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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
January 2020

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven M. Wills and my business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Are you the same Steven M. Wills that submitted Direct Testimony in this case?

A. Yes, I am.

II. PURPOSE

Q. To what testimony or issues are you responding?

A. My testimony addresses a number of issues from the direct testimony of other parties in this case. First, I discuss the interplay of the rate reduction proposed in this case and the rate reduction that was implemented in August 2018 as a result of the Tax Cut and Jobs Act ("TCJA") of 2017, as enabled by Senate Bill ("SB") 564. Based on the testimony of Office of Public Counsel ("OPC") witness Bob Schallenberg, and the Staff's Class Cost of Service Report ("CCOS Report"), there appears to be significant confusion about this topic, which I will clarify.

Next, I discuss a number of other issues, many of which are related to residential rate design. The issues I will address include:

- Sierra Club witness Avi Allison's testimony related to the appropriate level of the residential monthly fixed charge.

- Staff's proposal to apply any residential rate decrease only to the first usage block of 750 kilowatt-hours ("kWh") or less.
- Mr. Allison's testimony recommending rejection of the Company's proposed three-part residential rate pilot.
- Issues raised by the Staff, Sierra Club, and Division of Energy witness Martin Hyman related to the design and implementation of the "Smart Savers" and "EV Savers" Time of Use ("TOU") rates proposed by the Company, and alternatives proposed to these rates by some of these parties.
- Certain issues raised by Missouri Energy Consumer Group ("MECG") witness Steve Chriss related to the design of the Company's Large General Service ("LGS") rate and Small Primary Service ("SPS") rate.
- Certain other issues raised by the Staff in their CCOS Report related to billing and data retention.

III. OVERALL RATE REDUCTION PROPOSED

Q. Please provide a short background of the rate change that arose from the TCJA and SB 564.

A. The TCJA, passed in December 2017, was a significant change to federal tax policy which included, among other things, a substantial reduction in the corporate income tax rate applicable to companies like Ameren Missouri. The resultant reduction in income tax expense had a substantial effect on the Company's revenue requirement. In May 2018, the Missouri legislature passed Section 393.137, RSMo, which gave the Missouri Public Service Commission ("Commission") authorization to reduce electric utility rates to reflect the tax savings associated with the TCJA without conducting a full rate case that would consider all relevant factors. Ameren Missouri and other stakeholders worked to expeditiously calculate a rate credit that would reduce customers' bills in an amount commensurate with the Company's tax savings, and the Commission approved the rate to be implemented effective August 1, 2018. Since that time, all of the Company's retail customers have received a bill credit for each kilowatt-hour of consumption each month that ultimately reduces bills by approximately 6%. The bill credit was initially introduced as a separate line item, but was intended to be "rolled into" base rates in the next electric rate case of the Company. This is that case.

Q. Please explain how the impact of the TCJA is included in the rates proposed by the Company in this case.

A. The calculation of income taxes included in the revenue requirement proposed by the Company in this case reflects the provisions of the TCJA, meaning that the revenue requirement in this case is lower than it would have been absent the TCJA. The Company's base rates, as proposed in this case, are therefore lower than they would have been absent the TCJA. The separate line item credit related specifically to this issue, however, will no longer be reflected in the Company's tariffs or applied to customer bills, as the credit was designed to be an interim mechanism.

Q. Since the credit represented an approximately 6% reduction for customers, and it is no longer being applied to bills, does that mean that the Company is effectively proposing a significant rate increase in this case as suggested by Staff's original CCOS Report and OPC?

A. No, that is a misunderstanding of OPC. The rates proposed by the Company in this proceeding represent a 0.03% decrease from the level of present revenues when *including the revenue reduction currently provided for by the tax credit line item.* Compared to base rates originally approved in the Company's last full electric rate case, File No. ER-2016-0179 (prior to implementation of the TCJA-related rate reduction in August 2018), this case represents a decrease of a little *over 6%*. Staff originally shared that misunderstanding, but filed supplemental testimony to clarify that, in fact, Staff also recommends a true rate decrease in this case.

Q. What evidence from the Company's filing can you provide to support the conclusion that this is a rate reduction compared to rates in effect today (including the tax credit)?

A. See Figure 1 below, which is a screenshot of workpapers provided with the direct testimony of Company witness Michael Harding:

Figure 1 – Workpaper of Michael Harding

Weather Normalized-12 months ending December 2018							
Projected Growth to December 2019					Cust Chrg	$9.00	
Residential Class						Unrounded	
	Billing Units	Rates	Revenue	Revenue Shift		Proposed	
						Rate	Revenue
Customer Charge							
Summer Bills	4,265,511	$9.00	$38,389,602				$38,389,602
Winter Bills	8,535,546	$9.00	$76,819,910				$76,819,910
TOD Bills	1,082	$9.00	$9,742				$9,742
Low Income Charge	12,802,139	$0.04	$512,086			$0.04	$512,086
Total Bills	12,802,139						
Energy Charge							
Summer kWh	4,703,625,375	$0.1258	$591,716,072			$0.1177	$553,603,452
On-peak	74,477	$0.3150	$23,460			$0.2947	$21,949
Off-peak	423,574	$0.0787	$33,335			$0.0736	$31,188
Energy Eff kwh	4,704,119,520	$0.0003	$1,411,236			$0.000000	$0
Tax Credit	4,704,123,426	-$0.00621	-$29,212,606				
				$563,971,497			
Winter kWh							
First 750 kWh	4,817,304,105	$0.0876	$421,995,840	$0	$0.0876	0.0819577	$394,814,953
Over 750 kWh	3,806,441,387	$0.0600	$228,386,483			0.0561354	$213,676,037
On-peak	0	$0.0000	$0				
Off-peak	0	$0.0000	$0				
Energy Eff Charge	8,623,717,675	$0.0002	$1,724,744			$0.000000	$0
Tax Credit	8,623,745,493	-$0.00621	-$53,553,460				
				$598,553,607			
Total kWh	13,327,868,918						
	0.00621	Total	$1,278,256,444				$1,277,878,919

Figure 1 shows Mr. Harding's preliminary calculation of residential rates for this case, prior to adjusting the customer charge for the change from $9 per month to $11 per month that I proposed in my direct testimony.[1] There are several things to note in this workpaper that clearly demonstrate that the Company's proposal is truly a decrease from rates customers are experiencing today, including the tax credit.

First, note that the column labeled "Rates" shows today's tariffed rates. The next column, labeled "Revenues," shows a simple multiplication of the test year billing units developed by the Company for this case by current rates, to show present retail revenues on a normalized basis. Notice that there is a line item in both the "Summer" and "Non-summer" sections of this calculation showing the tax credit of -$0.00621/kWh, which produce present revenues of -$29 million and -$53 million respectively. Those amounts are included in the total present normalized residential revenues shown, of $1,278,256,444 at the bottom of that column. Looking to the columns on the right in Figure 1 – those beginning with the column with a heading of "Proposed Rates" – we see that the tax credit line items (in both the Summer and Non-summer calculations) are set to zero, and there is therefore also zero revenue attributed to this charge type. And yet, under this Proposed Rates calculation, the total revenue of $1,277,878,919 is *lower* than the normalized present revenues that *included the tax credit* (not surprisingly, by 0.03%). The revenues proposed are lower than the present revenues, which themselves already reflected a nearly $83 million decrease that resulted from the rates set in the Company's last electric general rate case, File No. ER-2016-0179.

[1] Using a version of the calculation with no rate design changes provides a clearer comparison of present and proposed rates. Note that the version of rates Mr. Harding prepared with the $11 customer charge results in the same overall level of proposed revenue as this example shows.

Just to take one more step in the proof, a simple comparison of the present and proposed energy charges illustrates the point. Take just as one example, the summer energy charge. The current rate is shown to be $0.1258 per kWh, which is consistent with existing Company tariffs. The proposed rate is shown to be $0.1177 per kWh. The proposed rate of $0.1177 is 6.4% lower than the present rate of $0.1258. Following this exercise through for the other seasonal energy charges would yield a similar result, meaning there is no offsetting increase in any other charge types shown in this schedule. The only conclusion that can be arrived at upon completing this review is that the Company's proposal represents a decrease in rates – period; not a decrease that is offset by the removal of a credit which ultimately results in an increase.

Q. What did OPC witness Schallenberg say about this issue in his direct testimony?

A. Mr. Schallenberg states:

> On the effective date of new rates in this case, the Company proposes to remove the TCJA customer bill credits from customers' current bills. When considering the adequacy of Ameren Missouri's current rates, it is important to understand that the current TCJA bill credit is a monthly line-item reduction to customers' bills. Eliminating this credit will increase customers' bills, and consequently increase the Company's revenues. In the Company's response to OPC data requests, Ameren Missouri identifies that the annual impact of these bill credits to be $177,747,832. This amount will be additional revenues to Ameren going forward. [2]

Mr. Schallenberg implies that the additional revenues that result from the removal of this bill credit produce a net increase in rates that will be experienced by Ameren Missouri's customers. However, my previous analysis demonstrates that the decrease from the tax credit is reflected in the proposed rates the Company filed in this case. Customers

[2] Schallenberg Direct, page 11, lines 8-15.

will still be benefiting from lower income tax expense and lower rates when rates are implemented from this case than they are today.[3]

Q. What does Staff's CCOS Report suggest about the removal of the tax credit line item?

A. The Staff CCOS Report originally shared Mr. Schallenberg's concern that a net rate increase would be experienced by customers due to the removal of the tax credit. However, Staff subsequently filed the supplemental direct testimony of Sarah Lange that recognized an internal inconsistency in their case. Based on the supplemental testimony, Staff also validates that rates are proposed to be lower as a result of this case even with the removal of the tax credit line item on customer bills.

Q. What are the key takeaways for the Commission related to all of the discussion around the TCJA?

A. The key takeaway is that the Company's proposal is for rates to be lower when this case concludes than they are today – not lower but with a net increase resulting from the elimination of the credit – but lower, period. As a secondary takeaway, I would caution against relying on any; 1) statements about the nature of the rate change resulting from the case, 2) rate calculations, or 3) bill comparisons from the Staff CCOS report and refer to only the supplemental testimony filed on this topic.

[3] Mr. Schallenberg also references the rebasing of net energy costs as being a factor that suggests this case represents an increase. While future Fuel Adjustment Rates have the potential to increase eventually in part due to the rebasing of net energy costs to a lower level, the immediate outcome of the case will be a rate decrease. And Fuel Adjustment Rates could also decrease; whether they increase or decrease is largely a function of the volatile and uncertain components tracked in the FAC.

IV. RESIDENTIAL RATE DESIGN – MONTHLY CUSTOMER CHARGE

Q. Which parties are you responding to regarding the Company's proposal to increase the monthly customer charge from $9 to $11?

A. I am addressing the testimony of Sierra Club witness Avi Allison. Mr. Allison recommends reducing the customer charge to $7.90 per month. Mr. Allison makes his recommendation based both on cost of service considerations as well as policy considerations.

Q. What cost of service considerations lead Mr. Allison to argue for a lower residential monthly customer charge?

A. Mr. Allison argues against the Company's use of a Minimum Distribution System ("MDS") study to allocate costs of certain distribution system components between the customer-related and demand-related cost classifications.

Q. Do other parties to this case also use an MDS study in their class cost of service ("CCOS") studies?

A. Yes. In fact, every party to this case that performed a CCOS study other than Sierra Club used some form of MDS to allocate costs among the various classes. Staff used a method known as a zero-intercept study, while the Missouri Industrial Energy Consumers ("MIEC") used the Company's minimum size study as the starting point of its CCOS study. The specific methodological differences notwithstanding, each party with a CCOS witness determined that it was appropriate to consider some costs associated with the shared distribution system as customer-related. Maurice Brubaker, testifying on behalf of MIEC, expounds at some length on the merits of the MDS in his direct testimony. Company witness Tom Hickman's direct and rebuttal testimonies provide support for the

Company's MDS allocation approach. As I discussed in my direct testimony, the CCOS study is used to allocate costs on an inter-class basis, but rate design is a logical extension of that process, which is appropriately viewed as the means by which costs are effectively allocated on an intra-class basis. There is simply no reason that costs that are considered to be customer-related by all parties that perform a CCOS study — costs which are allocated on a customer basis between classes — should suddenly become demand-related costs when contemplated as a part of the intra-class allocation provided for by the residential rate design.

Q. What is Mr. Allison's rationale for arguing against using the results of the MDS to inform the appropriate level of the Residential customer charge, and what does Mr. Allison propose be used to set the customer charge in place of MDS?

A. Mr. Allison claims that the costs that are allocated using the MDS approach do not have a direct relationship to the number of residential customers on the system. He suggests that the costs associated with poles, conductors, conduit, and line transformers are driven by two factors: customer demand and the geographic dispersion of the grid. Mr. Allison proposes use of the Basic Customer Method to establish the residential customer charge, which only incorporates costs that vary *directly* based on the number of customers on the system into the customer charge.

Q. How are these two factors identified by Mr. Allison, demand and the geographic dispersion of the grid, reflected in the MDS study versus the Basic Customer Method?

A. Classifying costs (e.g., as customer- or demand-related) is a practice of determining what drives or causes the incurrence of particular costs. The MDS study is specifically designed to segregate out distribution costs associated with these two distinct cost-drivers identified by Mr. Allison, and allocate each in the most appropriate way. The Basic Customer Method, on the contrary, inappropriately treats all of these costs as being driven *solely* by demand, even when Mr. Allison acknowledges the geographic dispersion of the grid as a second distinct cost driver.

The MDS recognizes that, regardless of the demand on the system, good engineering practice and basic electrical standards require a certain level electrical infrastructure be in place simply to connect a customer to the grid – and that this infrastructure has a cost irrespective of the amount of demand to be served. While, as Mr. Allison correctly points out, this minimum sized system has some load-carrying capability, its cost is not in any way a function of that level of load. Said another way, *demand is not a cost driver for the minimum system*. Rather, the costs of that minimum system are those which Mr. Allison presumably meant when describing costs as being driven by the geographic dispersion of the system. I agree with his characterization in this regard, at least with respect to the number of poles and miles of wire and conduit.[4] However, the geographic dispersion of the system has *some relationship* to the number of customers served — in fact, logic suggests it is a fairly strong relationship — whereas it has *no relationship whatsoever* to demand on the system. By failing to recognize these costs as customer-related, Mr. Allison defaults these costs to the demand classification, which has no discernable relationship to the geographic dispersion of the system.

As new customers are added and the total geographic extent of the system expands, new poles, wires, and transformers must be installed, and the basic costs of the minimum

[4] Line transformers are, arguably, much more directly related to the number of customers.

size system grow regardless of the level of demand being served. The number of customers is clearly the more logical cost driver – and therefore, allocation basis – for the costs of the minimum distribution system.

Q. Mr. Allison references the marginal cost of adding a new customer as a relevant data point for the establishment of the customer charge. Please comment on the implications of marginal cost pricing and rate design.

A. Mr. Allison makes this reference in two places. First, he states: "Such costs are unlikely to have any direct relationship with the marginal costs of a customer joining or leaving the grid…" [5] Later, he states: "In addition, it is worth noting that even if one were to accept the MDS method as a flawed but acceptable approach for allocation of embedded costs across different classes, that does not justify its use for rate design purposes, where marginal costs are much more important than embedded costs."[6]

Marginal costs are most relevant in rate design for purposes of trying to develop rates with price signals that help to elicit economically efficient energy consumption decisions from consumers. To the extent that rates are too low, relative to marginal cost, customers may make wasteful energy consuming decisions; whereas to the extent rates are too high relative to marginal cost, customers may have to forego services that they actually value greater than the cost of rendering that service. However, this phenomenon should guide both inter-class (i.e., CCOS) and intra-class (i.e. rate design) cost allocations equally, and Mr. Allison's contention to the contrary is unsupported and counter to economic theory. All classes of customers make economic choices about energy that affect the total system

[5] Allison Rate Design Direct page 7, lines 10-11.
[6] Allison Rate Design Direct, page 8, lines 13-16.

and have alternatives to electricity for some energy services, and marginal cost considerations are as relevant to setting allocations between these classes (i.e., CCOS) as they are within classes (i.e., rate design).

But we also know – and this is true of rates set routinely by this Commission and virtually every other regulatory authority in the country – that rates are ultimately going to be set in a manner designed to recover the embedded costs of the total revenue requirement, which will not result in rates perfectly equaling marginal cost. If that ratemaking condition is going to exist (i.e., at least some rate component, and probably all rate components to a degree, will deviate from marginal cost in part due to the inclusion of fixed distribution costs in the revenue requirement), the question becomes: where is the best place to recover these joint and common distribution costs that will have the least impact on customers' economic choices? Clearly, the answer is the customer charge.

Q. Why do you say that?

A. The only energy-related decision that could theoretically be influenced by the level of the customer charge is the decision regarding whether to connect to the grid and take electric utility service in the first place. Once that decision is made, the customer charge is fixed and therefore completely irrelevant to the amount and timing of electricity consumption. Imagine a customer who is deciding whether to establish service with the local electric utility. Whether the utility's fixed residential monthly customer charge is $7.90 (Mr. Allison's proposal) or $11 (the Company's proposal), I can imagine no residential customer that would factor the $3.10 per month difference into a decision whether they wanted electric service at their residence or not. In effect, it is a forgone conclusion in today's society that everyone will choose to have residential electric service at any *plausible* level of customer charge, as supported by the class cost of service study of any of the parties to this case. The primary purpose of considering marginal cost in rate setting – to drive customer energy-consuming decisions that result in better economic outcomes – is totally irrelevant to the decision to establish residential electric service.[7]

But keep in mind that if we exclude the MDS costs that may not be *directly* driven by customer numbers from the customer charge for reasons associated with marginal cost considerations, we must push those same costs, which are *not in any plausible way* driven by demand, into a consumption-based charge. This means, in the case of Residential customers, that the MDS costs will be included in an energy charge that applies to every kWh consumed. And the inclusion of these fixed costs associated with poles, transformers and wire in the per-kWh charge drives *that charge farther away from marginal cost*. And that charge – the residential energy charge – is exactly the charge that *can* influence energy consumption decisions with real implications for economic outcomes.

Q. Please discuss the economic consequences of inflating the residential energy charge farther above marginal cost than necessary in order to maintain a low customer charge.

A. The first consequence of significance is the impact on electrification efforts. I mentioned in my direct testimony the importance of keeping the well-documented benefits of efficient electrification at the front of mind when considering rate design. Higher variable energy charges that arise when artificially keeping the customer charge low mean additional cost for electric consumption associated with, for example, electric vehicles ("EVs"), among other things. As customers decide whether to electrify their own

[7] It is conceivable that this could change in the future if going "off-grid" becomes a commercially viable option.

transportation (or other end uses), the electric rate is an important part of the total cost of ownership equation that many customers are likely to consider, along with the other tradeoffs between EVs and internal combustion engine vehicles. While it might seem counterintuitive at first, raising the customer charge (and by extension reducing the per kWh charge) makes the economics of the electrification case stronger and can drive increasing levels of benefits associated with greater use of electricity relative to direct use of fossil fuels.

This is not a trivial matter. Electrification is increasingly being viewed as an absolutely critical part of the nation's path to decarbonization. This is recognized by parties, jurisdictions, and studies from across the country, and the evidence of the importance of electrification is growing. In Ameren Missouri's service territory, the benefits of electrification will continue to grow as the Company deploys more and more renewable energy in coming years, such as the approximately 700 megawatts ("MW") of new wind capacity anticipated to come online this year.

The Sierra Club itself – the sponsor of Mr. Allison's testimony – recognizes the importance of electrification. For example, an article posted on Sierra Club's website titled "The Future is Electric!" opens with the statement: [8]

> Transportation is the largest source of carbon pollution in the U.S., producing 40 percent of our climate-disrupting greenhouse gases. One way to combat the climate crisis is to replace the vehicles that run on dirty fossil fuels with clean vehicles that give off no exhaust -- and not just the cars we drive, but also the school buses our children ride on, the transit buses we take to work, the cars we share and ride-hail, the vehicles our government fleets deploy, and even the vehicles we operate while on the job.

[8] Found at: https://www.sierraclub.org/compass/2018/09/future-electric

The American Council for an Energy Efficient Economy ("ACEEE") has also recognized the importance of electrification. The introduction of a recent report on truck electrification produced by ACEEE begins as follows: [9]

> To address climate challenges, many actions will be needed to reduce emissions of greenhouse gases (GHGs). A recent ACEEE report finds that energy efficiency can be used to cut US GHG emissions in half by 2050. Of these emissions reductions, nearly 9% are from electrifying trucks (Nadel and Ungar 2019), which is thus the focus of this paper.

It is noteworthy in this introduction that truck electrification is referred to simply and clearly as energy efficiency, as evident by the reference of 9% of the emissions reductions associated *energy efficiency* coming from truck electrification.

An additional study to note on the important role of electrification in decarbonizing the economy is the Electric Power Research Institute's ("EPRI") U.S. National Electrification Assessment published in April of 2018. The EPRI study analyzed a variety of future scenarios related to energy policy and support for electrification. A clear finding of the report is that the scenarios with the greatest economy-wide improvements in overall energy efficiency (across all fuels) and the steepest reductions in carbon emissions are those with the highest level of electric load growth driven by electrification (i.e., displacing direct use of fossil fuels with electricity). Figure 2 on the following page is a graphic from that EPRI report that illustrates the studies key findings:

[9] Electrifying Trucks: From Delivery Vans to Buses to 18-Wheelers, January 2020. https://www2.aceee.org/e/310911/-trucks-delivery-vans-buses 18/hq3k5l/485913271?h=m9An9lsajNJhjcvMENdvfPiu31JwOGncewHzpQsVddg

Figure 2: EPRI Electrification Study Scenario Results[10]

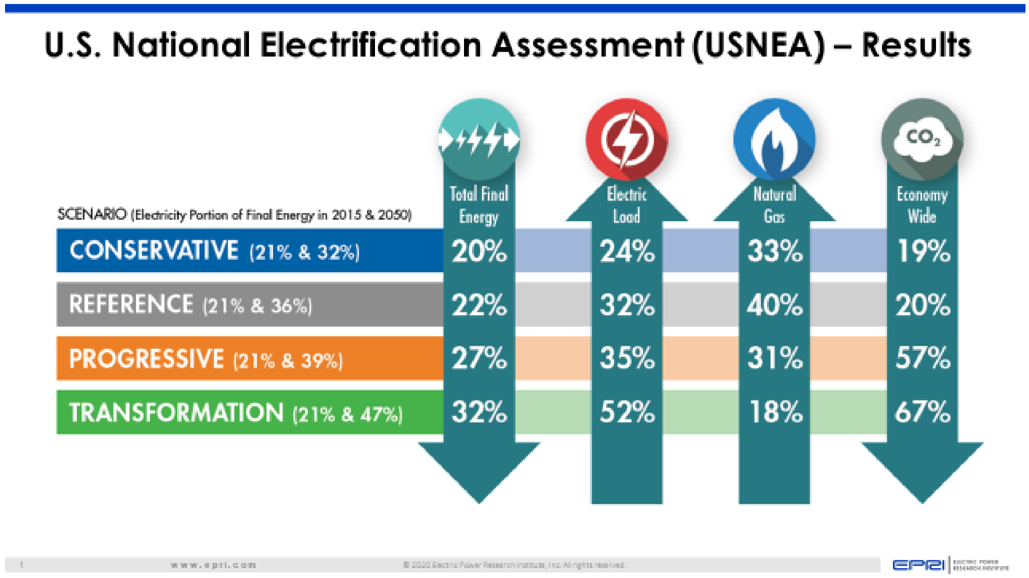


Figure 2 shows four scenarios based on different technology trends and policy environments. The figures in the graphic represent the percent change in each category projected by the study between 2015 and 2050. Noteworthy is the continuum where successive scenarios feature greater economy-wide reductions in total energy consumption, natural gas consumption, and carbon dioxide emissions accompanied by higher levels of electric energy consumption. This is a powerful illustration of the potential for electrification to make the economy more energy efficient while simultaneously reducing carbon emissions.

In order to provide greater economic support for the achievement of these important and broadly recognized benefits of electrification, fixed charges should be a preferred method of recovering costs of the type associated with the MDS study rather than

[10] Reproduced with permission from EPRI. U.S. National Electrification Assessment, April 2018, available at https://www.epri.com/#/pages/product/000000003002013582/?lang=en-US.

including them in energy charges that reduce the attractiveness of EVs and other electric end uses that compete with the direct use of fossil fuels.

Q. Mr. Allison also argues for a lower Residential customer charge on policy grounds. He starts by addressing the impact of the fixed charge on the incentive to use electricity more efficiently. Does the Company's proposal harm energy efficiency efforts?

A. No. In fact, to the contrary, *overall* energy efficiency is promoted by higher fixed charges offset by lower energy charges, as I discussed above at length regarding efficient electrification. But even in the context of looking only at *electric* energy efficiency, the concern Mr. Allison raises related to the impact of the customer charge is not nearly as significant as he implies. In the Company's last electric rate case, File No. ER-2016-0179, the Company analyzed the impact of its proposed Energy Grid Access Charge on the participant payback of various energy efficiency measures. First, it is noteworthy that the Company's proposal in that case included an almost $5 increase in monthly fixed charges, whereas the pending proposal in this case is only for a $2 per month increase. But even with that larger increase, the payback for the average energy efficiency measure in the Company's residential programs only increased from one year and ninety days to one year and one hundred fifteen days. It is hard to imagine that a customer that is willing to invest in an energy efficiency measure with just over a year payback would forego that same investment when the payback took just twenty-five days longer. And again, the impact of the proposal in the current case on measure paybacks would likely be less than half of that magnitude, given the requested increase in the fixed charge is only $2 versus the almost $5 underlying that analysis.

Q. Mr. Allison uses data from the Company's last Integrated Resource Plan ("IRP") to suggest that residential customer load will likely increase by 0.6% due to customers increasing consumption in response to the lower variable price. Do you agree with his analysis?

A. No. Mr. Allison is misinterpreting the Company's IRP. In my former role at Ameren, I was responsible for the IRP load forecast, so I understand precisely the nature of the price elasticity assumption that Mr. Allison adopted out of the IRP. The price elasticity assumption in the IRP is designed to forecast the impact of *average rate levels* on customer load over time. Said another way, if the overall general revenue requirement increases due to inflation and/or investment in the system and the Company comes in for general rate increases, the higher level of average bills is assumed to induce some increased conservation. [11] That elasticity assumption, however, is not designed to forecast customer response to a change in *rate design*. A rate design change creates a mixed effect in terms of individual customer outcomes, with some customers experiencing increased bills and others experiencing decreased bills, but no overall change in the total electric expenditures of the whole class. The impact on customer usage of that rate design change is much more complex than the impact of a general increase in price levels like the IRP analysis is designed to capture. I spoke at more length on the topic of elasticity and rate design in my direct testimony, citing the Company's IRP analysis of inclining block rates. The same effect exists in this context, please see my direct testimony for further support of the notion that a change in rate design has a more complex, and in the case of inclining blocks and this issue of the fixed versus variable charge, more muted effects on customer consumption

[11] Average bills, of course, are not just impacted by base rates. Variations in other charges also impact average bills.

levels than does an overall increase in revenue requirement and corresponding average price levels.

Q. Mr. Allison also suggests that higher customer charges give customers less control over their electricity bill. What is your response?

A. While giving customers the ability and the tools to control their electricity bill is indeed important, and Ameren Missouri takes seriously its role in helping customers manage their usage and bills, it is also important that the rates customers pay are aligned with the cost of serving them. The analysis in my direct testimony of the various candidate rate designs considered in this case showed a clear continuum where certain rate designs are more aligned with the cost of service, and therefore produce more equitable outcomes between customers and provide more economically efficient price signals. Aligning rates with cost of service creates an environment where customers who are successful at controlling their bills make everyone better off. In the absence of such cost alignment, one customer's savings can quickly become another customer's bill increase, as costs are shifted away from those who cause them to others who are burdened with subsidizing those customers. Again, see my direct testimony for more detail on this topic.

Q. Mr. Allison's final policy concern related to the customer charge is that higher customer charges will disproportionately burden low-income customers. Do you agree?

A. No. In general, except where law and policy allows for unique rates targeted at low-income customers (such as the Missouri Energy Efficiency Investment Act "MEEIA" allowance for a low-income exemption from the charges for energy efficiency programs, which Ameren Missouri has implemented) rate design is an ineffective means of relieving the energy burden of low-income customers. That is because low-income customers are not a monolithic group that all have the same usage characteristics. They are in fact, quite similar to the full population of residential customers in that they exhibit significant variability of usage across customers, as I will illustrate further below. A rate design that helps one low-income customer may very easily have a more detrimental impact on another. For example, a lower fixed charge with a correspondingly higher energy charge — as Mr. Allison advocates for — is almost certain to raise the home heating costs of low-income customers with electric space heating as their primary source of heat. It can also create an added financial disincentive for a budget conscious fixed-income customer to turn on their air conditioning at times when it is important to provide relief and safety from extreme summer heat.

Mr. Allison portrays that low-income customers are small users of electricity on average. The applicability of the regional data that he relies on to reach that conclusion for Ameren Missouri's service territory is unknown. What is certain, though, is that there are low-income customers across the usage spectrum from low to high, and a rate design change is certain to have disparate impacts on different individual low-income customers – with negative impacts in the form of higher bills for a large number of them including those who depend on electricity to warm their homes in the winter.

Q. What evidence do you have that the variability of usage reflected in the low-income population is similar to the variability of usage across the full Residential population?

A. In response to Sierra Club Data Request 2.48, the Company developed bill frequency analysis for the population of customers who had received LIHEAP energy assistance. Using this tool to compare the distribution of usage of LIHEAP recipients to the distribution of usage of the full residential population demonstrates that the two groups have similar dispersions of customers spread across all ranges of usage. Figures 3 and 4 below show the distribution of usage for the two groups for January 2018 and July 2018.

Figure 3 – Distribution of January 2018 Residential Usage

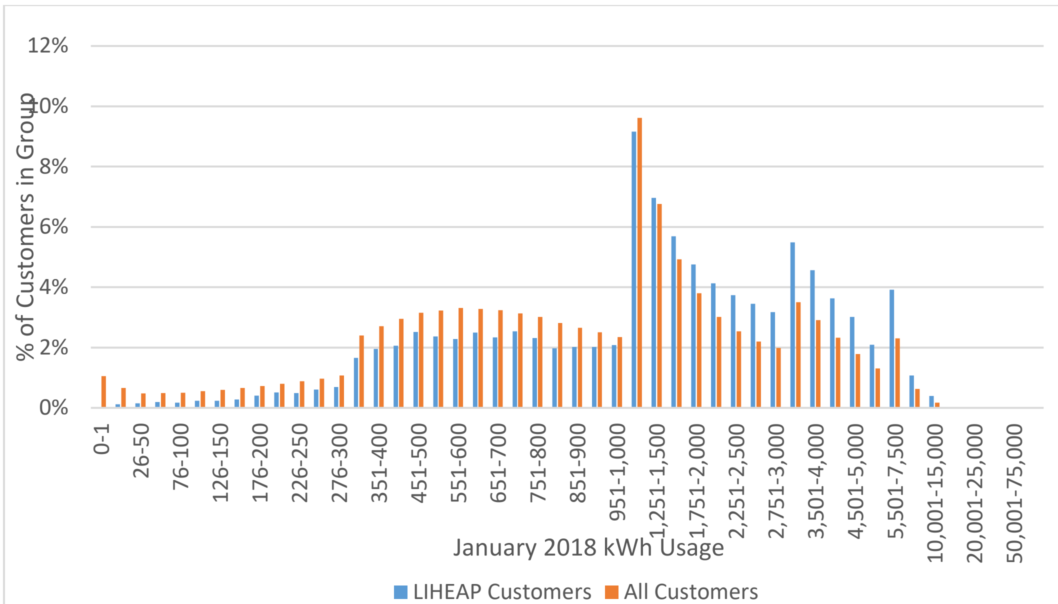
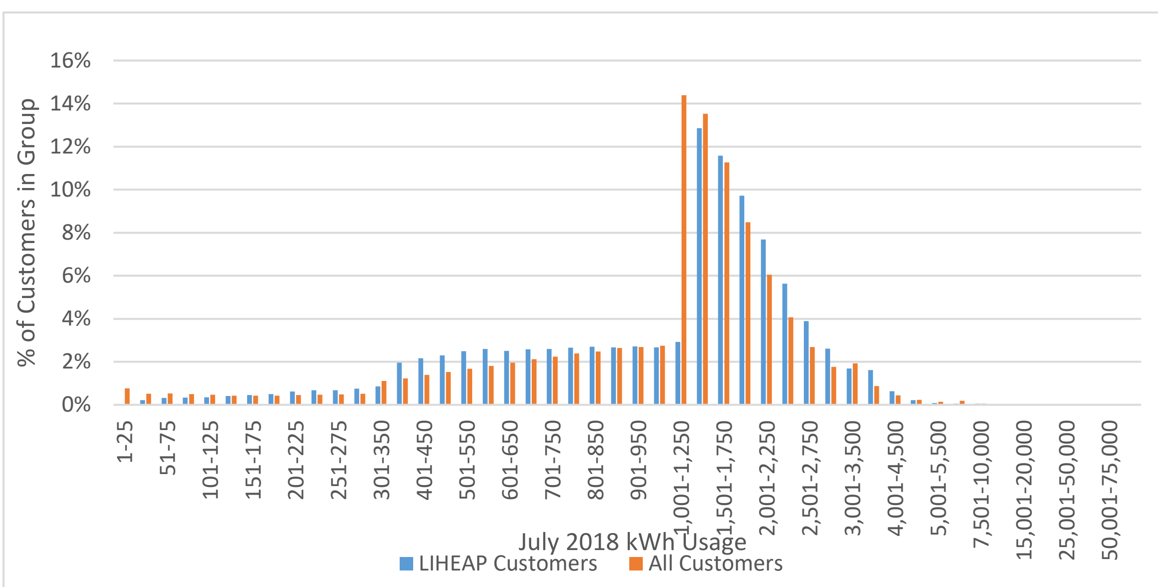


Figure 4 – Distribution of July 2018 Residential Usage



Q. How do you interpret Figures 3 and 4?

A. The x-axis labels show the level of monthly kWh usage associated with each bar in the graph. The height of the bar measured along the y-axis shows the percent of customers of the relevant group (orange bars relate to all residential customers, blue bars relate to LIHEAP recipients) that has usage in that range. What is notable to me is that the shapes and relative sizes of the blue and orange bars are strikingly similar between the two groups. I interpret this to indicate that the LIHEAP group has a similar percentage of customers with low, average and high usage as the total population. This further suggests to me that a rate design change is likely to have extremely disparate impacts on low-income customers, rather than systematically providing them with higher or lower bills as a group.

Q. Are there any other observations you would share regarding the impact of the customer charge on low-income customers?

A. Yes, while the impact of the level of the customer charge is disparate on low-income customers in general, it will unquestionably have a negative impact on those with the highest electric energy burdens. Imagine two households with incomes of $15,000 – one uses energy roughly consistent with the 10th percentile of the Low Income Home Energy Assistance Program ("LIHEAP") population shown above, or approximately 4,315 kWh per year and the other uses energy roughly consistent with the 90th percentile of the LIHEAP population shown above, or approximately 27,319 kWh per year.[12] The higher user has an annual electric bill of $2,451, or 16.34% of their annual income when the customer charge is at its current level of $9 per month. The lower user's annual electric bill

[12] For this analysis, I started with the normalized test year monthly usage for the average residential customer, and scaled it seasonally based on the ratio of the 10th and 90th percentile users from the LIHEAP distributions to the average class user for that season. Bills are calculated using rates based on the Company's proposed revenue requirement in this case and exclude riders such as the Fuel Adjustment Clause and all add-on taxes.

is $508, or 3.39% of income. The proposed change in rate design to implement an $11 monthly customer charge reduces the annual bill of the large user, whose electric bill already takes up a substantially larger portion of their income by $30 per year, while increasing the smaller user's bill by $14 per year. This suggests that the top 10% of customers by usage, those with the highest electric energy burdens (almost five times greater than customers with comparable income in the group of lowest users), realize $30 of bill savings under the Company's proposal. Mr. Allison's proposal would obviously do the opposite and increase the bills of that group with the highest electric energy burden. So again, while the rate design change associated with the monthly fixed charge has a disparate impact on the two customers, the one that has a significantly larger share of their income dedicated to their electric service is the one whose burden is slightly lessened by the Company's proposed change.

Q. Please summarize your response to Mr. Allison's recommendations for the appropriate level of the Residential customer charge?

A. Mr. Allison has raised a variety of objections to the Company's proposal to modestly increase the monthly customer charge with an offsetting decrease to volumetric energy charges. However, none of them withstand scrutiny as valid reasons to maintain an artificially low fixed charge below the level supported by analysis of the cost of service.

The MDS analysis that produces the cost of service relied on by the Company is consistent with the cost allocation principals put forth by every party to this case other than the Sierra Club, and is the only methodology that recognizes the two distinct and recognized cost drivers of shared distribution infrastructure.

More importantly, the policy considerations Mr. Allison cites take much too narrow of a view of the changing landscape around energy efficiency. The impacts of raising the fixed charge on traditional *electric* energy efficiency programs is minimal. But more importantly, whatever impacts it may have on such electric energy efficiency measures are the exact opposite of the nature of impacts that it will have on the vast potential of efficient electrification to broadly promote cross-fuel energy efficiency, reduce the direct combustion of fossil fuels by end-users, and reduce overall emissions levels. Mr. Allison's counter-proposal should be rejected, and the Commission should take a small step to better align rates with cost considerations while providing modest support for electrification by adopting an $11 monthly customer charge in this case.

V. RESIDENTIAL RATE DESIGN — ALLOCATION OF RATE DECREASE TO RATE ELEMENTS

Q. Apart from the level of the customer charge discussed above, what other rate design recommendations related to the standard Residential rate will you be addressing?

A. Staff recommends in their CCOS Report that any rate decrease allocated to the residential class as a result of this case be applied only to the first block usage charges — the first 750 kWh of monthly customer consumption.

Q. Do you agree with this recommendation?

A. No. This effectively creates a summer inclining block rate ("IBR") for the Company. I discussed IBRs — and the many problems with them — at length in my direct testimony. Dr. Faruqui of the Brattle Group, who also sponsored direct testimony in this case on behalf of the Company, further comments on the Staff's IBR proposal in his rebuttal testimony.

Q. What rationale does Staff give for its recommendation regarding rate design that results in the implementation of IBR?

A. None. This is surprising, given the fact that adoption of this proposal would result in the introduction of a new standard rate design for the Company's residential customers. Such a fundamental rate design change ought to be done for well thought out reasons, and yet Staff gives no support whatsoever for the creation of an IBR. As I just mentioned, I provided substantial direct testimony in opposition to IBRs in this case already. I summarize it briefly for convenience here as follows, but please refer to my direct testimony for more thorough coverage of the topic:

- When individual customer rate outcomes associated with IBRs are compared with the cost of serving those individual residential customers, they are quantitatively demonstrated to be the least equitable among any rates studied in this case, and to provide the poorest price signals for customers considering investments in new energy-related technologies.
- IBRs result in customers with relatively poor load factors paying lower realized rates (total bill divided by total consumption) than high load factor customers. This is counter to well-established rate design principles that suggest that customers that make more efficient use of the grid (i.e., have higher load factors and cause less idle capacity) should pay the lowest rates on a per kWh basis.

- IBRs provide particularly poor price signals related to efficient electrification. The discussion above about the impacts of the customer charge on electrification is applicable in its entirety to IBRs as well. IBRs are simply counterproductive to efforts to gain the significant benefits associated with electrification of transportation, among other end uses.
- IBRs are less effective than once thought at promoting electric energy efficiency due to the disparate impacts on the bills of different customers. Customers with usage less than average may interpret bill reductions that result for them from IBR as a price decrease that actually encourages increased consumption.
- States that once adopted IBRs are largely moving away from these rate structures now in favor of more modern rate designs, such as TOU rates like the ones the Company has proposed in this proceeding.

Q. Should the Commission reject the Staff's proposal that results in an IBR?

A. Yes, and not just for the reasons summarized above. Staff proposes an extremely modest rate differential between blocks that is unlikely to be even noticed by customers. While that means that this rate change will probably have little effect — positive or negative — on any of the policy issues I have discussed related to IBRs, it will still require considerable administrative effort for the Company to revamp its standard rate structure. This effort would include, at a minimum, re-programming its billing system to handle a new rate design, training employees including call center personnel to understand the new rate design and answer questions about it, and developing new frameworks for load analysis issues such as the weather normalization used in rate cases, among many other things. These are non-trivial efforts that will cause the Company to incur costs and exhaust resources that could be better spent dealing with other issues that are more meaningful to customers. The fact is that the rates proposed by Staff would move policy in the wrong direction for all of the reasons I have cited, but would move it so subtly that its effects would be imperceptible, except on the people who have to do a tremendous amount of administrative work to implement the change. This is wholly unproductive and should be reason enough on its own to reject this change.

VI. RESIDENTIAL RATE DESIGN — THREE-PART RATE PILOT

Q. In your direct testimony, you proposed a pilot of a three-part residential rate that includes a demand charge and a time-varying energy charge. Please briefly summarize that proposal here and provide an overview of other parties' testimony on the topic.

A. The findings of the rate design analysis presented in my direct testimony demonstrate that a three-part rate that includes a demand charge is the most cost reflective rate. This rate design promotes the greatest equity between customers, and provides the most economically efficient price signals for efficient use of the grid. However, residential demand charges have not been feasible prior to the implementation of advanced metering ("AMI meters"). While AMI meters are in the process of being rolled out across the service territory, the Company proposes a limited scale pilot for purposes of gathering data about this potentially valuable rate option to inform decision-making in the future about whether it should be adopted more broadly. For the most part, other parties' direct testimony was silent on this proposal other than Sierra Club witness Mr. Allison. He opposes the demand charge pilot and recommends either rejection of it, or the application of certain conditions to it.

Q. What are the reasons Mr. Allison opposes the pilot study of a Residential three-part rate?

A. Mr. Allison argues that a non-coincident peak ("NCP") demand charge is not cost-based and could have effects contrary to its intended purpose. He claims that the distribution demand-related costs that the Company is proposing to reflect in the demand charge are driven by local coincident peak demands, not individual NCP demands.

Q. What is your response?

A. Mr. Allison's claim that the NCP demand charge is not cost based is contrary to the significant quantitative evidence presented in my direct testimony. Dr. Faruqui also provides his expert opinion on the cost basis for reflecting distribution system costs in non-coincident peak demand charges in his rebuttal testimony. Mr. Allison claims misalignment of the rate with cost considerations due to the fact that the demand levels that the Company used to allocate distribution demand-related costs covered a narrower subset of the hours of the day and year than the hours during which the demand charge would be levied. The implication being that demand charges would be levied when system conditions did not warrant it – i.e., when costs related to investment in distribution infrastructure are not being driven. He takes this as evidence that the NCP demand charge is not consistent with cost causation. However, in making this claim, he completely ignores the *outcomes and findings* of the analysis from the Company's direct testimony that he just referenced. The evidence quantitatively demonstrated that the rate that featured the NCP demand charge *more accurately reflected the cost of serving individual customers — as derived from the* *allocation of distribution costs using the very hours Mr. Allison is discussing — on those customer's bills across every metric calculated than any other rate design studied*. In fact, it is puzzling to me that he would make any reference to the Company's analysis to support his contention that the rate is not cost based, when that analysis unambiguously and quantitatively demonstrated that the NCP demand charge brings bills into closer alignment with cost than any other candidate rate structure.

Q. Are there other reasons that the NCP demand charge is particularly appropriate to reflect demand-related distribution costs?

A. Yes, the nature of the distribution system itself supports use of an NCP demand charge. The distribution system is made up of many thousands of different components that each serve distinct loads depending on their location, and which are sized to meet the demand of the unique mix of customers that rely on them for service. For context, there are over 2,800 different circuits and more than 800 different substations on the Company's system, and there are more than a quarter of a million different transformers that provide residential service. These components serve parts of the system with winter peaks due to high localized concentrations of customers that rely on electric space heating as the primary home heat source, and areas with summer peaks driven by air conditioning – along with any number of other unique circumstances. Mr. Allison is critical that the Company did not analyze the loading of each of these pieces of equipment to determine the hours that the demand charge should cover. But this complexity of the system dictates that cost of service analysis and its cost allocation rely on various class and system level load measurements that we describe as different types of NCPs or Coincident Peaks ("CPs"). That said, the diversity of distribution equipment and of the customers spread across the system virtually guarantees that the handful of hours that we use for cost allocation do not cover all of the relevant distribution peaks loadings that occur on the hundreds of thousands of unique pieces of equipment.

The goal of the NCP demand charge, therefore, is to develop price signals that result in customer energy consuming habits that flatten individual load profiles (reduce peaks whenever they occur and shift consumption to time periods when usage is otherwise lower). This type of customer behavior is generally good for the system, and any subpart of it, wherever and whenever it occurs. And again, the analysis in my direct testimony confirms that the NCP demand charge also results in customer bills that align with the cost of providing their service. As I will discuss later, this is in contrast to costs associated with the generation and transmission functions, which are to a much larger degree only impacted by the system's coincident peak load. The Company has proposed to reflect these generation and transmission costs in the pilot rate structure in a time-varying energy charges that focus the highest prices on the hours closest to the system peak.

Q. You mentioned flattening individual customer load profiles as a goal. Mr. Allison provides an anecdotal example of how this behavior could have an adverse impact of increasing loads during times of system peak. Is that anecdote a good reason not to study the deployment of demand rates with the Company's proposed pilot program?

A. Absolutely not. Mr. Allison describes a hypothetical customer that, in response to an NCP demand charge, declines to run its dishwasher at 11 a.m. (a relatively lower summer load hour) because it would establish a higher level of demand due to the fact that the customer is also running their clothes washer at this time. The customer eventually ends up running the dishwasher at 2 p.m. when system loads are higher. In this scenario, the customer's action has increased load during a higher load hour on the system.

To paraphrase Mr. Allison's concern, it appears to be that he worries that customers will become *too good* at flattening their individual load profiles, such that a few of them who previously had relatively beneficial load profiles will occasionally stumble into a scenario where they make a less-than-beneficial load shift. That is a problem we should all welcome. Because, if a large number of customers are this conscious of their own consumption that they flatten their individual load profiles, it is a virtual certainty that the net effect will be that the overall system load profile will become flatter, as will the load profile on almost every subpart of the distribution system. When customers are shifting load to flatten their individual load profiles, there is simply more consumption to be shifted during periods when system loads are high. I think the behavior represented by Mr. Allison's example is exactly what we should hope for, the possibility of the infrequent unfortunate outcome he described notwithstanding.

I would also note that Mr. Allison comments in a footnote that the "free" demand hours associated with the Company's proposal to not assess a demand charge between 10 p.m. and 6 a.m. are "extremely inconvenient" for customers. However, his example of the family's decision regarding when to run the dishwasher is a good one. Every dishwasher I have seen in the last many years has a delay feature that allows you to finish loading it and set it to run sometime later. Hitting the one or two required buttons to set that delay feature in order to avoid the demand charge entirely does not seem like a particularly onerous inconvenience to me. Increasingly, certain end uses are getting the "smart" technology capabilities to automate this type of load shifting. There are and will continue to be, of course, some end uses that are more difficult to shift, which most customers probably will not attempt to move to the overnight hours. But the fact that they are assessed a demand charge for running them during the day is not any kind of penalty, it is simply a reflection of the cost of the grid that is there to serve them at that more convenient time.

Q. Mr. Allison also argues that demand charges are too complex and difficult for Residential customers to understand. Is this a good reason not to pursue this pilot?

A. No, in fact, it is a perfect reason to pursue it. Dr. Faruqui provides his perspective on this issue in his rebuttal testimony. But from my perspective, one of the most valuable learnings from the proposed pilot could be in this area. It will be incumbent upon the Company to attempt to educate pilot participants on the demand charge and how to manage their bills when subjected to it. The pilot will show one way or another whether that effort was effective. This will shed some light on whether such a rate will cause customer confusion if more broadly applied in the future.

Q. Mr. Allison's recommendation against the Company's pilot proposal also indicates his view that TOU rates and/or Critical Peak Pricing ("CPP") are more equitable and efficient ways to reflect demand-related distribution costs in rates. Is that accurate?

A. No. TOU rates were included in the study of various rate designs in my direct testimony, which clearly established that the three-part rate is better at reflecting the cost of service on customer bills. The quantitative evidence is clear on this point. CPP rates were not included in my study, but CPP rates only focus on shifting load during a few hours of the year when the Company would call critical peak events. Other than these few hours a year, customers would have no incentive to do anything different. The benefits of the price signal to flatten the individual load profile simply doesn't exist on any routine basis – and neither would the corresponding benefits to the system.

In my direct testimony, I spent considerable effort discussing the impacts that the various candidate rate designs would have on customers considering investment in energy-related technologies such as EVs, solar photovoltaics ("PV"), and batteries. Rates without a demand charge – even time varying rates – are simply not as effective at providing appropriate price signals for adoption of these new technologies that can radically reshape customer usage profiles, as my previous analysis demonstrates. See my direct testimony for more detail on this.

Q. Mr. Allison recommends that, if the Commission does approve the pilot study, certain data collection and reporting be required. Does the Company object to his conditions?

A. For the most part, no. Data collection and reporting is in fact the objective of the pilot proposal. However, there is one specific element of data that Mr. Allison proposes to collect that should be excluded from the requirements of the study. Specifically, Mr. Allison proposes that the Company collect one full year of hourly load data for participants *prior* to transitioning them to the rate intended to be studied. Since the Company does not have AMI meters in place yet, this data does not already exist. Getting that data would, obviously, take a full year. Effectively, Mr. Allison is suggesting a full one year delay before beginning the study, in order to capture data that is not necessary to generate pilot learnings. The pilot design described in Dr. Faruqui's direct testimony does not require this pre-collection of data in order to evaluate the impact of the rate structure on customer loads, and to subject the study to such a delay would be more detrimental than any benefit – a benefit which is not even identified by Mr. Allison as a part of his request – that could be generated by collecting this data.

Q. Did any other parties comment on the proposed pilot in their direct testimony?

A. Not directly. But there are a couple of items in the Staff CCOS Report that warrant discussion while on this topic.

Q. What is the first item?

A. First, I would note that Staff's CCOS Report cites some information first produced by Staff in a report from a Commission workshop on Distributed Energy Resources (File No. EW-2017-0245). In this report, Staff lays out its own vision of the future of Residential rate design for electric utilities in the state. It is noteworthy that Staff's roadmap includes a suggestion that, by approximately 2025, residential rates should feature "a 12 month demand charge for recovery associated with local distribution facilities."[13] Later in that report, Staff recommends an "on-peak" demand charge to recover generation costs. The fact that the generation cost-related demand charge recommended by Staff is specifically called out to be "on-peak" suggests by the omission of that language from the description of the distribution demand charge that it would be a non-coincident peak (NCP) demand charge. I point this out because, while Staff did not directly comment on the Company's Residential three-part rate pilot proposal, they have testified in support the notion that this type of rate design should be considered in Missouri within a relatively near

[13] Staff CCOS Report, page 34, lines 1-2.

term time horizon. If that is the case, it further supports the notion that we should be studying residential demand charges now, as the Company has proposed.

Q. What is the second item from the Staff CCOS Report that is relevant to the discussion of the Company's proposed three-part rate pilot?

A. In proposing this pilot, the Company also proposed a cost recovery mechanism for costs that would be incurred as a result of the pilot. The Company proposed to build an amount into base rates for the pilot, and establish a one-way tracker to return any ultimate over-recovery of pilot costs that may occur to customers. Staff addresses this cost recovery request, but refers to the tracker as relating to the Company's proposed "TOU Pilot." It is unclear to me whether that is just what Staff has labeled the three-part rate pilot the Company proposed, or whether Staff is suggesting some of the other TOU rates that the Company also proposed in this case be implemented as pilots with a tracker. At this point, I would just clarify that the pilot cost recovery proposal was intended by the Company to relate specifically to the three-part rate pilot. The "Smart Savers" and "EV Savers" TOU rate proposals included in the Company's direct testimony are not intended as pilot programs, but rather general rate offerings to be available indefinitely to all residential customers. Staff ultimately recommends that no amount of pilot costs be built into base rates, but that a tracker for future recovery consideration of the costs be established. If Staff's recommendation relates to the three-part pilot costs, the Company is agreeable to simply tracking these costs for consideration in a future rate case rather than building them into base rates with a one-way tracker to return potential over-recoveries.

IV. RESIDENTIAL RATE DESIGN - TOU OFFERINGS

Q. The Company proposed two new TOU residential rate offerings in its direct testimony. Please summarize the position of the parties that provided direct testimony related to these proposals.

A. In general, those parties who commented on TOU rates support the premise of advancing new rate offerings. There seems to be broad agreement that TOU rates are appropriate to include in Residential rate offerings. Beyond that, there are some different perspectives about the details of TOU rates that come across in testimony.

Division of Energy witness Martin Hyman does not comment on the merits of the Company's specific proposal, but rather outlines the criteria that he considers important for a sound TOU rate proposal. I largely agree with many of his perspectives, and believe that the Company's proposed "Smart Savers" rate includes many of the features Mr. Hyman recommends. Specifically, he advocates for cost based TOU rates with short, high-impact price signals to encourage load shifting. The four hour on-peak period and 6:1 peak/off-peak price ratio of the Smart Savers rate fit right in line with the criteria Mr. Hyman lays out.

Sierra Club witness Avi Allison supports the Company's efforts to develop new TOU rates generally, but offers several suggested modifications to the specific rate designs the Company proposed. I will address those recommendations further below.

Staff's CCOS Report also offers support for movement toward TOU rates, but Staff offers their own TOU proposal that features a markedly different on-peak/off-peak rate structure than the Company's proposal. Dr. Faruqui provides his perspective on the Staff's proposal and I will also comment on it briefly below.

Staff also appears to support the Company's EV Savers rate, but applied only to separately metered EV charging equipment. Staff's testimony on the topic is quite brief, though, consisting of only a section heading and no further discussion, so details of Staff's opinion on EV Savers and rationale for their recommendation are scarce. Finally, Staff notes that they will provide additional testimony related to the Smart Savers rate proposal in rebuttal testimony, which the Company will address as necessary and appropriate in its surrebuttal testimony.

Q. Please provide some perspective on how you recommend the Commission proceed in considering the TOU testimony in this case.

A. TOU rates, and the other modern rate designs that Dr. Faruqui discusses at length in his direct testimony, are more complex rates than the standard rates currently offered by the Company, and have many different parameters and permutations that can be proposed and debated. As demonstrated in its direct testimony by the number of witnesses, robust analysis, and thoughtful and complete testimony discussion, developing new TOU rates is something the Company did not take lightly and we have given significant consideration to those many details. The development of our proposal included cross-functional input and a team of people buying in to particular rate concepts. The Company has people already developing plans to deliver effective communications and customer experiences around these rates. As the Commission weighs all of the competing opinions about the ideal modern rate structures, I hope that they will consider the level of investment of time and effort that the Company put into advancing a thoughtful and forward-thinking rate proposal and start by looking at this through the lens of determining if the Company's proposed rates are just and reasonable and make an appropriate movement in the right direction.

Q. What specific issues raised by Mr. Allison related to the Smart Savers rate proposal will you address?

A. Mr. Allison recommends that the on-peak period be extended for one hour to cover the hour from 2 to 3 p.m. He also recommends that the on-peak price be moderated to a level under $0.30/kWh, to reduce the peak/off-peak price ratio from its current 6:1 to about 4:1. Finally, he recommends that the Commission order the Company to include a CPP component in the Smart Savers rate offering. I will start by addressing the last issue I mentioned first.

Q. What are your thoughts on adding a CPP component to the rate?

A. I believe that, while CPP is a legitimate modern rate design to consider and certainly has its merits, this is the wrong time and place to adopt it. As a first foray into a more widely deployed residential TOU rate, the Company is hesitant to add this additional layer of complexity. Mr. Allison has already discussed that the Company's proposed $0.30/kWh on-peak charge could create some hesitance in customers to enroll. CPP rates, however, while only applicable a small number of hours per year, are characterized by much, much higher prices during those event hours. The potentially punitive nature of those rates if customers do not respond appropriately during events could discourage customers from enrolling or frustrate those who do.

Q. Are there other offerings the Company is considering for the future that could fill much of the same role as a CPP rate?

A. Yes. The goal of CPP rates is similar to demand response in that it attempts to encourage customers to reduce load during specific hours when the utility determines the system is experiencing heavy peak load conditions or there are other reliability reasons that it would be helpful to reduce demand. The Company has existing demand response programs in its MEEIA portfolio. The addition of a price responsive demand response program is something the Company is studying in the context of its demand side management potential study. I indicated in direct testimony, and also in data request responses to the Sierra Club, that the Company remains interested in Peak Time Rebates as a potential demand response program that could achieve the same goal as a CPP rate, but in a more customer-friendly way (e.g., by using incentives to reduce load during peak events rather than high charges for using energy at those times – "carrots versus sticks"). Customers then could choose between TOU and a more basic structure as their rate, and then make a separate decision to enroll in a price responsive (or any other type of) demand response program.

The practical reason not to order CPP rates in this proceeding is that they also require the development of many different rate parameters that have not been vetted at all to this point in the proceeding, as well as the development of substantial information technology ("IT") systems capabilities to implement that the Company has not even begun to evaluate. For all of these reasons, this is not the time to order CPP.

Q. Please respond to Mr. Allison's proposal to extend the on-peak period, which the Company proposed to cover the hours of 3 to 7 p.m. for summer weekdays, to also include the 2 o'clock hour.

A. Mr. Allison goes through quite a bit of load analysis in an effort to demonstrate that the hour from 2-3 p.m. on summer weekdays is a high load hour worthy of consideration for peak treatment. I do not dispute any of his specific analyses that suggest that the 2 o'clock hour has loads that are similar to the 6-7 p.m. hour, which the Company did include in the peak period window. However, in an effort to keep the peak period relatively short, so as to be more manageable for enrollees in the rate, the Company elected to stay with a four-hour period. Dr. Faruqui explains in his testimony that each hour that the peak period is lengthened makes it more difficult for customers to shift load and save on their bills. If the four hour period is to be maintained, which I recommend, the 3 to 7 p.m. window is a more appropriate peak period, regardless of which the two hours in question (2 to 3 p.m., or 6 to 7 p.m.) may have marginally higher load levels.

Q. What is that reason?

A. Load patterns (and increasingly generation supply patterns that are driven by availability of intermittent renewable resources) evolve over time. As solar becomes a more prominent generation resource – whether on the customer side of the meter or the utility system – the balance of load to generation is pointing to a greater need to reduce demand in the hours where the supply that is dependent on solar irradiance is in sharp decline, such as the 6-7 p.m. hour. Focus on the later hour under consideration is really an effort to create a better balance between demand and supply that will enable the system to integrate more solar generation over time. This is a way to try to create and tailor load flexibility to help with renewable integration. As Dr. Faruqui testifies, states with higher levels of solar penetration today have begun to shift their peak periods later, with 4-9 p.m. being a common TOU period in the western part of the United States. This has been done in order to overcome operational challenges grid operators in these states face when a major generation source – solar – goes into its decline phase in the late afternoon and early evening hours. Even here in Missouri, this Commission has approved Evergy's new TOU rate structure to cover the hours of 4-8 p.m., a full hour later than the Company's proposal. Despite the fact that solar integration is not a significant challenge just yet in Missouri, the time when it becomes a challenge is likely to come sooner rather than later. It makes little sense to establish one peak period today and have customers start to learn to adapt their energy consuming choices to it, and then need to change that peak period definition — for a reason that was completely foreseeable — just a few years later. It makes the most sense to define our peak period today in a way that supports greater renewable integration.

Q. What is your response to Mr. Allison's recommendation to reduce the peak rate below $0.30/kWh, with a peak/off-peak price ration of closer to 4:1?

A. The Company developed its proposed peak and off-peak prices based on the principles espoused by Dr. Faruqui, both in testimony in this case and in his numerous studies and publications. Dr. Faruqui explains in his rebuttal testimony that he believes the 6:1 price ratio reflected in the Company's proposal is reasonable, and not likely to negatively impact participant recruitment. I would just add that the Company carefully considered this issue when developing this rate proposal. While we are mindful of the optics of the on-peak rate to customers, I do not think there is anything magical about the $0.30/kWh threshold Mr. Allison proposes. If the standard rate proposed in this case for residential summer usage is a little over $0.11 per kWh, whether the peak rate is around $0.29 per kWh or $0.32 per kWh, it is going to take education and tools to get customers to understand how it will impact them. The Company is working to develop the right tools to help customers assess the impact of TOU rates on them, and intends to help customers see that a relatively higher peak rate can provide them greater savings opportunities.

Q. Turning to Staff's TOU testimony, what does Staff say about the Smart Savers rate proposal?

A. Staff does not directly address the Smart Savers rate, stating that they will provide more response in their rebuttal testimony. However, Staff does make a recommendation to adopt a different TOU rate proposal that they developed, which seems to be offered as an alternative to the Company's proposal. Staff refers to it as a "training wheels" approach to TOU. The rate design has a very long on-peak period with an extremely small peak/off-peak rate differential.

Q. Does the Company recommend that the Commission adopt Staff's "training wheels" proposal?

A. No. Dr. Faruqui discusses the Staff's rate proposal in more detail. He explains why the rate is not designed as an effective modern rate structure, and also why its introduction may create a negative customer experience that actually sets back efforts to introduce TOU rates to Ameren Missouri's customers.

Q. Staff also suggests that the "training wheels" rate be the default rate for new customers to the system that have AMI meters. Should this rate, if adopted by the Commission, or any other TOU rate, be today's default rate?

A. No. First of all, it is important to remember that no customers will have AMI meters as of the day rates take effect from this case. The deployment of AMI meters will take place over a period of several years. It is likely to create customer confusion and unnecessarily complex administrative processes for the Company to have a default rate that may or may not be applicable to any given customer at a particular time. Also, the Company's preferred approach to helping customers transition to modern rate designs is to initially provide the opportunity, information and tools to them in order for customers to have the ability to choose to explore a new rate options on their own terms. Changing default rates to something more complex may be appropriate at some time in the future, but is premature until the metering is in place and customers have been introduced and exposed to new rate concepts.

Q. Staff also recommends some communication/marketing strategies for TOU rates, including shadow billing of all customers with AMI meters, showing them on their bill what they would have paid on TOU rates, and specific communication timelines. What is your response?

A. The Company appreciates the input and will take those recommendations under consideration as it develops its marketing and customer education strategies. As I mentioned, the Company is already considering marketing of these new rates. We definitely intend to make bill comparisons available for customers to understand the impact of different rate options on them. However, prior to a determination of how and when those bill comparisons are delivered, it is important to consider the overall stage of the AMI deployment, the costs of using any particular communication channel, and how the different communications fit into an overall outreach strategy. Until the Company has a more complete marketing plan it is premature to mandate specific communications strategies for TOU.

Q. The Company proposed another TOU rate offering tailored to EV drivers called the "EV Savers" rate. Did parties address that rate in direct testimony?

A. Yes, but to a lesser extent than the comments on the Smart Savers rate. No party objected to the concept of having such an EV-focused rate, or the specific design proposed by the Company. Staff and Sierra Club did, however, comment on the details about how the rate should be made available.

Staff's testimony on the topic amounted to a section heading that said:

> **F. Staff recommends establishment of a TOU rate schedule to be applicable to separately-metered EV charging equipment, on an opt-in basis.** [14]

That section heading of the report was followed by no additional text with any further detail regarding Staff's recommendation, so it is not clear exactly what Staff intends with this recommendation. To the extent that Staff recommends that the rate be available *only* to separately-metered EV charging, I think that would be problematic. If instead customers could opt to apply the rate to either their whole house *or* separately metered EV charging, I have no issue with that suggestion.

This rate was designed to provide incentives for EV charging to occur off-peak, but also to be a rate that is appropriate for the whole house. The reason that is important is that separate metering options that are currently available carry a substantial additional cost to the customer, which would in all likelihood more than offset the potential benefits of charging a vehicle on the off-peak rate. Providing the customer with the *option* to separately meter the charger and incur the associated incremental cost is fine, but it is also worthwhile to allow a customer that is willing to subject their household usage to the rate to do so without adding the cost of installing separate metering. While the rate's goal is to

[14] Staff CCOS Report, page 44, lines 16–17.

promote off-peak EV charging, application to the whole house can also have the benefit of giving the customer an added incentive to shift other household usage to overnight hours.

Q. How does the question of separate metering relate to Mr. Allison's comments on the EV Savers rate proposal?

A. In my direct testimony, I mentioned the Company's aspiration to eventually make the EV Savers rate available to separately metered EVs without requiring the installation of a second utility meter. This could be possible by leveraging the metrology on smart EV chargers that customers could install on their own in their garages and parking areas. But this solution — i.e., using what essentially is third-party metering data to bill the Company's customers — would, of course, require partnerships or agreements with the vendors that provide smart charging solutions, testing or certification of vendor equipment, establishment of systems integration or data exchange protocols, etc. The Company indicated in testimony that exploring these issues will take some time and that we are not prepared today to offer separate metering through third party equipment.

In his testimony, Mr. Allison advocated for application of the EV Savers rate to only the EV load using third party metering data sooner rather than later. Mr. Allison cited jurisdictions where he believes this type of arrangement has already been worked out as models, and recommended that the Commission order Ameren Missouri to deploy a similar solution "promptly."

The Company appreciates Mr. Allison's passion for encouraging progress on this topic quickly, and will research the cited jurisdictions for lessons that may be adapted to Ameren Missouri's situation; however, I would suggest that Mr. Allison's request for the Commission order a particular deadline for developing this service is inappropriate. Again, there are many details that need to be thoroughly researched in order to move forward with this. After all, we're talking about customer metering data that will be used to calculate bills. Whether and when to enter into agreements with third parties to provide such metering services for the Company should be left to the discretion of the Company to negotiate and enter into on its own terms and timelines.

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

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

A. Mr. Chriss recommends that the Commission order the Company to redesign its LGS and SPS rate structures prior to the completion of AMI deployment to those rate classes, which is expected to occur in 2025. 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. Harding elaborates in his rebuttal testimony further on the appropriate allocation of any rate decrease in this case, but suffice it to say that Mr. Chriss' proposal for this case — to allocate any decrease to the demand charge — is consistent with principles that I have discussed in this testimony, to the extent that the distribution demand-related costs are not currently fully reflected in the demand charge. The LGS and SPS demand charges are NCP demand charges, which was the topic of much discussion earlier in my testimony related to the Company's proposed residential three-part rate pilot. As I said then, I believe an NCP demand charge provides the most appropriate alignment of rates with the cost structure of the utility when considering the distribution demand-related cost classification. To that end, I support Mr. Chriss' suggestion for allocation of any decrease that arises from this case to only the energy charges.

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 at least worth mentioning the potential impact on efficient electrification. Support of the electrification of transportation can be impacted by LGS/SPS rate structures due to impacts on 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 support MECG's recommendation in this case, but 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 Commission order the Company to revamp its rate structure by 2025 and the expected completion of the AMI meter rollout?

A. I think it is premature for the Commission to order anything regarding the Company's rates in 2025. There will be another general rate case or rate cases that occur between now and then, where proposals for the post-AMI rate structure can be evaluated. Mr. Chriss correctly notes that the Company has emphasized modernizing its rate structure in this case, and also correctly observes that Residential rates received the bulk of the attention in the Company's testimony. I agree with Mr. Chriss, however, that the rate structures of all classes are important and should follow cost of service considerations, so Mr. Chriss's concern is not entirely unfounded. 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, but does not agree that this case is the right time for the Commission to order anything related to rates that will only be in effect years in the future after an additional rate case or cases have likely been completed.

Q. Do you agree that Mr. Chriss' analysis clearly demonstrates that a problem exists with the "hours use" rate structure?

A. Not completely. His analysis is predicated on the assumption that all demand-related costs, including those associated with the production function, should be included in the determination of the demand charge. His analysis compares bill outcomes to cost of service based entirely on that assumption.

In support of this line of testimony, Mr. Chriss cited my direct testimony where I said there is a "logical mapping" of cost classifications from the class cost of service study to the customer, demand and energy charge types. His implication seems to be that my own statement suggests that all of these production demand-related costs should be in the demand charge. I stand behind my original statement, but would also observe that I said that this is true "in general," and that there are still *many details* to consider when designing cost based rates.

The pertinent details that, in my opinion, are missing from Mr. Chriss' analysis on this topic are: 1) whether the demand charge used to reflect production demand-related costs should be based on the individual customer NCP, or some measurement of coincident peak; and 2) whether the nature of the production function is as easily segregated into true and distinct demand and energy classifications as the other major functions (i.e., distribution and transmission). I argued earlier at some length that an NCP demand charge is appropriate to reflect distribution demand-related costs in rates, and it appears that Mr. Chriss and I agree on this point. However, I think that this (NCP) demand charge is less suited as a means of handling production demand-related costs.

Q. Why is that?

A. Generation capacity is generally designed to meet overall system needs. For the most part, generation in one location can be replaced by generation in an entirely different location, meaning the total amount of generation capacity needed is pretty much the same system-wide. Because of this, the coincident peak (i.e., highest load observed on the entire system) establishes the need for generation capacity, whereas each piece of distribution infrastructure may have a unique and different load driving its capacity requirement. That is one distinction that argues for potentially different treatment of distribution costs versus production demand-related costs.

The type of generation capacity added (e.g., baseload, peaking), and hence the amount of capital costs associated with generation, is also driven by complex factors that must be evaluated in the IRP, which also may include consideration of energy requirements. Distribution costs are generally unrelated to energy considerations.

These additional considerations that are unique to generation planning give rise to the Company's use of the more complex 4 NCP Average and Excess allocation method for production demand-related costs in the CCOS study, which actually reflects a partial allocation of production demand-related costs on an energy basis. So even those costs that are classified as "production demand-related" are in reality partially driven by energy requirements. Without digging much deeper into the complexity that can surround this topic, suffice it to say that production demand-related costs are of a complex nature that are probably better reflected in a combination of energy charges (possibly time-varying energy charges, which Mr. Chriss does mention, but also possibly the existing hours use structure) and some type of demand charge – but not necessarily an NCP demand charge.[15] While I do not believe the "hours use" rate structure is as misaligned with cost as Mr. Chriss portrays it, his concern that it can be a difficult rate to understand is valid, and I am also not in a position to say there are not better alternative rate structures out there. My recommendation to the Commission is to defer consideration of changing the rate structure until its adoption is "on the table" in a future proceeding when many more variables are known, rather than issuing an order in 2020 that presupposes that something needs to be changed in 2025.

IX. MISCELLANEOUS STAFF RECOMMENDATIONS

A. Billing Practices and Data Retention

Q. Throughout the Staff's CCOS Report, they make other recommendations related to billing practices and certain data tracking and retention practices. Do you have any overarching comment on these issues identified by Staff?

A. Yes. Staff makes a number of recommendations, some of which I agree with and others I do not. In certain instances, Staff identifies data that would helpful or interesting to have, and then jumps straight to recommending that the Company be required to collect it. But the collection and retention of new types of data can impact many business

[15] Coincident peak demand charges have their own set of challenges that need to be explored prior to recommending their adoption as well.

processes and IT system designs. The fact that a data element would be interesting to have does not, per se, mean that the costs of acquiring it are justified by the benefits.

For example, Staff recommends that the Company be required to retain more granular data related to distribution equipment, such as the voltage level at which customers served by that equipment connect to the system. Staff argues that this is critical information to cost allocation studies that will become increasingly important as the Company makes higher levels of grid modernization investments. As a class cost of service study practitioner, I completely understand the desire to have the most detailed information possible to inform such studies. However, I recognize that, where that data does not already exist associated with existing distribution infrastructure, it would be nearly impossible to go back and identify each property record, find associated items in the field, and categorize the voltages they serve. Even capturing this information for new equipment would potentially require changes in operating procedures for field personnel, training associated with those changes, potential system redesigns to applications where field personnel enter the relevant data about new property installations, re-programming existing software and database applications to capture and house the information that they were never designed to capture. It is beyond the scope of what I can research in the time allotted for rebuttal testimony to completely determine all of the precise costs and challenges that would be presented if this data tracking were required. Moreover, the benefits of collecting it are also unknown. There is no reason to believe that the allocations performed in any of the CCOS studies presented in this case are materially negatively impacted by the level of detail available. Staff's Report suggests that "Ameren Missouri was unable to provide information concerning which types of meters, transformers, and other items of distribution equipment were used for serving customers by rate schedule or by service voltage."[16] I do not think that is a completely accurate representation of the data that was provided to Staff. While certainly not every detail that Staff requested was something the Company was able to provide, there was a large amount of useful detailed information made available that I believe was completely adequate to perform reasonable cost allocations. Company witness Tom Hickman describes a particular example related to metering costs in his rebuttal testimony.

Q. Please respond briefly to each such Staff recommendation, starting with the request you just mentioned to increase the granularity of data collected and retained related to distribution equipment and voltage.

A. The Company is happy to further research the potential barriers that I mentioned above to collecting this information and engage in a dialogue with Staff about any appropriate enhancements to the data collected, but I do not think this should be the subject of a Commission order to increase data retention. Staff has not adequately characterized the benefits and the potential costs are undefined at this time.

Q. What is your response to Staff's recommendation that the Company utilize AMI meter data to enhance load research capabilities?

A. Load research capability enhancements are a significant and sometimes underappreciated potential benefit of AMI deployment. The Company agrees that appropriately leveraging this data will be important, and fully anticipates doing so. There is no need for a Commission ruling on this issue.

[16] Staff CCOS Report, page 16, lines 8-10.

Q. Staff's next recommendation is to retain hourly interval data for customers on AMI for at least a year to facilitate rate comparison analyses.

A. This is definitely already being planned. As I mentioned previously, the Company is working on just such a rate comparison tool to help customers understand the potential impact of new rate offerings on their bill. Interval data will be acquired, retained, and leveraged for this purpose. That said, while I again agree generally with the recommendation, this is not an issue requiring a Commission order.

Q. Staff next recommends that the Company retain data to calculate billing determinants for a CP demand charge for all classes from its AMI data.

A. While I am confident the Company's AMI data will provide such data, and that an adequate amount of data will be available on an ongoing basis after full AMI deployment to establish reasonable billing units for a variety of rate designs that may be considered, I do not think that this recommendation warrants Commission action.

Q. Staff makes recommendations related to certain billing practices of the Company, specifically related to the determination of billing periods and meter reading dates. Ultimately when AMI data is fully available, the Staff recommends changing the seasonal billing practices of the Company to effect seasonal rate changes on a date certain, rather than based on Company meter reading schedules. What is your response?

A. This is a more complex request with multiple parts to my answer. In part, this request is one that does belong in front of the Commission in a rate case — at least with respect to the proposal to change seasonal billing practices. That is because it would require tariff changes that ultimately need to be authorized by the Commission. However, I also believe that the other part of Staff's proposal — to change how the Company schedules meter readings and billing schedules — is an inappropriate and highly problematic request.

Q. Starting with the change proposed to seasonal rate applications, please describe the issue and provide the Company's response.

A. Staff notes that the Company's current seasonal billing practices result in some unusual inconsistencies in the application of seasonal rates for some customers. Currently, summer rates are applied to customers' June through September bills, but the dates of those bill vary significantly among customers depending on the meter read schedule to which they are subject. I agree with Staff that this is a less than ideal circumstance, and in fact I think this issue will be a significant problem for potential future TOU enrollees. [17] The way the current billing schedule works, customers will have a difficult time knowing when their summer TOU schedule begins, and for some, it will begin and end at times that do not really align the application of the rate with the time period for which it is intended. Staff points out, for example, that usage as early as the end of April can occasionally get classified as summer usage for a small number of customers due to the happenstance of where their billing cycle falls. On the flip side, those same customers may begin non-summer rate application before the end of August, when extremely hot summer weather is still possible and summer rates are still extremely relevant.

[17] MECG witness Steve Chriss discusses this issue as well, showing that it is not just an issue with residential rates, but also other rate classes. The proposed solution I present to Staff's issue should also address the issue described by MECG.

Part of Staff's recommendation is that the Company change its practice of seasonal rate application so that the summer rates are applied to usage that occurs between June 1 and September 30 rather than usage that appears on bills rendered in the June through September billing months. However, Staff recommends waiting until AMI is fully deployed to do this so that more precise measurement of usage in those time periods is available. The Company's preference would be, in fact, to make that change sooner, and for those bills that rely on monthly information like that provided by current metering, we would simply prorate the usage between the summer and non-summer period when the meter reading dates straddle the beginning or end of the summer period.

Q. Can you provide an example of how this would work?

A. Yes. Imagine a customer had metered usage of 1,000 kWh for what is now classified as its June bill, measured from May 11 to June 10. Under current practices, all of this usage would be classified as summer usage because it is reflected on the bill rendered in the June billing month. We could prorate this bill based on the ratio of days in each season — 21 days on non-summer rates and 10 days on summer rates — and then similarly prorate the bill on the tail end of summer. While proration does not absolutely guarantee that no usage crosses over the seasonal threshold — a kWh used in May could still be billed at summer rates or a kWh used in June could still be billed at non-summer rates — it will almost certainly be far more aligned with the proper season than the current practice, which bills all of the kWh from May 11 through May 31 at summer rates. In fact, this is exactly how the Company's affiliate, Ameren Illinois, currently applies its seasonal rates. So Ameren Missouri's shared customer billing system is capable of handling this change.

Q. How do you recommend the Commission proceed with handling this issue?

A. I recommend that the Commission order this change (i.e., prorated application of the seasonal rates to usage between June 1 and September 30) effective for summer rates in 2021, and that they direct the Company and Staff to develop appropriate tariff language to implement the change as a part of the compliance filing in this case. I do not think it would be appropriate for immediate application in the summer of 2020, when rates in this case take effect, because some customers will already have been experiencing summer rates for up to a few weeks. Making those same customers experience summer rates through September 30th of this year would unfairly subject them to higher seasonal rate levels for more than the four-month period defined as summer. Implementing this change for 2021 ensures that it will be in place for the first full summer that new optional TOU rates will be available to residential customers.

Q. You mentioned that Staff proposed that this change occur after full AMI deployment. What was their interim solution, and what is your response to that?

A. Staff made very detailed and specific recommendations about how the Company should be ordered to change its meter reading and billing cycle schedules in the interim to avoid certain outcomes. I must stress strongly that imposition of these conditions would be extremely disruptive to the Company's metering and billing operations. Accordingly, I highly recommend the Commission adopt the proration change as a long-term solution and give no consideration to this interim solution.

Q. Why is the interim solution so problematic?

A. Establishing meter reading dates is much more complex than it seems. It is different year–to-year based on when weekends and holidays fall, and it may have implications for contractual agreements with metering and billing vendors, and department workflows. Additionally, meter reading schedules are currently common across all of Ameren's Missouri and Illinois electric and gas operations. Creating a unique set of conditions to Ameren Missouri electric operations would likely create quite significant costs, which I have been unable to quantify, in order to develop Ameren Missouri specific changes to the existing systems that perform these operations, since its affiliates would be unlikely to share in the costs of those changes.

I would note also, that the benefit of these substantial changes would be so small as to not be worth incurring any level of cost to achieve. Staff notes in testimony that under the current schedule, a group of customers could, for example receive their October bill (at non-summer rates) with usage from the end of August reflected on it. They recommend that meter reading dates be adjusted to prevent that occurrence. However, even if the Staff's recommendation were adopted, that October bill could still reflect usage from September 1^{st} and beyond. That one or two day shift in which usage could fall "out of season" barely scratches the surface of truly aligning the bill timing with the change of the season, but at significant operational complexity and cost.

Q. Finally, Staff recommends that the Commission require Ameren Missouri to bill all TOU customers based on beginning and ending monthly register reads rather than a summation of interval readings. What is your response?

A. This request injects an issue from a different proceeding into this rate case. The Company has a pending request for a variance from certain Commission rules in File

No. EE-2019-0382 to enable the use of advanced AMI functionality for billing and other purposes. The request Staff made in this case is directly related to one of the waiver requests in that AMI waiver case. The AMI waiver case has been suspended for settlement negotiations, and the Company and other parties are hopeful that they will be able to resolve this issue. To the extent that that happens, this issue would be resolved outside of this case. However, if the AMI waiver case does not get resolved and the Commission were to act on Staff's request to order this billing treatment, the Company will not be able to offer timely TOU rates at the conclusion of this case. Consequently Ameren Missouri opposes Staff's request.

B. Pure Power Revenues

Q. Staff's CCOS Report also referenced potential changes to the Company's Pure Power program. What are those potential changes and what impact might they have on issues pertinent to rate setting?

A. Pure Power is a voluntary program in which customers can enroll to purchase Renewable Energy Credits ("RECs") to match some or all of their energy usage in order to achieve their individual goals related to renewable energy. The program has run for several years in a pilot status, whereby the Company purchased RECs on the market and passed through the cost to the customer on whose behalf those RECs were retired. In this form, program revenues matched program costs, and the net effect on base rates was zero. So under this paradigm, consideration of the program costs and revenues was excluded from the determination of base rates.

The Company has engaged with Staff and OPC about the future of the program, which may include moving it from a pilot status to a permanent program. Staff's CCOS

Report correctly alludes to a concept that the Company has put forward as a future path for the program, namely, sourcing the RECs from Company-owned renewable resources rather than from the market. If this change were to be adopted, it would be appropriate to consider the change in program structure in the context of a future rate case. Specifically, this would be appropriate because under such a program design the cost of the resources providing the RECs would likely be included in the rate base underlying the revenue requirement used to set rates paid by all customers.[18] If that is the case, it would also be appropriate to use the program revenues to offset that revenue requirement to the benefit of all customers. This has the potential to be a "win-win" scenario where subscribers get RECs sourced from known Missouri renewable resources, and non-subscribers get the benefit of a revenue stream that reduces the cost of the renewable resources that they are otherwise paying for.

The only issue I have with Staff's characterization of this issue in their CCOS Report is that they mention that the revenue from any future program with this design would offset *rate base*. The revenues from the program would be essentially an ongoing income stream from the asset that should offset revenue requirement on an ongoing basis, much like the revenue from, for example, third parties that attach their equipment to the Company's poles (a utility asset that is in rate base, which has an alternate ongoing revenue stream derived from it that is used to reduce ongoing revenue requirements). The program revenues would not, however, be an upfront payment similar to a contribution in aid of construction, which should be applied one time as an offset to rate base. So I agree that, if this new program design is implemented in the future, the revenues will be a valid

[18] To be clear, any renewable resources contemplated to source program RECs would not be the same resources that the Company uses for Renewable Energy Standard ("RES") compliance. There would be no double-counting of RECs between RES compliance and the Pure Power program.

consideration in the rate case to reduce the cost of the renewable generation for all customers, but I disagree with the specific manner that Staff suggests that this would be accomplished. While it is premature for the Commission to decide this issue, since Staff has weighed in on it, I wanted to provide this clarification.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service.	)))	File No. ER-2019-0335

AFFIDAVIT OF STEVEN M. WILLS

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

COMES NOW Steven M. Wills, and on his oath declares that he is of sound mind and lawful age; that he has prepared the foregoing *Rebuttal Testimony*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Steven M. Wills
Steven M. Wills

Subscribed and sworn to before me this 21st day of January, 2020.

Geri A. Best
Notary Public

My commission expires:

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