.80	$ 0.02682	11.61%	$ 739	$ 90,430	$ 2,529	$ 23,844	$ 117,541
6	3/12/21	3M	No	40%	12	$ 106,694	$ (42,666)	491	1,376,640	$ 64,028	$ (46,390)	$ 69,617	$ 1.80	$ 0.02682	11.61%	$ 669	$ 36,924	$ 1,032	$ 12,387	$ 51,013
Aggregate						$ 1,041,166	$ (438,178)	3,360	16,134,453	$ 602,987	$ (452,310)	$ 678,512				$ 4,508	$ 428,923	$ 12,101	$ 120,879	$ 566,411

Realized Rate
$ 0.0421

Variable Cost per kWh
$ 0.0351

Contracts which have not billed all months of the test year

Actual EDI Incremental Data (above Baseline at Historic Rates)											Expected Base Rate Bills at		Marginal Cost of Service (ER-2021-			Total Variable Cost and Average Variable Cost				
Contract	Effective Date	Rate	Baseline Applicable	Discount %	Test Year Months	- Undiscounted Base Rate $ less Baseline	Rider EDI Discounts	Demand (kW) (2)	Energy (kWh)	Discounted Bills	Projected Rider EDI Discount	Projected Bills	Annual Capacity ($/KW)	Energy ($/kWh)	N&I Support	Prorated Capacity (3)	Energy	RES	N&I Support	Variable Cost
7	5/16/21	3M	No	40%	10	$ -	$ 107,219	(42,887)	497	$ 1,383,708	$ 64,331	$ (46,492)	$ 69,737.89	$ 1.79556	2.68%	0	565	$ 37,113	1,038	$ 12,448
8	5/28/21	11M TOD	Yes	40%	10	$ -	$ 132,133	(57,663)	648	$ 2,450,370	$ 74,470	$ (62,314)	$ 80,389.90	$ 1.74121	2.60%	0	824	$ 63,734	1,838	$ 12,896
9	6/25/21	4M	Yes	40%	8	$ -	$ 101,518	(39,933)	553	$ 738,514	$ 61,585	$ (43,439)	$ 66,992.65	$ 1.74121	2.60%	0	475	$ 19,209	554	$ 11,786
10	11/7/21	3M	No	50%	5	$ -	$ 48,391	(24,195)	525	$ 858,240	$ 24,195	$ (21,558)	$ 29,876.36	$ 1.79556	2.68%	0	298	$ 23,020	644	$ 5,618
Aggregate						$ -	$ 389,260	(164,679)	2,223	$ 5,430,832	$ 224,581	$ (173,802)	246996.802				2,162	143,076	4,073	42,749

Realized Rate
$ 0.0455

Variable Cost per kWh
$ 0.0354

(1) Billing Demand at during August, the month of system peak.
(2) Billing Demand at during August, the month of system peak. If incremental billing demand does not exist in August, then max of observed incremental billing demand is used.
(3) Demand is divided by the class specific August diversity factor to determine capacity obligation needed to determine capacity cost. August diversity factors: LGS - 1.318, SPS - 1.351, LPS - 1.141

RIDER RESRAM

RENEWABLE ENERGY STANDARD RATE ADJUSTMENT MECHANISM

RESRAM Rate Schedule

Accumulation Period Ending: 07/31/2022

1.	Actual RES Costs Incurred in AP (ARC)		$xxxx
2.	RES Expenses Recovered in AP (RCR)	=	$xxxx
	=(RBA + sum of monthly MBAs)		
3.	RES Over/Under Recovery (ROUR)=	=	$xxxx
	3.1 Interest	+	$xxxx
	3.2 (Over)/Under Recovered Costs (ARC-RCR)	+	$xxxx
4.	RES Revenue Requirement (RRR)	+	$0
5.	True-Up (T)	+	$xxxx
6.	Ordered Adjustment (OA)	±	$xxxx
7.	Total RESRAM Recoveries(TRR)=(ROUR+RRR+T+OA)	=	$xxxx
8.	Estimated Recovery Period Sales (S_{RP})	÷	xx,xxx,xxx,xxx kWh
9.	TRR_{RATE} = MIN of((TRR/S_{RP}),(RAC))	=	$(x.xxxxx)/kWh
10.	$RESRAM_{RATE}$ = TRR_{RATE} + ROA[1]	=	$(x.xxxxx)/kWh
11.	Required Offset Amount (ROA)	**+**	$x.xxxxx/kWh
12.	**$RESRAM_{RATE}$ (applicable for the first 6 months if ROA is greater than $0.00000)**	**=**	**$(x.xxxx)/kWh**

*A negative RESRAM Rate represents a per kWh credit that would be applied to a customer's bill.

Recovery Period for Above RESRAM Rate
February 1, 2022 to January 31, 2023

Current RBA = $0

Base Amount File No. ER-2022-0337 = $20,211,415

[1] If ROA is equal $0.00000, The $RESRAM_{RATE}$ stated in this Line 10 shall apply for the entire Recovery Period. If ROA is greater than $0.00000, the $RESRAM_{RATE}$ shall be the value shown on line 12 for the first 6 months and, thereafter, the value shown on Line 10.

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 Adjust Its Revenues for Electric Service.	)))	Case No. ER-2022-0337

AFFIDAVIT OF NICHOLAS BOWDEN, PhD

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

Nicholas Bowden, PhD, being first duly sworn states:

My name is Nicholas Bowden, PhD and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Nicholas Bowden, PhD
Nicholas Bowden, PhD

Sworn to me this 1st day of August, 2022.