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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

REBUTTAL TESTIMONY

OF

MARK C. BIRK

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
October, 2021

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REBUTTAL TESTIMONY

OF

MARK C. BIRK

FILE NO. ER-2021-0240

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark C. Birk. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. By whom are you employed and what is your position?

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Company" or "Ameren Missouri") as Senior Vice President, Customer and Power Operations.

Q. Please describe your educational background and employment experience.

A. I received my Bachelor of Science degree in Electrical Engineering from the University of Missouri-Rolla in 1986 and my Master of Science in Electrical Engineering from the same institution in 1991. In 2009, I also received a Master of Business Administration from Washington University in St. Louis. I am a licensed professional engineer in the State of Missouri. I began my employment with Union Electric Company in 1986 as an assistant engineer in the nuclear function. In 1989, I transferred to Union Electric's Meramec Power Plant as an electrical engineer. In 1996, I transferred to the Energy Supply Operations Group and became a Power Supply Supervisor. I became Manager of Energy Supply Operations in the spring of 2000. I became General Manager of Energy Delivery Technical Services in the fall of 2001 and Vice President of that department in 2002. I became Vice President of Ameren Energy, Inc., Ameren Corporation's short-term trading affiliate, in the fall of 2003 and assumed the position with Ameren Missouri as Vice President of Power Operations in September of 2004. In 2012, I was promoted to Senior Vice President of Corporate Planning and Business Risk Management, and in 2015, I became Senior Vice President of Corporate Safety, Planning, and Operations Oversight. I assumed my current position in 2017.

Q. Please summarize your duties and responsibilities as Senior Vice President, Customer and Power Operations for Ameren Missouri.

A. In this position, I am responsible for Generation and Trading Operations, Energy Delivery Electric and Gas Operations, Planning and Engineering Design, along with Customer Experience and call center operations for Ameren Missouri.

Q. To what testimony or issues are you responding?

A. My testimony responds to concerns or issues raised by Office of the Public Counsel witness Dr. Geoff Marke's testimony in a section of his direct testimony he labeled "Plant in Service Accounting ('PISA')".

Q. More specifically, what do you understand Dr. Marke's concerns or issues to be?

A. As I read Dr. Marke's testimony, he is concerned about what he characterizes as a lack of "transparency" or "accountability" about the investments in the grid that we are making as part of the Smart Energy Plan ("SEP") we undertook at the beginning of 2019.

II THE COMPANY'S ENERGY DELIVERY INVESTMENTS

Q. Do you agree with Dr. Marke's concerns?

A. No, I do not, but before getting into the details of why Dr. Marke's viewpoint on these issues is incorrect, I would like to first make sure the Commission has a complete understanding of why the Company has substantially increased its energy delivery system investments since the passage of S.B. 564.[1]

Q. Please elaborate.

A. To understand why we are making these investments to better support customers now, one needs to understand some history about our energy delivery system and our investments in it in the past.

For many years prior to the passage of S.B. 564, which as I discuss further below enabled us to implement the SEP, Ameren Missouri operated and maintained its energy delivery system – and replaced certain components of it after they had degraded or even failed – in a much more reactive manner which often led to longer customer outages and lower resiliency and reliability. We did so at a level of capital investment that while sufficient at the time to maintain a reasonably reliable system, was not sustainable over the long term. While we were able to deliver safe and adequate service, our investments in the system and our approach to operations at that time meant the system had less ability to withstand severe weather, continued to age further past the design life of many of its components, and overall, the system was not capable of serving our customers in a manner that they expect today, much less in the future. While we did the best we could to meet customer expectations, there were significant limits to

[1] Enacting, among other things, RSMo Section 393.1400, which is commonly referred to as the "PISA" statute.

how much capital we could reasonably invest in the system given the disincentive to invest in electric utility infrastructure that existed prior to the passage of S.B. 564.

Q. How did S.B. 564 enable Ameren Missouri to increase its investments in ways that would address the kind of energy delivery system concerns you just mentioned?

A. While we still have limits on what we can invest, both to balance system needs with customer affordability and to avoid the negative impacts of remaining regulatory lag on the Company, S.B. 564 created a tool designed by the legislature to remove the disincentive to investment that existed under traditional regulatory treatment of investments, that tool being plant-in-service accounting, or "PISA". As the Commission knows, the PISA mechanism allows utilities like us to defer to a regulatory asset the return and depreciation expense on 85% of prudent investments in qualifying electric plant (most energy delivery system investments qualify) that we would otherwise lose forever between rate cases, and then recover the deferred sums through base rates over 20 years. Regulatory lag exists on the remaining 15% of our capital investment. And there is even some lag on the 85%, due to the impact of certain accounting rules around what return can be recorded to earnings at the time of the deferral, although that portion of the return is eventually recovered.[2] The legislature's purpose was to substantially remove the disincentive to invest so that utilities like us could provide better, more reliable and resilient service by investing more heavily in our systems for the long-term benefit of our customers and the state – but the legislation purposefully retained some of the regulatory lag inherent in traditional ratemaking to maintain the incentive to make those investments prudently. These investments also provide the ancillary benefit of creating jobs, economic activity, and a greater tax base in the state.

[2] PISA applies to investments other than energy delivery investments but my focus here is on the energy delivery system.

By mitigating the regulatory lag and mitigating the disincentive to invest, S.B. 564 enables us to deploy more capital into our aged energy delivery system for the long-term benefit of our customers, and that is what we are doing.

Q. You earlier talked about what it appears could be characterized as some shortcomings in the existing system given the capital constraints in the past that you discussed. Why do those shortcomings exist?

A. To put this issue in context, please note that Ameren Missouri has more than 30,000 miles of distribution circuits spread across 62 of Missouri's 114 counties (including the City of St. Louis). Much of it was built-out in the 1950s and 1960s and even though replacements and upgrades have occurred, especially after storms damaged or destroyed the original equipment, our system is very much showing its age. For example, when SEP investments began in 2019, over 250 of our distribution substations (we have over 500 such substations) contain critical operating components, either a transformer or circuit breaker that was installed more than 50 years ago. These substations with aged critical components serve over 500,000 of our 1.2 million customers, meaning many of our critical substation components are well beyond their design life, which increases safety and reliability concerns; they simply need to be replaced. If we had not begun upgrading our substation fleet in 2019, by 2023 over 50 additional distribution substations serving an additional 200,000 customers would have a critical component reach 50 years of age. This means, in total, that 700,000 of our 1.2 million customers would have been served by a substation with critical components that are at least 50 years old. Upgrading and modernizing this critical infrastructure will improve safety for Ameren Missouri coworkers and customers while also improving reliability and resilience to meet the needs and expectations of our customers over the long term.

These issues go beyond our substations. Many of the system's 34 kilovolt ("kV") and 69 kV sub-transmission circuits were installed in that 1950's and 1960's timeframe I mentioned earlier, utilizing construction approaches and technology from that time period. Those assets are both past their design lives and inferior from a safety, operating, and performance perspective when compared to today's construction standards and technology (composite poles, standoff insulators, wind resistant conductors, OPGW shield wire, etc.). Other parts of our system are even older. We have nearly 3,700 miles of cable across the system that is also past its design life with some vintages dating as far back as the 1920's, much of which is at least 40 years old. Not only is it old, but much of it was buried directly in the ground without protective conduit and the impact from the direct contact with the soil has degraded the cable more quickly than originally expected, resulting in higher risk of failure compared with modern cable properly installed in protective conduit. In fact, our customers experience a failure rate of this older cable that is double the failure rate of newer cable installed after 1984.

To put these needs into perspective, we estimate that through 2030 it will take approximately $11 billion (in 2021 dollars) of investments in our distribution system to address all of the aged infrastructure, complete the effort of hardening those portions of the sub-transmission system that most need it against severe weather, deploying Distribution Automation ("DA") across the system and the associated circuit upgrades needed to take advantage of DA, and address capacity constraints across the system that limit operating flexibility and delay restoration time in contingent scenarios, among other needs.

Ameren Missouri is not alone in facing these issues and we are not the only ones who recognize the problem. According to the American Society of Civil Engineers, "most of the nation's transmission and distribution lines were constructed in the 1950s and 1960s, with a 50-year life expectancy, meaning they have reached or surpassed their intended lifespan."[3] That assessment is very much true of our system, and it is a key reason why we are prioritizing distribution investments.

In addition to just the basic need to replace aging infrastructure as a means to de-risk the system against what would inevitably be more frequent and lengthy outages and higher costs to replace equipment reactively instead of doing so in an orderly and planned fashion, we also need to be ready to meet the needs of the grid in the future, including issues created by things like the greater proliferation of distributed energy resources ("DER") and the need for two-way power flows. We will also need many more monitoring and sensing devices to be ready to accommodate changes in policy, such as we are seeing in the FERC's recent issuance of Order 2222.

Q. So how are you attacking the problem?

A. The first thing we are doing is we are making what I would call "foundational" investments to upgrade and modernize the grid using construction approaches and components manufactured and installed to today's standards. By "foundational", I mean those assets that are required for the basic movement of electrons from a generation location to the customer premise including poles, wires, transformers, cables, substation replacement program, etc. Much of this infrastructure both supports and benefits from its part of the integrated grid. Ameren Missouri relies on field personnel and Ameren Missouri subject matter experts in areas of distribution planning and operations who have detailed knowledge in the daily operation of the grid to make the best judgment, based on their

[3] American Society of Civil Engineers, "Failure to Act: Electric Infrastructure Investment Gaps in a Rapidly Changing Environment," 2020.

expertise, in identifying investments to upgrade and modernize the distribution system. These experts who identify investments for the distribution system consider a number of factors when proposing a project, such as age of assets, safety, historical reliability measures, worst performing circuits, number of customers impacted, operating experience in the field, operating performance during storms, asset loading, expected future load growth, voltage conditions, and many others. Specifically, on an annual basis a team of distribution planning engineers examine the recent and five-year projected peak loading of all circuits and substations on the system for any limitations to serve the peak load. Additionally, the distribution planning engineers evaluate system losses and system voltage levels in their annual evaluation of the overall system.

Q. Is it appropriate to require that benefits that can be quantified reach a certain threshold for projects to be executed?

A. No, it is often not possible to accurately quantify discrete financial benefits, and even if estimations can be made for some projects, the discrete quantifiable benefits of an individual project may or may not meet a 1.0 threshold.[4] However, when looking at the grid as a whole and taking all of the factors listed above into account, the need for a project becomes clear in order to maintain or improve continued safe and reliable service for our customers. To justify every project on an individual basis via just determining quantifiable benefits, Ameren Missouri would likely have to wait until customers have experienced a certain number and length of outages and also increased maintenance on the assets before a given project could "pass" a prescriptive cost/benefit test, which would almost always rely on a set of assumptions that may or may not be very accurate. To put it another way,

[4] A "1.0 threshold," meaning quantified benefits exceed quantified costs.

essentially what we are in the midst of doing is replacing the old, outdated past-its-design-life system with a better and more modern robust system to lay the foundation for a more reliable grid over time and for the current and future electrical needs of our customers that will better prevent or limit interruptions and longer outages.

Q. What structure exists around this effort?

A. To execute on these investments, we developed a structure to categorize and then prioritize projects based on the varied need being addressed by the required improvement, creating six categories of investments, as follows:[5]

> ***Grid Resiliency*** – This category primarily supports maintaining and improving customer reliability. This is achieved by building in the needed capability to support switching activities that allow Ameren Missouri to restore a larger number of customers more quickly through alternate grid configurations during various outage scenarios. Some resiliency projects might also include work that hardens the system or adds smart grid technology.
>
> ***Smart Grid*** – Ameren Missouri's grid currently relies on manual intervention to determine the cause and location of outages and then subsequent switching to repair and restore the grid. To reduce the need for manual intervention and ultimately to improve reliability (fewer outages or shorter outages when they happen), we are investing in technologies which will enable new digital grid management capabilities to support more

[5] There is some overlap between the categories, but projects are categorized into a given category based upon the predominant purpose of the project, as identified by planners and field personnel when the projects are developed.

efficient switching of the flow of electricity and quicker outage restoration. Working together, these smart switching devices, grid-edge sensing devices, and communication technologies enable new capabilities such as real-time grid visibility, remote control options, enhanced data collection, and self-healing capabilities. Projects in this category are primarily identified based on reliability history and operating considerations.

Substation CBM –Substations play a critical role in delivering customers safe, reliable, and affordable energy as the midpoint between high voltage, long distance transmission lines and the distribution lines that deliver energy to customers' homes and businesses. The substation condition-based modernization ("CBM") strategy is a critical element of a comprehensive substation asset management plan. Projects in this category are primarily identified based on addressing end-of-life assets that contribute to reliability and maintenance related issues, i.e., we are attacking the high age of our substations as discussed earlier. We also take into account the operational and maintenance historical performance when making replacement or upgrade decisions on some of these substation assets.

System Hardening –The System Hardening category includes both replacing the aged assets I spoke of earlier and the upgrading of assets because construction practices and equipment standards have improved from when the asset was originally installed 40 plus years ago.

Underground Cable –This category targets aged underground direct buried cable infrastructure outside of downtown St. Louis and Clayton – the 3,700 miles of cable I mentioned earlier - to address the aged condition of the cable and reliability concerns that have arisen or that will continue to arise from defects in the cable, as well as the occasional safety issues when the cable fails.

Underground Revitalization – This category targets aged underground infrastructure in downtown St. Louis and Clayton with a history of failures. Most of this system is over 50 years old. Given the criticality and size of many downtown customers, a comprehensive multiyear plan was established and is being executed to replace all of the cables running under the streets in downtown St. Louis. The plan includes redesigning the layout of cables across downtown St. Louis to increase the route diversity and mitigate the risks of multiple outages from many cables following the same pathway and being impacted when a single cable in the path fails. We are also installing modern cable, manhole and conduit technology to replace the aged infrastructure in downtown St. Louis, and using remote controlled switching devices to speed restoration activities in the event of future planned or unplanned outages. In addition to installing an improved system from an operational and outage mitigation standpoint, the upgrade reduces existing safety risks arising from deteriorated manholes and cable and splice conditions.

Q. The above discussion suggests that there have been and are more system needs than there is or has been capital to address those needs. Is that a fair interpretation?

A. Yes, it is. The work we are doing is not "gold plating" or " nice to have" work but rather it is work that our system planners and those that operate and maintain the system on a day-to-day basis have determined should be done to have a reliable system that will meet the needs and ever-increasing expectations of our customers. While there are assets on the system that have operated beyond their intended design life, like any other mechanical device, they cannot be expected to last forever, and the risk of malfunction and mis-operation increases the longer they remain on the grid.

Q. Which brings us back to what appears to be Dr. Marke's main contention, that is, that he desires to see some kind of quantifiable metrics relating to the energy delivery system investments the Company is making. How do you respond?

A. Dr. Marke's primary focus is on having a "cost/benefit analysis" underlying our energy delivery projects. By that I take it he means we should estimate the cost of a project, then make assumptions about benefits that (based on those assumptions) could be quantified, and then make a "go or no go" decision only if the calculated cost/benefit ratio is at least 1.0. Such an approach is inappropriate (and we are not taking it) for the energy delivery system investments we are making.

Q. Why is such an approach inappropriate?

A. Because one cannot make the decisions we need to make to address the needs of our aging system, expectations of our customers, or to address acute problems on the system via a quantification exercise. Instead, we have system needs and problems that need to be addressed and solved. To do so, we must prioritize the most pressing needs and problems, as identified by those with responsibility for operating and maintaining the system, and then choose the best solution to solve the problem, regardless of whether some kind of "pass-fail" quantification test would theoretically be met, so long as we can do so consistent with the capital we have available each year, subject to practical considerations and constraints such as limited equipment and or limits on the availability of labor.

Q. Please explain how decisions on the investments do need to be, and are being, made.

A. Aside from the fact that we know that there are large areas and components of our energy delivery system that are at, near, or past their design lives, and that we need to modernize and upgrade them or risk a significant degradation in our system reliability (and to arrest what would otherwise be the continued aging of the system), we also identify projects based on specific needs identified within each district by our engineers and field personnel, and based upon the judgment of subject matter experts in areas of distribution planning and operations who have detailed knowledge in the daily operation and maintenance of the grid. Collectively, these coworkers identify potential projects for the distribution system based upon a number of considerations (and this varies depending on the need/problem being addressed/solved), including, but not limited to, age of assets, safety, historical reliability measures, worst performing circuits, number of customers impacted, operating experience in the field, operating performance during storms, asset loading, expected future load growth, and many others. While the subject matter experts and the owners of the categories I listed earlier in my testimony do consider costs and benefits, this is not the overriding factor by any means.

Q. Are there other drivers of the need for greater investment in the system that come to mind?

A. One obvious one is the increased severity and frequency of major weather events which can have a profound effect on reliability year-to-year. A consensus certainly appears to exist that we have seen and will be seeing storms with greater frequency and intensity. Even a system that may have performed reasonably well during storms historically – especially before it became aged – will face more performance challenges in the harsher environment we are seeing, especially when coupled with customers' ever-increasing expectations. However, as I described previously, we are upgrading the system to better withstand the impact of these weather events.

Q. **Do you have a specific instance where these upgrades have benefited customers after a storm?**

A. Yes, a very recent one. On August 12, 2021, a very severe storm rolled over a significant part of Ameren Missouri's service territory interrupting service for an extended period to nearly 94,000 customers. As we recovered from the storm it was clear that circuits that had been upgraded with automated switching capabilities along with the necessary line, tie, and substation upgrades prevented an extended outage for an additional 8,500 customers. This means that circuit and substation upgrades of the type we are implementing resulted in an 8% reduction in the number of customers who experienced an extended outage from this one storm. Moreover, the totality of our upgrades discussed in this testimony allowed us to restore 56% of the customers who did experience an extended outage within 12 hours and 80% of those customers within 24 hours, which in my experience is significantly faster than we would have been able to achieve had a similar storm occurred ten years ago. For example, on May 31, 2013 at a time when there was little to no automated switching capability on the system, a storm interrupted service for 94,000 customers and only 15% of them were restored within 12 hours, and just 36% within 24 hours.

Q. Dr. Marke uses the term "performance metrics", suggesting those have a role in deciding on system investments. Please comment.

A. While Dr. Marke may make it sound simple, that is, to set some quantifiable target and make investment decisions based on that target, as I discussed earlier ensuring that we have a robust distribution system that will meet the long-term needs of our customers is not that simple. We do of course track certain reliability metrics and we have established short- to intermediate-term targets for them. Specifically, performance targets for SAIFI and SAIDI[6] are set each year. Continuous improvement is the primary driver behind both the one- and five-year targets. An example was when setting the 2020-2024 SAIFI targets, a five-year average was used from 2014-2018 that excluded the anomaly of 2019 and was set at .74 with a target to achieve a .01 decrease in each of the following years. The one- and five-year targets are updated annually with previous year's results taken into consideration. In 2021 the following targets were set:

SAIFI - .73, each customer would have on average less than one outage a year.

SAIDI – 86, each customer would experience an outage lasting no more than 86 minutes on average.

In addition to the 2021 targets that are described above, five-year targets are also established for these reliability metrics. As shown below, a continuous improvement is applied to the annual targets each year through 2025. These metrics are calculated using

[6] System Average Interruption Frequency Index and System Average Interruption Duration Index, respectively.

industry standard Institute of Electrical and Electronics Engineers ("IEEE") methodologies that exclude major event days as determined by historical reliability data.

Measurement	2021	2022	2023	2024	2025
SAIDI	86.1	85.0	83.8	82.6	81.4
SAIFI	.73	.72	.71	.70	.69

Q. Dr. Marke throws out a possible metric where one would compare the distribution rate base per customer nationally to energy sales and system peaks, and then cross-reference those numbers to metrics like SAIDI and SAIFI. What are your views about such a comparison?

A. There are several reasons why such comparisons are not meaningful and end up amounting to a numbers-crunching exercise that does not tell us much of anything useful about how we should maintain, replace, and upgrade our distribution system. While it is true as I discussed earlier that there is a general consensus that distribution systems across the country are aged and a lot of the assets are in need of replacement, the situation on the ground for every utility is drastically different. This means comparing metrics from one utility to the next isn't going to produce valid comparisons. Utilities along the coasts that have experienced repeated (and ever-increasing and extensive) hurricanes and tropical storms have likely "refreshed" much larger parts of their distribution systems than we have and may have lower ongoing needs now than we do. Utilities in areas with much lower tree density will also perform much differently from an outage perspective during storm events. Investment levels are also driven by terrain, density of customers, how far-reaching a service territory is, population trends, labor rates in given areas, and many other factors. Investment needs are also not necessarily correlated to energy sales or system peaks. A utility could have flat sales or a flat or even declining peak but if its system needs significant replacement and upgrade, it still should be completing that work to maintain or improve reliability and functionality for the load that it's required to serve on its system. Also, reliability metrics are lagging indicators that only indicate a need to invest after customers have experienced outages.

Q. Dr. Marke expresses worry about "gold-plating" of the distribution system. How do you respond?

A. Replacing an aging system, modernizing it so that it can serve customers for decades into the future, and thereby laying the foundation for a more reliable system that can accommodate DERs and other growing needs, including increasing customer expectations over time, is not "gold-plating," as I addressed in detail above. One only has to look at our system to realize we are not "gold plating" anything but making decisions to provide the best service to customers while always balancing the need for customer affordability.

Q. Putting aside some of the specifics of Dr. Marke's testimony on this topic, he seems to take issue with the information the Company has provided about its distribution system (and its overall SEP investments) in the docket the Commission created when the Company elected to utilize PISA. Please comment.

A. S.B. 564 requires that we submit detailed information to the Commission– at the <u>project level</u> for the prompt year - and at an aggregate level for the succeeding four years. We have done this each and every year – in 2019, 2020, and 2021. As an example, the detailed listing submitted to the Commission in File No. EO-2019-0044 and available to all stakeholders for 2021 is attached to my testimony as Schedule MCB-R1. The statute also requires that we hold a stakeholder meeting about this information each year. We have also done this each year along with providing a separate update to the Commission at its Agenda. In summary, we have done exactly what the General Assembly required and aside from Dr. Marke's general complaints in a couple of questions and answers in our last rate review (cut and pasted into his testimony in this case) no party – not the Staff or anyone else – has ever claimed that anything more is needed. In fact, Dr. Marke and OPC have not taken the opportunity given them to ask detailed questions about the investments Dr. Marke is now questioning during the stakeholder meeting or in the two rate reviews that have occurred since we elected to utilize PISA. I should note that Staff opined that our process for identifying the need for projects and how we evaluate them appeared to Staff to be reasonable.

Q. I take it you disagree with Dr. Marke's "encouragement" appearing at page 15, ll. 8-9 of his direct testimony?

A. Yes, I do for the reasons discussed above. These quantifications and metrics that Dr. Marke seems to think are the only means of deciding upon investments in our distribution system largely do not make sense for those investments, as I have testified. There were not "omissions" in our filing in this case. We are making investments in the system as we have always done <u>based upon the experience, knowledge and feedback</u> of those who operate and maintain the system, but at a higher investment level than in the past because we can do so as a result of the passage of S.B. 564, just as the legislature expected and intended when it passed the statute. We are also in full compliance with what the legislature said was an appropriate level of reporting and data submission.

Q. Is there a role for certain metrics in assessing ongoing system needs and prioritization of investments?

A. I believe there is, including continuing to assess how we are doing on the reliability metrics I discussed earlier, continuing to evaluate whether we should target even greater improvements in those metrics, and working to assess the impacts of investments that we have made in the past two or three years – and that we will continue to make – on system reliability and performance. However, for several reasons it takes a significant amount of time to see the effects of investments in the metrics. For example, not all circuits are impacted by a given storm, or impacted in the same way by the same storm. Moreover, storms vary in intensity. While some locations may experience multiple severe storm events in a given year, others may go many years without any impact. In order to really gauge the impact of system hardening, making the system more resilient, and improving its switching capabilities, we must have enough time and data to normalize for these variations, among other things. We are working on improving our use of data analytics to assess investment impacts over time and as we get better and better data, we will use it to inform future investment strategies and project decisions.

Q. Dr. Marke takes one other approach in questioning the system investments that are being made, that is, he implies that because of the existence of the Covid-19 pandemic or general economic conditions among low-income customers perhaps investments should not be made. Please address Dr. Marke's testimony in this area.

A. First, let me be clear that the Company is aware that some customers face greater difficulty in paying their utility bills than others. We have many programs including many funded with shareholder dollars to assist low-income customers. Ameren Missouri witness Warren Wood discusses many of these in his direct testimony, and Page Selby addresses some of these programs in her rebuttal testimony. Second, our statutory obligation is to provide safe and adequate service, and it is our belief – and we firmly believe the Commission would agree with this – that we need to maintain and operate a system that provides a level of reliability consistent with the needs and expectations of all of our customers, consistent with us being able to have a reasonable opportunity to earn a fair return. I have outlined in detail above why the investments we are making are needed to meet that obligation. Finally, the pandemic has shone an even brighter light on just how critical highly reliable electricity is for everyone – including for low-income customers. Many customers still work from home, at least a part of the time. Their devices will not work if the power is not on, and they will not work right if the power quality is poor. Most of their kids had to be schooled from home for long periods of time during the pandemic, and while this is less true today, it remains true for many. Overall, consider that virtually all of our customers depend on a digital world today – computers, appliances, electronics, etc. They have much less tolerance for even momentary outages, which used to be normal, as any outages at all are far more disruptive to customers than they used to be. This is not the time *not* to invest in the system. It should also be kept in mind that we are investing at a time when the cost of capital to do so is quite low by historical standards. Our authorized weighted average cost of capital was set by the Commission in 2015 at 7.911%. It dropped in our 2019 case (using the midpoint of the return on equity underlying the settlement of our 2019 rate case, it was 7.116%), and it has dropped further given that our request in the case is for an authorized weighted average cost of capital of 6.995%. Just as this has been a good time for customers to improve their homes by taking advantage of low borrowing rates, this too has been a good time to invest in the system at a cost of capital that is roughly 80 to 100 basis points lower than it was just a few years ago.

Q. Aside from his overall expression of concerns, Dr. Marke notes three specific areas of distribution system investments, undergrounding part of the system, replacing 4kV substations, and voltage reduction programs. Please address each of those topics.

A. Dr. Marke appears to confuse the *replacement* of 400 miles of *existing* but old, and as I discussed earlier degraded and flawed underground cable, with a plan that does not exist to take existing overhead circuits and instead underground them.[7] According to a data request response from Dr. Marke, perhaps the wording of one of our SEP publications gave him the wrong impression (it referred to "400 miles of new underground cable"). Regardless, the cable would be new, but it *replaces* existing, old underground cable.

Q. What about replacing 4 kV substations?

A. Early in the planning of the SEP, Ameren Missouri did consider whether it should convert all its 4 kV substations to 12 kV in an effort to streamline operations and achieve efficiencies. However, as part of our ongoing evaluation of projects, we determined that conversions should only occur when (a) load is projected to grow beyond the capacity that can be supported by the 4 kV system or voltage challenges exist with the 4kV system, or (b) to eliminate "voltage islands." These islands represent parts of the system served at a nonstandard voltage (2.4 kV for instance) from legacy systems acquired by Ameren

[7] There may be isolated instances where a specific overhead circuit has significant reliability problems and where the only way to address the issue is to underground a part of that circuit, but there is no large-scale plan to underground existing overhead circuits.

Missouri in the past or 4 kV systems geographically surrounded by 12 kV systems which we can't easily back up. These voltage islands present operating challenges as specialized knowledge is needed in operating them and at times specialized equipment is needed to repair the assets, which may prolong the length of an outage and also requires Ameren Missouri to maintain additional equipment in inventory for these voltages outside the standard 4 kV and 12 kV. Another significant problem with these voltage islands is that when outages occur, there are limited to no rapid restoration abilities since we are unable to tie an adjacent circuit at a different voltage together to restore service. We are not, however, doing a wholesale replacement of 4 kV substations.

Q. What about voltage reduction?

A. Company witness James Huss addresses Dr. Marke's suggestion that Ameren Missouri implement a voltage reduction program in his rebuttal testimony, explaining why doing so does not make sense for Ameren Missouri.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

ER-2021-0240

SCHEDULE MCB-R1

HAS BEEN MARKED

CONFIDENTIAL IN ITS

ENTIRETY

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF MARK C. BIRK

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

Mark C. Birk, being first duly sworn on his oath, states:

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

/s/ Mark C. Birk
Mark C. Birk

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