MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2021-0240

Jefferson City, Missouri
September 17, 2021

** Denotes Confidential Information **

TABLE OF CONTENTS OF
CLASS COST OF SERVICE REPORT OF
UNION ELECTRIC COMPANY,
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Executive Summary

Based on Staff's Accounting Schedules filed on September 3, 2021, in conjunction with the Staff Cost of Service Report ("CoS Report"), Ameren Missouri's gross revenue requirement is $3.38 billion, annually. However, this amount is offset by $242.9 million related to tax impacts and prepayment of taxes by ratepayers, and further offset by $422 million in other revenues.[1] Netting these values results in an annual amount of revenues to be collected from ratepayers of $2,715,258,037.[2] Staff's Class Cost of Service Study separately assigns (where possible) and allocates (when necessary) the gross revenue requirement, net tax impacts, and other revenues to Ameren Missouri's various classes in order to find the approximate net revenue requirement associated with each class of customers.

The class revenue requirements are compared to the revenue generated by each class under existing rates. Staff's calculated normalized and annualized revenues provided in the CoS Report were $2,493,871,829, indicating that an increase to the rate schedules of $221,386,208, or 8.88%, is cost justified. Staff evaluates the relationship of existing revenues by class to the allocated revenue requirement for each class in addition to considering customer impacts and the overall relative reliability of the study in recommending a revenue requirement increase for each class. Staff also considers the causation of the revenue requirement as well as customer impacts to provide a recommendation for the rate elements within each class for recovery of the recommended class revenue requirement.

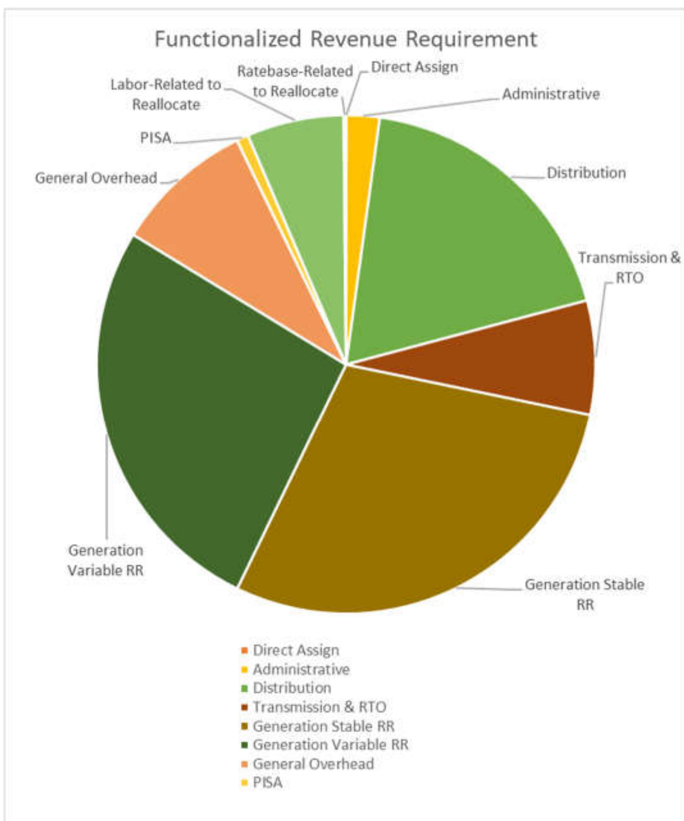
[1] Other revenues includes sales of energy and capacity through the integrated marketplace, rental proceeds, and what are typically referred to as "miscellaneous revenues" which are the product of tariff charges such as disconnection charges, bad check charges, and other charges that are not contained on class rate schedules.

[2] Including lighting revenue, but not including miscellaneous revenues.

Functionalized Revenue Requirement

The functionalized net rate base, expenses, other revenues, and resulting revenue requirement by function are provided in the table below,[3] with a pie chart indicating the relative signs of the revenue requirements in the graphic that follows:[4]

	Net Rate Base	Depreciation Expense	Labor Expense	Non Labor Expense	6.725%	-1.87%	Revenue	Line Item RR
Direct Assign	$ 54,673	$ -	$ -	$ 544,703	$ 3,677	$ (1,024)	$ -	$ 547,356
Administrative	$ -	$ -	$ 27,127,731	$ 40,374,397	$ -	$ -	$ -	$ 67,502,128
Distribution	$4,252,358,387	$ 244,539,935	$ 62,661,413	$ 72,762,287	$ 285,971,102	$ (79,644,370)	$ 30,576,775	$ 586,290,367
Transmission & RTO	$1,118,815,296	$ 33,522,958	$ 23,890,486	$ 120,079,637	$ 75,240,329	$ (20,954,805)	$ 42,767,632	$ 231,778,605
Generation Stable RR	$6,854,525,609	$ 399,111,376	$ 87,218,478	$ 89,242,230	$ 460,966,847	$ (128,381,553)	$ 17,934,854	$ 908,157,378
Generation Variable RR	$ 201,712,125	$ -	$ 97,530,053	$ 724,837,440	$ 13,565,140	$ (3,777,959)	$ 317,238,366	$ 832,154,675
General Overhead	$ 447,153,284	$ 35,896,674	$ 63,621,554	$ 163,460,701	$ 30,071,058	$ (8,374,939)	$ 10,266,185	$ 284,675,048
PISA	$ 243,125,609	$ -	$ -	$ 12,349,259	$ 16,350,197	$ (4,553,611)	$ -	$ 24,145,845
Rate Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$2,497,171,135	$ -
Labor-Related to Reallocate	$ (84,926,173)	$ (1,925,722)	$ 6,041,169	$ 197,416,488	$ (5,711,285)	$ 1,590,621	$ -	$ 197,411,271
Ratebase-Related to Reallocate	$ (61,799,741)	$ -	$ -	$ 7,677,039	$ (4,156,033)	$ 1,157,476	$ -	$ 4,678,482
Total	12,971,019,070	711,145,221	368,090,884	1,428,744,181	872,301,032	(242,940,163)	2,915,954,947	3,137,341,155

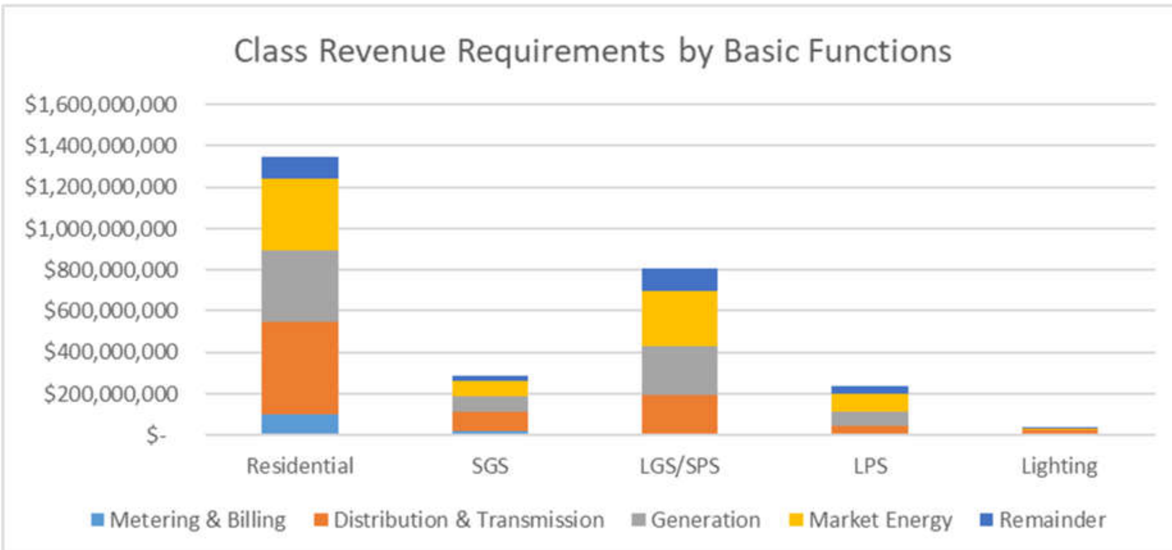


[3] The column "6.725%" refers to the expected rate of return associated with each row as recommended in the Staff CoS Report, and the column "-1.87%" refers to the net income tax and ADIT impact as a percentage of ratebase as determined from the Staff CoS Report.

[4] "RR" is used as an abbreviation for "Revenue Requirement" and "RB" for "Rate Base" in graphics throughout this Report. Note, the "Rate Based Related Reallocate" and "Direct Assign" shares of the pie chart are not visible at the resolution of the graphic due to the relatively small shares of cost-causation of these functions.

Summary of CCoS Results and Class Revenue Requirement Recommendations

Staff's CCoS studies allocate or, when possible, directly assign the revenue requirement components of each of the above functions to the studied classes. For clearer presentation at a class level, the functions presented have been combined where appropriate.



Based on the results of Staff's CCoS studies and its expert judgement considering the precision of such studies in general and known shortcomings of these studies in particular as described within this Report, Staff recommends that the approximate $221,386,208, or 8.88%, be allocated to the classes as an equal percentage increase, based on Staff's direct revenue requirement as constituted, analyzed, and described in this Report.

Summary of Rate Design and General Recommendations

Staff makes the following rate design recommendations:

1. Retention of existing customer charges, except that the LPS customer charge should be increased to approximately $515.00 from its current charge of $323.82.
2. That the residential revenue requirement increase ordered in this case be implemented as an equal percent adjustment to all energy charges on all rate schedules, except that the existing time-of-use rate differentials for the Daytime/Overnight schedule be increased to $0.01 for summer energy usage and $0.005 for non-summer energy usage.
3. Except as identified above, Staff recommends that all charges for service on each non-residential rate schedules be increased by an equal percentage increase to recover the revenue requirement ordered for that customer class.

4. Staff recommends Ameren Missouri require, on a non-optional basis, that non-residential customers participate in Rider I, which incorporates a time of use element to customers' billing as those customers obtain AMI metering equipment.
5. Staff recommends that unless the costs of substation equipment that is dedicated to primary customers is specifically assigned to the bills of primary customers, that the discounts provided to primary customers under Rider B be suspended until Ameren Missouri provides the information necessary to include the cost of primary customer substations in the bills of primary customers (and such costs are so included).

Staff recommends the Commission order Ameren Missouri to undertake data collection to facilitate more reasonable allocation or assignment of labor and non-labor distribution expenses in future rate cases.

Staff recommends Ameren Missouri continue the rate structure modernization process by retaining billing determinants in a manner that facilitates the establishment of shoulder month rates to more accurately reflect the disparity in cost-causation between peak-winter months of December, January, and February, and the shoulder months that are currently included in the "winter" billing season.

Staff is aware that Ameren Missouri has marketed its Residential rate schedule options not under the tariffed names, but rather under promotional names. Staff recommends adoption of more objective or informative names for Ameren Missouri's use in education and promotional materials.

Staff recommends the Commission order that Ameren Missouri perform a full study of the reasonableness of the calculations and assumptions underlying Rider B and Rider C to be filed as part of its direct filing in its next general rate case.

Staff recommends the Commission order Ameren Missouri to update the Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) Tariff Sheet No. 93.4 to reflect the RESRAM base amount ultimately determined in this case.

Staff recommends the Commission order Ameren Missouri to update the MEEIA margin rates used for calculating the throughput disincentive within the MEEIA mechanism.

Staff recommends the Solar Facilities Charge rate be adjusted by the percentage change to the relevant residential and SGS volumetric rates

Staff recommends the Commission order Ameren Missouri to take the following data retention measures:

1. Track customer information by service classification and voltage level and collect, retain, and provide to Staff upon request the following data collected from AMI for load research purposes.
2. File for Commission approval no later than June 1, 2022, proposed record keeping and data accessibility policies that Ameren Missouri will follow in order to implement record keeping and data accessibility practices to associate distribution system costs with the voltage of energy distributed and whether distribution system costs are used for network purposes or customer-specific purposes.
3. Study and retain determinants associated with the creation of a coincident peak demand charge for all classes.

Summary of other items addressed in this Report

Fuel Adjustment Clause

Staff proposes the Base Factor rates be rebased and Staff recommends the following changes to Ameren Missouri's FAC tariffs:

- Order Ameren Missouri to include language in its FAC tariff that any retirement and/or decommissioning costs related to the retirement of the Meramec Plant be removed from the FAC after the official retirement date, and no other costs will be included for recovery in the FAC after that date;
- Order Ameren Missouri to include language in its FAC tariff that all wind revenues associated with High Prairie and Atchison Wind Farms will be included for recovery in the FAC; and
- Order Ameren Missouri to change the FAC tariff Fuel Cost definition to state: "Fuel costs incurred to support sales and revenues associated with the Company's in service generating plants consisting of the following".

Community Solar Tariff

Although Staff is not recommending any tariff changes at this time, Staff recommends Ameren Missouri implement a system to track customer feedback regarding participation in the program in order to get a better idea of how to improve the program in the future.

Staff's CCoS Study

Studied Classes

Ameren Missouri does not make all data available at the rate schedule level, so rate schedules with common characteristics are grouped into classes for study, as shown in more detail below.[5] The class names provided below are associated with the indicated rate schedules and tariffed programs.

Studied Class	Rate Schedule or Program
Residential	Residential - Basic Service
	Residential - Daytime/Overnight Service
	Residential - Time-of-Use Smart Saver Service
	Residential - Time-of-Use Service
	Residential - Time-of-Use Ultimate Saver Service
SGS	Small General Service
LGS/SPS	Large General Service
	Small Primary Service
LPS	Large Primary Service
	Large Transmission Service
Lighting	Street & Outdoor Area Lighting - Company Owned
	Street & Outdoor Area Lighting - Customer Owned
Socialized Programs	Economic Development Riders
	Low Income
	Solar Rebates
	Charge Ahead
Discrete Programs	Community Solar
	PAYS

The studied SGS class also includes service for the Metropolitan Sewer District.[6] The LGS and SPS classes are summed for purposes of the CCoS because customers can readily switch back and forth between the rate schedules through application of Rider B and related provisions, and also because some data provided by Ameren Missouri consolidates the classes in a manner that is not easily disaggregated. There are currently no customers served on the LTS rate schedule, so it is included with the LPS for convenience.

[5] Tariff sheets bearing charges for electric service are referred to here-in as "rate schedules." As the table shows, a class is a broader customer classification and within each class, there are various rate schedules that a customer within that class could take service.

[6] The Metropolitan Sewer District is not served on any specific rate schedule, but has a contract for service with Ameren Missouri.

Background Technical Information

Data sources

The costs, expenses, and revenues that are assigned and allocated within the CCoS are obtained from the Staff accounting schedules, which were included as an attachment to the CoS Report. To facilitate assignment and develop allocators, Staff primarily relies upon Ameren Missouri's Continuing Property Record ("CPR"), and to a lesser extent, Ameren Missouri's General Ledger ("GL"). Additional data was obtained from responses to data requests.

The CPR identifies asset activities (either the addition or retirement of assets) by retirement unit (the type of asset) by vintage (the year in which the activity took place), at differing subaccount levels based on the type of asset.[7] The GL provides the beginning and ending balance for each FERC account and each FERC sub account by month with entries further delineated by transtype and other detailed coding per the company's chart of accounts. However, for purposes of allocator development the GL used is not adjusted by Staff's auditors for any disallowances, normalizations, annualizations, or other adjustments made in Staff's direct case. Those adjustments by Staff auditors are taken into account in the final percentage that is applied to the plant balance in Staff's CCoS accounting schedules.

Generation, Fuel, and RTOs

Ameren Missouri participates in the Midcontinent Independent System Operator ("MISO") integrated energy market, and much of Ameren Missouri's transmission is under the functional control of MISO. While net quantities of purchased power and sales are recorded on Ameren Missouri's books based on accounting conventions separating base load and interchange, in reality, essentially all energy consumed by Ameren Missouri's retail customers or sold to Ameren Missouri's wholesale customers is purchased through the MISO integrated energy market, and essentially all energy generated by Ameren Missouri is sold into the MISO integrated energy market. The exception is a relatively small level of energy enters in the Ameren Missouri system at the distribution level that have been generated by net-metered solar customers, or at relatively

[7] Additional information, in some cases, is also included concerning the in-service year, engineering year in service, asset ID number, and "asset location."

small Ameren Missouri-owned generation facilities.[8] Given the maturation of the MISO energy markets, Staff has moved over the last several Ameren Missouri rate cases toward consolidating and netting the costs of fuel and plant operation with the energy and capacity sales revenues received for purposes of CCoS studies. However, recently enacted legislation requires that "In determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual."[9] While Staff's CCoS in prior Ameren Missouri cases were developed to better reflect participation in the integrated energy markets, the 1992 NARUC manual significantly predates the mature integrated markets in which Ameren Missouri participates. A description of the various methods

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[8] This generation occurring at the distribution level is essentially an offset to Ameren Missouri's load requirements within the MISO market.

[9] The terms "average demand," "non-coincident peak demand," "peak load," and "system load factor" are not defined by the statute. In the context of CCoS studies, "average demand" means the level of usage that would occur in each hour if a studied class used the same amount of energy in every hour of a year. "Non-coincident peak demands" means the highest hour of a studied class's usage in a given month. "Peak load" means either a month with the highest usage in a given hour, a month with the most usage throughout the month, or a month expected to cause peaks when system load planning occurs. "System load factor" means the percent of the system peak demand that is met in each hour if the system used the same amount of energy in each hour.

§393.1620. 1. For the purposes of this section, the following terms shall mean:

(1) "Average and excess method", a method for allocation of production plant costs using factors that consider the classes' average demands and excess demands, determined by subtracting the average demands from the non-coincident peak demands, for the four months with the highest system peak loads. The production plant costs are allocated using the class average and excess demands proportionally based on the system load factor, where the system load factor determines the percentage of production plant costs allocated using the average demands, and the remainder of production plant costs are allocated using the excess demands;

(2) "Class cost of service study", a study designed to allocate a utility's costs to each customer class on the basis of which customer class causes the costs;

(3) "Commission", the Missouri public service commission;

(4) "Electrical corporation", the same as defined in section 386.020, but shall not include an electrical corporation as described in subsection 2 of section 393.110;

(5) "Production plant costs", fixed costs reflected on the electrical corporation's accounting books for the applicable test period, as updated or trued-up, associated with the production or purchase of electricity.

2. In determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual.

3. This section shall expire on August 28, 2031.

described in the 1992 NARUC manual is included as Appendix 2 to this Report. To best facilitate compliance with this provision, Staff has prepared this CCoS to segregate the revenue requirements associated with each type of production plant.

Transmission, Distribution, and the USOA

In general, transmission assets connect generation to load, and connect load centers to load centers, operating at voltages at and above 69kV.[10] The assets associated with the transmission system are recorded in FERC Accounts 350-359, which are separate from the Distribution plant accounts. The distribution accounts include the assets that connect customers to transmission substations and, to some extent, interconnect load centers.

Given the significant flux and expansion of distribution assets under Ameren Missouri's Smart Energy Plan (SEP), one of the more complex aspects of this case is the allocation of the costs associated with the distribution system, which is recorded in FERC Accounts 360-373, to the purposes and voltages at which the system operates.[11]

(1) High Voltage Distribution assets, typically operating between 34kV and 69kV;[12]
(2) Primary Distribution assets, operating between 600 Volts and 34kV;
(3) Secondary Distribution assets, operating at 600 Volts and below;
(4) Customer-specific assets, operating at various voltages;
and
(5) Customer-based, or "minimum system."[13]

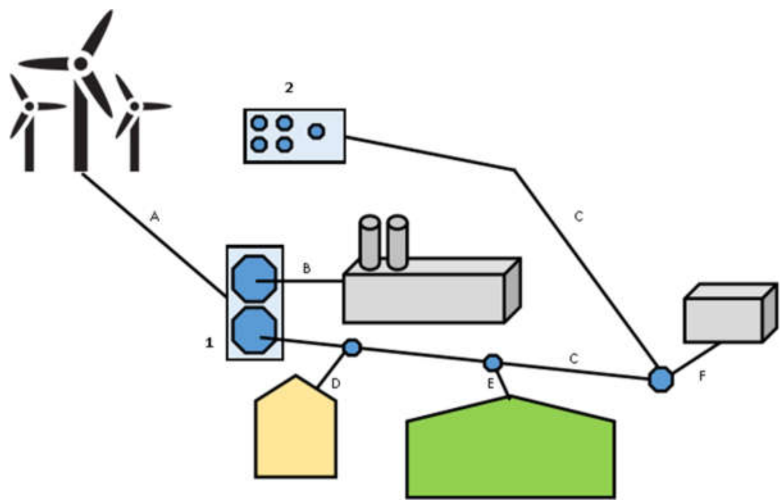
[10] Ameren Missouri's transmission assets are under the functional control of MISO. Since the mid 2000s most or all projects built in or around Ameren Missouri's service territory have been built and are owned and operated by ATXI, an Ameren Missouri affiliate.

[11] The level of assets within each distribution account that falls into each classification vary greatly. If the classification process relies on data that is not applicable to the updated plant value than the resulting allocation may be unreasonable. To assist in the classification process in light of the significant distribution account balance increases associated with the SEP, Staff attempted to negotiate data retention improvements in the last Ameren Missouri rate case, File No. ER-2019-0335. As discussed more fully within this Report, those retention improvements were not implemented, and this CCoS Study is complicated by a large influx of assets to the distribution accounts without guidance from Ameren Missouri as to the proper classification of those assets, nor of the assets already within the distribution accounts.

[12] Some assets in this range may be functionally considered transmission. Staff relies on Ameren Missouri's classification of these assets as reflected in the accounts to which they have been recorded.

[13] The distinction between "Customer-specific" assets and the "Customer-based" classification is that Customer-specific assets are those assets which each serve only one customer, and exist as constituted. The "Customer-based" classification is typically a hypothetical quantification of the portion of an account balance that exists because customers exist to be served, regardless of the size of the customer served, which is included in some class cost of service studies.

A very simple example transmission and distribution system is illustrated below:



Line A represents a transmission line. Line A ties a generator to Substation 1.

Substation 1 interfaces the transmission system to the primary distribution system.

Line B is a primary distribution line operating at 12.4 kV, and has an endpoint at the facility of a customer served on the Large Primary Service rate schedule, and an endpoint at a transformer dedicated to the customer, and would be known as a radial line because it does not tie back in with other lines or substations.

Line C is a primary distribution line operating at 12.4 kV and has an endpoint at Substation 1 and another endpoint at Substation 2. In addition to supplying Substation 2, it serves three customers.

Line D is a service line for a customer served on the Residential service rate schedule. It operates at 120 Volts, and has an endpoint at a transformer that interfaces Line C's 12,400 Volt operation with the customer's 120 Volt meter.

Line E is a service line for a customer served on the Large General Service rate schedule. It operates at 600 Volts, and has an endpoint at a transformer that interfaces Line C's 12,400 Volt operation with the customer's 600 Volt meter.

Line F is a primary distribution line operating at 4.1 kV, and has an endpoint at the facility of a customer served on the Large Primary Service rate schedule, and an endpoint at a transformer dedicated to the customer, and would be known as a radial line because it does not tie back in with other lines or substations.

Ameren Missouri would record the assets associated with each line as follows:

Line A	Transmission accounts
Line B	364 Poles, Towers, & Fixtures and 365 Overhead Conductors & Devices – OR – 366 Underground Conduit and 367, Underground Conductors & Devices
Line C	364 Poles, Towers, & Fixtures and 365 Overhead Conductors & Devices – OR – 366 Underground Conduit and 367, Underground Conductors & Devices
Line D	369.1 Overhead Services or 369.2 Underground Services
Line E	369.1 Overhead Services or 369.2 Underground Services
Line F	364 Poles, Towers, & Fixtures and 365 Overhead Conductors & Devices – OR – 366 Underground Conduit and 367, Underground Conductors & Devices

Ameren Missouri would record the assets associated with each transformer as follows:

Transformer to Line B	362 Station Equipment
Transformer to Line C	362 Station Equipment
Transformer to Line D	368 Line Transformers
Transformer to Line E	368 Line Transformers
Transformer to Line F	370 Meters

In some instances, the customer served by Line B may own the transformer used in its power supply, rather than Ameren Missouri. In that case, the customer would receive a Rider B credit to reduce a customer's bill when that customer does not rely on utility-owned customer-specific substation equipment.[14]

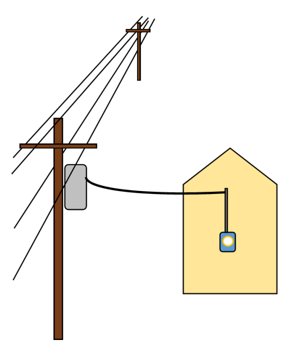
A series of examples are provided below to illustrate how assets providing similar uses are recorded differently depending on whether the ultimate customer takes service at a primary voltage

[14] The remaining assets associated with both substations would be primarily recorded to Account 362, Station Equipment, with underlying real estate and structures recorded to Account 360, Land Rights, and Account 361, Structures & Improvements.

or at a secondary voltage. With certain exceptions described below, Staff is not alleging that Ameren Missouri's accounting of recording the assets dedicated to the service of primary customers to Accounts 360, 361, 362, 364, 365, 366, and 367 is improper. However, it is important to be aware of the placement of these assets in these accounts in determining the appropriate allocation of these accounts within a CCoS study.

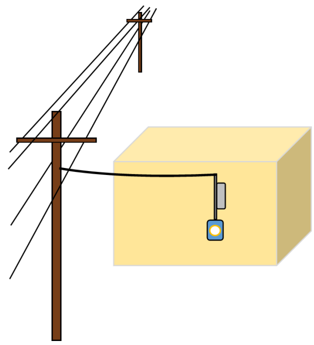
Specifically, these examples will illustrate instances when the line dedicated to a customer would be recorded to a service line account (369.1 for Overhead, 369.2 for Underground) and when the line dedicated to a customer would be recorded to Account 365, Overhead Conductors & Devices and Account 364, Poles, Towers, & Fixtures (For underground facilities, the analogous accounts are Account 367, Underground Conductors & Devices, and Account 366, Underground Conduit). Similarly, if a customer does not take service at the same voltage as the immediately adjacent power grid, the transformer equipment is recorded to Account 368, Line Transformers, for the customers served at secondary voltages while the transformer equipment is recorded to Account 362, Station Equipment, for customers served at primary voltages. The underlying real estate and structures are recorded to Account 360, Land and Land Rights, and Account 361, Structures & Improvements. An additional distinction is whether metering the customer requires only the meter itself, or if additional transformers are needed to facilitate operation of the meter for that customer.[15] Examples are demonstrated below:

Example A: The drawing below represents a 12.47kV primary overhead line, a line transformer, a service drop, and a meter installation, all associated with a Single Family home.

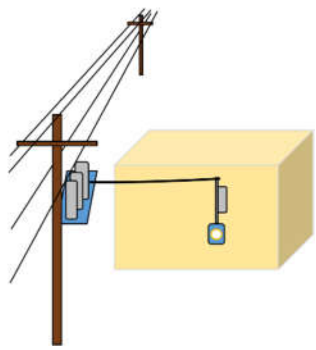


[15] Additional transformer equipment is also required for some LGS customers.

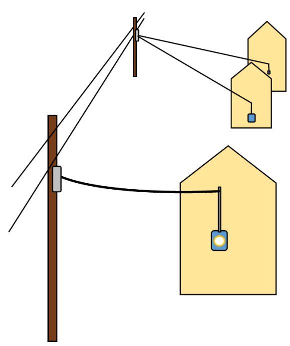
Example B: The drawing below represents a 12.47kV primary overhead line, a 12.47kV overhead cable providing service to a customer, and a meter installation including a potential transformer, all associated with a Small Primary Service customer.



Example C: The drawing below represents a 69kV primary overhead line, a small substation, a 34kV overhead cable providing service to a customer, and a meter installation including a potential transformer, all associated with a Large Primary Service customer.



Example D: The drawing below represents a 12.47kV primary overhead line, two line transformers, three service drops, and three meter installations, all associated with Three Single Family homes.



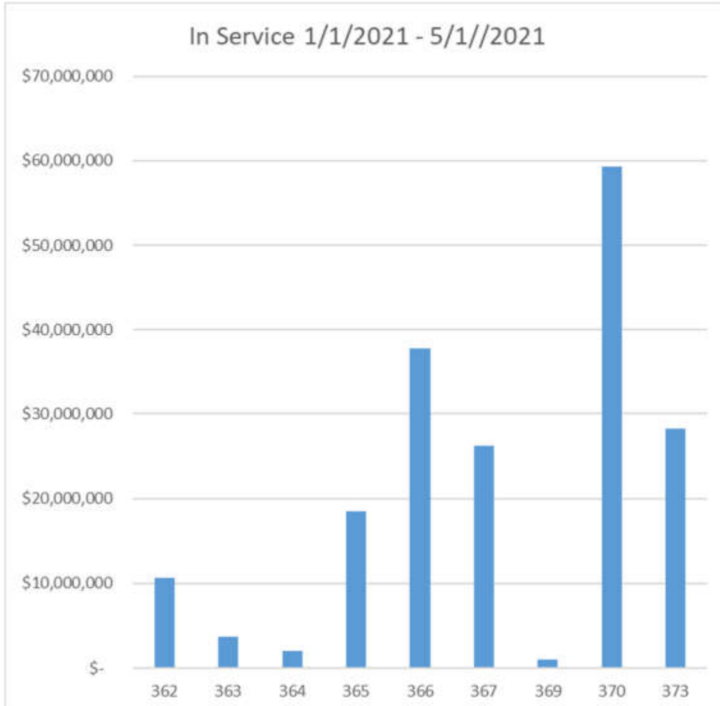
The poles and conductors associated with the primary overhead lines would be recorded in FERC Account 364, Poles, Towers & Fixtures and FERC Account 362, Station Equipment, respectively.[16] In addition, the plant required to serve the customers in each example would be recorded to the accounts indicated below:

Account Number	Account Description	Example A - Single Family home	Example B - Small Primary Service customer	Example C - Large Primary Service customer	Example D - Three Single Family homes
360	Land/Land Rights			Small substation	
361	Structures & Improvements			Small substation	
362	Station Equipment			Small substation	
364	Poles, Towers, & Fixtures				
365	Overhead Conductors & Devices		Cable providing service	Cable providing service	
368	Line Transformers	Line Transformer			Two line transformers
369.1	Services - Overhead	Service Cable			Three service cables
370	Meters	Meter	Metering Transformer and Meter	Metering Transformer and Meter	Three meters

Complications of Smart Energy Plan Capital Projects

Generally, a class cost of service study is conducted at the outset of the case by the utility, relying on CPR data that is more or less current as of the conclusion of the test year. Generally, Staff conducts its class cost of service study using the accounting schedules produced by Staff auditors for the non-utility direct filing, which is based on account information as of the end of the update period. To develop its allocators, Staff typically relies on the same CPR data that was used for the utility's direct case, which is from an earlier point in time than the Staff's updated case. However, the level of retirement activity and new construction which typically occur in the intervening months generally do not rise to a level that would be expected to materially impact the allocators developed. However, in this case, between January 1, 2021 (the date of the data that is the basis of the utility's direct-filed allocator calculation) and May 1, 2021 (the date of the data provided to Staff in response to DR 242), Ameren Missouri represents that it placed an additional $190 million of distribution assets into service. This causes a complication for developing an accurate class cost of service study.

[16] An overhead system is depicted here, but the recording of assets associated with the underground system is similar, with entries made to comparable underground accounts.



Further complicating matters, in the CPR Ameren Missouri provided with its direct filing, which is typically relied upon by Staff for allocator development, approximately $210 million of account balances for FERC Accounts 364 – 373.2 are described as "non-unitized," meaning that the dollars have been added to the account, but that the assets associated with those dollars have not been described within Ameren Missouri's property accounting systems. Note that the data reviewed does not include FERC Accounts 360 – 362. As discussed below, significant SEP investment is being recorded to FERC Account 362, Station Equipment, in particular.

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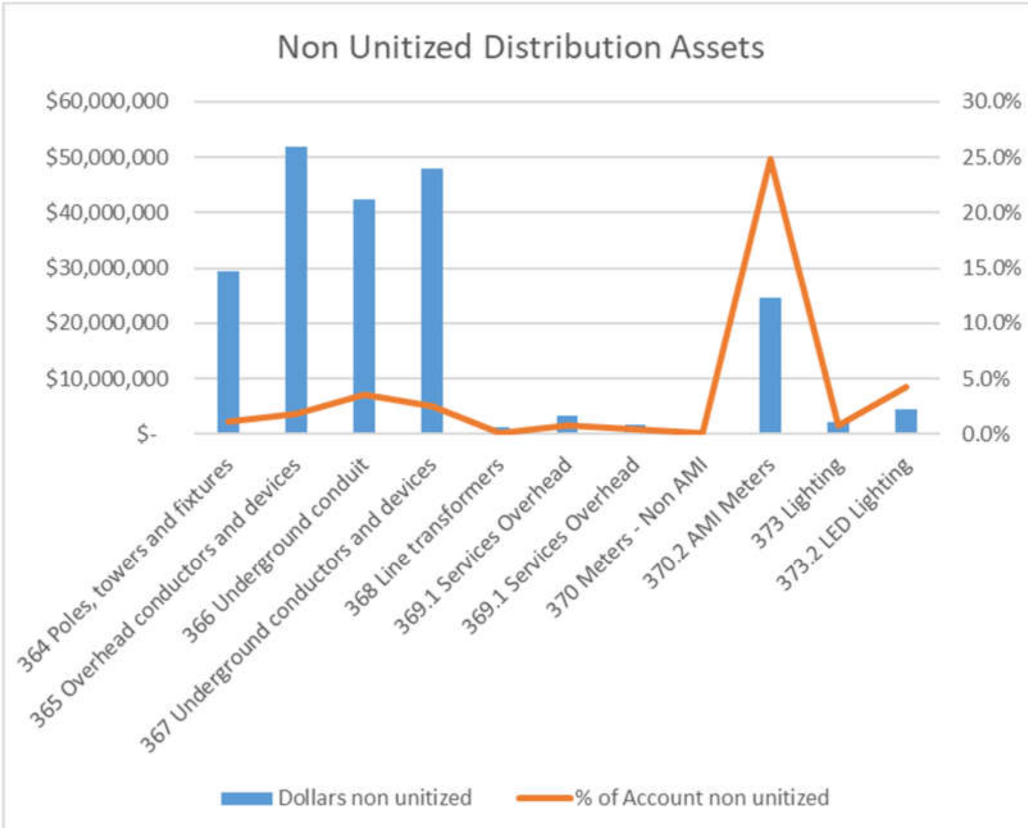
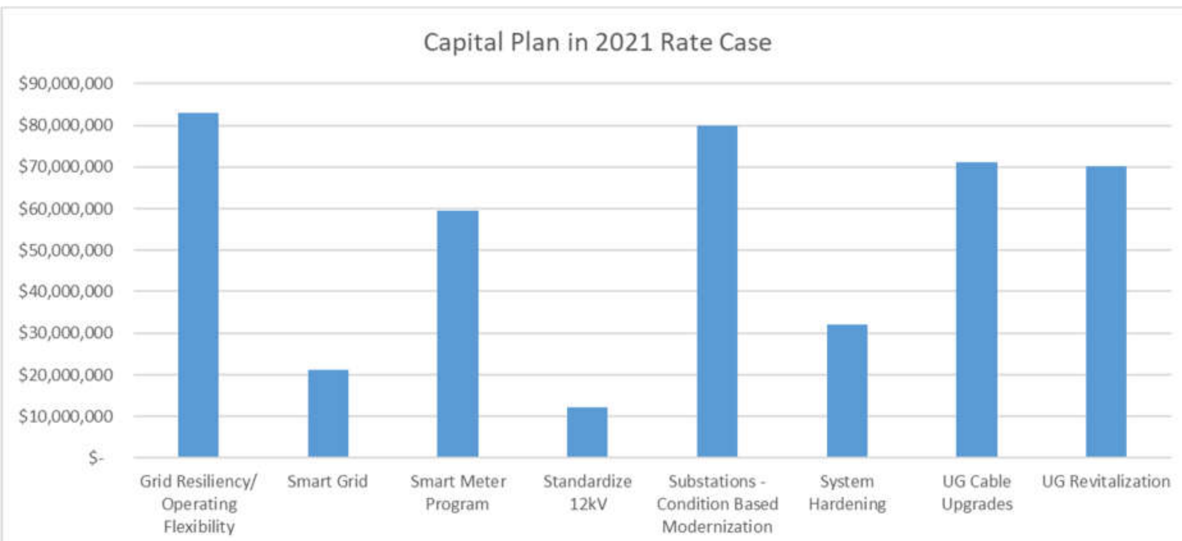


Generally in a class cost of service study, assets – especially distribution assets – are assumed to have been driven by one of the following:

a. Customer counts, which influence the number of system endpoints and the level of investment in customer-specific infrastructure, such as meters;
b. Customer geographic dispersal, which influences the overall size of the system in terms of line miles;
c. Annual demands, which influence the size of individual system components necessary to safely meet or carry the maximum required load, and;
d. Some measure of multiple demands (such as 12 coincident peaks), which influence the optimization for efficiency of components to serve the maximum aggregate loads that occur throughout the year.

If additional customers request to connect to Ameren Missouri's distribution system, the investments Ameren Missouri will make to connect a new customer with the existing electric grid and the investments Ameren Missouri will make to install adequate transformers, service drops, and meters will be caused by those customers. If customers use more energy at a given time (or as additional customers connect), whether that energy is cooling larger homes, reopening shuttered businesses, or charging electric vehicles, from time to time that increased demand will cause Ameren Missouri to replace system components with larger components, or to add redundant components to relieve the strain on existing components, the investments Ameren Missouri will make will be driven by those demands.

However, this rate case reflects the addition of approximately $429 million to Ameren Missouri's distribution plant accounts associated with its SEP projects, with Ameren Missouri representing multiple causations for projects comprising that regulated rate base, summarized below:



These investments in the distribution system were apparently not driven by customer counts, customer geography, or various measures of demands. Rather, these investments were made for "grid resiliency,"[17] or other purposes such as the implementation of AMI metering. For some investments, such as the automation of meter reading, or the installation of remotely controllable or self-activating devices, eventual reductions to expense should offset some portion

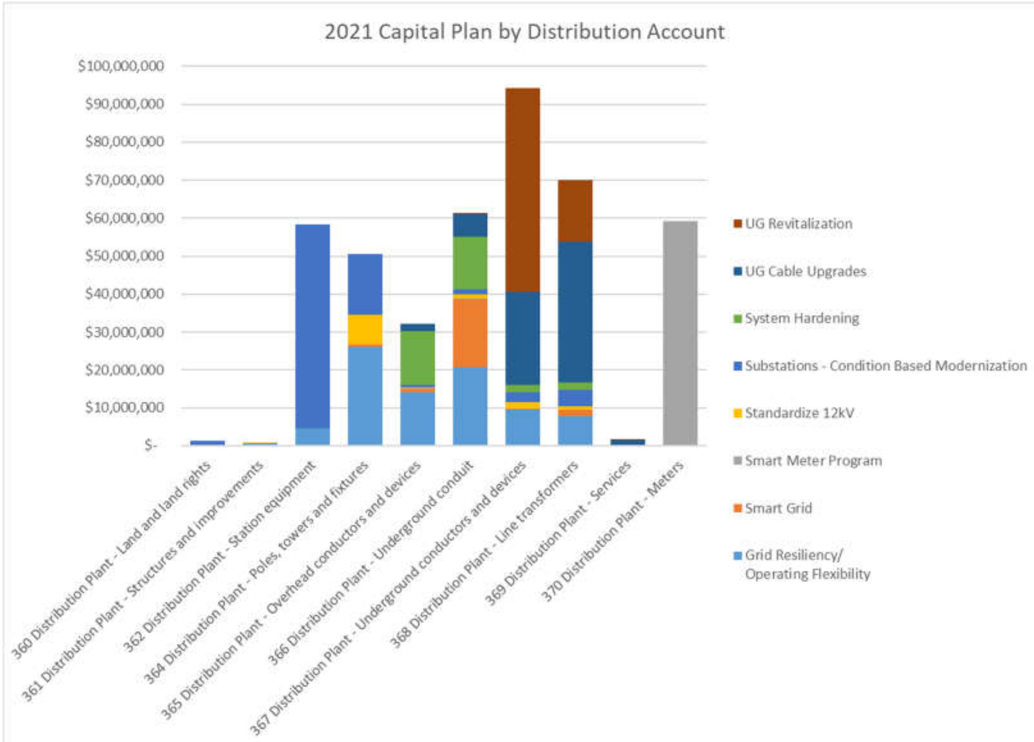
[17] Ameren Missouri's response to DR 665 states that "Subject to the Company's objection, grid resiliency relates to increasing system capacity, whether it is an individual line capacity or overall substation capacity. System hardening can also relate to grid resiliency. As such, almost any asset within the distribution and transmission systems has an impact on grid resiliency. For example, a transformer and cable may be replaced in a specific area to add system capacity. That transformer and cable could be viewed as adding to grid resiliency. However, if a new area of the system is being built, a transformer and cable will be installed contemplating, among other things, grid resiliency. As such, we are unable to identify distribution and transmission assets that are ""used for grid resiliency"" as almost any asset on those systems could be identified as being used for grid resiliency."

of the increased revenue requirement.[18] However, at this time, the clearest causation of the investment is none of the above listed items but rather is the provision of Section 393.1400 RSMo, which requires electric utilities seeking to obtain favorable accounting treatment to develop a capital plan under which:

> [a]t least twenty-five percent of the cost of each year's capital investment plan shall be comprised of grid modernization projects, including but not limited to: (1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid; (2) Dynamic optimization of grid operations and resources, with full cybersecurity; (3) Deployment and integration of distributed resources and generation, including renewable resources; (4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources; (5) Deployment of smart technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications, concerning grid operations and status, and distribution automation; (6) Integration of smart appliances and devices; (7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal storage air conditioning; (8) Provision of timely information and control options to consumer; (9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and (10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

The impact of these projects, by type, on each distribution plant account is illustrated in the graph below:

[18] Ameren Missouri's response to DR 631 states that "Substantially all of the expense in FERC Major 902 – Meter Reading relates to meter reading services provided through contract with Landis and Gyr. These values are driven by the number of AMR readings performed every month and the expense as a whole is expected to decrease over time in line with the conversion of AMR meters to AMI meters. The AF 7A allocator is based off the count of AMR meters. To the extent we have customers already taking service through AMI, those customers are excluded from the allocation of these expenses through this allocator. A specific analysis relating to FERC Major 905 - Miscellaneous was not performed in this case, due to the relatively small amount of dollars included in the account coupled with the fact that the majority of customers are still being served by AMR meters. Please see attached excel file (MPSC 0631.xlsx) for the requested AMI Deployment figures. Please note, total meters is as of a date in time (7/12/2021) as the number of meters is changing constantly. The percentage per month should be seen as an approximation for this reason. Please also note, that the monthly numbers are monthly conversions and are not cumulative. A cumulative value could be found by adding them together."



Distribution Revenue Requirement

Classification and minimum system

The net plant (gross plant in service minus accumulated depreciation reserve) and depreciation expense associated with each of the distribution plant accounts is provided below. Note, the amounts provided below do not include the reallocated general plant associated with distribution facilities, which constitutes an additional approximate $30.6 million in revenue requirement, nor the reallocation of plant-related costs, which constitutes an additional approximate $1.5 million in revenue requirement.

continued on next page

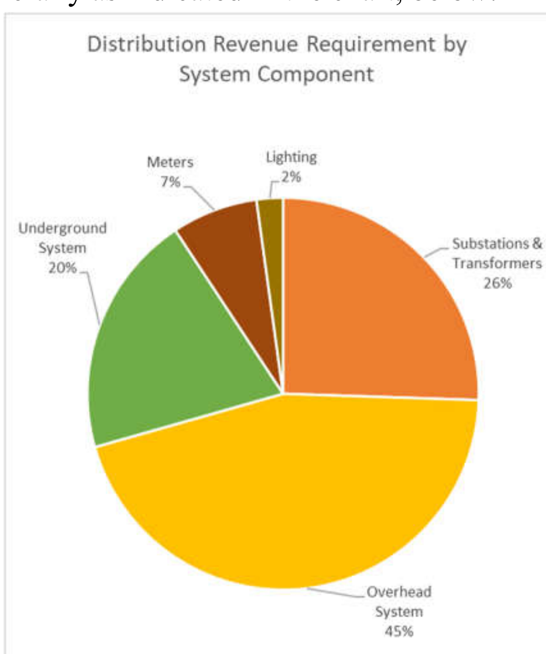
Account	Description	Net Rate Base	Depreciation Expense
360	Land/Land Rights - DP	$ 36,025,911	$ -
361	Structures & Improvements - DP	$ 10,916,151	$ 333,498
362	Station Equipment - DP	$ 930,826,204	$ 23,565,741
364	Poles, Towers, & Fixtures - DP	$ 151,910,646	$ 79,253,093
365	Overhead Conductors & Devices - DP	$ 1,193,332,398	$ 34,855,201
366	Underground Conduit - DP	$ 459,220,581	$ 13,924,779
367	Underground Conductors & Devices - DP	$ 662,713,833	$ 24,793,641
368	Line Transformers - DP	$ 316,482,213	$ 12,789,201
369.1	Services - Overhead - DP	$ (75,975,622)	$ 8,658,454
369.2	Services - Underground - DP	$ 36,760,092	$ 5,076,055
370	Meters - DP	$ 51,163,749	$ 16,304,967
370.1	AMI Meters	$ 91,978,352	$ 5,095,929
371	Meter Installations - DP	$ (4,795)	$ 1,961
373	Street Lighting and Signal Systems - DP	$ 98,698,978	$ 4,625,864

The labor and non-labor expenses associated with the distribution system are reflected below. Note, the amounts provided below do not include the reallocated pension, benefit, and other labor costs associated with distribution labor expenses, which constitutes an additional approximate $34 million in revenue requirement.

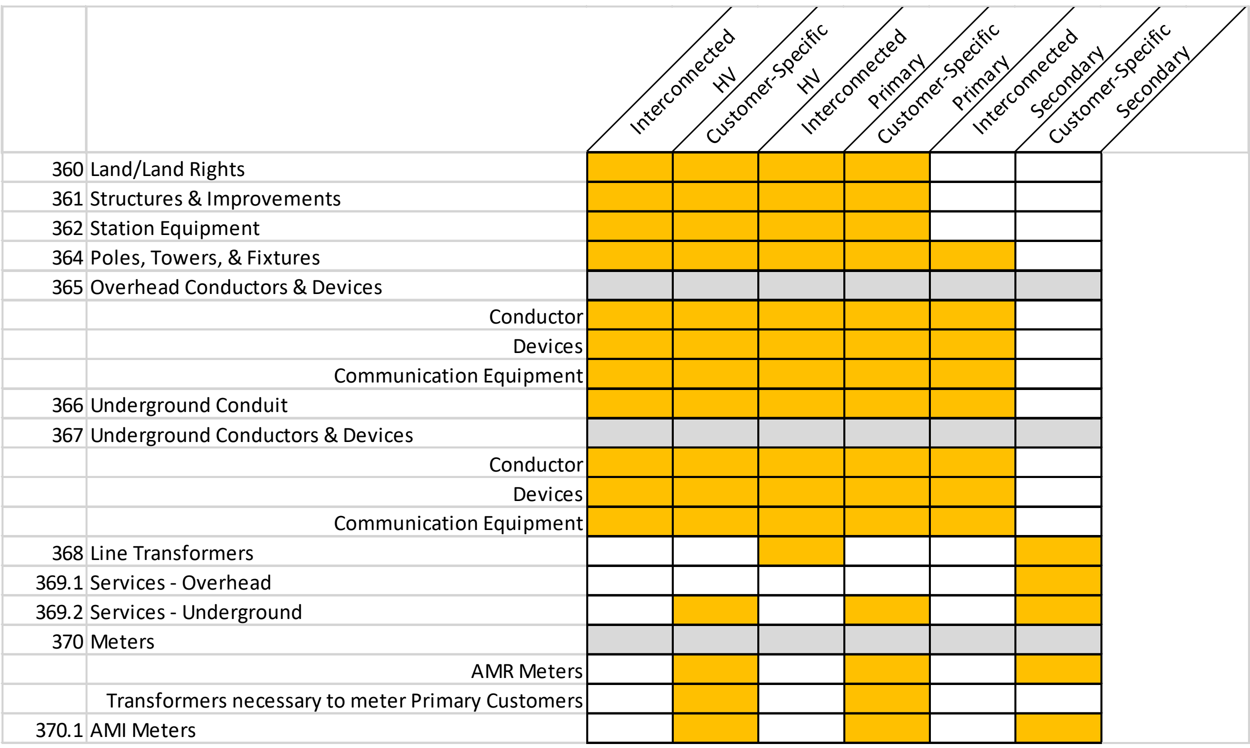
continued on next page

Account	Description	Labor Expense	Non Labor Expense
580	Operation Supervision & Engineering - DE	$ 6,269,490	$ 739,370
581	Load Dispatching - DE	$ 1,689,560	$ 115,373
582	Station Expenses - DE	$ 2,501,990	$ 1,292,701
583.1	Overhead Line Expenses - DE	$ 3,568,536	$ 885,523
583.2	Line Transformer Expenses	$ 2,355,956	$ 3,317,076
584.1	Underground Line Expenses - DE	$ 1,175,890	$ 1,442,423
584.2	Underground Transformer Expenses	$ 1,367,264	$ 940,327
585	Street Lighting & Signal System Expenses - DE	$ 770,627	$ 549,177
586	Meters - DE	$ 5,584,113	$ 515,402
587	Customer Install - DE	$ 1,251,722	$ (19,670)
588	Miscellaneous - DE	$ 7,063,799	$ 16,242,339
589	Rents - DE	$ -	$ 377,930
590	Supervision & Engineering - DE	$ 906,474	$ 238,204
591	Structures Maintenance - DE	$ 1,326,682	$ 582,442
592	Station Equipment Maintenance - DE	$ 10,764,776	$ 4,459,209
593	Overhead Lines Maintenance - DE	$ 10,991,169	$ 38,299,757
594	Underground Lines Maintenance - DE	$ 2,814,199	$ 1,909,194
595	Line Transformers Maintenance - DE	$ 329,090	$ 208,205
596	Street Light & Signals Maintenance - DE	$ 409,820	$ 125,889
597	Meters Maintenance - DE	$ 760,882	$ 111,847
598	Miscellaneous Plant Maintenance - DE	$ 759,374	$ 429,569

Combining these two sets of accounts, incorporating the indicated amounts to be reallocated, and calculating the revenue requirement derived from the rate base values produces a revenue requirement of approximately $591 million or around 22% of Ameren Missouri's revenue requirement, comprised generally as indicated in the chart, below:



The Distribution plant accounts are used for recording the assets operating at voltages as low as 120 Volts and up to 69kV, and contains some assets that are used to provide service to thousands of customers as well as assets that are used to provide service to only one customer. A graphic depiction of what voltages and usages of assets are included in each Ameren Missouri distribution account is provided below, with gold fill indicating the account in which a given voltage or usage of asset may be recorded:[19]



As this graphic illustrates, the assets contained within each account are more varied than the USOA name of the account may imply.[20] Staff intended to rely on the disaggregation of information Ameren Missouri agreed to create and provide pursuant to the February 28, 2020, File No. ER-2019-0335 "Corrected Non-Unanimous Stipulation and Agreement," however, as discussed

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[19] For accounts for which Staff was able to subdivide assets by type, the account row is filled in gray, with the relevant blocks shaded in gold for each asset type contained in that account.

[20] On the afternoon of September 14, 2021, Ameren Missouri provided its response to Staff DR 747.1 indicating that the distribution accounts also include infrastructure to support the interconnection of at least some of Ameren Missouri's utility scale solar generation. Given the timing of this response Staff was unable to further reflect this information in its CCoS Study or this Report.

later in this Report, Ameren Missouri did not create and provide that disaggregation. Had Ameren Missouri provided the information described within the Stipulation, Staff would have followed the steps identified below to identify the costs associated with each category (the diagonal words at the top of the graphic) with each account, by contents (the rows within the graphic) for more direct allocation and assignment in this case:

> Step 1 is to identify assets that serve (A) more or less all customers in a geographic area ("interconnected assets"), and (B) one customer or a very small group of customers ("customer-specific assets"). It is most reasonable to assign the costs of assets that serve specific customers to those customers, and to develop allocators for those assets that serve multiple customers.
>
> Step 2 is to divide the network assets within each account into groups of like assets based on the retirement unit information provided. For example, FERC account 365 contains both conductors and various devices. Not all accounts will require this step.
>
> Step 3 is to group together the network assets within each account by the voltage at which the asset operates or facilitates operation of other assets. Ideally, this step would be applied to each specific voltage at which the system operates or at which customers are served; in the absence of adequate information, more general voltages like "secondary," "primary," "HV," may be used in lieu of service voltages like 120 Volt, 240 Volt, 600 Volt, 12 kV, 34 kV, etc.

Given data unavailability, Staff was unable to conduct this process, except as specifically noted below.[21] This information would have allowed the CCoS Study to more closely align cost causation for the distribution system infrastructure with the class revenue responsibilities that are determined through the CCoS Study process.

[21] Because this data was not provided(or (as discussed later in this Report), not timely provided, Staff was unable to directly assign the costs for assets associated with service to Primary and HVDC customers to the revenue requirement of those customers, and had limited information to develop allocators to account for those costs. Similarly, Ameren Missouri failed to provide a description or reasonable estimate of the voltages at which plant within each account operate, and Staff had no option but to rely on the "Vandas study" as presented in Mr. Hickman's workpapers. Staff looks forward to Ameren Missouri's cooperation to identify the plant that operates at each voltage by retirement unit and asset value prior to the next rate case. Staff will address this further in its rebuttal testimony.

Accounts 362 - Distribution Plant Station Equipment, 361 - Distribution Plant Structures and Improvements, and 360 - Distribution Plant Land

Staff generally relied on Ameren Missouri's classification and allocators for FERC Accounts 360 through 362, however, Ameren Missouri's allocators failed to account for substations that serve individual primary customers.

Based on Ameren Missouri's responses to Staff DRs 591.2 and 678, approximately $42 million of the total approximate $1.24 billion in FERC Account 362 is related to substations that serve individual primary customers. This results in an initial allocation of approximately 3.73% of the Account 362 balance to primary customers. This amount does not appear to include facilities located within a larger substation that are dedicated to an individual primary customer.

Rider B is a credit received by customers who are billed at primary but who own their own substation equipment.[22] It is sized to compensate those customers for the revenue requirement associated with customer-specific substations that did not have to be built.[23] This is reasonable under the assumption that the bills these customers would be charged otherwise reflects the cost of customer-specific substations that the company built and maintains for other primary customers.[24] In its direct tariffs in this case, Ameren Missouri proposes setting the Rider B credits at $1.51 per kW for customers at 115 kV, and at $1.28 per kW for customers at 69 kV. This would result in Rider B credits of approximately $4.3 million of revenue requirement, compensating customers for the utility rate base avoided in that the Rider B customers have constructed their own substations. This implies that if Ameren Missouri had constructed substations for all of its primary customers, then the revenue requirement associated with distribution substations to serve primary customers would be approximately $20 million.[25] Since 22% of those substations did not have to be built by Ameren Missouri, the $4.3 million of Rider B credit received by those

[22] Sheet 75: 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 $1.14/kW of billing demand for customers taking service at 34.5 or 69kV. 2. A monthly credit of $1.35/kW of billing demand for customers taking service at 115kV or higher.

[23] It may also be sized to adjust the billed amount for the transformer losses if the customer's meter is located after the transformer, instead of before. Rider B is discussed in greater detail in the section Rider B & Rider C.

[24] This treatment assumes that the class revenue requirement has been grossed up to not only reflect the cost of customer-specific substations that has been built, but also customer-specific substations that have not been built.

[25] The billing demand of Rider B customers is approximately 3.2 million kW per year, which is about 22% of the total class billed kW of approximately 14.5 million kW.

customers who built their own substations should be removed from this total. This leaves approximately $14.8 million in revenue requirement that is associated with distribution substations that Ameren Missouri has built to serve primary customers.

In order to determine an approximate value of the plant in service in FERC Account 362 that would produce a revenue requirement of approximately $14.8 million, Staff reviewed the costs and expenses assignable and allocable to the ownership and operation of distribution substations within its functionalized revenue requirement. This exercise resulted in finding an approximate revenue requirement for Distribution Substations of approximately $139.5 million in net plant in service. Net plant in service is only a portion of a utility's overall rate base. In the cost of service calculation, rate base dollars are not included in revenue requirement on a dollar for dollar basis. The revenue requirement associated with rate base is a percentage of total rate base dollars. Because $14.8 million in revenue requirement dollars translates to approximately 11% of $139.5 million in net plant in service dollars, Staff was able to determine from that sample that the plant in service associated with distribution substations built to serve primary customers constitute approximately $134.7 million of Ameren Missouri's net plant in service.

Accounts 364 – Poles, Towers, and Fixtures and 365 – Overhead Conductors and Devices

Staff generally relied on Ameren Missouri's classification and allocators for FERC Accounts 364 and 365. However, Ameren Missouri's classification and allocators (1) failed to account for circuits that serve individual primary and HV customers, (2) failed to retain the calculated minimum when applied to the account balance, (3) double-allocated system costs associated with lower voltages and the minimum system.[26]

(1) Staff did not have adequate information to develop an assignment of plant in order to account for circuits that serve individual primary and HV customers. Staff looks forward to Ameren Missouri's cooperation to identify the plant by retirement unit and asset value prior to the next rate case.

(2) For development of its allocators, Staff relied on the total minimum cost valuation Mr. Hickman calculated, as opposed to a percentage of plant account as recorded in the CPR at the time of Direct. For example, if the calculated minimum cost is $50, the direct CPR contains $500 of plant, and Staff's updated Revenue

[26] Ameren Missouri's distribution account allocators relied on a minimum system approach. Under this approach, a portion of each account is allocated to the classes on the basis of the number of customers in the class based on the cost of building a hypothetical minimum-sized distribution system, or, in other words, the minimum amount needed to serve the class.

Requirement is based on a plant balance of $1,000, Staff's method retains the minimum valuation of $50.[27]

(3) In response to Staff Data Request 474, Ameren Missouri indicated that the 40' pole and two-wire "WIRE,1/0,ALUMINUM" circuit that is the basis of its minimum distribution system calculation is designed to operate at primary voltage. Because the "minimum" system as determined by Mr. Hickman is actually a primary system, it is appropriate to remove that portion of the system valuation from Mr. Hickman's estimated secondary system valuation and Mr. Hickman's estimated primary system valuation. This step is needed to avoid double allocation of the minimum-allocated system.

Staff generally relied on Ameren Missouri's classification and allocators for FERC Account 365 – Overhead Conductors & Devices. However, Ameren Missouri's classification and allocators (1) failed to account for conductors that serve individual primary and HV customers, (2) failed to reasonably recognize the various voltages at which devices operate, (3) failed to retain the calculated minimum when applied to the account balance, (4) double-allocated system costs associated with lower voltages and the minimum system, and (5) over-allocated customer-based costs for customer classes taking service at secondary voltage.

(1) Ameren Missouri was unable to identify the conductor and devices associated with interconnecting primary customers to the distribution system. However, in response to DR 104.2, Ameren provided a list of the current circuits that included information on the number of miles each non-secondary circuit spanned overhead and underground, as well as the number of customers served on each circuit, and the line transformers on each circuit.[28] Staff reviewed this information and submitted follow-up DRs to identify the miles of circuit that are currently used to provide distribution access to a single customer. Ameren Missouri's response to DR 104.3 refined this list to exclude circuits that could be switched for operational purposes, such as to provide redundancy. Ameren Missouri identified 1.76 miles of overhead circuits that are currently used to provide service to single customers, which constitutes 0.712% of all non-secondary overhead miles. Staff relied on the DR 104.3 data to find the conductor cost (based on Ameren Missouri's identified minimum conductor) for a two-wire circuit for each identified single primary customer circuit. Staff then estimated the number of primary customers served overhead based on the Ameren Missouri partial response to DR 639. Staff found the average cost per overhead secondary customer of Account 369.1, Overhead services, and calculated the difference in the cost of the most common Account 369.1 conductor and the most common Account 364 conductor. Staff applied this

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[27] In contrast, under this example the Ameren Missouri allocator would convert that $50 minimum valuation to 10%, which it would factor up to $100 when applied to the update plant balance of $1,000.

[28] See also responses to DRs 104.10 and 104.11, attached.

average cost per service, grossed up for the higher cost of the conductor, to the estimated number of overhead primary and HV customers net of the number of customers with an identified overhead circuit to approximate the value of conductors in Account 364 that are used to connect individual primary and HV customers to the distribution system. This calculation is conservative in that it assumes that the facilities to serve the individual primary and HV customers do not exceed the size of a 4.7 kV -12.47 kV system, and does not include switches or other devices.

(2) Staff categorized the retirement units in FERC Account 365 to identify similar devices and, where applicable, the minimum size of a category of devices. Staff then found what the cost would be for that type of property if all of the units of that type of property were the price of the minimum-cost unit, as identified below:

	Account Dollars	Number of Units	Dollars if each unit were the price of the minimum unit of that type
Wire	$ 713,959,033	577,010,577	$ 21,345,293
Switch	$ 360,265,992	416,699	$ 63,381,531
Recloser	$ 116,303,008	8,928	$ 20,417,384
Arrester	$ 84,493,962	283,928	$ 25,904,614
Unitization	$ 51,816,146	1,239	$ -
Capacitor	$ 32,703,845	8,276	$ 4,016,075
Regulator	$ 16,989,006	1,119	$ 1,069,683
Control	$ 16,977,214	1,640	$ 16,977,214
Cable	$ 11,287,199	1,953,186	$ 1,132,795
Indicator	$ 7,614,623	8,009	$ 7,614,623
Capacitor Control	$ 4,157,900	3,463	$ 1,680,482
Fuse	$ 1,584,052	575	$ 1,584,052
Operator	$ 697,904	29	$ 697,904
Breaker	$ 444,923	142	$ 341,306
Crossarm	$ 323,370	234	$ 27,659
Communication	$ 190,481	21,690	$ 12,580
Bus	$ 131,807	14,410	$ 67,727
Receiver	$ 128,022	50	$ 128,022
Monitor	$ 58,090	6	$ 58,090
Land	$ 51,663	-	$ -
Transfer Equipment	$ 45,893	3	$ 45,893
Miscellaneous	$ 18,320	2,381	$ -
Transformer	$ 6,654	14	$ 6,654
Retirement	$ -	4,996	$ -

The CPR for FERC Account 365 – Overhead Conductors & Devices includes “Land-Easements”, which is typically not recordable in Account 365 as it is not a depreciable asset. It is also unclear why transformers are recorded in the account, and also whether some retirement unit names may be associated with dissimilar plant. For example, the response to Staff DR 555 identified that a particular retirement unit was used for communications, but Ameren Missouri's response to Staff DR 624 indicated that unit is used for conductors, and the response to Staff DR 555.2 indicated it is used for both.[29] Given the level of non-unitized plant in the account and the lack of timely responsive information from Ameren Missouri, Staff abandoned efforts to perform a more robust study.

(3) For development of its allocators, Staff relied on the total minimum cost valuation Mr. Hickman calculated, as opposed to utilizing a percentage of the plant account as recorded in the CPR at the time of Direct.

(4) In response to Staff Data Request 474, Ameren Missouri indicated that the 40' pole and two-wire "WIRE,1/0,ALUMINUM" circuit that is the basis of its minimum distribution system calculation is designed to operate at primary voltage. Because the "minimum" system as determined by Mr. Hickman is actually a primary system, it is appropriate to remove that portion of the system valuation from Mr. Hickman's estimated secondary system valuation and Mr. Hickman's estimated primary system valuation. This step is needed to avoid double allocation of the minimum-allocated system.

(5) Because the minimum system that is the basis of the Ameren Missouri classification and allocators would operate at primary voltage, allocation of the "customer" portion of the system to the classes on the literal number of customers per class would result in an over-allocation of costs to classes of

[29] In response to Staff's question "By account, and by retirement unit, please identify the assets used for communication and/or operation of remote equipment on the distribution system, including intangible assets. By account, please identify the expenses and revenues associated with the operation and maintenance of these assets, including, if known, property taxes associated with these assets.", Ameren Missouri's August 30, 2021 response to DR 664 provided "Subject to the Company's objection, communications equipment is accounted for in FERC Major 397. Please refer to response to DR MPSC 0591 for the specific retirement units included within this account. Associated O&M expenses would be accounted for in 935003 (Admin and Mtce – Communications Equipment) and 930227 (Operations of Communication Equipment) and associated revenues would be accounted for in 454008. A breakdown of property taxes for these specific assets is unavailable,"

In response to Staff's question, "Refer to response to DR 555, indicating that "Cable, fiber optic," and "cable and wire, control" are typically used for communications purposes. Please supplement the Company's response to DR 664 to identify assets such as those identified in DR 555 that are not recorded in account 397, or clarify what was meant by the response to DR 555 and state whether and in what amount assets consistent with this clarification are found outside account 397," Ameren Missouri's September 13, 2021 response to DR 664.1 provided "For transmission lines, fiber optic cable is used as shield wire for transmission lines. Additionally, the cable can be used for communications, but is recorded in transmission accounts because it serves as shield wire, protecting transmission conductor. These dual purpose assets are accounted for as transmission assets. For distribution lines, the OPGW also serves a dual purpose, lightning protection for the distribution lines and high speed fiber communications backhaul from substation sites and private LTE transmitter sites. These dual purpose assets are accounted for as distribution assets." This response was submitted August 3, 2021. Given the date of the receipt of this response, Staff was unable to incorporate the "dual purpose" nature of the indicated asset into its allocation factor development. Further, this response contradicts Ameren Missouri's response on July 14, 2021, to DR 475.1 which stated, in pertinent part, "Subject to the Company's objections**, typically there are not Ameren owned communication cables on 40' wood poles**. A 40' wood pole will typically have three primary voltage conductors, three secondary voltage conductors, **and a neutral conductor**…." [Emphasis added.]

> customers taking service at secondary voltage. To conservatively weight the customer numbers by class for the number of customers that would be served by a primary conductor, Staff applied the diversity factors for each class provided in response to Staff DR 632 to Ameren Missouri's identified non-coincident peaks by class at primary voltage. The results of this process indicates that based on the data made available by Ameren Missouri, about 50 residential customers or about 23 SGS customers, on average, require the same amount of system as one LGS/SPS customer.

Accounts 366 – Underground Conduit and 367 – Underground Conductors and Devices

Staff generally relied on Ameren Missouri's classification and allocators for FERC Account 367 – Underground Conductors & Devices, and Staff relied on Ameren Missouri's use of the Account 367 allocations for FERC Account 366. However, Ameren Missouri's classification and allocators for Account 367 (1) failed to account for conductors that serve individual primary and HV customers, (2) failed to reasonably recognize the various voltages at which devices operate, (3) failed to retain the calculated minimum when applied to the account balance, (4) double-allocated system costs associated with lower voltages and the minimum system, and (5) over-allocated customer-based costs for customer classes taking service at secondary voltage.

(1) Ameren Missouri was unable to identify the conductors and devices associated with interconnecting primary customers to the distribution system. As this data was not available to Staff, Staff utilized another method for allocation with the response to Staff DR 104.2. In that response, Ameren Missouri provided a list of the current circuits that included information on the number of miles each non-secondary circuit spanned overhead and underground, as well as the number of customers served on each circuit, and the line transformers on each circuit. Staff reviewed this information and submitted follow-up DRs to identify the miles of circuit that are currently used to provide distribution access to a single customer. Ameren Missouri's response to DR 104.3 refined this list to exclude circuits that could be switched for operational purposes such as to provide redundancy. Ameren Missouri identified 10.93 miles of underground circuits that are currently used to provide service to single customers, which constitutes 0.712% of all non-secondary overhead miles. Staff relied on the data from Staff DR 104.3 to find the conductor cost (based on Ameren Missouri's identified minimum conductor) for cable for each single primary customer circuit. Staff then estimated the number of primary customers served underground based on the partial response to Staff DR 639. Staff found the average cost per overhead secondary customer in FERC Account 369.2, Underground Services, and calculated the difference in the cost of the most common conductor in FERC Account 369.2 and an appropriate conductor in

FERC Account 367. In order to approximate the value of each conductor in FERC Account 367, Staff applied this average cost per service described above, grossed up for the higher cost of conductor, to the estimated number of underground primary and HV customers net of the number of customers with an identified overhead circuit which are used to connect individual primary and HV customers to the distribution system. This calculation is conservative in that it assumes that the facilities to serve the individual primary and HV customers do not exceed 5 kV, and does not include switches or other devices, or conduit. *Staff looks forward to Ameren Missouri's cooperation to identify the plant by retirement unit and asset value prior to the next rate case.*

(2) Staff categorized the retirement units in FERC Account 367 to identify similar devices and, where applicable, the minimum size of a category of devices. Staff then found what the cost would be for that type of property if all of the units of that type of property were the price of the minimum-cost unit, as identified below:

Voltage	Type	Account Dollars	Number of Units	Dollars if each unit were the price of the minimum unit of that type
High Voltage	Conductor	$ 52,266,820	$ 1,408,428	$ 27,942,866
Low Voltage	Arrester	$ 2,663,613	$ 6,282	$ 2,663,613
Low Voltage	Conductor	$ 266,533,075	$ 26,305,597	$ 40,706,370
Med Voltage	Arrester	$ 2,570,621	$ 5,055	$ 2,143,356
Med Voltage	Conductor	$ 516,943,822	$ 49,430,049	$ 23,551,044
Unspecified	Bus	$ 59,654	$ 1,996	$ 59,654
Unspecified	Conductor	$ 4,193,613	$ 1,414,902	$ 1,691,048
	Capacitor	$ 444,379	$ 13	$ 120,767
	Communication	$ 345,710	$ 35,111	$ 170,854
	Conduit Related	$ 4,774,743	$ 1,875	$ 4,774,743
	Controller	$ 220,016	$ 3	$ 220,016
	Enclosure	$ 609,056	$ 57	$ 609,056
	Fault Indicator	$ 983,577	$ 1,391	$ 983,577
	Miscellaneous	$ 5,483	$ 813	$ 5,483
	Net Salvage	$ 6,597	$ -	$ 6,597
	Non Unitized	$ 47,819,545	$ 1,059	$ 47,819,545
	Switchgear	$ 54,880,512	$ 2,170	$ 10,866,796

(3) For development of its allocators, Staff relied on the total minimum cost valuation Mr. Hickman calculated, as opposed to a percentage of plant account as recorded in the CPR at the time of Direct.

(4) In response to Staff Data Request 533.1, Ameren Missouri indicated that the "CABLE,5KV,1-2,RUBBER,CONC NEU" conductor that is the basis of its minimum distribution system calculation is designed to operate at primary voltage. Because the "minimum" system as determined by Mr. Hickman is actually a primary system, it is appropriate to remove that portion of the system valuation from Mr. Hickman's estimated secondary system valuation and Mr. Hickman's estimated primary system valuation. This step is needed to avoid double allocation of the minimum-allocated system.

(5) Because the minimum system that is the basis of the Ameren Missouri classification and allocators would operate at primary voltage, allocation of the "customer" portion of the system to the classes on the literal number of customers per class would result in an over-allocation of costs to classes of customers taking service at secondary voltage. To conservatively weight the customer numbers by class for the number of customers that would be served by a primary conductor, Staff applied the diversity factors for each class provided in response to Staff DR 632 to Ameren Missouri's identified non-coincident peaks by class at primary voltage. The results of this process indicates that based on the data made available by Ameren Missouri, about 50 residential customers or about 23 SGS customers, on average, require the same amount of system infrastructure as one LGS/SPS customer.

Accounts 368 – Line Transformers, 369.1 – Overhead Services, and 369.2 – Underground Services

Staff relied on Ameren Missouri's classifications and allocators for FERC Accounts 368 – Line Transformers and FERC 369.1 – Overhead Services.

Through its review of the CPR, Staff noticed that Account 369.2 – Underground Services, contained retirement units identified at voltages higher than secondary. In response to Staff DR 666 on several of these assets Ameren Missouri stated, "Subject to the Company's objections, these assets would be used to provide service to Primary customers. Please note, these assets appear to be potentially misclassified as being recorded in Account 369. The original book value of these assets represent approximately $1,570,000 in an account with an original book value of approximately $182,120,000 and the vast majority of the asset value has vintage years prior to the year 2000. Due to the small impact this potential misclassification would have on the total revenue requirement, additional research was not conducted."[30] Staff assigned the plant identified as operating at primary and HV voltages to SPS and LPS customers. Staff identified the minimum conductor in use, and applied its average book value to the total units of *secondary* conductor contained in FERC Account 369.2.

[30] Further research by Staff located additional plant that was labeled above secondary voltage, for a total of $1,681,548 recorded in the direct CPR.

Meter Accounts 370 and 370.2

On August 13, 2021, Ameren Missouri provided a spreadsheet as part of its response to Staff DR 633. Based on the cover sheet also provided in response on that date, this spreadsheet provides the meter models in use by the company, the replacement cost of each of those meters plus some value of potential or current transformers when required for metering, and the number of each model used by customers taking service on each rate schedule.[31]

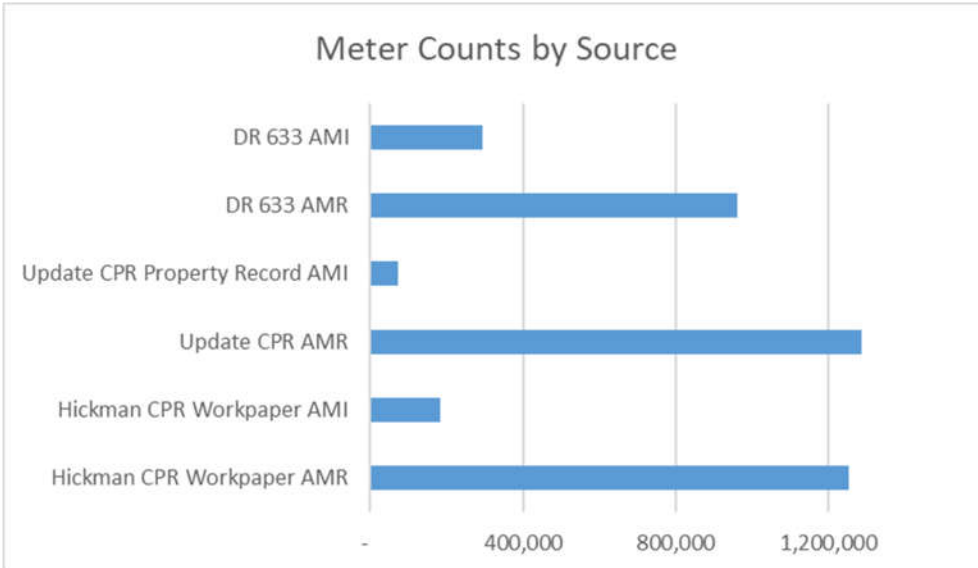
There are a number of complications that arise due to the manner in which Ameren Missouri provided this data, and that become apparent with the company's data.

First, the problem with incorporating the value of the associated potential or current transformer into the meter cost is that all current and potential transformers are recorded in FERC Account 370.

Second, at least some of the data provided by Ameren Missouri is clearly wrong. Given the process described by Ameren Missouri for the development of the response to Staff DR 633, and the continuing process of AMI deployment and AMR retirement, Staff does not expect all numbers to tie out entirely. However, the data provided by the company is conflicting in manners that are not consistent with the expectations of the impact of AMI deployment and AMR retirement. The most blatant example is that the updated CPR indicates *more* AMR meters than the CPR at the time of direct, and *fewer* AMI meters than CPR at the time of direct. The updated CPR and the response to Staff DR 633 are more or less contemporaneous, yet indicate a difference of a net 105,467 meters. The meter count, by source, is provided below in Table 111, and illustrated in the chart below.

	AMR Count	AMI Count	Total
Hickman Direct CPR	1,254,387	183,805	1,438,192
Update CPR	1,287,315	70,618	1,357,933
DR 633	959,732	292,734	1,252,466

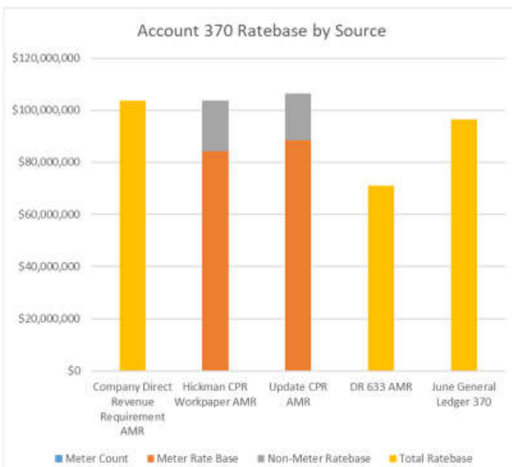
[31] The cover sheet of Ameren Missouri's response to DR 633 is attached, describing Ameren Missouri's development of the material provided in a separate attachment. This was not the information requested by Staff in DRs 633 and 634. DR 634 was substantially identical to DR 633, but regarded AMI meters.

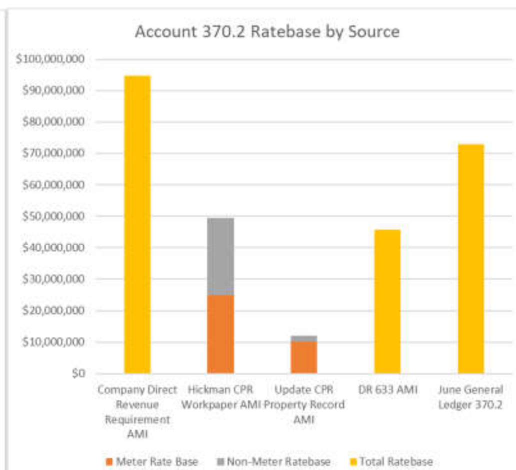


The dollar values associated with the meter accounts across sources are more confounding. As illustrated below, Ameren Missouri's CPR at the time of direct and their Direct Revenue Requirement values were similar for the AMR account, but different for the AMI account. This is not unexpected if one assumes there is some delay in recording investment to the CPR. However, the updated CPR is significantly lower than either value at the time of direct, and the Staff DR 633 value, which includes values for transformers that are not recorded to the AMI account. The value is lower than either amount at the time of direct, but significantly higher than the updated CPR amount. These results are nonsensical. However, the general ledger totals for May 2021 are consistent with expectations relative to the filings at the time of direct, reflecting an increase in the AMI account, 370.2, and a decrease in the AMR (and transformer account) 370.

continued on next page

	Meter Rate Base	Non-Meter Ratebase	Total Ratebase
Company Direct Revenue Requirement AMR			$ 103,632,157
Company Direct Revenue Requirement AMI			$ 94,675,627
Hickman CPR Workpaper AMR	$ 84,271,357	$ 19,360,800	
Hickman CPR Workpaper AMI	$ 24,913,180	$ 24,547,530	
Update CPR AMR	$ 88,439,108	$ 18,064,436	
Update CPR Property Record AMI	$ 10,041,198	$ 1,983,796	
DR 633 AMR			$ 71,077,056
DR 633 AMI			$ 45,736,957
May General Ledger 370			$ 96,470,012
May General Ledger 370.2			$ 72,788,338





The changes in the AMI counts and rate base values across the CPRs are summarized below:

	Direct Count	Update Count	Direct Cost	Update Cost	Count Increase Since Direct	Cost Increase Since Direct
AMI Meters in 370.2	183,829	70,618	$ 24,913,180	$ 10,041,198	(113,211)	$ (14,871,983)
AMR Meters in 370	1,254,387	1,287,315	$ 84,271,357	$ 88,439,108	32,928	$ 4,167,751
Metering Transformers in 370	128,724	127,175	$ 18,981,139	$ 17,483,509	(1,549)	$ (1,497,630)

The changes by retirement type are similarly nonsensical, reflecting an overall increase in the number of AMR meters, and an overall decrease in the number of metering transformers:

	Direct Count	Update Count	Direct Cost	Update Cost	Count Increase Since Direct	Cost Increase Since Direct
METER,AMI,12K480,120/480V,S4X	112	76	$ 53,312	$ 35,274	(36)	$ (18,038)
METER,AMI,12S200,120/480V,S4X	684	680	$ 206,263	$ 206,854	(4)	$ 591
METER,AMI,12S200,120V,FOCUS AXRE-SD	4,032	3,024	$ 940,034	$ 693,569	(1,008)	$ (246,466)
METER,AMI,12S200,120V,FOCUS AX-SD	124	96	$ 19,523	$ 22,613	(28)	$ 3,091
METER,AMI,12S320,120/480V,S4X	20	12	$ 4,751	$ 3,974	(8)	$ (777)
METER,AMI,16K480,120/480V,S4X	576	202	$ 272,981	$ 93,755	(374)	$ (179,226)
METER,AMI,16S200,120/480V,S4X	3,138	3,072	$ 943,684	$ 931,533	(66)	$ (12,151)
METER,AMI,16S320,120/480V,S4X	218	216	$ 70,151	$ 71,452	(2)	$ 1,301
METER,AMI,1S100,120V,FOCUS AX-SD	4		$ (263)		(4)	$ 263
METER,AMI,2K480,240V,FOCUS AX	843	560	$ 238,231	$ 156,642	(283)	$ (81,590)
METER,AMI,2S200,120/480V,S4X	296	292	$ 87,953	$ 88,544	(4)	$ 591
METER,AMI,2S200,240V,FOCUS AXRE-SD	167,520	57,312	$ 20,566,811	$ 6,475,501	(110,208)	$ (14,091,310)
METER,AMI,2S320,120/480V,S4X	56	48	$ 16,520	$ 15,743	(8)	$ (777)
METER,AMI,2S320,240V,FOCUS AXRE-SD	2,496	1,896	$ 311,107	$ 232,543	(600)	$ (78,564)
METER,AMI,2S320,240V,FOCUS AX-SD	16		$ (946)		(16)	$ 946
METER,AMI,3S20,120/480V,S4X	20	16	$ 4,296	$ 4,887	(4)	$ 591
METER,AMI,4S20,120/480V,S4X	644	256	$ 202,739	$ 77,628	(388)	$ (125,111)
METER,AMI,5S20,120/480V,S4X	476	456	$ 143,645	$ 140,218	(20)	$ (3,427)
METER,AMI,6S20,120/480V,S4X	4		$ (591)		(4)	$ 591
METER,AMI,9S20,120/480V,S4X	2,354	2,208	$ 720,388	$ 677,877	(146)	$ (42,512)
METER,1PH,SELF-CONTAINED,DEM/TOU	23	23	$ 4	$ -	-	$ (4)
METER,30AMP,1PH	279	281	$ 18,620	$ 18,760	2	$ 140
METER,3PH,CT-RATED,DEM/TOU/REC	14	12	$ 575	$ 566	(2)	$ (10)
METER,3PH,DEM/TOU/REC,W/KYZ	38	43	$ 4,854	$ 5,528	5	$ 674
METER,CELLNET AMR,1PH,320 OR K-BASE	24,324	25,110	$ 2,164,620	$ 2,239,358	786	$ 74,738
METER,CELLNET AMR,1PH,CT RATED	7,358	7,671	$ 788,134	$ 821,355	313	$ 33,222
METER,CELLNET AMR,1PH,SELF CONTNED	1,113,699	1,137,216	$ 68,566,083	$ 71,355,398	23,517	$ 2,789,314
METER,CELLNET AMR,1PH,W/KYZ	64	65	$ 3,826	$ 3,875	1	$ 49
METER,CELLNET AMR,3PH,CT RATED	16,236	18,110	$ 2,191,640	$ 2,413,567	1,874	$ 221,926
METER,CELLNET AMR,3PH,K-BASE	8,047	9,093	$ 1,906,212	$ 2,315,856	1,046	$ 409,644
METER,CELLNET AMR,3PH,SELF-CONTNED	67,726	72,176	$ 6,421,264	$ 6,881,335	4,450	$ 460,071
METER,CELLNET AMR,W/RECORDER	12,817	13,422	$ 1,393,940	$ 1,525,295	605	$ 131,355
METER,CELLNET,3PH,W/KYZ	305	338	$ 24,126	$ 26,522	33	$ 2,396
METER,ELECTRONIC MULTIFUNC RECORDER	103	117	$ 32,101	$ 33,240	14	$ 1,138
METER,ELECTRONIC MULTIFUNC,QUAD 4	40	41	$ 215,137	$ 215,218	1	$ 81
METER,MULTIFUNC CELLNET AMR,3PH	2,578	2,838	$ 370,048	$ 410,889	260	$ 40,841
METER,MULTIFUNC CELLNET AMR,3PH,KYZ	485	508	$ 34,938	$ 37,114	23	$ 2,176
TRANSFORMER,CURRENT,<=300AMP,34500V	87	85	$ 196,165	$ 172,615	(2)	$ (23,550)
TRANSFORMER,CURRENT,>300AMP,34500V	31	27	$ 142,020	$ 64,494	(4)	$ (77,527)
TRANSFORMER,CURRENT,100AMP OR LESS	4,536	4,530	$ 1,402,740	$ 1,378,268	(6)	$ (24,472)
TRANSFORMER,CURRENT,2000AMP	5,997	5,865	$ 1,025,730	$ 867,220	(132)	$ (158,509)
TRANSFORMER,CURRENT,200AMP	15,612	15,571	$ 1,346,121	$ 1,217,421	(41)	$ (128,700)
TRANSFORMER,CURRENT,2500AMP	24	13	$ 99,722	$ 5,526	(11)	$ (94,195)
TRANSFORMER,CURRENT,400AMP	22,774	22,741	$ 1,623,986	$ 1,566,799	(33)	$ (57,186)
TRANSFORMER,CURRENT,600AMP	39,895	39,205	$ 3,883,992	$ 3,572,415	(690)	$ (311,576)
TRANSFORMER,POTENTIAL,2400V(METERG)	2,874	2,865	$ 966,826	$ 940,142	(9)	$ (26,683)
TRANSFORMER,POTENTIAL,34500V(METER)	233	227	$ 1,346,142	$ 1,249,158	(6)	$ (96,985)
TRANSFORMER,POTENTIAL,600V OR LESS	10,595	9,995	$ 2,177,878	$ 1,715,369	(600)	$ (462,510)
TRANSFORMER,POTENTIAL,7200V	1,596	1,581	$ 1,136,437	$ 1,100,701	(15)	$ (35,736)

All of this review and detailed data analysis is necessary because the fundamental questions to ask in developing assignments and allocation factors for a CCoS are (1) what plant is associated with the rate base in the account, and (2) what is the causation of the company's purchase of the plant in the account? Here, we have no clear answers to either question, on accounts that quite simply should not be this complicated to understand, since each customer should have a meter and customers do not share meters.

On August 23, 2021, Staff received Ameren Missouri's response to Staff DR 681.1. Staff attempted to cross-reference the meter counts by meter model in Staff DR 681.1 with the responses to Staff DR 105.2, which cross-referenced meter models to retirement units. The quantities of various meters recorded in the CPR varied notably from those identified in Staff DR 681.1, particularly with regard to AMI meters. Further, the CPR for FERC Account 370 contains approximately 108,000 Current Transformers and 18,000 Potential Transformers. The response to Staff DR 681.1 identifies 25,743 Current Transformers and 4,143 Potential Transformers as in use for metering customers. Staff attempted to use the differences between costs per meter included in the response to Staff DR 681.1 (which appear identical to those provided in response to Staff DR 633) and the average cost in the CPR to estimate the average cost of the metering transformers to serve each class,[32] but the discrepancies between transformer counts and meter counts between the DR responses and the underlying CPR data undermine the reasonableness of the results.

Because the CPR data at the time of direct is clearly out of date with reference to the GL values, and because the updated CPR data is clearly wrong, for purposes of its direct CCoS allocators, Staff has no realistic choice except to rely on Ameren Missouri's response to Staff DR 633. However, since this response integrated the cost of metering transformers with the costs of meters, Staff must compile the results provided in Staff DR 633 to create a single allocator that is clearly inapplicable to either Account 370 or 370.2, but will approximate the results of Staff DR 633 when applied to both accounts, having the effect of consolidating the meter accounts.

Rate schedule	Class Name	Consolidated for 370 and 370.2
1M	Residential	62.85%
2M	SGS	19.95%
3M	LGS	10.63%
4M	SPS	4.18%
6M	Lighting	1.46%
11M	LPS	0.93%

[32] Only AMI meters were used to eliminate the impact of inflation across various vintages of AMR meters.

Distribution Expense Allocators

An adage in CCoS studies is that "expense follows plant," and is typically provided as a rationale to allocate an expense cost using the allocator developed based on plant data. However, in the context of distribution system automation, this adage produces unreasonable results. Consider a very simple example: if Ameren Missouri hired a technician to unplug each streetlight each morning, and plug each streetlight in each evening, the plant associated with street lighting would decrease (no more need for a dusk-to-dawn sensor) but the labor cost incurred would skyrocket. Using the "expense follows plant" adage, street lighting would be allocated *less* labor cost, even though the additional labor costs are clearly caused by workers performing work related to street lighting. It appears, the opposite scenario is playing out with regard to the distribution plant accounts in this case. Ameren Missouri's Smart Energy Plan is premised, at least in part, on eventual reductions in operations and labor expenses due to distribution system automation. The deployment of distribution automation infrastructure and concurrent reductions in distribution expenses is ongoing. Because the planned automation is not complete in this case, the misallocation created by using distribution plant allocators for distribution expense accounts will become more significant in future cases. Given the approximate $170 million revenue requirement associated with distribution operations and maintenance expenses, Staff recommends the Commission order Ameren Missouri to undertake data collection to facilitate more reasonable allocation or assignment of labor and non-labor distribution expenses in future rate cases.

Given the lack of detailed data available in this case, Staff has generally allocated distribution expenses consistent with its allocation of related plant. This results in a general over allocation of costs to classes with relatively higher allocations of distribution system costs, particularly Residential, SGS, LGS, and Lighting.

Energy Supply and Capacity Revenue Requirement

Generation Revenue Requirement Overview

Staff sub-functionalized the Generation Stable Revenue Requirement Function and the Generation Variable Revenue Requirement Function (explained below) by the generation type.

The revenue requirement components and approximate total, by plant type, for the cost of owning and maintaining generation facilities (Generation Stable Revenue Requirement) are provided below:

	Nuclear	Coal	CT	Taum Sauk	Osage
Net Rate Base	$1,774,106,778	$2,805,889,134	$ 567,303,242	$ 159,261,757	$ 150,357,487
Depreciation Expense	$ 88,651,458	$ 228,864,366	$ 21,522,035	$ 3,492,671	$ 6,122,158
Labor Expense	$ 37,422,389	$ 46,376,897	$ 1,793,833	$ 1,508,427	$ 822,778
Non Labor Expense	$ 55,471,561	$ 70,092,868	$ 8,605,029	$ 2,562,305	$ 1,435,661
Revenue	$ 1,949,863	$ 8,284,946	$ 5,658,858	$ 693,565	$ 378,308
Revenue Requirement	$ 265,676,167	$ 473,192,445	$ 53,787,899	$ 14,597,306	$ 15,297,716

	Keokuk	Wind	Landfill	General Solar	Community Solar
Net Rate Base	$ 187,852,024	$1,097,082,422	$ 40,108,986	$ 12,925,011	$ 6,277,331
Depreciation Expense	$ 6,420,056	$ 41,155,264	$ 949,022	$ 981,443	$ 488,992
Labor Expense	$ 517,665	$ 225,353	$ 3,997	$ 1,568	$ 899
Non Labor Expense	$ 959,144	$ 1,695,657	$ 42,450	$ 14,967	$ 7,905
Revenue	$ 238,019	$ 710,904	$ 12,610	$ 4,945	$ 2,837
Revenue Requirement	$ 16,773,528	$ 95,596,404	$ 2,928,969	$ 1,620,161	$ 799,539

Note, these amounts include reallocated General Plant, Labor-Related, and Rate Base-Related revenue requirement components, as well as approximately $18 million in capacity sales revenue.

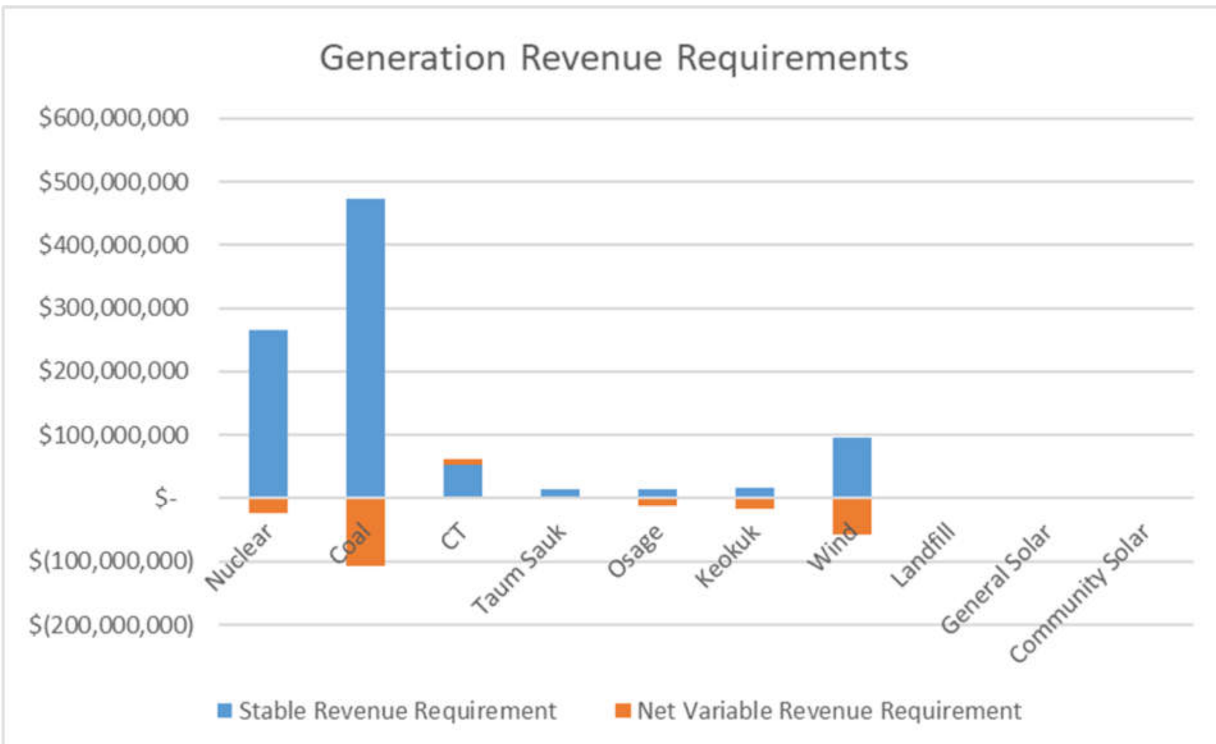
The revenue requirement components and approximate total, by plant type, for the cost of fueling and operating generation facilities as occurred within Staff's fuel run (Generation Variable Revenue Requirement) are provided below:

	Nuclear	Coal	CT	Taum Sauk	Osage
Net Rate Base	$ 32,182,706	$ 135,521,754	$ 7,145,081	$ 363,856	$ 369,259
Variable Generation Net Revenue	$ 26,643,901	$ 115,118,627	$ (8,525,128)	$ 1,854,173	$ 11,671,617

	Keokuk	Wind	Landfill	General Solar	Community Solar
Net Rate Base	$ 404,302	$ 1,823,528	$ 42,468	$ 8,556	$ 4,701
Variable Generation Net Revenue	$ 18,077,588	$ 58,124,033	$ 1,662,809	$ 146,643	$ 71,140

Note, these amounts include reallocated General Plant, Labor-Related, and Rate Base-Related revenue requirement components, and reflect the net of combined expenses less the market value of energy generated by each unit type.

The cumulative (or in some cases, net) revenue requirement for each type of plant is indicated in the graphic below. Where the net variable revenue requirement is negative, those revenues would offset the costs of owning and maintaining the plant:



Production Capacity Allocators

Section 393.1620 RSMo requires that "[i]n determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual."

The National Association of Regulatory Utility Commissioners ("NARUC") cost allocation manual from 1992 describes over 18 different production cost allocation methods, many of which have multiple variations that could be possible.

The Commission rarely (if ever) orders approval of a specific allocation method because the appropriate method will vary from case to case based on the utility's characteristics and available data. Since roughly 2005 to present, the Commission has relied on:

- The Average and Peak method (1 case, KCPL[33] Case No. ER-2007-0291),
- The Average and Excess 4 non-coincident peak[34] ("A&E 4NCP") method (1 case, Ameren Missouri ER-2010-0036),[35]
- The Base Intermediate and Peak ("BIP") Method (1 case, KCPL ER-2012-0174),[36] and
- The Detailed Base Intermediate and Peak method ("Detailed BIP") (2 cases, Empire Case No. ER-2014-0351 and KCPL ER-2016-0285).

In an additional case, Ameren Missouri electric Case No. ER-2014-0258, both the A&E 4NCP and Detailed BIP were implicitly relied upon,

> The Commission will once again reject the Office of Public Counsel's P&A[37] study because it has the effect of double counting average demand. Also, because the results of the A&E and BIP studies are similar, the Commission does not need to decide which particular study is most appropriate.

Other methods that have been presented before the Commission and either rejected or not directly addressed through a Commission order (many cases are resolved by Agreements between

[33] Kansas City Power and Light ("KCPL") is currently named Evergy Metro and Kansas City Power & Light Greater Missouri Operations ("GMO") is currently named Evergy West.

[34] A non-coincident peak is the peak load of a rate class regardless of when the Company's system is peaking.

[35] "Since the class cost of service studies offered by Staff and Public Counsel are unreliable, the Commission must choose between the Average and Excess method studies submitted by AmerenUE and MIEC."

[36] The CCoS relied upon and its method were not discussed in the order; but the Commission ordered shifts in revenue responsibility as defined in KCPL's BIP study, as was reflected in a Stipulation that was opposed.

[37] Peak and Average.

the parties) [38] include A&E 6NCP, A&E 12 coincident peak ("CP")[39], A&12CP, Capacity Utilization, Market-based study, and Assigned Capacity study.

A description of the various methods described in the manual is included as Appendix 2 to this Report.

Reasonable cost allocation requires a high level of confidence in the amount of energy consumed in each hour of the normalized test year both at a utility-wide level and at the rate schedule or class level. This is true whether data for all hours is used directly in the study, or whether that data is used only for the development of a relatively small number of hours of peak data. Utility load research programs are typically the source of this raw data, which is adjusted through a series of "normalization adjustments." In the most recent round of rate cases, there were problems with utility data acquisition and retention calling into question the reliability of both the hourly energy consumption data and the monthly billing data used to complete the normalization adjustments. The relatively few data points relied upon in some studies causes concerns with data reliability to undermine the results. Recent deployments of Advanced Metering Infrastructure technology, if reasonably implemented, should overcome this data issue.

Other factors to be considered are a given utility's relationship with emerging policy issues including the proliferation of regional energy (and potentially capacity) markets, advances in the level of detail of customer and class usage information, the shift of resource mixes to non-dispatchable generation, whether the utility's resource mix is optimized for serving its own load or for participation in energy markets, the emergence of net metering customers and distributed generation, emergence of dual or winter peaking load characteristics, and required inputs for desired rate design development – such as seasonal, time of day, or other more complex rate designs. Additional discussion of these issues is found in the 2019 Regulatory Assistance

[38] ER-2005-0436 – Resolved by Stip (Aquila), ER-2006-0314- resolved by Stip (KCPL), ER-2006-0315 – Resolved by Stip (Empire), ER-2007-0002 – resolved by Stip (Ameren), ER-2007-0004 – Resolved by Stip (Aquila), ER-2008-009 - – Resolved by Stip (Empire), ER-2010-0355 - Resolved by Stip (KCPL), ER-2010-0356 - Resolved by Stip (GMO), ER-2012-0175 – Resolved by Stip (GMO), ER-2014-0370 - Resolved by Stip (KCPL), ER-2016-0023 – Resolved by Stip (Empire), ER-2016-0156 - Resolved by Stip (GMO), ER-2016-0179 - Resolved by Stip (Ameren), ER-2019-0335 – Resolved by Stip (Ameren).

[39] Coincident Peaks, in this context, refers to each class's usage during the hour the system was experiencing its highest usage. In contrast, Non-Coincident Peaks in this context means each class's highest hour of usage in a month, regardless of whether or not the system was experiencing its highest usage.

Project ("RAP") "Electric Cost Allocation for a New Era" manual, by Jim Lazar, Paul Chernick, William Marcus, and Mark LeBel.[40]

In this case, Staff has prepared the following allocators for review and consideration for allocation of the revenue requirement components associated with Nuclear, Coal, Combustion Turbines, Taum Sauk, and Osage generation facilities:

	Residential	SGS/MSD	LGS/SPS	LPS	Lighting
1 CP @ Gen.	54.483%	9.809%	27.856%	7.316%	0.535%
12 CP @ Gen.	52.525%	9.571%	29.484%	8.264%	0.156%
12 NCP @ Gen.	50.331%	11.061%	30.101%	7.850%	0.657%
1 NCP @ Gen.	52.803%	11.310%	28.281%	7.070%	0.536%
A&E 1 NCP	52.014%	11.185%	28.826%	7.445%	0.530%
A&E 2 NCP by total month high	52.038%	11.222%	28.834%	7.377%	0.530%
A&E 2 NCP by class month high	52.018%	11.218%	28.827%	7.401%	0.537%
A&E 4 NCP summer months	52.132%	10.907%	28.921%	7.476%	0.563%
A&E 4 NCP by class month high	52.110%	10.968%	28.880%	7.471%	0.572%
A&E 6 NCP by total month high	53.077%	10.892%	28.466%	6.978%	0.586%
A&E 6 NCP by class month high	52.660%	10.934%	28.361%	7.451%	0.593%
A&P 1 NCP	47.760%	10.511%	31.750%	9.461%	0.518%
A&P 2 NCP by total month high	47.740%	10.524%	31.776%	9.443%	0.518%
A&P 2 NCP by class month high	47.731%	10.522%	31.771%	9.454%	0.521%
A&P 4 NCP summer months	47.501%	10.334%	32.009%	9.624%	0.532%
A&P 4 NCP by class month high	47.499%	10.363%	31.984%	9.618%	0.536%
A&P 6 NCP by total month high	47.709%	10.302%	31.947%	9.501%	0.541%
A&P 6 NCP by class month high	47.560%	10.324%	31.879%	9.694%	0.544%

Given the use of Keokuk, Wind, Landfill Gas, and Solar generation (other than Community Solar) for the generation of renewable energy certificates, which are required based on the energy consumed by each class, and their non-dispatchable nature, Staff allocated the revenue requirement components associated with these plants on class energy consumption. Community Solar costs are appropriately assigned directly to community solar customers.

[40] RAP Manual https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

Energy Cost Allocation

Staff relied on the class hourly load data provided by Ameren Missouri in response to Staff DR 592 and Staff's normalized market prices to find the percentage of the cost of energy to serve load to allocate to each retail class.[41]

Remaining Revenue Requirement

Staff assigned revenue requirement components related to the Pay as You Save "PAYS" and Charge Ahead programs to the "Discrete Programs" class and "Socialized Programs" class, respectively.

Staff relied on Ameren Missouri's direct-filed allocators for Meter Reading, and Uncollectable Accounts. Other Administrative function expenses were allocated to the classes on the basis of the number of customers in each class, except for the customer assistance expense associated with PAYS and Solar Rebates, which were assigned to the "Discrete Programs" class and "Socialized Programs" class, respectively.

Staff reviewed the general plant account balances as described in the general ledger and CPR, and in some instances requested additional data to allocate these costs to other functions.

Approximately $284 million of revenue requirement was found to be related to the general cost of doing business or were so general in nature that they could not be reasonably allocated to other functions or directly to classes. Revenue requirement components within the "General Overhead" function include:

- approximately $64.8 million in revenue requirement associated with General Plant (primarily related to the ownership, maintenance, and operation of the general office buildings in St. Louis and Jefferson City);
- approximately $66.8 million of revenue requirement related to Administrative & General Salaries;
- approximately $58 million of revenue requirement related to Intangible Plant Amortizations and;
- approximately $32 million of revenue requirement related to Office Supplies and Expenses.

[41] The July 20, 2021 response to this DR that was requested June 14, 2021, included data through April 30, 2021, and did not include lighting class data. An average cost of energy for lighting was estimated.

The revenue requirement related to PISA accounting is approximately $24 million as reflected in Staff's direct case.

The revenue requirement of Socialized Programs is approximately $7.3 million.[42]

Staff reviewed allocations for distributing the revenue requirement components functionalized as "General Overhead," and PISA, to the classes, as well as for re-allocating the revenue requirement components associated with the "Socialized Program," class. These revenue requirement components are indirectly allocated on the basis of directly-allocated net rate base associated with each class, or directly-allocated net revenue requirement associated with each class. Staff also reviewed allocation on the basis of the sales to each class – as the essential business of any electric utility is the sale of electric energy to the ultimate customer at the point of the meter.

Results of CCoS Studies

For all of its CCoS studies Staff allocated or assigned costs to the classes as described above. For the Generation Stable Revenue Requirement function, the Generation Variable Revenue Requirement function, and the Transmission Revenue Requirement function, Staff applied a range of allocators. The re-allocation of the revenue requirements of General Overhead, PISA, and Socialized Programs all hinge greatly on the allocation of the aforementioned programs to the extent those costs are reallocated to the classes on the basis of revenue requirement or class ratebase.[43]

Three allocation combinations reviewed by Staff are summarized below:

	Study 1	Study 2	Study 3
Gen Stable RR:	1 CP @ Gen.:	A&P 4 NCP summer months	A&E 4 NCP by class month high
Gen Variable RR:	1 CP @ Gen.:	A&P 4 NCP summer months	A&E 4 NCP by class month high
Transmisison RR:	12 CP @ Gen.:	12 CP @ Gen.:	12 CP @ Gen.:
General Overhead:	Reallocate on Existing RR	kWh @ Meter:	Reallocate on Existing RR
PISA:	Reallocate on Existing RB	kWh @ Meter:	Reallocate on Existing RB
Socialized Programs:	Reallocate on Existing RR	Reallocate on Existing RR	Reallocate on Existing RR

[42] This amount includes the bill credits provided to customers receiving Economic Development riders, including those offered pursuant to Section 393.1640, RSMo. Section 393.1640-2 provides, in pertinent part "In each general rate proceeding concluded after August 28, 2018, the reduced level of revenues arising from the application of discounted rates provided for by subsection 1 of this section shall be allocated to all the electrical corporation's customer classes, including the classes with customers that qualify for discounts under this section. This increase shall be implemented through the application of a uniform percentage adjustment to the revenue requirement responsibility of all customer classes."

[43] For example, even if a group of diners agree to allocate the tip as a percentage of their meal costs, the size of tip a diner would contribute if they are responsible for 50% of the ticket cost is much different than if the diner is responsible for 5% of the ticket cost.

Without completion of a time-consuming Assigned Capacity study, a Detailed BIP study, one of the three Time-Differentiated study methods, or one of the four Marginal Production Cost study methods, these combinations of methods identify a range of study results. Both Studies 2 and 3 are energy-weighted, meaning that production plant allocations are highly dependent on class load factor, regardless of the time of day or year that energy is consumed. The parameters of Study 2 tend to allocate less revenue responsibility to classes with below-average load factors, the parameters of Study 3 tend to allocate less revenue responsibility to classes with above-average load factors. The parameters of Study 1 are generally more similar to an Assigned Capacity study, however Study 1 is not adjusted to allocate plant in excess of current capacity needs in a more reasonable manner; thus Study 1 tends to over-allocate costs to classes with a relatively high portion of peak demand and relatively lower portions of energy consumption.

The outcomes of these studies are provided below:

	Residential	SGS	LGS/SPS	LPS	Lighting
	% Over/Under Contribution @ System Average				
Outcome 1	-3.01%	2.92%	4.66%	-0.29%	14.56%
Outcome 2	3.83%	1.77%	-2.95%	-16.78%	18.84%
Outcome 3	-1.52%	-0.54%	3.53%	-0.93%	13.76%
	Class Revenue Requirement per kWh @ Meter				
Outcome 1	$ 0.1069	$ 0.0948	$ 0.0704	$ 0.0574	$ 0.2244
Outcome 2	$ 0.1003	$ 0.0958	$ 0.0756	$ 0.0660	$ 0.2142
Outcome 3	$ 0.1054	$ 0.0979	$ 0.0712	$ 0.0577	$ 0.2263
	Percent Return Generated by Current Revenues				
Outcome 1	2.65%	3.68%	4.00%	2.97%	5.86%
Outcome 2	3.84%	3.49%	2.64%	0.40%	6.63%
Outcome 3	2.89%	3.09%	3.79%	2.86%	5.71%
	Percent Change to Current Revenue to Exactly Match CoS				
Outcome 1	11.9%	5.9%	4.2%	9.2%	-5.7%
Outcome 2	5.0%	7.1%	11.8%	25.6%	-10.0%
Outcome 3	10.4%	9.4%	5.3%	9.8%	-4.9%

The functionalized transmission gross revenue requirement of approximately $232 million is offset by approximately $43 million of revenue, and is driven by plant investment of over $1.1 billion and operations and maintenance expenses of approximately $125 million. In the studies described above, Staff allocated the net transmission revenue requirement to the classes using the 12 coincident peaks. As a further reasonableness check, Staff modified the study designs above to reflect allocation of the transmission revenue requirement on the same basis as the generation revenue requirements. Those study parameters and results are provided below:

	Study 1a	Study 2a	Study 3a
Gen Stable RR:	1 CP @ Gen.:	A&P 4 NCP summer months	A&E 4 NCP by class month high
Gen Variable RR:	1 CP @ Gen.:	A&P 4 NCP summer months	A&E 4 NCP by class month high
Transmisison RR:	1 CP @ Gen.:	A&P 4 NCP summer months	A&E 4 NCP by class month high
General Overhead:	Reallocate on Existing RR	kWh @ Meter:	Reallocate on Existing RR
PISA:	Reallocate on Existing RB	kWh @ Meter:	Reallocate on Existing RB
Socialized Programs:	Reallocate on Existing RR	Reallocate on Existing RR	Reallocate on Existing RR

	Residential	SGS	LGS/SPS	LPS	Lighting
	% Over/Under Contribution @ System Average				
Outcome 1a	-3.36%	2.72%	5.17%	0.84%	12.22%
Outcome 2a	3.83%	1.77%	-2.95%	-16.78%	18.84%
Outcome 3a	-1.44%	-1.71%	3.72%	0.02%	11.20%
	Class Revenue Requirement per kWh @ Meter				
Outcome 1a	$ 0.1072	$ 0.0950	$ 0.0701	$ 0.0568	$ 0.2300
Outcome 2a	$ 0.1003	$ 0.0958	$ 0.0756	$ 0.0660	$ 0.2142
Outcome 3a	$ 0.1054	$ 0.0990	$ 0.0711	$ 0.0572	$ 0.2324
	Percent Return Generated by Current Revenues				
Outcome 1a	2.59%	3.65%	4.10%	3.18%	5.43%
Outcome 2a	3.84%	3.49%	2.64%	0.40%	6.63%
Outcome 3a	2.90%	2.89%	3.82%	3.03%	5.25%
	Percent Change to Current Revenue to Exactly Match CoS				
Outcome 1a	12.2%	6.1%	3.7%	8.0%	-3.4%
Outcome 2a	5.0%	7.1%	11.8%	25.6%	-10.0%
Outcome 3a	10.3%	10.6%	5.1%	8.8%	-2.3%

These results indicate that the lighting rate class appears to be over-contributing to Ameren Missouri's return on investment, and that the LPS class may be under-contributing to Ameren Missouri's return on investment, however most classes are generally within a reasonable range of providing their target contribution to Ameren Missouri's Staff-recommended rate of return upon application of a system average increase to revenue requirement.

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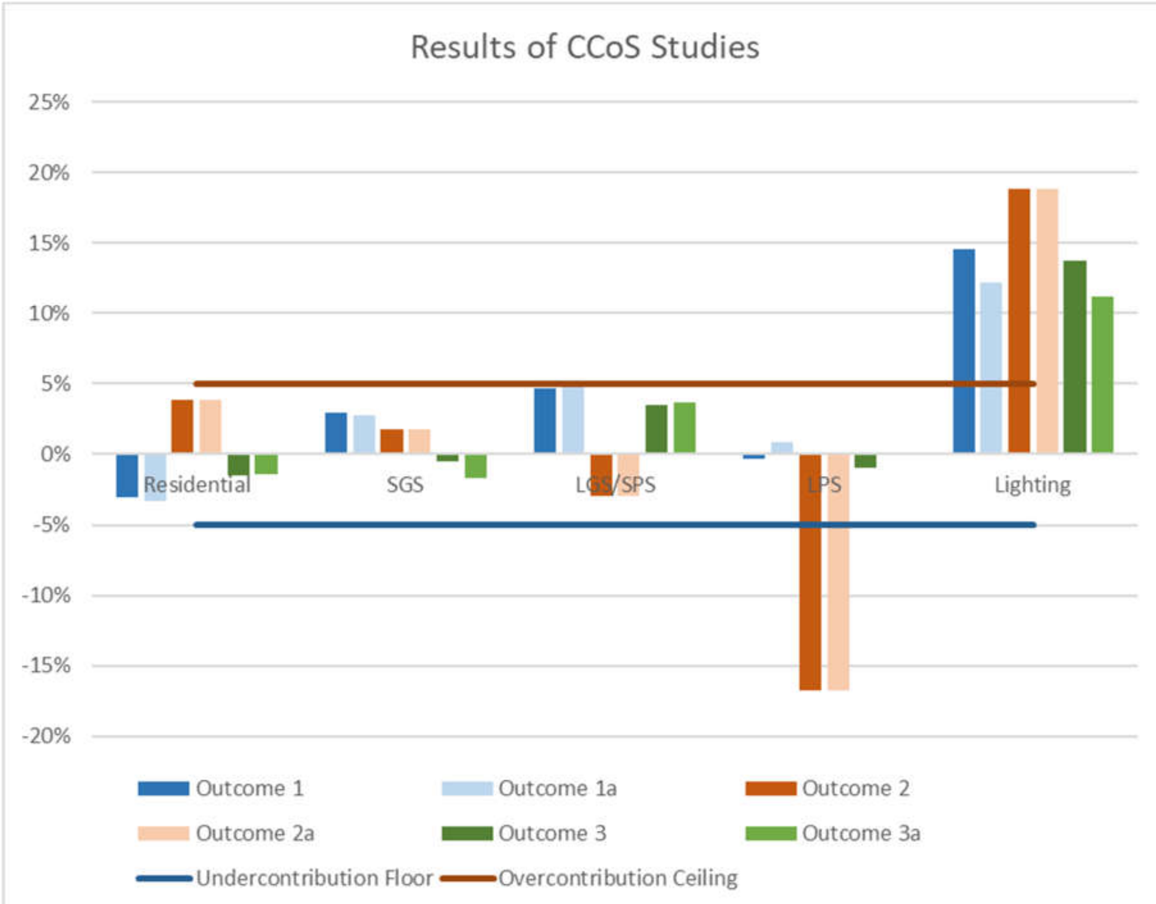


CCOS studies serve as a guide to setting rate class revenue requirements and should not be solely relied upon for establishing each class' revenue requirement because they are not precise, and are not updated for changes from the studied revenue requirement and billing determinants to the ordered revenue requirement and billing determinants.[44]

Policy considerations, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, meeting of incremental costs, and consideration of promotional practices are also taken into account in Staff's recommendation of Ameren Missouri's

[44] CCOS studies are based on a direct-filed revenue requirement, and the allocation of that revenue requirement among specific accounts, using a specific rate of return. Unless that study is updated, or unless the Commission approves that exact set of accounting schedules as well as the direct-filed billing determinants in setting the revenue requirement in a particular case, there is an inherent disconnect between the CCoS study results used in providing a party's class cost of service and rate design recommendations, and the actual class cost of service that would result at the conclusion of a case.

class revenue recovery through rate design. Staff endeavors to provide methods to promote revenue stability and efficiency when implementing any Commission-ordered overall change in customer revenue responsibility in rates. Staff must also balance this, to the extent possible, with retaining existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock. Rate schedules should be understood by all parties, customers, and the utility as to proper application and interpretation.

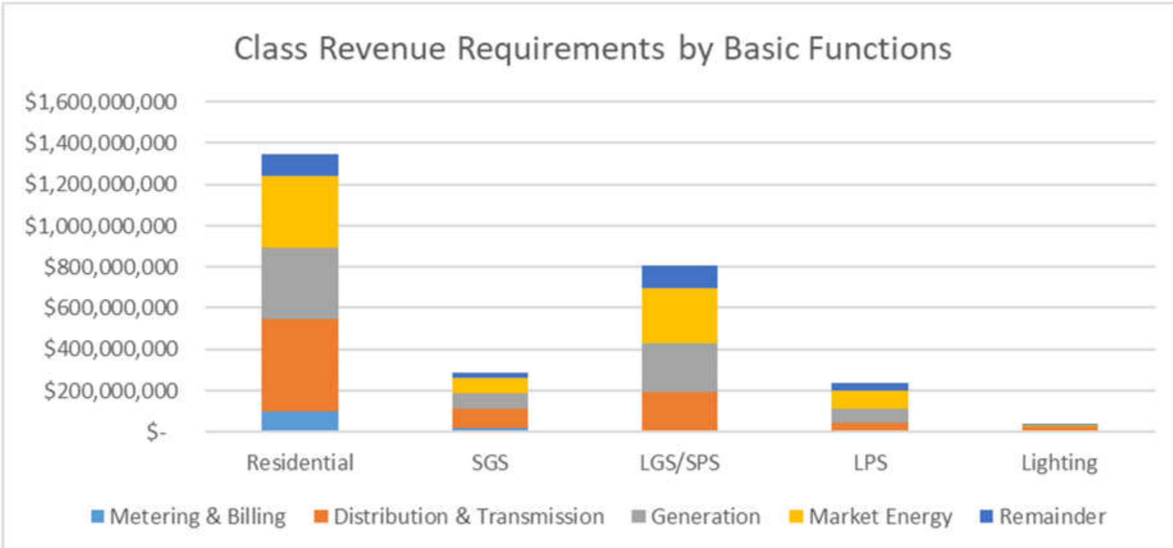
With the above parameters in mind, Staff endeavors to provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility and yield the total revenue requirement to all classes in a fair manner avoiding undue discrimination. This includes methods to recover both fixed and variable costs in a timely manner. This ensures Ameren Missouri receives an amount above its marginal costs on sales of electricity, and each class is providing a contribution to cover fixed costs.

In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that once the rate increase has been applied, a given rate class does not underpay by greater than 5% of its revenue requirement while another rate class or rate classes overpay by greater than 5% of its revenue requirement.

Revenue Responsibility and Rate Design Recommendations

As described above, based on the results of Staff's direct CCoS Studies and its expert judgement considering the precision of such studies in general and known shortcomings of these studies in particular Staff recommends that the approximate $221,386,208, or 8.88%, be allocated to the classes as an equal percentage increase, based on Staff's direct revenue requirement as constituted and analyzed as described in this Report.

Because the Outcome 3 study indicated more moderate shifts to interclass revenue responsibility were needed to exactly match cost of service than did the other Outcomes, Staff will use the Study 3 parameters for presentation of the class revenue requirements below. A graphic representation of the studied class revenue requirements, by basic function, is provided below:



Metering & Billing Revenue Requirements (Customer Charges)

The approximate revenue requirements associated with metering and billing each class, as well as an approximation of a reasonable customer charge, are provided in the table below:

	Residential	SGS	LGS/SPS	LPS	Lighting
Meter Reading	$ 10,807,787	$ 1,466,077	$ 230,463	$ 2,518	$ 14,655
Customer Records and Collection	$ 39,628,631	$ 5,615,564	$ 415,909	$ 2,355	$ 2,003,386
Line Transformers	$ 20,465,905	$ 3,528,370	$ 3,595,944	$ -	$ 669,876
Services	$ 8,726,009	$ 1,510,874	$ 1,519,668	$ 60,948	$ -
Meters	$ 22,757,481	$ 6,543,807	$ 5,228,827	$ 326,060	$ 415,102
Customer Charge portion:	$ 102,385,813	$ 18,664,691	$ 10,990,811	$ 391,881	$ 3,103,020
Customer Count:	1,076,972	152,612	11,303	64	54,445
Customer Charge:	$ 7.92	$ 10.19	$ 81.03	$ 510.26	$ 4.75

With the exception of the LPS class, the current customer charges equal or exceed the CCoS Study-determined customer charge by class. Staff recommends retaining existing customer charges, except that the LPS customer charge should be increased to approximately $515.00 from its current charge of $323.82.

Non-Customer Charge Revenue Requirements

Under various rate designs, the revenue requirement associated with distribution and transmission and with generation may be recovered as either a rate applied to a customer's annual non-coincident peak, a rate applied to a customer's monthly non-coincident peak, a rate applied to a customer's monthly energy usage, or a rate applied to a customer's monthly energy usage at specified times of day. The sum of a customer's annual and monthly non-coincident peaks are not readily available for all classes. In the table below, these functionalized revenue requirements are provided as an average per class kW per month, and as an average per kWh, by class. Also, the average cost of market energy per kWh,[45] by month, is provided in the table below:

	Residential	SGS	LGS/SPS	LPS	Lighting
Distribution and Transmission per class kW per Month:	$ 12.35	$ 11.53	$ 8.44	$ 7.39	$ 44.67
Generation per class kW per Month:	$ 9.35	$ 9.27	$ 10.59	$ 12.26	$ 8.03
Distribution and Transmission per kWh:	$ 0.03138	$ 0.02849	$ 0.01614	$ 0.01114	$ 0.12765
Generation per kWh:	$ 0.02377	$ 0.02290	$ 0.02024	$ 0.01848	$ 0.02296
Market Energy per kWh per Month:	$ 0.02419	$ 0.02425	$ 0.02347	$ 0.02222	$ 0.01921

Additional revenue requirement is allocated to each class as that class's share of general overhead costs, socialized program costs, and PISA recovery costs. Because the essential business of any electric utility is the sale of electric energy to the ultimate customer at the point of the meter, recovery of these costs as a component of the per-kWh rate is reasonable.

Modernizing Rate Structures

In the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245, concerning residential and utility-wide rate design, Staff recommended the following:

Initial steps to be taken during or prior to applicable rate cases:

a. Residential Rate Design:

i. Improve customer education regarding cost composition and energy cost differences over time of day and season.

ii. Review rates on an unbundled basis, with potential to provide tariffed rates on an unbundled basis.

iii. Implement a Low-differential TOU rate design related only to energy price difference or existing rate design blocks, with relatively long on-peak periods.

iv. Study determinants for an on-peak demand charge.

[45] This value is provided as the average cost of energy at the transmission system voltage by class, and is provided as a year-round average. The actual cost of energy to be considered in setting rates should be related to the cost of energy at the voltage level at which the customer is metered, and varies significantly by the time of the year and the time of the day.

c. Utility-wide

i. Study bifurcating Fuel and Purchased Power costs into the TOU time periods for recovery of differences through bifurcated FACs.

ii. Study distribution of DER on existing system.

iii. Identify locations on the distribution and transmission systems where DER may be an alternative to expansion or replacement of the system.

iv. Develop strategies to encourage strategic placement and deployment of DER to reduce overall system investment needs and operation expenses, including transmission congestion including study of locational rate designs and location-dependent compensation schemes.

v. Study located DER scenarios as part of Chapter 22 planning consistent with Staff's recommendations contained in *Section VII. Changes to IRP process or Chapter 22*.

vi. Study energy cost distribution and system utilization to find opportunities for efficient utilization and pricing – for example, some utilities experience significant winter night and evening usage – to refine time periods applicable to time of use rates and develop super on-peak or super off-peak rates.

Phase 2 (approximately 2025 time frame, will vary by utility and rate case timing):

a. Residential:

i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.

ii. Increase TOU differential to recover some generation capacity costs on-peak.

iii. Incorporate super on-peak and super off-peak TOU elements, which may vary by season.

iv. Implement a 12 month demand charge for recovery associated with local distribution facilities.

c. Utility-wide

i. Study distribution locational pricing determinants for locational rate designs; study location-dependent compensation schemes.

ii. Revenue Decoupling.

iii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

Anticipated goals (approximately 2030 time frame, will vary by utility and rate case timing):

a. Residential:

i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.

ii. Implement on-peak demand charge to nearly fully recover generation capacity costs on peak not already included in on-peak and super on-peak elements.

iii. Consider and implement, if appropriate, distribution locational rates or rate elements.

c. Utility-wide

i. Study distribution locational pricing determinants.

ii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

As an outcome of ER-2019-0355, Ameren Missouri has begun the process of prorating bills (or using AMI readings) to address the concerns described by Staff at page 39 et seq. of Staff's CCoS and Rate Design Report in that case with Ameren Missouri's application of "billing periods." This is a necessary first step to better reflection of the variation in costs of providing service during the winter versus the spring and summer, as driven by wintertime demands and higher market energy costs. Staff recommends Ameren Missouri continue the rate structure modernization process by retaining billing determinants in a manner that facilitates the establishment of shoulder month rates to more accurately reflect the disparity in cost-causation between the peak-winter months of December, January, and February, and the shoulder months that are currently included in the "winter" billing season.

Residential Rate Design

Staff recommends that the residential revenue requirement increase ordered in this case be implemented as an equal percent adjustment to all energy charges on all rate schedules, except that the existing time-of-use rate differentials for the Daytime/Overnight schedule be increased to $0.01 for summer energy usage and $0.005 for non-summer energy usage. This modest design reinforces a low-impact, low-differential, long time period time-of-use rate as an excellent customer education opportunity. This modest differential is intended to produce little to no bill variation to customers and will begin to impart to customers the concept that, in general, energy used during the daytime is more cost-intensive, whereas energy used during the night time is less cost-intensive, as a continuation of Ameren Missouri's ongoing default ToU roll-out strategy.

Staff is aware that Ameren Missouri has marketed its Residential rate schedule options not under the tariffed names, but rather under promotional names. In general, these names are not descriptive and in and of themselves portray the ToU rate schedules as money-saving opportunities. These names do not indicate the risks of bill increases that are attendant to the optional rates Ameren Missouri promulgated in the last rate case. Staff recommends adoption of more objective or informative names for Ameren Missouri's use in education and promotional materials.

Other Rate Schedules

Except as identified above, Staff recommends that all charges for service on each non-residential rate schedules be increased by an equal percentage increase to recover the revenue requirement ordered for that customer class. Staff recommends Ameren Missouri require on a non-optional basis that non-residential customers participate in Rider I, which incorporates a time of use element to customers' billing, as those customers obtain AMI metering equipment.

Rider B & Rider C

In Staff DR 677, Staff requested that Ameren Missouri "Please provide all workpapers and historical information supporting the factors and credits applied pursuant to Rider B and Rider C." In response, Ameren Missouri stated "No historical information has been identified. No adjustments to Rider C have been proposed in this case so there are no work papers associated with it. Adjustments to Rider B in this case are included in the work paper MO_RateDesign_BU21_3_25-21 that was presented along with my direct testimony." The referenced workpaper simply applies the class-average percent adjustment to the indicated Rider B value.

Rider B is intended to credit primary customers who own their own substations for the portion of their bill that is related to the cost of supplying primary customers with substation equipment dedicated to that customer. However, Ameren Missouri does not assign the cost of substation equipment that is dedicated to primary customers to primary customers. Absent a specific adjustment as performed by Staff in this case, costs for dedicated substation equipment is simply allocated to all customers along with all other substation costs. Thus, there are only incidental costs included LPS and SPS customer bills for the cost of primary customer substations, and those costs are not included to any greater proportion than the cost of primary customer substation equipment that is included in the bill of a residential, SGS, LGS, or lighting customer.

Staff recommends that unless the costs of substation equipment that is dedicated to primary customer is specifically assigned to the bills of primary customers, that the discounts provided to primary customers under Rider B be suspended until Ameren Missouri provides the information necessary to include the cost of primary customer substations in the bills of primary customers (and such costs are so included).

Rider C provides "Where service is metered at a voltage other than the voltage provided for under the applicable rate schedule, an adjustment in both the kilowatt-hour (kWh) and kilowatt (kW) meter readings for the applicable service will be made as follows:

> For customers on rate schedule 2(M) or 3(M) taking delivery at secondary voltage:
>
> 1. Metered at Primary Voltage or higher, meter readings (kWh and kW) will be decreased by 0.68%.
>
> For customers on rate schedule 4(M) or 11(M):
>
> 2. Metered at 34kV or higher, meter readings (kWh and kW) will be decreased by 0.68%
>
> 3. Metered at Secondary voltage, meter readings (kWh and kW) will be increased by 0.68%
>
> 4. Delivered at 34 kV or higher, served through a single transformation to secondary voltage, and metered at secondary voltage, no Rider C adjustment will apply.
>
> 5. Served at transmission voltage, metered kWh will be increased to account for the energy line losses from the use of a transmission system other than Company's, if any.
>
> Company shall not be required to provide any distribution facilities beyond the metering point except when required for engineering or other valid reasons."

These adjustments are not apparently consistent with the loss factors provided by Ameren Missouri in this case.

Staff recommends the Commission order that Ameren Missouri perform a full study of the reasonableness of the calculations and assumptions underlying Rider B and Rider C to be filed as part of its direct filing in its next general rate case.

Special Tariffs

On Tariff Sheet No. 93.3 of Ameren Missouri's currently effective Rider RESRAM tariffs, it states:

> The Base Amount is the revenue requirement associated with RES Compliance Costs and RESRAM Benefits reflected in the revenue requirement established in the applicable general rate proceedings. At the conclusion of each general rate proceeding, unless otherwise ordered, the Base Amount shall be published on a replacement sheet for Sheet 93.4.

Staff recommends the Commission order Ameren Missouri to update the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") Tariff Sheet No. 93.4 to reflect the RESRAM base amount determined in this case.

On Tariff Sheet No. 91.21 of Ameren Missouri's currently effective Energy Efficiency Investment Charge Rider (Rider EEIC), it states:

> The Company shall file an update to NMR [Net Margin Revenue] rates by month by Service Classification and by end-use category contemporaneous with filing any compliance tariff sheets in any general electric rate case reflecting the rates set in that case, and the billing determinants used in setting rates in such case. Updates to the NMR values shall be calculated following the same process described in the Marginal Rate Analysis section of the MEEIA 2019-21 Plan.

Staff recommends the Commission order Ameren Missouri to update the MEEIA margin rates used for calculating the throughput disincentive within the MEEIA mechanism.

Community Solar Charges for Use of Distribution System

Tariff Sheet 158 (Community Solar Pilot Program) includes facilities charges for participating customers. Per the Amended Unanimous Stipulation and Agreement filed in EA-2016-0207 on May 14, 2018, the Facilities Charge portion of the total solar block charge will be adjusted when rates are reset in future rate cases. The Stipulation further provides that the

Facilities Charge rate will be adjusted by the percentage change to volumetric rates in future rate cases, unless a party provides a cost study demonstrating that it would be unreasonable to adjust the Total Facilities Charge rate by percentage change to volumetric rates in future rate cases post-File No. ER 2016 0179. *At this time Staff recommends the Facilities Charge rate be adjusted by the percentage change to the relevant residential and SGS volumetric rates.*

Rate Caps

Ameren Missouri's election of PISA under SB 564 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 LPS rate class rates 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 Missouri Energy Efficiency Investment Act ("MEEIA"). Winter Storm Uri impacted market energy prices and retail energy sales during February of 2021. The RESRAM and FAC recovery for February 2021 will each begin February 1 of 2022, which is likely to be at or near the time of the Commission's Report and Order in the rate case, and potentially between the issuance of the Order and the compliance tariffs. In conjunction with the recommended revenue requirement increase of approximately 8.88% to be implemented on or around February of 2022, the changes in the RESRAM and FAC rider rates expected to occur February 1, 2022, make it likely that the rate caps contemplated by 393.1655 will become triggered.[46] Staff will continue to monitor this situation and will address in subsequent rounds of testimony as additional information – including estimates of the future rider rates – becomes available.

Stipulation violations and Recommended Data Retention and Development

On February 28, 2020, certain parties to Case No. ER-2019-0335 filed a "Corrected Non-Unanimous Stipulation and Agreement," (February 2020 Stipulation.) In that Stipulation, Ameren Missouri made the commitments excepted below to provide data to facilitate reasonable classification of distribution system investments, among other things:

[46] Ameren Missouri represents the overall cap at the time rates are anticipated to take effect in this case will limit-application of rate increases in excess of a 14.82% as compared to rates in effect at the conclusion of File No. ER-2016-0179. Ameren Missouri represents the subcap for the LPS cap will limit rate increases of 10.27%.

41. AMI Data Tracking.

a. Ameren Missouri shall retain a minimum of rolling 12 months interval data for customers with AMI meters so that customers may compare TOU options. Data shall be maintained in such a manner that it is accessible for load research purposes, which will require at least 16 months of data. Upon request by Staff, the Company shall make available determinants associated with the potential creation of a coincident peak demand charge for all classes, which may be based on either fifteen (15) minute or one (1) hour readings. Data shall be made available in the form of hourly usage per customer and aggregate hourly usage by rate schedule with and without applicable metering or voltage adjustments.

b. Ameren Missouri shall meet with Staff, OPC, and other interested Stakeholders in April 2020 to discuss data collection and retention policies around voltage level data, including but not limited to the following:

1. Cost of 600 V network elements;
2. Cost of network between 600 V and 34 kV;
3. Cost of 34 kV network;
4. Cost of 69 kV network;
5. Cost of 115 kV network;
6. New customer-prepaid investments by voltage and rate schedule of customer;
7. New meter investment by rate schedule;
8. Service drop investment by rate schedule and by voltage;
9. Transformer investment by rate schedule; and
10. Customer load data by geographic area as may be useful in creation of cost based DSM programs.

c. Ameren Missouri shall follow up with Staff, OPC, and other interested Stakeholders by the end of June 2020 regarding any outstanding questions on data collection and retention policies.

Discovery Issues and Data Provided Related to Stipulation Provision 41.a. regarding Demand Determinants

On June 14, 2021, Staff submitted DR 592, "Demand determinants," requesting as follows:

> Refer to the "Corrected Non-Unanimous Stipulation and Agreement" in ER-2019-0335, providing "Upon request by Staff, the Company shall make available determinants associated with the potential creation of a coincident peak demand charge for all classes, which may be based on either fifteen (15) minute or one (1) hour readings. Data shall be made available in the form of hourly usage per customer and aggregate hourly usage by rate schedule with and without applicable metering or voltage adjustments." For each month for which data is available, and for each rate schedule, please provide hourly usage per customer and aggregate hourly usage by rate schedule with and without applicable metering or voltage adjustments. Please indicate whether data provided is based on load research data or

> gross AMI meter data, and whether such load data is derived from load research sample customer, aggregated AMI readings, or some other source.

On July 20, 2021, Ameren Missouri responded:

> Please refer to the attached spreadsheet "Per_Customer_Usage_Response_Data.xlsx" for the data requested. Please see below for the descriptions on each tab in the spreadsheet.
> • The tab named "USAGE": This tab contains hourly aggregated rate class level estimated usage between 01/01/2020 and 04/30/2021 based on calendar month. Estimated usage for various classes are derived from the Load Research samples except for large primary service or LPS (11M) class which uses census analysis. Hourly usage for the LPS customers are directly sourced from Ameren Missouri's billing system.
>
> > o While usage for residential (1M), small general service or SGS (2M), and large general service or LGS (3M) are estimated at the secondary voltage level, usage for small primary service or SPS (4M) class is provided at the primary voltage level. Load research estimates for SPS class are aggregated at the primarily voltage level. Usage in large primary service (11M) are provided at various delivery voltage levels namely primary, sub-transmission and transmission.
>
> • The tab named "CUSTOMER_COUNT": This tab contains monthly customer counts by primary month.
> • The tab named "PER_CUST_USAGE": This tab contains estimated usage per-customer.

The data provided by Ameren in response to DR 592 does not provide information by rate schedule with and without applicable metering or voltage adjustments. Also, the data provided by Ameren is not usable for the potential creation of a coincident peak demand charge for all classes, which may be based on either fifteen (15) minute or one (1) hour readings. Rather, the data provided by Ameren on July 20th is the result of simply dividing Ameren's load research load by rate schedule by the number of customers per rate schedule. This DR response is not consistent with Ameren's obligation under the Non-Unanimous Stipulation to retain a minimum of rolling 12 months interval data for customers with AMI meters so that customers may compare TOU options. Data shall be maintained in such a manner that it is accessible for load research purposes, which will require at least 16 months of data. Upon request by Staff, the Company shall make available determinants associated with the potential creation of a coincident peak demand charge for all classes, which may be based on either fifteen (15) minute or one (1) hour readings.

Data shall be made available in the form of hourly usage per customer and aggregate hourly usage by rate schedule with and without applicable metering or voltage adjustments.

On September 8, 2021, Ameren Missouri supplemented its response:

> Pursuant to topics of discussion raised by Staff at the August 24 discovery conference, the following analysis is being provided as a supplemental response to this data request. This analysis is designed to create potential billing units for a "peak window" or "peak period" demand charge for each rate class, and includes subdivision of the LPS class by the voltage at which customers are served (i.e., primary, sub-transmission (high voltage), or transmission). This data is based on Ameren Missouri's load research program. The data to bill such a charge does not currently exist for Ameren Missouri customers without an AMI meter, and Ameren Missouri has not attempted to determine its billing system readiness or capability to program and bill such a charge at the current time. The peak period used for analysis of this demand charge is 3 to 7 pm on non-holiday weekdays, consistent with the current peak period associated with the energy charge in the residential Ultimate Savers rate option, and also with the proposed peak period for the residential Smart Savers rate option. All demand data used for this analysis is based on an hourly measurement of customer demand within the defined peak period.
>
> Please refer to the attached spreadsheet titled "RC_PEAK_ANALYSIS_CONFIDENTIAL" for this discussion. The spreadsheet contains raw data, analysis and summary. Please note that this spreadsheet contains customer data and is considered confidential. The following table describes various tabs in the attached spreadsheet. Unit for the reported load data is in kW.
>
> [Table omitted]
>
> The analysis started by identifying monthly peak between 3PM and 7PM for each available customer in the load research sample for various rate schedules. Ameren utilized Oracle Lodestar (software tool used for load research) to report the hourly and peak data from the validated load research sample. Since the load research sample is stratified, Ameren also utilized the strata weights to estimate overall peak. Sample data was used for all the rate schedules except for Large Primary Service (LPS) since the Company is able to collect interval data for all of LPS customers for billing purpose.
>
> This analysis utilized "Mean per Unit" (MPU) methodology to estimate the overall non coincident peak during the window of analysis from the sample data for all the rate classes except for LPS. MPU methodology is a simple load research technique where sample average load is grossed up to the class level by multiplying by the overall class population. In this analysis, a weighted average peak was calculated using the average peak demand per customer for each strata and the corresponding strata weights. The sample weighted average was then multiplied by the customer count (class

> population) for December 2020 to achieve overall estimated demand. The analysis is conducted for all of 12 months in the test year.
> For the LPS class, overall non-coincident peak between 3PM and 7PM was determined by simply aggregating individual customer peak during the specified time window. This response also indicates the voltage level for each LPS customer and reports estimated non-coincident peaks during the said time window by such voltage class.

This response was not received in time to facilitate incorporation into Staff's rate design recommendation.

Discovery Issues and Data Provided Related to Stipulation Provisions 41.b.1-5,9, and c., regarding Costs by Voltage

On April 12, 2021, Staff submitted DR 104, "Transmission and Distribution System Investment," requesting:

> Please provide, for FERC accounts 360-368, and 373, by account, the total investment, as well as the related total depreciation reserve, and the total of other offsets to ratebase including CIAC associated with each of the following: 1. Facilities operating at 600V or below; 2. Facilities operating between 601 Volt and 34 kV 3. Facilities operating above 34 kV but below 69 kV 4. Facilities operating above 69 kV but below 115 kV 5. Facilities operating above 115 kV. For each of the above, please provide as detailed records as are available as to what plant is included within each account in each category, and the associated dollar value. Please separately identify the property (and associated reserve and other offsets) for which CIAC or similar payments have been received or billed. Please separately identify the property (and associated reserve and other offsets) which ultimately serve only one customer.

On May 11, 2021,[47] Ameren Missouri responded:

> The requested level of detail of investment, associated reserves, offsets including CIAC or other similar payments, and assets contained within these accounts which ultimately serve only one customer for FERC accounts 360-368 and 373 does not generally exist with the exception of project level voltages being provided on a certain subset of assets in the response to DR MPSC 0242. Please reference that DR for that detail. Please further reference the direct testimony of Ameren Witness Tom Hickman and the associated workpapers for relevant results of historic analysis

[47] While the pdf response is dated 4/30/2021, Ameren Missouri did not provide the response to Staff for an additional 11 days.

> utilized in allocating the referenced capital accounts to the various voltage classes included in Ameren's Class Cost of Service Study.

On May 13, 2021, Staff submitted DR 104.1, "Cost by Voltage 2nd Meeting," requesting:

> Please refer to the presentation titled "Voltage Cost 2nd Meeting Powerpoint" that was attached to an Outlook meeting organized by Thomas Hickman, occurring on 6/26/2020, subject "2nd Cost by Voltage Stipulation Meeting."[48] Please refer to slide 6 and please provide all data as requested in DR 104 in the format of the "reasonable breakout," referenced in the 6/26/2020 presentation. To the extent that assets serve a single customer, Staff understands that Ameren Missouri has not taken steps to identify those assets.

On June 3, 2021, Ameren Missouri responded:

> The requested data is unavailable as analysis at the level of review of distribution plant allocators mentioned in the referenced PowerPoint presentation has not been completed to date.

Based on the discussions that occurred in June of 2020, Staff was left with the impression that Ameren Missouri would be preparing a "reasonable breakout" of the costs within each distribution account by operating voltage. Staff understood from this meeting that there would be difficulties and subjective analysis related to breaking out depreciation reserve amounts, and related to breaking out poles and conduit and appurtenant plant associated with multiple circuits. Staff proposed resolution of the former issue as a simple percentage allocation based on plant as a default approach, which may be subject to refinement at a later time. Staff's proposed resolution to the latter issue was that Ameren could identify such plant as being associated with multiple voltages with some indication of the voltages involved. Also during this timeframe Staff and Ameren Missouri discussed the use of information similar to that provided in response to DR 191 in ER-2019-0355 to facilitate the assignment or allocation of plant by voltage (this response provided a matrix of circuit numbers and circuit miles, overhead and underground).

Staff requested draft information or a progress update in October of 2020, and January of 2021. Ameren Missouri set up a meeting to discuss the project status in February of 2021. In that discussion Ameren Missouri emphasized that the depreciation reserve issue and the multiple voltage issue were still concerns, and Staff reiterated its proposed resolutions. Ameren Missouri

[48] The June 26, 2020 email and attachments referenced are attached.

discussed that it would be easier to identify the voltages and retirement units associated with new plant built out pursuant to the Capital Plan than to backcast the existing plant. By its July 21, 2021 response to Staff's June 21, 2021 DR 104.8, Ameren Missouri has confirmed that it was unaware of any additional correspondence or meetings on the matter subsequent to the February meeting.[49]

In response to Staff's DR 104.2, Ameren Missouri did provide an updated version of the circuit matrix that had been discussed in the June meeting. Staff requested a subsequent update of the matrix to include the number of conductors associated with each circuit, as DR 104.6, stating:

> Refer to the response to DR 104.2. For each circuit identified on tabs "Distribution" and "Subtransmission" please indicate the number of conductors, separately by overhead and underground portions, if applicable. If known, please identify the conductor by retirement unit name. If retirement unit name is not retained within this record system, please provide any identifying information contained within the relevant record system. For each circuit please indicate whether an additional conductor or other cable or wire is installed for lightning protection. For each circuit please indicate whether fiber optic or other communication cabling or wiring is installed and provide the retirement unit name or other identifying information for such cabling or wiring, as well as the miles and numbers of conductor installed. Please clarify whether the columns identified as "OH Miles", "UG Miles," and "Total Miles," refer to miles that the circuit extends, or to miles of conductors where more than one conductor is present.

On July 21, 2021, Ameren Missouri submitted its response, stating "Subject to the Company's objection, with respect to the last sentence which does not require analyses that have not been performed to answer, the columns identified as "OH Miles", "UG Miles", and "Total Miles" refer to miles that the circuit extends."[50]

Staff attempted to confirm by email the apparent misunderstanding that Staff had requested additional analysis with its request for Ameren Missouri to provide the number of conductors associated with its subtransmission and distribution circuits. In an email dated July 30, 2021, 2:31pm, counsel for Ameren Missouri stated that "Regarding 104.6, the information that you

[49] See DR 104.8 and referenced email chain, and Ameren Missouri's data request response, attached.

[50] Staff attempted to obtain an understanding of what information was maintained by Ameren Missouri in its July 23, 2021 DR 716, however, Ameren Missouri objected in full. A response, attached, was eventually provided on September 3, 2021, however, this did not permit time for the issuance of subsequent data requests nor for incorporation of responses to those data requests into Staff's allocator development.

indicate "surely must exist" does not exist absent developing it through substantial analysis that the Company is not required to do."

Staff submitted DR 104.10 on August 3, 2021,[51] "2021 Followup to 104.6 and Lowery email of 7/30/2021," requesting:

> Refer to Lowery statement that "Regarding 104.6, the information that you indicate "surely must exist" does not exist absent developing it through substantial analysis that the Company is not required to do." Describe all analysis necessary to determine the number of conductors on each circuit and which circuits have communications cabling. Identify any database or repository of information within the Company's possession that contains information about how many physical cables are mounted on its defined circuits, and provide access to that data set.

On September 3, 2021, Ameren Missouri responded, stating, "Subject to the Company's objections, please see the response to DR MPSC 688.1 for information relating to the number of conductors for each circuit. As for the communication cable. Our GIS system has not been the master of the location of the communication cables. It has only been in the past year that there have been requests to create an intelligent cable feature to list the size and type of cable, and also models for the UG conductor being purchased with OPGW cable used as the neutral. We have mapped very little of either of these. The current communication cable has no relationship to the

[51] Also on August 3, 2021, Staff submitted DR 104.11, requesting, "Refer to company's response to DR 104.9. Please provide any available information identifying the miles of system and/or number of devices and/or the value of such systems and/or devices and/or the retirement units and quantities of retirement units that operate below 2.4kV which are recorded in accounts 364 Poles, Towers, & Fixtures, 365 Overhead Conductors & Devices, 366 Underground Conduit, and/or 367 Underground Conductors & Devices. Please indicate the voltage and phase at which such assets operate, particularly distinguishing and quantifying assets that operate above 600 Volts from assets operating below 600 Volts, and assets operating at 600 Volts. Please identify the number of customers served at each level of voltage and phase. If full information is not available please provide the best information that is available." On August 23, 2021, Ameren Missouri submitted its response, stating "Ameren Missouri does not have a complete mapping of assets below 2.4kV. A number of assets, as identified by retirement unit, may have a mixed use that can not be identified directly based on the retirement unit alone. Poles, for example, do not operate at a specific voltage but are viewed in Ameren's Class Cost of Service Study as related to the voltage of equipment attached. Poles are not specifically associated to conductors in Ameren Missouri's mapping. Certain types of conductor may be used for a range of secondary applications but could also be used for a mix of primary and secondary applications. As the secondary system is not mapped, Ameren Missouri is unable to specifically or directly identify how much of these mixed use retirement units are used at different voltages. As a result of this, Ameren Missouri currently relies (and has historically relied upon) the results of a study, commonly referred to as the "Vandas Study", which allocated the cost of assets in those mixed use cases to Secondary, Primary, or High Voltages, based on a combination of methods, including but not limited to, sampling. Please see response to DR MPSC 635 detailing this study and including workpapers. This study represents Ameren Missouri's best available information on what voltage assets by specific retirement unit are operating at. For information regarding number of customers served at each level of voltage and phase, please see response to DR MPSC 0681.1"

primary electrical cable, so cannot be tied to a circuit. As a result, a substantial analysis would be required to map this communication cable and to create relationships to the primary electrical cable. Information relating to our defined circuits is contained within ESRI GIS. The amount of data contained within this database is substantial and would be very difficult to compile and transfer. There is a more commonly used read only viewing tool (AMV) used to view and understand the relational data that exists in this system. Ameren Missouri would propose to either provide onsite access to review information contained in this system or a remote session whereby this information could be presented and questions could be asked."

This response was not received in time to incorporate in the development of allocators in this case, and time has not permitted such a meeting to determine if the information that could be obtained from viewing the information in the AMV tool to determine whether it satisfies Ameren Missouri's commitments made in Stipulation Provisions 41.b.1-5,9, and c.

Finally, on September 13, 2021, in its fourth response to Staff DR 104.9,[52] Ameren Missouri provided a list of retirement units found in FERC Accounts 365 and 367 which it represents *could* be used for secondary voltages.

This response was not received in time to incorporate in the development of allocators in this case, and given the lack of certainty as to whether these assets are used at secondary voltage, or could be used at secondary voltage, or could be used at secondary voltage or some other voltage, it does not satisfy Ameren Missouri's commitments made in Stipulation Provisions 41.b.1-5,9, and c.

Discovery Issues and Data Provided Related to Stipulation provisions 41.b.6-8, Customer-specific distribution infrastructure

On April 12, 2021, Staff submitted DR 105, "Meters and Service Drops" requesting:

> Please provide, by rate schedule, a breakdown of Accounts 369 – 372 and associated reserve accounts and other offsets such as CIAC as such investment is used to serve customers taking service on each rate schedule. Please provide as detailed records as are available as to what plant within each account is used in the provision of service to customers taking service on each category, and the associated dollar value.

[52] All four responses are attached, although due to formatting the spreadsheet attached to the fourth response is omitted.

On May 6, 2021,[53] Ameren responded:

> The requested level of detail of account, associated reserve, and offsets such as CIAC balances relating to FERC accounts 369-372 by rate schedule of customer served does not exist. Please reference the direct testimony of Ameren Witness Tom Hickman and the associated workpapers for available detail. Please especially note the counts provided of in service meters (broken down separately between AMI and AMR) and marginal replacement costs of meters (broken down separately between AMI and AMR) utilized to allocate the costs of FERC account 370 between classes. Please also note the identification of Overhead and Underground Services as relating to secondary service and the use of secondary service customer counts and secondary service class level demands to allocate the costs of FERC account 369 between classes.

On June 22, 2021, in an attempt to obtain information concerning the portion of costs contained in distribution accounts which serve only single customers, Staff submitted DR 240.1, "Dedicated Substation Equipment," requesting:[54]

> Please refer to the list of substation assets provided in response to DR 240. Please identify any assets currently used by a single customer or group of affiliated customers. For example, if a transformer supports one large industrial customer and that general business entity also has an on-site SGS account for its guard shack, please identify that transformer (preferably by retirement unit name and account number to which it is recorded) and the rate schedule(s) under which that entity takes service at that location. Please identify instances where all assets associated with a substation are in support of a single customer or group of affiliated customers. If a given substation contains multiple assets in support of different single customers or groups of affiliated customers, please identify assets associated with different customers or groups of customers by a unique identifier, such as a name or customer number.

Ameren Missouri's August 16, 2021 response provided that "Subject to the Company's objections, for the list of substations currently used by a single customer, please refer to the response to DR MPSC 0678. The assets associated with these substations that are primarily or entirely dedicated to serving single customers as described in DR MPSC 0678 can be identified in

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[53] The Ameren response is dated 4/30/2021, but was not submitted into EFIS until May 6, 2021.

[54] On May 18, 2021, in an attempt to spotcheck the usage of various high dollar plant items, Staff issued DR 489, to which Ameren Missouri provided its attached response on June 17, 2021, and its attached supplemental response on August 26, 2021.

the Continuing Property Record by referencing the response to DR MPSC 0591S1 and filtering the data associated with utility account 1362000-Station Equipment on the asset location field for locations 048-DISTRIBUTION CUSTOMER SUBSTATIONS and 048-UEC DISTR.CUSTOMER SUB."

In regards to both Customer-specific distribution infrastructure, Stipulation provisions 41.b.6-8 and Costs by Voltage, Stipulation Provisions 41.b.1-5,9, and c, Staff was optimistic that Ameren Missouri would retain and provide detailed information related to the uses of newly-installed plant pursuant to the Capital Plan. However, as indicated by Ameren Missouri's responses to DRs 102.5, 102.6, and 665, a reasonable level of detail to facilitate distribution cost assignment and allocation is not being retained.[55]

Finally, on September 13, 2021, Staff received a partial response to its DR 533, which through the discovery conference process had been reduced to a request for any indicative or

[55] Ameren Missouri's response to DR 665 is excerpted in section "Complications of Capital Plan Projects," infra. Staff's DR 102.5 stated, "Refer to spreadsheet provided as first supplement to DR 102. Please identify and describe the customer request underlying each of the following "Project Descriptions," including, but not limited to a description of the work done, the assets involved (preferably by retirement unit), the customer making the request, and the rate schedule and voltage under which the customer is served: 0C126 , 0C226 , 0C326 , 0C426 , 0C526 , 0C726 , 0C826 , J007C . Please identify any CIAC or other payment including payments in kind made in connection to these projects."

Ameren Missouri's response stated, "Subject to the Company's objections, projects 0C126, 0C226, 0C326, 0C426, 0C526, 0C726, 0C826, and J007C are standing work orders, which fund jobs under $100,000 within their respective divisions for Customer Requested work. These standing work orders have combined for nearly $12M from January 2019 through February 2021. Due to the volume of jobs funded by these standing work orders, a breakout of assets, customers, rate schedule, voltage, and CIAC payments is not available."

Staff's DR 102.6 stated, "Refer to spreadsheet provided as first supplement to DR 102. Please identify and describe the new business underlying each of the following "Project Descriptions," including, but not limited to a description of the work done, the assets involved (preferably by retirement unit), the customer(s) to be served, and the rate schedule and voltage under which the customer(s) will be served: 0C101 , 0C201 , 0C301 , 0C401 , 0C501 , 0C701 , 0C801 , J007N , J0DBD , J0GN5 , J0KBF , J0Q5G . Please identify any CIAC or other payment including payments in kind made in connection to these projects. For each project, please identify the number of miles of network system installed, separately identifying portions underground and overhead, and the number of feet of services installed, separately identifying portions underground and overhead."

Ameren Missouri's response stated, "Subject to the Company's objection, for projects J0DBD, J0GN5, J0KBF, and J0Q5G, see attached MPSC 0102.6 Attach Project Detail CONF. **Projects 0C101, 0C201, 0C301, 0C401, 0C501, 0C701, 0C801, and J007N are standing work orders, which fund jobs under $100,000 within their respective divisions for New Business. These standing work orders have combined for over $67M from January 2019 through February 2021. Due to the volume of jobs funded by these standing work orders, a breakout of assets, customers, rate schedule, voltage, CIAC payments, and network/services installed is not available**." [Emphasis added.]

relative pricing for installation of various levels of distribution system. That response is attached, but was not received in time for consideration in development of Staff's allocators in this case.[56]

Data Retention Recommendations

Going forward, Staff recommends the Commission order Ameren Missouri to take the following data retention measures:

1. Track customer information by service classification and voltage level and collect, retain, and provide to Staff upon request the following data collected from AMI for load research purposes.

Staff recommends the Commission order Ameren Missouri to track meter installations by service classification and by voltage level, and integrate the ability to identify the general characteristics of the premise meter within its customer information systems to be deployed to utilize AMI metering. Staff further that Ameren Missouri retain or organize information as necessary to accurately cross-reference customer data to facilitate organization of data by such characteristics as customer voltage, rate schedule, applicable Rider B adjustments, net metering customer, etc.

At a minimum, the data Ameren Missouri retains should include the following information:

1. For each rate schedule the total number of customers served on that rate schedule on the first day of the month and the last day of the month;
2. For each rate schedule on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month;
3. For each rate schedule the number of customers served on that rate schedule on the first day of the month and the last day of the month for which interval meter readings are obtained;
4. For each rate schedule on which customers may take service at various voltages the number of customers served at each voltage on the first day of the month and the last day of the month which interval meter readings are obtained;

[56] Earlier responses did provide examples of facility extensions, which were determined to be non-representative through discussions with Ameren Missouri personnel, those responses are included but attachments are omitted due to formatting.

5. For each rate schedule on which customers may take service at various voltages the sum of customers' interval meter readings, by interval and by voltage;
6. For each rate schedule on which service is available at a single voltage the sum of customers' interval meter readings, by interval;
7. If any internal adjustments to customer interval data are necessary for the company's billing system to bill the interval data referenced in parts 5 and 6, such adjustments should be applied to each interval recording prior to the customers' data being summed for each interval;
8. Individual customer interval data shall be retained for a minimum of thirty-six months. If individual data is acquired by the company in intervals of less than one hour in duration, such data shall be retained in intervals of no less than one hour.

This information will facilitate more accurate calculation of billing determinants for the more sophisticated rate designs Ameren Missouri has begun to deploy, and more accurate assignment or allocation of meter-related costs and expenses within future CCoS Studies.

2. File for Commission approval no later than June 1, 2022, proposed record keeping and data accessibility policies that Ameren Missouri will follow in order to implement record keeping and data accessibility practices to associate distribution system costs with the voltage of energy distributed and whether distribution system costs are used for network purposes or customer-specific purposes.

Staff recommends that Ameren Missouri develop tracking systems to identify the voltage at which distribution plant operates and to identify the portions of the HV and primary distribution plant that are dedicated to individual customers with such information to be available by customer rate schedule and voltage. This information is needed for the CCoS Study to more closely align cost causation for the distribution system infrastructure with the class revenue responsibilities that are determined through the CCoS Study process. This would also identify equipment such as transformers used to support community solar integration that are more reasonably assigned to customers participating in that program, and to mitigate socialization across all customers of the costs of infrastructure that supports the interconnection of a single customer.

3. Study and retain determinants associated with the creation of a coincident peak demand charge for all classes.

In the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245, concerning residential and utility-wide rate design, Staff recommended progress towards a rate design that would incorporate an on-peak demand charge to reflect the revenue requirement associated with resource adequacy and capacity costs. Staff recommends Ameren Missouri begin retaining data associated with the potential determinant associated with the creation of a coincident peak demand charge for all classes. An example of the data to be retained would include the highest 15 minute level of usage at any time between 12:01 pm and 6:00 pm on weekdays during the calendar months of June – September, leveraging AMI data as available.[57] Actual customer NCP demands during the indicated time period should be obtained from AMI data and retained on a per-customer basis by rate schedule and by voltage.

Staff Witness/Expert: Sarah L.K. Lange

Fuel Adjustment Clause Tariff Sheet

Staff provides its recommendations for the issues that have an impact on Ameren Missouri's fuel adjustment clause ("FAC") and FAC tariff sheets, as listed below.

Revised Base Factors

Staff proposes the Base Factor ("BF") rates be rebased as follows: summer BF $1.147 and winter BF $0.991 cents/kWh[58] based upon an analysis of data compiled during the 12 months ending June 30, 2021 (see Appendix 5, Confidential Schedule BM-d1[59]). Staff will true-up its recommended BF summer and winter rates in its True-up surrebuttal testimony to be filed on November 5, 2021.

Staff Witness/Expert: Brooke Mastrogiannis

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[57] Billing determinants are the quantity of each charge type to be billed to collect an allowed revenue requirement. Every charge type that appears in a company's rate structure must have an associated billing determinant.
[58] Months included in each corresponding BF: Summer (June – September); Winter (October – May).
[59] Confidential Schedule BM-d1-C information is included in the work papers of Staff witness Lisa M. Ferguson.

Revised Transmission Percentage

Staff calculated the percentage of Midcontinent Independent System Operator ("MISO") related transmission services costs and revenues arising from sales and purchases for load to be 2.52%.

Policy

In summary, Staff makes the following recommendations to the Commission regarding Ameren Missouri's FAC:

- Order Ameren Missouri to include language in its FAC tariff that any retirement and/or decommissioning costs related to the retirement of the Meramec Plant be removed from the FAC after the official retirement date, and no other costs will be included for recovery in the FAC after that date;
- Order Ameren Missouri to include language in its FAC tariff that all wind revenues associated with High Prairie and Atchison Wind Farms will be included for recovery in the FAC; and
- Order Ameren Missouri to change the FAC tariff Fuel Cost definition to state: "Fuel costs incurred to support sales and revenues associated with the Company's in service generating plants consisting of the following".

Staff Witness/Expert: Brooke Mastrogiannis

Community Solar

The Community Solar program tariff was approved in 2018 in File No. EA-2016-0207 and was recently modified in ET-2020-0022.[60] The Community Solar Pilot Program provides subscribing customers an opportunity to participate in renewable energy generation without installing solar panels themselves. Ameren Missouri constructed the Lambert solar facility to support the Community solar program, which became operational in August 2019. The Commission recently granted Ameren Missouri a Certificate of Convenience and Necessity for the

[60] The modification changed the deadline for refund purposes for an enrollee who has paid the participation fee and has not received service, from October 13, 2021 to March 31, 2022, and made other clarifications to the tariff related to the approval of the Montgomery solar facility.

Montgomery solar facility, which will support the program. The Montgomery solar facility is expected to be complete in December of 2021. The Lambert and Montgomery solar facilities are both fully subscribed.

The original purpose of the Program was to conduct a pilot of a voluntary subscription-based solar program offering an alternative to customer-owned solar for customers unwilling or unable to install or lease their own solar panels. Since it started the Program has been fully subscribed with a waitlist that continues to grow. Staff recommends the current pilot Community Solar Program be kept in place for the time being with no modifications. Staff recommends that Ameren continue to collect feedback from its customers regarding the program. Staff had requested information on why customers left the program and the waitlist and Ameren was unable to provide it, therefore Staff also recommends Ameren implement a system to track this in order to get a better idea of how to improve the program in the future.

Staff Witness/Expert: Amanda Coffer

Appendix 1 - Staff Credentials and Case Participation

Appendix 2 – NARUC Manual Summary

Appendix 3 – PDFs of attached DRs in numerical order - Confidential

Appendix 4 - Schedule BM-d1 - Confidential

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-2021-0240

AFFIDAVIT OF AMANDA COFFER

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW AMANDA COFFER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Report - Class Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Amanda Coffer

AMANDA COFFER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 16th day of September 2021.

D Suzie Mankin

Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

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-2021-0240

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Report - Class Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange

SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 16th day of September 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin

Notary Public

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-2021-0240

AFFIDAVIT OF BROOKE MASTROGIANNIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BROOKE MASTROGIANNIS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Report - Class Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Brooke Mastrogiannis

BROOKE MASTROGIANNIS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 16th day of September 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin

Notary Public