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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
October, 2021

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REBUTTAL TESTIMONY

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STEVEN M. WILLS

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven M. Wills. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. Are you the same Steven M. Wills that submitted direct testimony in this case?

A. Yes, I am.

Q. To what testimony or issues are you responding?

A. I am responding to direct testimony associated with a number of topics, parties, and witnesses, including:

- Staff's opposition to the Company's proposed rate switching revenue tracker, found in the Staff's Cost of Service Report ("COS Report").
- A variety of inter-related issues arising from Staff's COS Report, that include:
    - Staff's highly unorthodox and deeply flawed attempt to re-invent the allocation of distribution costs to the various customers and customer classes in its class cost of service study ("CCOSS");
    - Staff's stunning proposal to suspend Rider B credits that exist to recognize the significant investments that certain customers served at

primary voltages have made in their own substations, which displace the need for substantial amounts of utility investment;

- Staff's clear misreading of the Stipulation and Agreement from File No. ER-2019-0335 ("2019 Stipulation") and resultant unsubstantiated allegations that the Company has not complied with its terms; and
- Staff's request of the Commission to order the Company to undertake onerous, expensive, and unecessary data collection practices.

- Staff's recommendations related to residential rate design that:
  - Ask the Commission to order the Company to make changes to its Time of Use ("TOU") rate plan names just months after customers have begun to learn about them, and
  - Widen the differential between peak and off-peak rates for the default TOU rate shortly after hundreds of thousands of customers have just been provided with guidance about the potential bill impacts of that rate based on the current differential.
- Staff and the Consumer Council of Missouri's ("CCM") recommendations to maintain the existing $9 per month residential customer charge for all rate plans.
- Midwest Energy Consumer Group's ("MECG") recommendations related to Large General Service ("LGS") and Small Primary Service ("SPS") rate designs.
- MECG's proposals related to changes to the content of Electronic Data Interchange ("EDI") bills and non-residential customer interval data access.

II. AMEREN MISSOURI'S RATE SWITCHING REVENUE TRACKER IS NOT CONTRARY TO MISSOURI LAW AND ACCORDS WITH PUBLIC POLICY

Q. Staff opposes the Company's request to establish a two-way tracker to capture changes in revenue that arise from customer elections to participate in voluntary TOU rates, and their subsequent actions to manage their usage to save money on those rates, as well as from rate switching that may occur between Rate 4(M) and Rate 11(M) pursuant to a change in the qualification requirements for Rate 11(M) proposed by the Company. Please summarize the arguments Staff relies on for its opposition.

A. There are essentially two arguments raised by Staff in its COS Report. First, Staff makes a general argument about the limited circumstances they view as being appropriate for the use of trackers in the context of Missouri utility regulation. Staff appears to believe that those limited circumstances do not apply to the Company's request, and that therefore, as a matter of policy, the tracker should be rejected. The second argument is specific to the nature of the rate switching tracker proposal. Staff characterizes the Company's request as a "Rate Stabilization Mechanism" that they argue is effectively prohibited by Missouri law for a utility in Ameren Missouri's circumstance.

Q. Starting with the second argument first, why does Staff claim that the Company is prohibited under Missouri law from requesting this tracker?

A. Staff claims that this tracker request "would effectively act as a Revenue Stabilization Mechanism," as described in Section 386.266.3, RSMo.[1] A provision of that section prevents any utility that has elected Plant in Service Accounting ("PISA") under

[1] Section 386.266.3, RSMo., does not include the phrase "Revenue Stabilization Mechanism," but as the Company understands Staff's testimony, Staff is using that phrase as shorthand for the specific type of mechanism described in that provision of the law, and I will adopt that convention for my testimony.

Section 393.1400.5, from utilizing a Rate Stabilization Mechanism. As a result, Staff claims that this prevents the Company from requesting this tracker.

Q. Is Staff correct about this?

A. No. While Staff is correct that the Company has elected PISA, and therefore cannot request to utilize a Rate Stabilization Mechanism under Section 386.266.3, they are clearly incorrect in characterizing the Company's tracker proposal as having anything to do with that provision of the law.

Q. Can you please cite the language of Section 386.266.3 that Staff characterizes as a Revenue Stabilization Mechanism?

A. Section 386.266.3 provides in pertinent part as follows:

> 3. Subject to the requirements of this section, any gas or electrical corporation may make an application to the commission to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both. No electrical corporation shall make an application to the commission under this subsection if such corporation has provided notice to the commission under subsection 5 of section 393.1400.

Q. Would the Company's proposed tracker "effectively act as a Revenue Stabilzation Mechanism" as Staff suggests?

A. No. The Company's proposal is, neither in form nor substance, close to the mechanism contemplated by Section 386.266.3. While I am not an attorney, the statute plainly refers to "rate schedules authorizing periodic rate adjustments outside of general rate proceedings." The tracker that is the subject of the Company's request is merely an accounting mechanism to defer certain items for future consideration *within* a future general rate proceeding. The Company's proposal does not guarantee recovery of tracked amounts, and it certainly does not do so without the opportunity to consider those amounts in the context of a general rate proceeding.

Further, the statute goes on to explain that the purpose of the authorized rate schedules (which do not exist in the Company's proposal to begin with) is to "account for the impact on utility revenues of ***increases or decreases in residential and commercial customer usage*** due to variations in either weather, conservation, or both." (emphasis added)

The form of revenue stabilization described in the statute is not at all what the Company's tracker proposal in this case does, and any assertion to the contrary is clearly a misunderstanding of what the tracker is accomplishing. The rate switching tracker is designed only to capture changes in revenue that arise from the impact of applying ***different rate structures*** (TOU versus the legacy flat rate, or 4(M) rates vs. 11(M) rates) to ***a constant level of customer usage***. *Increases or decreases* in usage, whether arising from weather, conservation, both, or from some other cause entirely, are not addressed at all by the tracker.

Moroever, no baseline level of usage is established for the tracker that can be compared to observed usage to determine and track the impacts of increased or decreased usage on Company revenues. And there is no methodology proposed in this tracker to estimate or measure any increases or decreases in usage that are associated with weather or conservation, which could be used to determine and track the impacts of such changes. At least one of these concepts – a baseline usage to compare actual usage against for purposes of determining any increases or decreases in that usage, or a methodology for directly calculating increases or decreases in usage from the factors defined in the statute – would be essential elements of a Revenue Stabilization Mechanism as described in this provision of law, and neither exists here; the statute, by its plain terms, simply does not apply.

The proposed tracker is designed to compare the bill of the TOU adopting customer, based on whatever usage actually occurred, to what the bill of the customer would have been on the legacy rate structure, also based on whatever usage actually occurred. There is clearly *no consideration whatsoever of increases or decreases of usage* arising from weather, conservation, or anything else. Therefore, Staff's assertion that the Company's election of PISA legally prevents it from requesting this tracker is obviously false.

Q. Please turn to Staff's policy arguments regarding the limited role they see for trackers. What is the basis of Staff's policy concerns with this tracker?

A. Staff argues that the use of trackers should be rare, and identifies three types of circumstances where they may be justified. Those include material costs, as delineated in Staff's COS Report:

- When the applicable costs demonstrate significant fluctuation and up-and-down volatility over time, and for which accurate estimation is difficult;
- New costs for which there is little or no historical experience, and for which accurate estimation is accordingly difficult; and
- Costs imposed upon utilities by newly promulgated Commission rules.

Presumably, the fact that the rate switching tracker does not fit neatly into one of these circumstances that Staff identifies as potentially justifying a tracker factors in to Staff's recommendation to reject it.[2]

[2] To the extent Staff is attempting to articulate factors the Commission may have applied in rejecting certain other trackers (e.g., Kansas City Power & Light Company's request for a transmission expense tracker a few years ago), I should note that the Commission has adopted no rule that establishes a "policy" of when a tracker should or should not be approved. As discussed below, if one wants to examine Commission history for a tracker of the type sought by the Company in this case, that history supports approval of the tracker.

Q. Apart from those three policy justifications for trackers identified by Staff, are there other policy reasons that have been recognized by the Commission as the basis for approving any trackers?

A. Yes. In the Company's "Charge Ahead" case (File No. ET-2018-0132), the Company requested a tracker for the costs of incentives and program administrative and education costs associated with its electric vehicle charging infrastructure program. Staff opposed the Company's request for a tracker for this program, but ultimately the Commission found that it was appropriate. In its Report and Order in that case, the Commission's findings of fact included the following numbered paragraphs:

> 13. The Commission also uses another type of deferral accounting mechanism referred to as a "tracker." Unlike AAOs, trackers tend to concern ongoing costs ***for which there is a public policy interest***. The criteria that the Commission has utilized for approving trackers has differed from the criteria it follows for an AAO.
>
> 14. The Commission has approved deferral accounting on many occasions without a finding of an "extraordinary event." ***The Commission has often authorized a deferral mechanism when it is authorizing a new program that is beneficial to customers, but where without the deferral mechanism in place, it could be financially detrimental to the utility to pursue. (emphasis added)***[3]

The last sentence in that section of the order clearly indicates that, where the Commission sees an opportunity to align the financial incentives of a utility it regulates with an opportunity for that utility to provide benefits to its customers, a tracker can be good public policy. The logic that applied to the Charge Ahead tracker applies almost identically with respect to this rate switching tracker.

[3] File No. ET-2018-0132, *Report and Order*, p. 27, paras. 13-14, issued February 6, 2019.

Specifically, the TOU rate options are very much a new programmatic offering made available to customers, that can provide significant benefits to those customers in the form of lower bills, achieved in a manner that can also provide system benefits for all customers arising from the shifting of usage away from periods of high demand, and therefore higher cost, on the system. The Commission has expressed a public policy interest in advancing TOU rates in recent years in several contexts. However, the public policy benefits – which are manifested in the form of lower bills for customers – result in reduced revenues to the Company, which negatively impact its opportunity to cover its revenue requirement. This means that, exactly as the Commission stated in its Charge Ahead Report and Order, that something that "is beneficial to customers … could be financially detrimental to the utility to pursue."[4]

Obviously the TOU rates are already approved, and the Company is "pursuing" them. That said, the alignment of financial incentives is still good policy, as it removes that potential financial detriment to the utility. This alignment also encourages the Company to propose more advanced TOU rates and otherwise pursue modernization of rates in the future as well.

[4] *Id*. at p. 27.

Q. In its argument against trackers, Staff states that "… regulatory lag does provide utilities with incentive to be as efficient and cost-effective over time as they can. Excessive use of trackers can serve to eliminate or weaken these beneficial incentives."[5] Does the rate switching tracker weaken beneficial incentives associated with regulatory lag?

A. Absolutely not. It is the exact opposite in this circumstance. In the case of TOU rates, regulatory lag provides an incentive to the utility ***not to take actions that clearly can benefit customers***. Staff's argument regarding regulatory lag and the incentives it provides the utility is exactly backwards in the circumstance of the rate switching tracker. Not authorizing the tracker would create the exact type of misalignment of incentives that Staff worries might occur by authorizing trackers in other circumstances.

III. REBUTTAL OF STAFF'S APPROACH TO DISTRIBUTION COST ALLOCATION, UNFOUNDED ALLEGATIONS OF NON-COMPLIANCE WITH PRIOR SETTLEMENT COMMITMENTS, AND UNREASONABLE DEMANDS FOR FURTHER DATA TRACKING AND RETENTION FOR NEGLIGIBLE, IF ANY, BENEFIT

A. Staff's Overall Approach to Distribution Cost Allocation is Deeply Flawed

Q. Is the methodology employed by Staff to classify and allocate distribution costs in this case consistent with Staff's past practices, or typical industry practices, in this area?

A. No. Staff has made a radical departure from standard industry practices, and even past Staff practices, for the treatment of costs, particularly distribution costs, in the CCOSS it prepared for this case. This is evident right from the outset of Staff's CCOS Report, when in the first paragraph of the Executive Summary, Staff says:

[5] File No. ER-2021-0240, Staff Cost of Service Report, at p.47, ll. 19-21.

> 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.[6]

This early emphasis on Staff's evidently strong preference for ***assignment*** of costs over ***allocation*** is a theme that recurs throughout Staff's CCOS Report, and its implications for the way the study proceeds are difficult to overstate. In fact, a simple search for the word "assign" in Staff's CCOS Report yields 32 occurrences, each of which relate to Staff's newfound hyper-focus on assignment of costs in place of the standard industry practice of cost allocation. The goal of a CCOSS is to use major recognized cost drivers to reasonably allocate the costs of the distribution system to the classes that cause the incurrence of those costs in order to develop rates for service that reflect the cost structure of the utility. The goal is not to ensure recovery of specific costs from specific customers and customer classes.

Q. Why is Staff's emphasis on cost assignment rather than allocation so noteworthy, and indeed, problematic?

A. Simply put, it turns Staff's CCOSS into a completely unwieldy and impractical study that gets so caught up in minutiae that Staff fails to recognize the big picture economic principles of cost causation and apply them rationally.

Staff repeatedly criticizes the Company for the amount of detailed data it was able to provide related to distribution plant throughout its CCOS Report, and suggests this hampered its ability to "assign or reasonably allocate" distribution costs. The problem

[6] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 1, ll 11-14 (emphasis added).

though, is not with the Company's record keeping practices,[7] nor its efforts to comply with the 2019 Stipulation,[8] nor even its commitment to responding to Staff's weighty discovery requests. The problem is that Staff perceived a need for a level of granularity of data that ***generally does not exist in utility record keeping*** in a manner that is readily available and usable for the type of analysis Staff sought to undertake, and is not necessary for the reasonable allocation of costs to classes. The result is a hodge podge of approaches where Staff took the most granular data they could manage to assemble and cobbled it together with a variety of subjective assumptions in an ill-conceived attempt to re-invent the CCOSS.

It is important when considering this idea of direct assignment to keep in mind the incredible complexity that is the electric distribution grid. Ameren Missouri's grid is literally made up of millions of components – poles, conductor, transformers, switches, lightning arrestors, and a wide array of other pieces of specialized equipment, dynamically networked in a very complex and interrelated web in order to provide reliability and redundancy, that ultimately connects to well over a million endpoints in order to serve each unique electric customer. Most of these components are shared among different numbers and types of customers and customer classes, and many of them impact service at a variety of voltage levels and phases. The grid must also continually evolve with some components repaired, replaced, and/or upgraded, utility additions made to serve new customers or new premises, dynamic two-way power flow from customer generators when generating and to customer generators when not generating, etc. This is exactly why CCOS studies across the industry do, and frankly must, rely on *allocations* that simplify the relationship between

[7] These requirements are described below.
[8] I refute these allegations in Section III.C. below.

the system and the customers it serves by focusing on analysis of the most significant drivers of utility system costs.[9]

Direct assignment of the cost of these distribution components, however, as Staff attempted to do, is an incredibly complex effort to uniquely trace which specific poles, wires, and devices historically served and/or currently serve which specific customers, voltages, phases, and customer classes. But beyond that, assignment requires not only identifying which components serve which customers, but also requires the identification of the unique costs of each asset in order to assign those costs to those particular customers. This gets into accounting and financial data, the nature of which is established in large part by the FERC Uniform System of Accounts.

The distribution plant accounts that Staff had the greatest difficulty *assigning* to classes are what are known as mass property accounts. Mass property accounting is set up precisely to handle the problem of these types of assets – poles, conductors, transformers, meters – that exist within a system in huge numbers and are unwieldy to individually track. In the instructions of FERC's Uniform System of Accounts, FERC prescribes the level of detail that should be maintained in financial records related to mass property as follows:

> B. For each category of mass property:
> (1) A general description of the property and quantity;
> (2) The quantity placed in service by vintage year;
> (3) The average cost as set forth in Plant Instructions 2 and 3 of this part; and
> (4) The plant control account to which the costs are charged.[10]

The language of the FERC definition, where it refers to "a general description," "quantity" (implying aggregated rather than individual records), and "average cost" (rather

[9] See the direct testimony of Company witness Tom Hickman for an overview of these drivers.
[10] 18 CFR Part 101, Definitions, Subsection 8.

than the unique costs of different individual components) - is very revealing about the appropriate level of detail that utilities are expected to keep related to mass property in their financial records. The level of data that Staff would need to directly assign mass property distribution plant *does not exist* in the financial records of utilities, and is not even contemplated to exist. Ameren Missouri witness John Spanos explains in his rebuttal that Ameren Missouri's level of detail and quality of the detail is comparable to and, in many instances, more detailed than the property records of many other utilities.. This realization gets right to the heart of the problems with Staff's attempt to re-invent CCOSS – the data to do what Staff wants to do does not exist.

Q. Even if the financial records are only kept in mass property formats, which does not allow direct assignment, shouldn't the operational records of the utility be detailed enough to provide much more granular information so that Staff could make "reasonable allocations"?

A. Not necessarily. The first question to ask is, data that is much more granular than what? I would observe that the detail with which the Company allocates its distribution plant investment in its CCOSS is already significant, and entirely adequate to make reasonable allocations. Staff's testimony about the topic would lead one to believe that the Company's allocations are so basic as to be unreasonable or unreliable. To the contrary, there is acutally a quite robust study that is referred to as the "Vandas Study" (named for the engineer who had primary responsibility for conducting it), described further in the rebuttal testimony of Ameren Missouri witness Thomas Hickman, supporting the reasonable allocations of different asset types to voltages, which are subsequently allocated to customer classes based on class customer counts and demands – as is industry standard practice. Mr. Hickman cites a Staff data request response and attaches it as an exhibit to his testimony to demonstrate that the Company's Vandas Study is even recognized by Staff as being the basis of reasonable allocations. I would highlight an additional observation from that data request response. Staff references the RAP Manual (which I discuss further later in my testimony) in that response as saying ""[t]he FERC accounts do not differentiate lines, poles or conduit between primary and secondary equipment, and *many utilities do not keep records of distribution plant cost by voltage level*. This means any subfunctionalization requires some sort of *special analysis*, such as the review of the cost makeup of distribution in areas constituting a representative sample of the system." (emphasis added) The quote provided by Staff seems to reinforce my point that the information that Staff sought in this case related to more detail about distribution system is generally not maintained in utility records. Further, the Company's Vandas Study that Mr. Hickman describes is in fact the type of "special analysis" that the RAP Manual calls for to develop this information.

Staff has obviously sought access to more detail from these operational records, which they believe "must exist," in order to make increasingly granular analyses on which to base their allocations. But again, the reality is incredibly complex. It's not that a huge amount of information does not exist about the operational equipment on the system. It most certainly does. But not always in a way that can be queried, summarized, and analyzed in the way Staff wants. Keep in mind that the grid as it exists today has been constructed over a period of many decades, which oviously and significantly predates the types of digital records that can be created today. There are countless paper versions of maps and electrical drawings that have largely been converted into digital records over time in varying amounts of specificity and detail, but that information cannot all be quickly summarized in a data request response. The Company does now have a very substantial amount of digital records of the system, but detailed and interrelated digital mapping of all assets is still an ongoing, long-term process. And again, even where things are fully digitally mapped, the incredible complexity that is the grid and its ever-evolving nature still makes providing useful information for performing analysis at the level of granularity that Staff imagines virtually impossible.

For example, Staff's CCOS Report cites an instance where Staff requested data regarding the number of conductors on each of the Company's approximate 380 subtransmission circuits[11] and more than 2,100 distribution circuits.[12] This is specifically the level of detail that Staff's request, cited at page 63 in their CCOS report discussing exchanges related to DR 104.6, indicated "surely must exist." The reality is not that the data on conductors in circuits does not exist. The reality is that to answer Staff's "simple" question would require substantial analysis that is not feasible to perform (and upon advice of counsel, not required to be undertaken under the rules of discovery) on demand by Staff. That substantial analysis arises, again, from the incredible complexity of the grid. The answer is not that this circuit has 4 conductors and that one has 2. Each unique circuit can be many miles long, operating at different voltages and with different numbers of phases over different segments that were installed at different times and interacting with different electrically connect devices. The answer to Staff's question would require synthesizing and

[11] This equates to approximately 3,699 miles of conductor, either overhead or underground, for the Company's subtransmission circuits.
[12] This equates to approximately 28,800 miles of conductor, either overhead or underground, for the Company's distribution circuits.

summarizing digitally mapped data independently for each of the over 2,400 circuits Staff asked about.

There are very good reasons that standard industry (and Commission) practice is to allocate the costs of the distribution system. Just from a practical perspective, regardless of the perceived or actual benefits of more granular allocations, the incremental effort (i.e., cost) to directly assign distribution costs, or even perform distribution cost allocations at Staff's desired extremely granular level, is simply not feasible, nor really even worthwhile.

Q. Is there any evidence from the remainder of Staff's CCOS Report that suggests that the incremental granularity that they seek might not be worth the cost of developing it?

A. Yes. In this case, Staff places so much focus on increasing the "accuracy" and/or "reasonableness" of distribution allocations (and assignment), as if the ability to develop just and reasonable rates hangs in the balance of our ability to assign distribution costs to the customer to the penny. And yet when it comes to production cost allocation, Staff does not even take a position on which of eighteen different methods that they calculated is appropriate to use for allocation of this ***huge*** bucket of costs. Because of that, they do not even try to make a point estimate of the cost of serving the different classes of customers in this case at all, but instead create three, or perhaps six depending on how you read their testimony, different scenarios to create ranges of cost of service for the classes. From there, Staff goes on to recommend an equal percentage application of the rate increase authorized in this case to each class because, as Staff says:

> 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.[13]

So I think it is a fair question how much expense and how many resources should be put toward increasing the granularity of distribution analysis – which is already based on a very appropriate and detailed study – to perhaps make small marginal increases in "accuracy,"[14] when Staff is not even going to take a position on the appropriate allocation of production costs, and if they do, it is not going to even influence Staff's recommendation for just and reasonable rates in the case until a class's rates are more than plus or minus five percent from their cost of service.

Q. Staff suggests that the Company's Smart Energy Plan ("SEP") investments change the basis of what causes costs on the distribution system and that this warrants Staff's extreme position related to distribution cost allocation (or assignment) in this case. Do the SEP grid investments create a need for a complete paradigm change related to distribution CCOSS?

A. No. Staff's SEP-related arguments are quite misplaced. Staff notes categories of investments included in the Company's SEP based on broad program names used by the Company to describe groups of similar projects. This categorization includes

[13] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 48, lines 14-17.
[14] Staff's use of the concept of "accuracy" in cost allocation is also misplaced. It is impossible to even assess "accuracy" of a cost of service study, since there is no objective "right answer" to measure against. Even with perfect data, it is almost certain that five different analysts would have five different opinions on what the true cost of service is for each class.

things, as Staff notes, such as "grid resiliency." From its observation of these SEP category names, Staff makes the leap to an absurd conclusion:

> 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," or other purposes such as the implementation of AMI metering.[15]

Staff seems to imply that the names under which the Company categorizes its reliability and grid modernization projects should be the determinative factor in cost allocation, even if the project categories are obviously not intended to be related to CCOSS concepts. CCOSS classification principles consider the drivers of the need for infrastructure to exist in order to determine which customers and classes cause the cost of that infrastructure – e.g., class customer counts, demands, and energy consumption which drive the amount and sizing of system components needed to serve customers. The Company's SEP investment categories were not defined based on these CCOSS classification principles at all, and no one should expect them to be. The categories really are irrelevant to CCOSS, but exist to group like projects based on things like the reason that the affected infrastructure would benefit by being replaced, automated, or otherwise upgraded. The fact that grid resiliency is enhanced, as noted by a particular project's SEP classification, by replacing an aging pole with a new composite pole that better withstands extreme weather events, changes nothing about the basic need to have a pole in that location in order to connect customers to the grid – i.e., it does not change the approrpriate CCOSS driver for the cost from being customer or demand driven to being "grid resiliency" driven.

[15] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 17, lines 11-13.

Quite frankly, Staff's assertion that a pole that is upgraded to enhance grid resiliency no longer fits in to traditional CCOSS framework is nonsensical.

Q. Staff's assignment approach to distribution costs seems to be an attempt to ensure that, to the greatest extent possible, customers pay for the specific costs that are incurred by the Company to serve them. Isn't that a laudable goal?

A. Actually, I think that if this is Staff's motivation, it reveals a misunderstanding of ratemaking generally. Over my two decades of experience being involved in rate review cases, I have been repeatedly advised and reminded by counsel that, legally, customers do not pay for specific costs – they pay for service that is provided. Costs are never directly "included" in any customers' bills by application of base service classification rates. However, rates are designed such that the amount paid for the service provided *reflects* the utility's underlying cost of service. Cost allocation is the means by which that cost structure is reflected in the CCOSS, which is the guide to setting rates that reflect those costs. It is actually appropriate for rates to reflect the amount and type of infrastructure that a customer uses, but at a system average (allocated) cost level. There is no reason that customer or customer class rates and bills should swing up and down over time to try to capture the then-current depreciated value of current assets serving that customer or class, which would change dynamically with infrastructure retirements, replacements, and reconfiguration. Ratemaking is intended to develop rates for customers and customer classes to pay for service in a manner that reflects the cost structure of the utilty, not in a manner that tracks the useful lives and original cost of specific components of the system used to serve them.

Q. Do any of the prominent industry reference materials on CCOSS provide useful insight on how to allocate distribution costs (or whether to assign them)?

A. Yes. The NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") is a highly authoritative source on the topic. In fact, as Staff points out, with respect to production allocations, recently enacted Missouri law specifically points to the NARUC Manual as ***the*** authoritative source for methodologies that should be used in the state. Mr. Hickman discusses the guidance that the NARUC Manual gives on the topic in more detail in his rebuttal testimony.

Staff also references a more recent source on the topic of CCOSS in their CCOS Report, the Regulatory Assistance Project's "Electric Cost Allocation for a New Era – A Manual" ("RAP Manual"), published in January 2020, as an authoritative reference. This manual, published nearly 30 years *after* the NARUC Manual and just over one year ago, has some very telling commentary on assignment of distribution costs. The following is an exceprt from the RAP Manual:

> 11.3.6 Direct Assignment of Distribution Plant - Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop.

> Beyond some limited situations**, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class** and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.[16,17]

To be clear, this is a 270 page plus manual focused exclusively on CCOSS, published in 2020, and by the title, obviously intended to be forward-thinking. The two paragraphs above are the *entirety* of the content on direct assignment of distribution plant to customers or customer classes in the manual, and it merely says that direct assignment "may" be appropriate in certain circumstances. Staff's insistence that direct assignment must be used for certain costs and cost types does not appear to be supported by the brief comment on direct assignment in the RAP Manual. But even more noteworthy is that the RAP Manual's guidance on direct assignment concludes with the apt statement (in bold above and repeated here) that "…***it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class.***" This further reinforces the notion that Staff's attempt to reinvent the CCOSS is not consistent with industry practice, and, for all the reasons I have discussed in this section of my rebuttal testimony, Staff's attempt really "is not practical or useful."

[16] RAP Manual, at p. 156.

[17] I would also note that it appears that Staff's attempts at direct assignment may be resulting in the "double-counting" that the RAP Manual warns against, due to a failure to adjust allocation factors applied to the balance of common costs after direct assignment occurs for the impact of the customer that received the assigned cost, meaning that customer may be inappropriately assigned and then allocated costs from the same category. Mr. Hickman discusses this issue further in his rebuttal testimony.

B. Staff's Recommendation to Suspend Credits Provided Under Rider B Should be Rejected

Q. Staff uses some of their criticisms and concerns related to distribution cost allocation, which you addressed in the previous section of your rebuttal testimony, as a rationale for recommending the suspension of credits for customers served at primary voltages that receive Rider B credits for owning their own substations. What is your reaction to this recommendation?

A. I am genuinely stunned by it. This is a clear example of how Staff's hyper-focus on direct assignment of costs has led them to ignore basic economic principles of cost causation and reach a truly unjustified and arbitrary conclusion.

Q. What is Rider B and why does it provide for certain customers to receive a credit on their bill?

A. The Rider B tariff's subtitle is:

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

The title really says it all. Customers that receive service under this rider own, operate, and maintain significant components of infrastructure – specifically substations that transform power from high voltages to standard primary voltages – that the Company otherwise would have to invest in, construct, operate, and maintain. For all other retail customers on the system (that do not qualify for Rider B), the Company incurs the costs of these facilities, and reflects them in the revenue requirement used to set rates. Base rates for all of the Company's retail service classifications are established on the premise that the Company will provide this infrastructure as a part of basic service, and anyone taking basic service while not receiving a Rider B discount implicitly contributes revenues to cover the cost of these facilities.

Customers who elect to install their own substations initially have to invest hundreds of thousands, or millions, of dollars that displace similar investments that the Company otherwise would have to make. They also bear the on-going cost to operate and maintain those substations. There should be no doubt that the cost of serving these customers is meaningfully lower than the cost of serving similarly situated customers in the same rate class who have not made these initial and on-going investments on their own behalf and instead relied on the Company to make them. But without the credit provided for by Rider B, that difference in the cost of serving these customers would be completely ignored. This punitive change would be unfair to customers that made such significant investment decisions based on an understanding that they would receive these bill credits as a result of their efforts.

Q. What impact would Staff's proposal have on the customers who made these investments in their own infrastructure?

A. There are 58 customers in the 4(M) – Small Primary Service ("SPS") rate class, and 22 customers in the 11(M) – Large Primary Service ("LPS") rate class, that currently receive Rider B discounts totaling approximately $3.8 million annually. The removal of these discounts would increase the SPS customers' and LPS customers' bills on average by an estimated 4.4% and 3.3% respectively, before consideration of any other rate increase granted in this case. These 80 customers would receive no economic benefit from the investments they made, which directly reduce the Company's revenue requirement, for the duration of the suspension of these discounts. There is really no justification to make these customers pay the same effective rates as customers that require the support of millions more dollars worth of infrastrcture than these customers who have self-supplied significant power transformation services.

Q. What is Staff's rationale for this remarkable recommendation?

A. Staff states:

> 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.[18]

Staff's argument appears to reflect a fundamental misunderstanding of cost allocation. Suffice it to say, the argument is objectively incorrect.

Q. How so?

A. In this assessment, Staff appears to be blinded by its hyper-focus on direct assignment of costs. The one correct thing in the paragraph is that "Ameren Missouri does not assign the cost of substation equipment that is dedicated to primary customers to primary customers." That much is true, we do not assign it, we *allocate* it, along with the costs of all substations that serve all customers, based on the demand that each customer class places on the level of the system at which those substations operate. But the point is that whether assigned or allocated, the costs of that substation equipment are reflected in the cost of serving primary customers. Period.

[18] File No. ER-2021-0240, Staff Cost of Service Report, at pp. 53, l. 27 to p. 54, l. 6.

In the section of Staff's CCOS report where Staff analyzed the alocation of Account 362, substations, Staff used a variety of data request responses and Rider B billing determinants to perform a convoluted analysis and discussion to try to back into an estimate of the amount of substation cost that the Company "assigned" to primary customers. Staff says in this section:

> 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.[19]

Staff's use of DRs 591.2 and 678 to understand anything about how the Company allocated or assigned substation expense is misplaced, because those DRs were developed at Staff's request during the discovery phase of the case and had nothing to do with the Company's allocation process it used in developing its own CCOSS. For example, Staff's statement in the quote above that "this results in an initial allocation of approximately 3.73% of the Account 362 balance to primary customers" is completely contradictory to the Company's filed workpaper in the case supporting the CCOSS testimony of Mr. Hickman. The allocation factor developed and used in that workpaper to allocate substation investment uses the class non-coincident peak ("NCP") demands to allocate those costs, and results in ***14.8% of all the plant in that account being allocated to primary***

[19] *Id*. at p. 24, lines 3-10.

customers.[20] It is unclear what Staff's 3.73% figure represents, but it certainly does not represent anything related to how the Company allocated substation costs to primary customers. The Company allocated a significant amount of the total cost of all substation investment to primary customers based on the driver of substation investment – i.e., the NCP demand that customers and customer classes place on that portion of the system. This inherently means that ***the cost of substations dedicated to primary customers is allocated to primary customers*** as long as that substation investment is driven by the size of the load it is serving.

Q. Staff's final sentence from the paragraph of their report that purported to justify the suspension of the Rider B credits, which you cited above was:

> **[T]here 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.**

Given what you discussed above, does this sentence make sense as a justification to suspend Rider B credits?

A. Not at all. First, as I discussed previously, costs are never included in the base rates of customers to begin with. Those rates are simply a charge for the service they receive, and do not recover the specific costs of the specific infrastructure that serves a customer or class. That said, clearly, based on the allocation process undertaken for substation costs, there are more than incidental costs reflected in the revenue requirement allocated to the LPS and SPS classes related to primary substations. In fact, a full allocation

[20] Mr. Hickman's workpaper titled "MO_ECOSS_2021 Final", tab "A.F. 8" shows 587 MW of demand for the SPS class and 467 MW of demand for the LPS class, which, summed and taken as a percentage of the sum of class NCPs on that tab of 7,134 MW equals ((587+467) / 7,134) = 14.8%.

of the cost of ***all substations*** (including those dedicated to primary customers), based on the proportion of LPS and SPS NCP demand – the recognized driver of substation cost – to the total NCP demand of all classes. This represents a reasonable allocation methodology to estimate the full cost of substations used to serve primary customers and reflect them in their cost of service and bills. Staff's statement is wrong and should not be used as the basis to impose an unjustified incremental $3.8 million rate increase on customers that have invested in infrastructure that reduce the amount and type of service that they rely on the Company to provide.

C. Staff's Allegations that the Company Violated the 2019 Stipulation are Competely Without Merit

Q. Staff dedicates over 10 pages of their CCOS Report to allegations that the Company violated provisions of the 2019 Stipulation in the context of this case. What is your reaction?

A. Staff's allegations are completely without merit. The Company clearly complied with the 2019 Stipulation when looking at the Stipulation requirements and the Company's actions during and leading up to this case.

Staff's allegations relate to paragraph 41 of the 2019 Stipulation, which is referenced in its entirety in Staff's CCOS Report. I will replicate it here for ease of reference of its text:

> 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[21]

Staff separately alleges violations of part a and parts b and c together. I will start first by responding to the allegations related to parts b and c.

Q. What was required by parts b and c of paragraph 41 of the 2019 Stipulation?

A. A series of two meetings to discuss the data collection and retention policies around voltage level data.

Q. Did those meetings occur?

A. Yes. The meeting required by part b was organized by Ameren Missouri and took place on April 30, 2020. The follow-up meeting required pursuant to part c was organized by Ameren Missouri and took place on June 26, 2020. Those meetings fully satisfied the Company's obligations under parts b and c of paragraph 41 of the 2019

[21] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 57, lines 1-27.

Stipulation. Staff appears to allege non-compliance with the 2019 Stipulation parts 41b and 41c because they did not receive granular data exactly how they wanted it in discovery in this case. Of course, that would be a discovery matter to be addressed in this case, and not an issue of 2019 Stipulation compliance. Moreover, the plain terms of 41b and 41c contain not one word that committed the Company to provide any specific data information in any specific format; the commitment was to "discuss" and "follow-up". We did both.

Q. What additional efforts did the Company make as a result of those 41b and 41c meetings to assist Staff in obtaining additional clarification and data that they were requesting?

A. Staff's biggest request coming out of those meetings was for detailed voltage level tracking for SEP projects and investments. The Company developed a template that it offered to complete in the next rate review case (this one) and shared it with Staff, who the Company understood to agree that it would be what they were looking for related to the SEP and voltage tracking issues. The Company preprared that template as requested, and provided it to Staff in the response to DR MPSC 242. The completion of this template represented a significant incremental effort of the Company that would not be required under normal discovery practices, but that the Company willingly undertook based on the conversations with Staff pursuant to the 2019 Stipulation.

For purposes of DR MPSC 242, Company personnel spent many hours of time and effort to manually review each SEP project, and characterize all of the investments in each one by FERC account and the voltage at which it operates. In total, 648 work orders representing over $890 million in investment were manually reviewed, and the information was provided to Staff upon its request in this case. The Company understood this to be a high value analysis for Staff and accordingly put in the extra effort necessary to deliver it.

As Staff acknowledges multiple times throughout their CCOS Report, at the meetings that were held pursuant to parts b and c of paragraph 41 and subsequent discussions, the Company expressed significant concerns about its ability to provide the level of granular voltage information about the full population of distribution assets – which goes beyond the SEP investments to cover all distribution assets installed over many decades – that were of interest to Staff. As Staff also indicates, there were ideas exchanged and concerns discussed. Apparently these exchanges left Staff with the "… impression that Ameren Missouri would be preparing a 'reasonable breakout' of the costs within each distribution account by operating voltage."[22]

First, I will say that Staff's impression does not alter the terms of the Stipulation or the commitments the Company was obliged to live up to, and it is remarkable that Staff is actually alleging non-compliance with a Stipulation based on something they cannot characterize as anything more than an impression they took away from a meeting (which itself was the only thing actually required for compliance).

But second, my recollection of the conversations left me with a different impression. What the Company suggested as an outcome of these meetings was that *some* of the information that Staff wanted, and formats that they wanted it in, was *a reasonable long-term goal* for the Company to develop the capability to provide. Our capability to provide that data *over time* would depend in part on the progress we were able to achieve in our digital mapping initiative, and in part on being able to allocate resources to

[22] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 61, lines 16-18.

developing additional reports, analyses, and studies. To my knowledge, none of that was anticipated by the Company, nor communicated to the Staff, to be an immediate deliverable in the next (this) rate review case.

That said, there was some level of additional granularity of distribution analysis undertaken in the development of this case that was a direct result of feedback from Staff in the Stipulation-related meetings and their interest in more granular use of voltage level information. The Company extracted more detailed voltage information regarding the utilization of assets in Account 364 (poles) from the Vandas Study. This additional voltage level information was incorporated in a new and more detailed analysis of Account 364 for the Company's minimum size study, as reflected in the workpapers supporting Mr. Hickman's direct testimony, which by virtue of inclusion in that workpaper also made an abundance of additional voltage level detail available to Staff related to Account 364. The Company definitely considered the enhanced analysis of the voltage allocations of poles to be a meaningful incremental step in providing the type of additional data that Staff is seeking.

Q. In its CCOS Report section related to alleged Stipulation violations, Staff recites a litany of DRs that they asked in this case pursuant to their expectations that arose from the meetings on this voltage tracking topic, and quotes many parts of the Company's answers in reply that they were dissatisfied with. Do these complaints have any relationship to to commitments under the 2019 Stipulation, and were the Company's efforts to respond to Staff's discovery requests reasonable?

A. Again, the 2019 Stipulation 41b and 41c requirements were to have meetings, and those meetings were held. These DRs are outside of any requirement of that stipulation and have no bearing on determining whether the Company complied with the 2019 Stipulation.

But with respect to discovery issues in this case more generally, the Company expended a tremendous amount of time and energy to provide Staff with responses to a huge volume of complex DRs related to distribution assets, allocations, and issues. While Staff is apparently upset with some of the DRs that the Company objected to or was unable to fully answer, the Company did provide Staff with orders of magnitude more data than any case I have been aware of in the past. For context, in the Company's last two rate review cases (File Nos. ER-2016-0179 and ER-2019-0335), the Company responded to approximately 10 and 16 Staff CCOSS-related DRs respectively. Whereas, in this case, Staff witness Sarah Lange of Staff submitted 111 DRs (to date). But beyond just the raw numbers of DRs that the Company responded to, the complexity of them far exceeded the complexity of DRs in past cases. For example, the average DR of the 111 had approximately 4 subparts, and at least 7 had more than 10 subparts, most of which were of a highly complex nature.

I have attached copies of two of the DRs that the Company objected to, and which apparently contributed to many of Staff's discovery complaints in the case, merely to demonstrate the extreme complexity and obvious call for substantial analysis found in Staff's DRs, and the tremendous resource burden they therefore created for the Company. See DR MPSC 533, attached as Schedule SMW-R1, for an example where Staff requested Company engineers to develop very detailed analyses for 30 different hypothetical construction scenarios. See also DR MPSC 716, as Schedule SMW-R2, which shows the incredibly complex reporting and analysis that the Staff wanted to the Company to provide related to every single digital system of the Company that had any information about distribution assets, which ostensibly was Staff's attempt to make the Company prove a negative – i.e., that we did not have the granular data that they wanted in an accessible manner.

But beyond just answering the large majority of the 111 DRs, the Company also made available a group of engineers, accountants, and cost of service staff for a meeting with Staff to further discuss some of the questions that the Company had not been able to answer in their entirety. Across the board, the level of information that the Company did provide, and the level of engagement and support from Ameren Missouri's engineers, data analysts, accountants, and a large variety of cross-functional teams that were required to respond to the broad array of new Staff questions, significantly exceeded any case that I have seen by a large margin. Staff's discovery complaints frankly relate more to their insistence on receiving data that generally is not available from industry-standard record keeping, as I discussed previously, rather than a lack of effort on the Company's part.

Q. Now please turn to commenting on Staff's allegations about non-compliance with part a of paragraph 41 of the 2019 Stipulation.

A. This allegation is similarly without merit, for a number of reasons. Staff claims that the requested information in DR MPSC 592, as required by part a of paragraph 41, was not provided. That is simply not true. It is best illustrated by highlighting the specifc wording of Staff's request, and the specific wording of the Company's response, as included in Staff's CCOS Report that raises the issue.

> From Staff's request: "Data shall be made available in the form of **hourly usage per customer** and **aggregate hourly usage** by rate schedule…"[23]

[23] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 58, ll. 35-36.

> From Company's response: "This tab contains **hourly aggregated** rate class level estimated **usage** between 01/01/2020 and 04/30/2021…" then further responds, "[T]his tab contains estimated **usage per-customer.**"[24]

Staff was specific in the type of data that they were requesting – i.e., hourly class aggregate usage and usage per customer, and the Company responded with that specific data. Staff states that what the Company provided "is the result of simply dividing Ameren's load research load by rate schedule by the number of customers per rate schedule." The reality is that load research load by rate schedule is in fact ***hourly aggregated usage*** for the rate schedule, which is what Staff asked for. When it was divided by the number of customers, it became *hourly usage per customer* (the other thing Staff asked for).

Staff goes on to claim that this information is not what is needed to create a Coincident Peak ("CP") Demand Charge, as had been requested. That is simply not true. A CP demand charge means a charge based on customer demand that is coincident with (occurs at the same time as) the system peak. To create billing units for such a charge, one would need to know the aggregate class demand (the sum of each individual customers' usage at the CP time which can be ascertained by load research, and which would be what the charge would be billed upon) at the hour of the system peak – i.e., exactly what Staff asked for and the Company provided.

What became evident at the August 24th discovery conference, where Staff first raised any issue with the Company's response to DR 592,[25] was that Staff's own request did not accurately describe the type of demand charge that they actually wanted to create

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[24] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 58, ll. 7-8 and ll. 23-24.

[25] Despite having received the response to DR 592 on July 20, Staff did not communicate any issues with the response to the Company until it raised their concerns to the Commission in its statement of dispute filed just in advance of the August 24th discovery conference.

in either the 2019 Stipulation or in DR 592. Staff did not want to create a CP demand charge at all, but they wanted to create a charge that could be characterized as a "peak period," "peak window," or "on-peak" demand charge.[26] Basically, this means that Staff wanted to create a demand charge based on each customer's maximum usage that occurs within some defined time period during which the system peak loads tend to occur, as opposed to a CP demand charge based on customers' usage at the *actual hour* of the system peak. The data that was provided, admittedly, was not sufficient to create an "on-peak" demand charge. Of course, that is because Staff had not asked for data to create an on-peak demand charge. If the Company had attempted to read Staff's mind and provided alternative data, the response actually would not have complied with what was specifically required by the 2019 Stipulation.

Staff observes that later – too late for them to use it – that the Company did provide information that could be used to create the on-peak demand charge they were interested in. To be 100% clear, this supplemental response provided by the Company after the August 24th discovery conference was not an attempt to suddenly comply with the Stipulation provision 41a. The Company already had complied with that when it provided the first answer. However, the supplemental response was provided as a courtesy to Staff in order to try to get it what they really wanted, once what Staff really wanted became clear.

[26] Note that on page 69 of Staff's CCOS Report where it makes recommendations for the data the Company should have to track going forward, Staff changes its wording to reflect an "on-peak" demand charge. Staff also used the "on-peak" demand charge wording in its report in File No. EW-2017-0245 that is referenced on page 50 of Staff's CCOS Report in the discussion of modernizing rate structures. While these may seem like very nuanced differences, the terms "CP" and "On-peak" have specific meanings that carry implications for different data to calculate them.

Q. In the Staff's complaint about the Company's compliance with paragraph 41a, they also claim:

> **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.**

How do you respond to this claim?

A. This claim is completely unfounded. The Company used load research data to respond to this data request instead of AMI data not because of a failure to maintain an appropriate amount of AMI data, but ***because fully half of the the test year in the case, and the period for which Staff was requesting data, occurred prior to even the very first AMI meter being installed*** pursuant to the Company's Smart Meter Program. It should go without saying that the retained AMI data will only begin as of the date that an AMI meter is installed and becomes operational, and that the Company would not be able to produce 12 or 16 months worth of such data until 12 or 16 months (or more) have elapsed since AMI metering was installed.

Staff is aware of the Company's AMI rollout timeline, and even asked the Company via DR 592 to "[p]lease indicate whether data provided is based on load research data or gross AMI meter data." The fact that Staff raised this issue as a Stipulation compliance issue is puzzling. It was literally impossible to have 12 or 16 months of rolling AMI data available to use in the response to this DR, since there was not a single AMI meter that had been in service for even 12 months by the end of the time period for which data was being requested. And, to answer the follow-up question that may come as a result of this allegation, I can verify that the Company is retaining customer AMI interval data for substantially longer than 12 or even 16 months, for this and a variety of other purposes.

D. Staff's Request for the Commission to Order Additional Data Retention Should Unquestionably Be Denied

Q. Staff's CCOS Report includes a recommendation that the Commission order the Company to undertake certain data retention measures. Is Staff's request reasonable?

A. No. The Commission should deny Staff's request in its entirety. I would first point out that Staff's characterization of this request as pertaining to "data retention measures" is a misnomer. It makes it sound like there is a bunch of useful data sitting around that the Company is discarding or otherwise failing to capture and retain. Staff's request is actually a request to perform a massive overhaul of many of the digital systems and processes that the Company relies on to run the Company, in order to capture and correspond different data than that which is needed to operate the business. The data and systems that the Company builds and maintains are designed around the operational needs of running an electric utilty. It is especially noteworthy that Staff has not alleged any shortcoming in service that the Company is providing to its customers that arises from the alleged deficiencies in data retention, and has alleged no shortcoming in retention of information required by the Uniform System of Accounts or other accounting requirements. That is because the Company has the data it needs to operate its system and serve its customers. The goals of Staff in performing extremely granular distribution direct assignments and allocations are not the primary business considerations that should drive the development of the Company's systems and processes, and the costs and business impacts of modifying those systems and processes to achieve the additional purposes of Staff's request should be carefully considered.

The first consideration is the incremental value of the data Staff is seeking. Mr. Hickman and I have testified at length to the point that the allocation process the Company uses for distribution costs is in line with industry standards as it exists today. We have also provided many reasons, both conceptual and practical, that the approach Staff seeks to take to CCOSS is deeply flawed. Beyond that, even if Staff's method were perceived to be more accurate for allocating costs, as I observed earlier, the Staff does not even change its recommendation in the case until that accuracy causes a greater than plus or minus 5% difference between cost of service and current class revenue responsibility. To be frank, there would simply be negligible, if any, incremental value brought to the ratemaking process that would result from the Commission ordering the extremely expensive measures that Staff recommends.

Q. Please further explain the impacts that such an order would have with respect to costs incurred and/or resources needed to comply.

A. I will speak generally to this point. Quite frankly, certain parts of Staff's request are so impactful on our digital systems that there is not even time to truly scope all of the work that would be required in the time allotted for rebuttal testimony in this case. Further, to fully scope the project would likely have significant cost and resource implications in and of itself. Staff's recommendation is really segregated into three distinct requests, and I will address them individually.

Let me start with the easiest. Staff's third request pertains to AMI meter data needed to create an on-peak demand charge. There actually is no incremental cost or effort at all for this request, because the Company is already doing it, and will continue to do it regardless of whether or not the Commission orders us to. AMI interval data is a valuable resource and a benefit of the Smart Meter Program, and the Company has every intention of retaining substantially more data than Staff is recommending that we be ordered to retain. A Commission order on this topic is simply unnecessary.

Next, I will turn to the first item on Staff's list, their recommendation that the Company be ordered to "[t]rack 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."[27] Staff goes on to create an itemized list of eight requirements that would be necessary to achieve minimal compliance with this request. Of those eight items requested by Staff, some are more problematic than others for the Company to be able to track.

Specifically, the request for all of this tracking to identify the customers by rate schedule at each specific voltage creates challenges. This request would require potential changes to a number of systems and substantial efforts to link, validate and subsequently update information between different data sources. There are a number of parameters of the data that would need to be defined, such as the measurement of what consitutes a customer for purposes of determing the voltage that should be reported, since certain customers have multiple meters that may be served at different voltages.

Aside from the technical challenges of tracking the information Staff has requested in this list, I would note that Staff has not clearly articulated the specific benefit of retaining this data. Staff claims that "[th]is information will facilitate more accurate calculation of

[27] File No. ER-2021-0240, Staff Class Cost of Service Report, at p. 67, lines 6-8.

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."[28] Yet, Staff does not explain what is not accurate about the calculation of current billing determinants. Knowing the specific voltage customers are served at does nothing to change billing determinants for customers or customer classes. For example, primary customers served at 4 kilovolts ("kV") and 12 kV are billed identically to each other – differentiating their billing units serves no apparent purpose. The same is true for any secondary voltage customer, whether served at 120 volts ("V"), 240 V, or 480 V. But Staff's DRs in this case ask for this level of granularity of information.

If Staff is going to demand this level of detail, it should be incumbent upon it not only to articulate that they think the information is necessary in order to "increase accuracy," but how and why that is the case, and what negative consequence will result if this is not done. At the end of the day, Staff should justify why this effort should be undertaken at all, and how the benefits of such granularity exceed the costs that would be incurred and/or warrant the diversion of Company resources from other customer- or operation-focused activities in order to resolve the issues.

That saves for last, Staff's second data retention request for the Company to "[f]ile 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."[29] This sweeping request to "associate distribution

[28] *Id*. at p. 68, lines 12-14.
[29] *Id*. at p. 68, lines 15-19.

system costs with the voltage of energy distributed and whether distribution system costs are used for network purposes or customer-specific purposes" has a potentially massive scope that is extremely burdensome in terms of costs and/or diversion of resources from more pressing customer or operational issues.

I had more in depth interactions with digitial personnel at the Company to understand just how burdensome this is. To be frank, Staff's description raises more questions for the people that would have to develop this plan than it answers. But based on what is immediately apparent and understandable from Staff's request, the following initial thoughts on the process that would have to be followed were conveyed to me by digital personnel:

1. "Plant that are dedicated to individual customers" – This requirement would necessitate an intense GIS (Geographic Information System)-based analysis and tracing of every customer (defined as premise or meter) through the facilities that serve them. This would entail tracing/tagging every feature (transformer, conductors/wires, poles, switches, substation, subtransmission, subtransmission substation, etc.) in the GIS database as serving that individual "customer". Although the poles are a further complication as our poles are not owned/tagged to the conductors that reside on them and many poles also support multiple conductors and voltage levels. The end result, if feasible, would be a database of all GIS features (transformer, conductor segment, pole, etc.) and the "customers" that are provided service from that specific feature….*although it would have no perspective on the portion (often defined by their load) of that they utilize.* It would just be an identification of the "normal" configured network/plant that is required to provide them any portion of their load/usage. It is also important to note that the distribution system is fairly dynamic in that operation or load based switching occurs frequently and any point in time customers may be served by a different source (substation, feeder, etc.). GIS only contains the normally configured network and not those abnormal switched configuration There are also likely other constraints/limitations in the GIS data that may also impact feasibility.
2. "Plant" – If this is relating to the book value/asset value of each specific plant category (poles, conductor, substation), some of these are mass asset accounts. So there is no way to determine how much of a specific plant's rate base should be allocated to any specific GIS

feature. Perhaps this could be attempted to be captured by age, although we don't have information in our GIS on the install date or age of every GIS feature. GIS began at Ameren Missouri in the mid 1980's when all paper maps were converted into the electronic system. Plant mapped in GIS at that time generally did not capture any information on the age/install date of those facilities. There are likely other complications with allocating plant/rate base to the GIS features.

3. The two data sources (1 and 2) above would need to be combined through process/analytics to produce the desired "record keeping and data accessibility" information requested. Is this a database or is there an application needed that then has to expose/provide that information to users? Does it then need to be easily accessible for internal use or even external use (customers or developers)? Represented on a GIS viewer for locating/finding/reviewing?

This initial brainstorming by Company digital personnel reveals that it is clear both that the scope of Staff's request would be massive, and yet it is still unclear exactly what all would need to be included in that scope. That said, the value of this information, which still has not been articulated clearly by Staff, cannot possibly be believed to exceed what would undoubtedly be a staggering cost to create, maintain and update it.

Staff's data retention requests indicate an extreme overreach by a Staff that is hyper-focused on direct assignment of distribution costs, but Staff has not, and perhaps cannot, articulate the merits of that approach. The Commission should reject Staff's request out of hand.

IV. STAFF'S RECOMMENDATIONS ON RESDIENTIAL RATE DESIGN IGNORE THE CURRENT STATUS OF AMI DEPLOYMENT AND CREATE TOO GREAT A RISK OF CUSTOMER CONFUSION

Q. What recommendations does Staff make with respect to the Company's ongoing introduction of TOU rates to its customers?

A. Staff makes two recommendations. First, Staff recommends widening the peak to off-peak rate differential in the new TOU default rate. Next, Staff recommends the adoption of "more objective or informative names" for the Company's TOU rate plan offerings.

Q. Do you have any overarching comments on considerations that the Commission should keep in mind as they evaluate these proposals?

A. Yes. The Company is very interested in the success of the new TOU program, and the Commission itself has expressed keen interest in this as well.[30] One of the key determinants of success in getting customers to adopt TOU rates, stay on TOU rates, and respond to TOU rates is creating a positive experience for customers that are being introduced to the new rate options. Significantly changing parameters of rate structures and renaming rate options so shortly after the initial rollout of the TOU options creates a significant risk of creating customer confusion and frustration. I spoke of this at more length in my direct testimony in this case, as did Company witness Dr. Ahmad Faruqui.

In today's environment of social media, it would be very easy for confused or frustrated customers to create negative perceptions of TOU rates that would be difficult to overcome, which may make it more difficult to achieve higher levels of advanced rate adoption. Creating a stable environment around the TOU program – in terms of communications (rate plan names) and bill impacts (not tripling the price differential between on-peak and off-peak rates) is a key way to reduce the risk of negative perceptions of TOU rates and help grow the popularity of these plans among the Company's customers. The success of TOU in Missouri may just depend on doing so.

[30] Indeed, the Commission asked that Ameren Missouri present updates on the TOU rollout at public Agenda Meetings, and the Company presented on the TOU rollout at Commission Agendas on July 29, 2020 and February 24, 2021.

A. Staff's Recommendation to Triple the TOU Default Rate Peak Differential Could Trigger Current Customers' Frustration

Q. Staff proposes to triple the peak/off-peak differential associated with the new default rate. What complications would this create around the current rollout of TOU rates?

A. I described in my direct testimony the Company's communication plan for introducing TOU rates, along with the process for customers to choose a new optional rate or move to the new default TOU rate. Recall that the Company communicates directly with customers prior to transitioning those customers that do not elect another rate plan to the default rate with information about the bill impacts that they can expect from this rate change based on a customized analysis of their own usage patterns applied to the new default rate. Of course, that bill comparison is based on the present peak/off-peak rate differential. Hundreds of thousands of customers will have already defaulted to the Evening/Morning Savers rate over the immediately preceding ten months when rates take effect from this case, armed with those personalized bill impact calculations. Tens of thousands more customers will have very recently received rate comparison letters that adivse those customers of what to expect when they are potentially defaulted in the very near future. All of that information the customers have relied on, or are relying on, to understand their experience will become inaccurate if the peak/off-peak ratio is tripled the day rates take effect from this case. This appears to be a recipe for customer confusion and frustration.

I would also note that the goal of this very-small-differential TOU rate was to introduce customers to TOU concepts in a setting with low expected bill impacts, while also making available to customers a set of more robust saving opportunities associated with more advanced optional TOU rates. Keep in mind that customers are only receiving this introduction once they receive an AMI meter, and the deployment of those meters, which leads to new customers being introduced to the rates, will still be ongoing through 2024. If we embark on a path of increasing the TOU differential for the default rate now, customers who do not receive an AMI meter until later in the Company's deployment will be exposed to larger potential bill impacts when they first default to the new rate and will not have the default TOU experience in a setting with the lowest risk of adverse bill impacts. These more significant bill impacts for customers being defaulted to a wider differential TOU rate will also exist for more economically vulnerable customers that have lower tolerance for higher bills. Delaying the idea of widening the default rate differential will give us more time to work through the AMI meter deployment, accumulate granular AMI customer usage information, and conduct customer education about peak and off-peak rates. Furthermore, if the widening of the differential is delayed, for those customers that are interested in greater savings opportunities immediately, we still have a number of high quality options for them to elect rates that can provide more significant rate differentials and savings potential available today. Dr. Faruqui discusses the need for consistency in the roll out of the default rate in his rebuttal testimony. The Commission should reject the request to widen the default rate differential ***at least until the deployment of AMI meters is complete in 2024***.

B. Staff's Recommendation to Adopt "More Informative or Objective Names" for the Residential Rate Plans is Unreasoned

Q. What is your reaction to Staff's recommendations to change the names of the rate plans that the Company has used to communicate the rate plans to customers?

A. If the proposal to widen the default rate is somewhat troubling to me, this proposal is even far more objectionable. Customers that have received AMI meters and the subsequent rate education materials, and/or taken it upon themselves to look into the rate options available to them, have started to learn the rate offerings by the existing names. Renaming all of the options as this point would create significant confusion and would likely set back the Company's rate education effort considerably. The Company would really need to start from scratch on re-educating customers about their options. Dr. Faruqui discusses this dynamic in more detail in his rebuttal testimony.

Q. Staff goes on to claim that the current names are "not informative and portray the ToU rate schedules as money-saving opportunities." Is the focus on saving opportunities in the rate plan names appropriate?

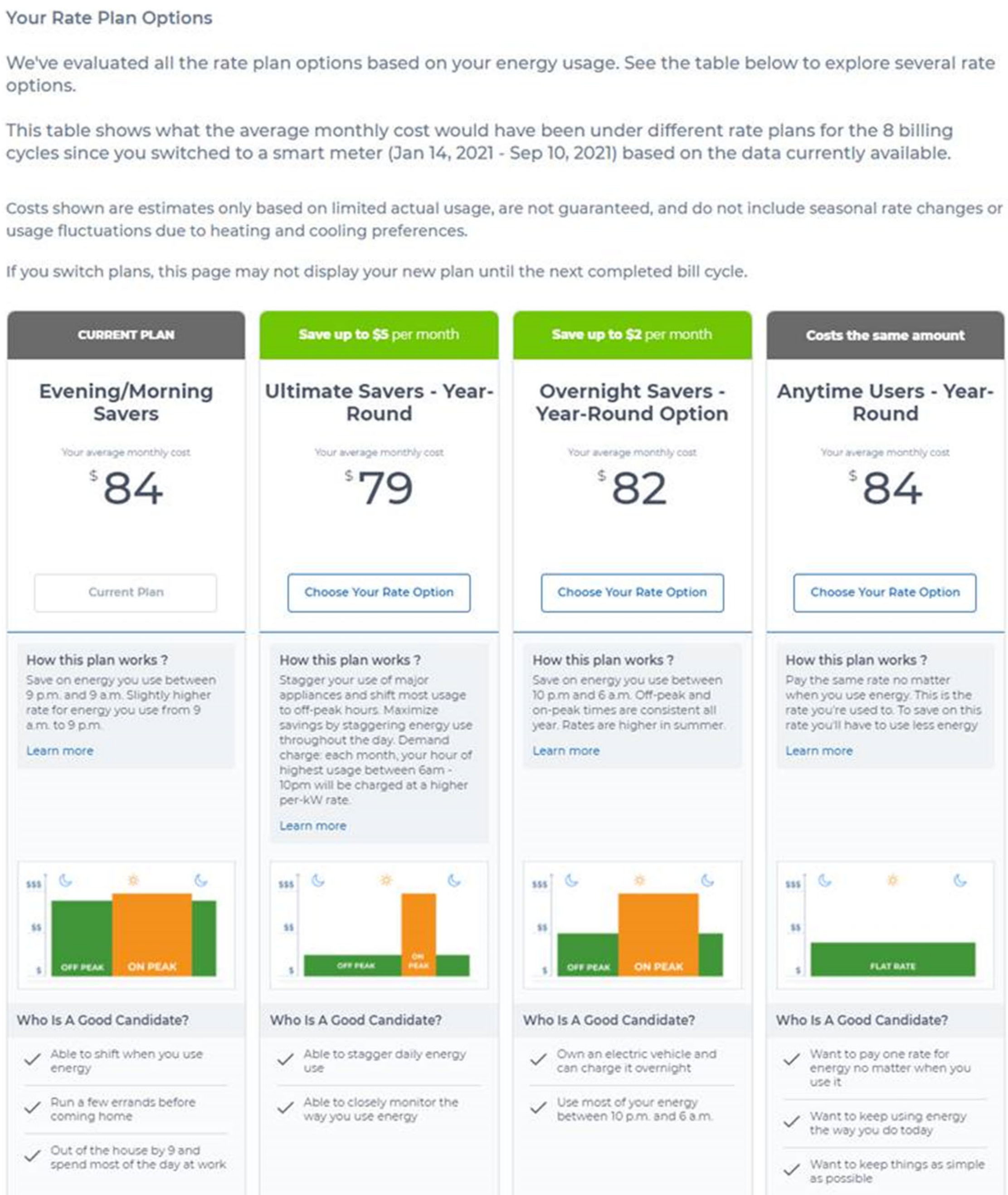
A. Absolutely. Focus on money-savings opportunities is ***exactly*** what we should be doing with these rates. First of all, the rates unquestionably do create savings opportunities. They are designed to encourage customers to take actions in response to price signals to shift load, provide benefits to the system, and subsequently save those customers that took action some money on their bills. Highlighting the savings opportunities is the best way to attract customers to want to learn more about the rates, and perhaps give one a try. As Ameren Missouri explained during its July 24, 2020 Commission Agenda presentation, Ameren Missouri conducted customer research, including focus groups and surveys with diverse customer segments and geographies, to aid the Company in its TOU enhancements. Staff did not propose any "more objective or informative" names, and they do not cite to any customer research to suggest that the current names are problematic,[31] but my guess is that those names would not be nearly as effective at promoting TOU to the Company's customers as the savings-oriented names.

Staff also mentions that the focus on savings does not communicate to the customer the risk of higher bills that these rates create. I would first observe, though, that the Company does differentiate in its communications with customers between "Basic" rates and "Advanced" rates to try to highlight the more complex nature of some rate plans. Moreover, the Commission should keep in mind that the Company is arming its customers with information to make these choices about these rates with eyes wide open about the effect these rate structures will have on them, based on their own lifestyles and usage characteristics. The Company has implemented a customer-facing usage presentment and bill comparison tool that provides customers with detailed but clear and easy to understand information about the experience they should expect on any of the rate options, including whether their current usage profile would create savings or adverse bill impacts. So, while the rate plan name may not directly highlight any risk of adverse bill impacts, for the customers whose usage is likely to result in adverse bill impacts, the information to understand that dynamic will be readily available.

[31] The Company is not aware of any complaints asserted against it before the Commission regarding the nomenclature of rate plans, and Staff did not cite to any inquiries or complaints it has received on the topic.

Figure 1 below shows a clip of what a customer sees when they log into their Ameren Missouri account online to learn more about how the rate plans would impact them:

Figure 1 – Rate Plan Comparison Online Tool



It is obvious from Figure 1 that the new online tool presents a clear image of expected bill impacts that would reveal any potential for an adverse bill impact. For residential customers that are not able to use or are not comfortable using the internet to find this information, the same data is available to Ameren Missouri's call center personnel to walk customers through their options. Incidentally, not only would changing the names impact our customers, but these call center and other Company employees that have become educated about the new rate options would require new training and would be subject to confusion around the changes.

Q. Are the early adopters of the advanced TOU options experiencing savings?

A. By and large, yes. Of 179 customers on the two most advanced rates – Smart Savers and Ultimate Savers – as of the September bill period, 79% of customers saved money during the part of the summer that they were enrolled in the rate. The average monthly savings for those customers with lower bills on the TOU rate was 15% ($20), and the few customers that did not save only saw bill increases of 6% ($6). The total savings for *all* customers on these rates (including the small number that saw higher bills) for the July through September period was 11%. The early returns are in, and customers that are choosing these rates are saving money. That's good news for those customers, for the system, and for the many customers who, over time, will find those opportunities for themselves. And we should try to attract customers who are interested in saving money to these opportunities, including through the continuation of the current savings-oriented rate naming convention.

Q. Please summarize your recommendation.

A. The robust customer research that underlies the rate plan names and overall customer education campaign, along with the new digital tools the Company is providing customers to understand potential bill impacts of the new rates, the success customers have already had saving with the new rates, and the general goal of driving improved system utilization through price signals to create savings associated with beneficial actions, all argue strongly for the continuation of the existing rate plan names that focus on savings opportunities. The customer confusion and also the disruption and potential added cost to the current AMI and rate option rollout that would result from a change argues strongly against making a change in naming conventions at this time.

V. THE RESIDENTIAL CUSTOMER CHARGE SHOULD VARY ACROSS RATE PLANS AS I DESCRIBED IN DIRECT TESTIMONY

Q. Staff, in its CCOS Report, recommends allocating the entire rate increase that is attributable to the residential class to the energy charges, implying that there should be no increase to the residential customer charge. What rationale is presented by Staff for their recommendation?

A. Staff indicates that the current residential customer charge (and those applicable to the other classes other than LPS) "equal or exceed the CCoS Study-determined customer charge."[32] They provide no more detail than that simple statement, and a table of their "CCoS Study-determined customer charges."

[32] File No. ER-2021-0240, Staff Class Cost of Service Report, p. 49, lines 8-9.

Q. Do the costs reflected in Staff's table on page 49, which shows Staff's calculation of the "CCoS Study-determined customer charge," include all of the costs that Staff classified as customer-related for purposes of allocating them to the classes?

A. No. Staff uses only a subset of the costs that they allocated to classes based on customer count to establish the "CCoS Study-determined customer charge." There are a number of distribution accounts for which the Staff utilized either the Company's minimum size study, or a variation on it, to allocate the revenue requirements to the classes, but these are omitted from the costs shown in the table on page 49. The costs associated with the minimum size distribution system – including a portion of the costs of poles and overhead and underground condutors and devices – are allocated to classes based on customer counts. These costs are therefore appropriately classified as customer-related costs.

Q. If the driver of those costs is customers for purposes of allocating them between classes, should they be associated with energy charges in the rate design process?

A. No, I spoke about this at greater length in my direct testimony. Rate design is really an extension of the cost allocation process. The same principle of cost causation is at work in the design of rates, which effectively determines the allocation of costs among customers within a class. Generally, reflecting costs in the rate element (e.g., customer charge, demand charge, energy charge) that matches the cost classification (e.g., customer-related costs, demand-related costs, energy-related costs) from the CCOSS, reflects the cost structure of the utility to customers on their bills. An appropriate determination of the customer charge would include these additional customer-related costs from the CCOSS.

Q. Jacqueline Hutchinson, of the Consumers Council of Missouri, also recommends maintaining the current residential customer charge. What is your response to Ms. Hutchinson's argument?

A. In part, it is the same as my response to Staff's rationale. Ms. Hutchinson states that "[I]deally, the rate design for residential customers should include a fixed charge that is based on no more costs than the meter, customer service, and the line to the dwelling."[33] To the extent that there are other costs that are customer-related, such as the minimum size costs of poles and conductor, those costs are also appropriate to reflect in the customer charge in order to develop a rate structure that reflects the cost structure of the utility.

Q. Ms. Hutchinson also argues that customer charges hurt low-income customers, and that in order to give customers the ability to control their bills, fixed charges should be kept low. Do you agree?

A. No. I also addressed these specific issues extensively in my direct testimony in this case, so I will be brief here. Low-income customers, like all residential customers, exist all across the usage spectrum, meaning that there are some low-income customers with relatively low usage and some with relatively high usage. High usage low-income customers have the highest energy burden of anyone on the system, but keeping a low customer charge negatively impacts affordability for these customers. Lower customer charges mean higher variable charges, which raise the bill of high usage customers, including those with low income – those customers that I just identified as having the highest energy burden of any customers on the system.

[33] Rate Design Direct Testimony Jacqueline Hutchinson on behalf of CCM, at p. 10, line 21 – p. 11, line 1.

As far as Ms. Hutchinson's suggestion that fixed charges should be kept low in order to provide customers with an enhanced ability to control their bills, the Company's proposal in this case already accommodates this recommendation. Recall that the advanced TOU rates, which are designed with customers who want to control their bill in mind, are proposed to have no or little increase in the customer charge.

VI. MECG'S PROPOSAL ON LGS/SPS RATE STRUCTURES

Q. What issue does MECG witness Steve Chriss raise regarding the Company's rates applicable to its LGS and SPS rate classifications?

A. Mr. Chriss recommends that the Company redesign its LGS and SPS rate structures prior to the completion of AMI deployment to those rate classes, which is expected to occur by the end of 2024. He suggests that the current "hours use" rate structure is overly complex and is not fully aligned with cost of service considerations. He recommends increasing the share of costs that are covered by demand charges relative to those covered by energy charges in this case, and also redesigning the "hours use" energy charges prior to 2025.

Q. What is the Company's response to these recommendations?

A. Mr. Chriss' proposal for this case — to increase the demand charge more than the energy charge — is directionally consistent with cost of service principles to the extent that the distribution demand-related costs are not currently fully reflected in the demand charge. However, the amount of movement in the demand charge proposed by Mr. Chriss in this case is significant and would likely produce material bill impacts on a large number of LGS and SPS customers. I used the rates Mr. Chriss developed in his workpapers to examine an estimate of the bill impacts the proposal would have on the LGS rate class population in a given month. That analysis suggests that, for more than 1,600 of the smaller customers in the class, it would be likely to produce bill increases, arising just from the rate design change and in addition to any rate increase authorized in this case, of more than 5%. The largest individual increase for any customers would reach as high as an estimated 18%.

Q. Are there any reasons that it might be appropriate to delay shifting more costs to the demand charge and away from the energy charge?

A. Yes, it is very worthwhile to consider the potential impact of increasing the demand charge at this time on efficient electrification. Support of the electrification of transportation, and its many benefits to both the economics of the system, and its environmental impacts, can be impacted by LGS/SPS rate structures. This is because of impacts of the demand charge on the bills of such customers who may engage in the provision of public high speed EV charging services, or who may engage in their own fleet electrification efforts (including heavy duty trucks, buses, etc.). During the early years of EV adoption, a commercial customer that provides high speed EV chargers to the public may see significant contributions to their billing demand established as a result of the chargers, but not have as much total EV-related energy consumption due to the relatively low adoption of EVs so far. The demand charge impact can hurt the economic case for that customer to provide the higher speed EV charging service. Similar issues can impact fleet electrification considerations.

Some industry stakeholders are recognizing this fact and recommending "demand charge holidays" to emerging users of electric transportation in commercial and industrial sectors. It is generally acknowledged, though, that these accommodations for electrification are not consistent with cost of service considerations, and they are generally being offered on a temporary basis just to get vehicle electrification across an initial economic barrier, with a return to higher demand charges planned for the future.

I bring this up because I think it is a pertinent consideration for the Commission to be aware of. That said, the Company's LGS and SPS demand charges are not particularly onerous at this time in my opinion — hence MECG's request to increase them (relative to energy charges). I still generally believe modest increases in the demand charge may be reasonable, but I also do not think it would be unreasonable for the Commission to place a little more emphasis on early transportation electrification efforts by leaving the current demand versus energy charge balance as it is today.

Q. How do you respond to Mr. Chriss' suggestion that the Company revamp its LGS and SPS rate structures by the time of the expected completion of the AMI meter rollout?

A. Mr. Chriss correctly notes that the Company has emphasized modernizing its rate structure in its most recent two rate review cases including this one, and also correctly observes that residential rates received the bulk of the attention in the Company's testimony in those rate review cases. I agree with Mr. Chriss that the rate structures of all classes are important and should follow cost of service considerations, so Mr. Chriss's suggestion is well taken. I would simply observe that the residential rates were the initial focus of the Company because they are the farthest removed — and substantially so — from being modern rates that reflect the cost of service to customers of any of the Company's rate classes. The LGS and SPS rates that Mr. Chriss focuses on are already three-part rates, and while the hours use energy charges are complex, they also do factor in information related to the customer's demand, and therefore result in a much better relationship between bills and cost of service than do the Company's residential rates.

The Company is open to contemplating future rate design changes for these classes. Because I believe any such changes should take place when they can be applied to all customers, it is important to wait until the AMI meter rollout is complete to implement any such changes. It will also be important to carefully analyze any potential changes under consideration in order to understand the potential bill impacts that they would create for customers and potentially make any transition gradually and thoughtfully.

VII. MECG's REQUESTS FOR DATA ACCESS AND BILLING FORMAT CHANGES SHOULD NOT BE ORDERED

Q. MECG witnesses Steve Chriss and Andrew Teague make several recommendations related to customer data access and billing presentation. Can you please summarize your understanding of those issues?

A. Mr. Teague raises two related issues about increasing the availability of customer usage data that is collected through the new AMI meters. First, he recommends that the Company allow customers to download their own interval usage data, and that entities with multiple accounts, like his employer Walmart, be able to do that in one download for all of their service accounts at the same time. He next recommends that the Company implement Green Button Connect My Data functionality for customers to access usage data.

Mr. Chriss raises an issue related to EDI bill formats. He asks that the Company be ordered to provide more detail in EDI bills, including all components needed to verify the calculation of the complex 3M and 4M rate structures.

Q. What is your reaction to MECG's requests?

A. The Company certainly understands MECG's interest in having access to detailed usage information, and we are working currently to increase that type of access for our customers. On this point, I would share that the Company recently rolled out its new platform for customer usage presentment to its residential customers. I described that system, and shared a screenshot of the bill comparison functionality available to residential customers in it, earlier in my testimony when discussing residential rate design issues. That same system is expected to be rolled out for commercial customers in the future. Another enhancement to the system that is planned to be released in 2022 is the addition of Green Button Download My Data functionality.

But as we evaluate those and future system upgrades, it is helpful to have engaged customers communicating the type of data that they would find useful, as MECG has done here. We will take their feedback to heart in looking at potential system enhancements for the future. That said, I would be concerned if the Commission ordered the specific requests of MECG on this topic without there being an opportunity to further evaluate some of the challenges presented to the Company's digital systems and processes and timing thereof.

Q. What issues are there with the specific requests of MECG?

A. First, the issue of allowing an entity to download data associated with all of their accounts creates some challenges with respect to data privacy, cyber security, and related issues. There would have to be a means to verify the specific accounts that any system user is authorized to access. That may be more challenging than it appears, as different entities have different corporate structures and affiliate relationships, and the Company would need to have a means to identify the accounts that were controlled by a common entity versus those that were not to be included. While the Company is willing to explore its capabilities and what would need to happen to deliver this capability, I would encourage the Commission not to order a particular outcome until the technical issues can be more completely vetted.

Next, I would comment on MECG's request related to Green Button Connect My Data functionality. As I mentioned previously, the Company does have on its development road map the release of Green Button Download My Data functionality. The Company believes that this functionality is appropriate to meet customers' needs. I hesitate to endorse the idea of pursuing Connect My Data functionality. My understanding is that it is more complex and costly to develop. At the same time, it seems potentially duplicative of MECG's separate request to develop aggregated download capability and also with the Company's existing plan to implement Green Button Download My Data functionality. Again, I think the Commission should refrain from ordering a specific data access solution in order to allow the Company to evaluate the many options and make a comprehensive data access plan that will meet the needs expressed by MECG.

Q. What is your reaction to Mr. Chriss's request to make more data available through EDI bill formats?

A. Through some preliminary research with our digital team, I have learned that this request would be much more than a trivial amount of work to implement. That is because of the very nature of how these charges are programmed in the Company's billing system – what data is stored in what steps of the calculation, etc – dictates the availability of information to include in EDI bills. It is not simply a matter of reformatting the bill, but of actually reprogramming the billing system calculations, that would be required to make this change. To that end, I recommend that the Commission not order such a change. That is particularly the case, given MECG's suggestion that the hours use rate structure they would like more visibility into on their EDI bills is also something that they recommend that the Company transition away from in the not too distant future. The time and expense to reprogram the calculation of what is, as Mr. Chriss points out, a quite complex rate is not well spent if that rate design is to be considered for revision in the next few years anyway.

Q. Are there any other miscellaneous issues you wish to address before concluding your rebuttal testimony?

A. Yes. At the time of filing my direct testimony, I referenced a change to the Company's Keeping Current tariff that the Company proposed to implement as a result of a recommendation from the collaborative effort of parties related to that tariff. At the time, though, the Keeping Current tariff had a pending change, so a new tariff could not be filed that reflected that change. Now that the Keeping Current tariff does not have any pending changes, the proposal that was described in my direct testimony in this case will be filed simultaneously with this rebuttal testimony in the tariff tracking matter, YE-2021-0175.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

MPSC Data Request
ER-2021-0240
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service

No.: MPSC 0533

Consider the following hypothetical customers. For each, please provide an itemized construction estimate including a detailed list of the specific materials that would be expected to be used for that circumstance, the current cost of those materials, and the expected installation cost of those materials. Please identify those materials with labeling or reference numbers consistent with the descriptions used in the continuing property catalog.

1. A 3000 sq ft house with no gas or propane, located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

2. A 1000 sq ft house with propane located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

3. A 3000 sq ft house with no gas or propane, located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

4. A 1000 sq ft house with propane located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

5. A 5000 sq ft commercial office with no gas or propane, located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

6. A 1000 sq ft commercial office with propane located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

7. A 5000 sq ft commercial office with no gas or propane, located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

8. A 1000 sq ft commercial office with propane located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

9. A 1 MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

10. A 1 MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

11. A 5 MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

12. A 5 MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

13. A 10 MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

14. A 10 MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

15. A 20MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

16. A 20MW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

17. A 25 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

18. A 25 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

19. A 50 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

20. A 50 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

21. A 75 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

22. A 75 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

23. A 100 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

24. A 100 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

25. A 200 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

26. A 200 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

27. A 500 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

28. A 500 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

29. A 750 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area.

30. A 750 kW customer located 1 mile from a suitable point of interconnection with existing distribution infrastructure with sufficient capacity to serve the load. The line will be placed along an existing road with no other infrastructure present, and no surface or sub-surface issues. No additional load is expected to materialize in the area. Underground distribution and service facilities are requested.

DR requested by Sarah Lange (Sarah.Lange@psc.mo.gov).

MPSC Data Request
ER-2021-0240
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service

No.: MPSC 0716

Part A. Please generally explain and describe each ledger, data system, map, accounting system, or other source or repository of data to which the company records information associated with the distribution system, distribution plant, or distribution characteristics, or relies upon for operation or accounting concerning the distribution system, distribution plant, or distribution characteristics. The response should include but not be limited to the General Ledger, the Continuing Property Record, the Customer Information System, the GIS system, and distribution operations or maintenance systems or ledgers. Nonexclusive example (1) are meter numbers included in the Customer Information System a number that can be found on a physical meter? Does the CIS system include information about the model, size, or operational characteristics of a meter or information that allows cross reference to another system containing that information? Nonexclusive example (2) What purpose do asset numbers visible on poles, transformers, and substation assets serve? Where are those numbers recorded, what other information is contained in that source or ledger, and what other systems may it be cross referenced with? Nonexclusive example (3) Where a customer has been financially responsible through application of the facilities extension tariff or similar tariff provision for some or all of the cost of plant additions, and/or retirements, and/or associated labor or other expenses or costs, what information is retained and in what form and for how long? Is the rate schedule of the originally requesting customer known and/or retained? Is the plant for which contribution was obtained identified in any manner in any source, system, or ledger? Part B. For each system, ledger, or other data repository, please describe what data concerning the distribution system is contained in that system, and how it is accessible, how it is internally organized, and what other systems or ledgers it may be cross-referenced with, either directly or indirectly. For each system, ledger, or other data repository and, if applicable, for each type of information within each source, please identify the date at which the information was last updated, and the schedule or criteria for updating information. Part C. (1) Please provide an example or examples of what information would be entered into each system associated with a new customer at a new location requesting secondary service under a scenario(s) of the company's choosing, and the approximate timeline that would typically be associated with entry of that information. (2) Please provide an example or examples of what information would be entered into each system associated with a new customer at a new location requesting primary service under a scenario(s) of the company's choosing, and the approximate timeline that would typically be associated with entry of that information. (3) Please provide an example or examples of what information would be entered into each system associated with an existing primary circuit being rebuilt with new conductors and poles under a scenario(s) of the company's choosing, and the approximate timeline that would typically be associated with entry of that information. (4) Please provide an example or examples of what information would be entered into each system associated with a new circuit being rebuilt with new conductors and poles under a scenario(s) of the company's choosing, and the approximate timeline that would typically be associated with entry of that information. DR requested by Sarah Lange (Sarah.Lange@psc.mo.gov).

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	Case No. ER-2021-0240

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn on his oath, states:

My name is Steven M. Wills, and on his oath declare that he is of sound mind and lawful age; that he has prepared the foregoing *Rebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Steven M. Wills
Steven M. Wills

Sworn to me this 13th day of October, 2021.