Exhibit No.:	
Issue(s):	Avoided Revenue Mechanism; Avoided Costs and Avoided Earnings Opportunity Analysis; throughput Disincentive; Rate Case Annualization.
Witness:	Steven M. Wills
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	EO-2023-0136
Date Testimony Prepared:	April 26, 2024

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EO-2023-0136

REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
April, 2024

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REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

FILE NO. EO-2023-0136

I. INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Wills, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am the Senior Director of Regulatory Affairs for Ameren Missouri.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Music degree from the University of Missouri-Columbia in 1996. I subsequently earned a Master of Music degree from Rice University in 1998, then a Master of Business Administration ("M.B.A.") degree with an emphasis in Economics from St. Louis University in 2002. While pursuing my M.B.A., I interned at Ameren Energy in the Pricing and Analysis Group. Following completion of my M.B.A. in May 2002, I was hired by Laclede Gas Company as a Senior Analyst in its Financial Services Department. In this role, I assisted the Manager of Financial Services in coordinating all financial aspects of rate cases, regulatory filings, rating agency studies and numerous other projects.

In June 2004, I joined Ameren Services as a Forecasting Specialist. In this role, I developed forecasting models and systems that supported the Ameren operating companies' involvement in the Midwest Independent Transmission System Operator, Inc.'s ("MISO")[1] Day 2 Energy Markets. In November 2005, I moved into the Corporate Analysis Department of Ameren Services, where I was responsible for performing load research activities, electric and gas sales forecasts, and assisting with weather normalization for rate cases. In January 2007, I accepted a role I briefly held with Ameren Energy Marketing Company as an Asset and Trading Optimization Specialist before returning to Ameren Services as a Senior Commercial Transactions Analyst in July 2007. I was subsequently promoted to the position of Manager, Quantitative Analytics, where I was responsible for overseeing load research, forecasting and weather normalization activities, as well as developing prices for structured wholesale transactions.

In April 2015, I accepted a position with Ameren Illinois as its Director, Rates & Analysis. In this role, I was responsible for the group that performed Class Cost of Service, revenue allocation, and rate design activities for Ameren Illinois, as well as maintained and administered that company's tariffs and riders. In December 2016, I accepted a position with the same title at Ameren Missouri. In July of 2022, I was promoted to Director, Regulatory Affairs, and in January 2024 promoted to Senior Director, Regulatory Affairs. In this role, I oversee the teams responsible for contributing to all aspects of the Company's state regulated activities, including the Rates and Analysis team I previously directed.

Q. Are you including any schedules with your testimony?

A. Yes, I am including the following schedules:

[1] Now known as the Midcontinent Independent System Operator, Inc.

Schedule SMW-R1 – Excerpt from the Company's 2019-24 MEEIA Energy Efficiency Plan

Schedule SMW-R2 – Excel file calculation template for Throughput Disincentive

II. PURPOSE OF TESTIMONY

Q. To what testimony or issues are you responding?

A. I am responding to the direct testimony of several Staff witnesses, including J Luebbert, Sarah Lange, Brad Fortson, and Hari Poudel. My testimony will include overall commentary on Staff's posture related to resource planning issues in this and other cases. I will also address several specific topics, including Staff's discussions around earnings opportunities, the manifestation of benefits of reduced energy consumption through the fuel adjustment clause ("FAC"), and mechanisms to address the throughput disincentive.

III. STAFF CONTINUES TO OPPOSE RESOURCES CRITICAL TO THE RELIABILITY AND AFFORDABILITY OF THE ONGOING ENERGY TRANSITION

Q. Please provide an overall perspective on Staff's position in this MEEIA case in the context of other recent Ameren Missouri regulatory proceedings.

A. I have significant concerns with Staff's perspective on resource planning, especially given the ongoing and historic energy transition that is taking place as aging coal-fired energy centers – energy centers that are facing unyielding pressures from increasingly stringent environmental regulations – reach end of life. Staff's resource planning perspective lacks any clear direction or urgency to address the issues that are facing the Company, and rather looks to impede the progress on steps that the Company firmly believes are imperative to ensuring future reliability and affordability of energy services. Staff's perspective became apparent in recent Company applications for certificates of convenience and necessity ("CCNs") for new generation sources – the Boomtown solar facility that was approved by the Commission over Staff's objections in File No. EA-2022-0245, and four additional solar energy projects that were eventually the subject of a Stipulation and Agreement after Staff filed hundreds of pages of vehement opposition to the projects in File No. EA-2023-0286 - and that perspective further permeates its direct testimony in this case. While the industry as a whole – not just Ameren Missouri - has entered what is clearly the most dynamic period of change in the mix of generation resources employed to serve customers in its history, Staff continues to cling to a "do nothing" philosophy (e.g., deny CCNs, pause Demand Side Management ("DSM") programming) that, if followed, will inevitably lead to the failure of Missouri utilities to proactively develop the resources that will be needed to replace the aging and environmentally-pressured legacy coal-fired generation facilities that will be retiring in a systematic fashion, beginning a couple of years ago and continuing in a staged manner with additional retirements occurring at regular intervals every few years through 2042 (or even earlier if additional environmental regulations so dictate).

Staff now opposes the demand-side resources that are the subject of this proceeding, in addition to the opposition it enthusiastically voiced to the development of the first projects to begin the development of the "new fleet" of supply-side generation resources in the CCN dockets I just mentioned. However, adherence to Staff's world view would ensure that Missouri fails to proactively shape its own energy future, and instead will be left scrambling for solutions when the end of life for legacy fleet resources inevitably comes to pass for the Company, as it will for it and other utilities in the region and across the country. Staff's opposition to demand-side resources in this case exacerbates the problem from the CCN dockets, whereas now Staff not only opposes the "new fleet" resources that will replace the capabilities of retiring resources, but also wants to pause the measures that help to hold load growth in check and reduce the need for even more additional future supply-side capabilities. Adherence to Staff's perspective places the future reliability and affordability of energy services for Ameren Missouri's customers at risk, which is bad for customers in the state as well as for the economic climate generally, as businesses more than ever are considering infrastructure availability and access to clean and reliable power in their siting decisions.

Q. Why do you say Staff's approach puts future affordability and reliability at risk?

A. The Company's Integrated Resource Plan ("IRP") is the Company's primary planning exercise that establishes how it is going to meet customers' needs going forward. The IRP is discussed at length in Company witness Matt Michels' testimony. Reliability is at the heart of the IRP, in that all of the plans contemplated are grounded in robust analysis designed to ensure our ability to provide the energy and capacity customers will need while also addressing numerous risks and uncertainties. The selection of the Company's Preferred Resource Plan ("PRP") within the IRP is based on a primary criterion of identifying the plan with the lowest net present value of revenue requirement ("NPVRR") – i.e., the most affordable plan, consistent with other secondary planning objectives and in consideration of myriad risks. Staff's and OPC's recommendation to discontinue DSM programs means an alternative plan without DSM programs would need to be implemented. The alternative plan that would meet customers' needs without DSM

(Plan I from the 2023 IRP) is expected to cost customers approximately $4.197 billion more than the Company's PRP on an NPVRR basis.[2]

In this docket, Staff opposes implementation of DSM which is a key element in the PRP, while offering no alternative of its own as to how customers' needs should be met going forward. Opposing progress on the Company's PRP for providing reliable and affordable energy, while offering no concrete feedback about the PRP plan during the IRP proceeding and no alternatives to the PRP while opposing its implementation on multiple fronts is simply not a path that will lead to the fulfillment of the objectives of the IRP – reliable and affordable energy service.

Q. Please summarize your understanding of Staff's overarching rationale for its recommendation not to pursue additional MEEIA programs at this time.

A. Staff inexplicably appears to believe that if *any* new generation is being planned and/or built by the Company, then it must be true that *additional* generation above and beyond that amount cannot be avoided or deferred by demand-side programs.[3] Or said another way, Staff seems to be insisting that the Company would not need (build or acquire, and earn returns on) more generation than it is *currently planning* even if it's load is materially higher than the load it is *currently planning for* by virtue of including energy efficiency and demand response at the Realistic Achievable Potential ("RAP") level in its PRP.

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[2] File No. EO-2024-0020, Notice of Filing Correction to 2023 Integrated Resource Plan, Description of Correction and List of Revisions (Public, Confidential and Highly Confidential), Chapter 10 – Strategy Selection.pdf, page 50 Table 10.4 EVBI Analysis Results.

[3] I believe this to be a fair characterization of Staff witness Luebbert's testimony on p. 4 of his direct testimony at lines 3-7, where among other things, he says it is "bad public policy…to assume benefits associated with avoided generation…while the Company is simultaneously seeking a return on investments in generation…that will not be reduced or avoided as a result of MEEIA Cycle 4."

Q. What is your reaction to this rationale?

A. Staff's position simply cannot be squared with the facts. *Several gigawatts* of coal-fired resources, representing over 50% of the total capacity recently owned and operated by the Company – has retired or will retire within the visible planning horizon. This generation, which recently accounted for the generation of energy sufficient to meet over 85% of the Company's annual retail energy need, is systematically retiring and needs to be replaced – before even considering the possibility of future load *growth.*

Staff witness Fortson walks through an overview of the Company's PRP from its 2023 IRP filing (File No. EO-2024-0020) made on September 26, 2023. In his summary, Mr. Fortson correctly notes the generation *additions* planned by the Company as well as many corresponding generation *retirements*. However, from that point forward, Mr. Forston and other Staff witnesses appear to entirely *ignore the generation retirements* and only focus on the amount of new generation being planned and/or built by the Company. The retirements of existing capacity that Staff ignores are critical context for the generation additions Staff is pointing to as its purported proof that no new investment is being deferred or avoided by MEEIA. How can one possibly expect that energy efficiency will defer or avoid *all* investment in new generation when there is extremely significant investment needed just to maintain the capabilities that have historically been provided by a fleet of resources that is in the process of staged retirement? Other than Mr. Fortson's acknowledgement of the Company's Data Request ("DR") response that indicates that, without the continuation of MEEIA programs at the RAP level, the Company's plan would necessarily include *two additional natural gas-fired power plants within the 20-year planning horizon* (this is a very significant acknowledgement, but which Staff never seems to internalize into the formulation of its positions in this case), never once does a Staff witness attempt to compare the Company's planned generation with an amount of generation *that would otherwise be needed to meet the much higher load level that would exist without MEEIA*. Meanwhile, Staff continues to assert or imply that there is no generation being deferred or avoided by the Company's proposed MEEIA plan (nor earnings foregone by the Company) in this case, and also voices its doubt about whether customers have benefitted from past MEEIA programs, including in the form of deferred or avoided investment. Company witness Michels elaborates on the generation plan that the Company would have to undertake but for the inclusion of RAP level MEEIA portfolios in the Company's PRP.

Q. Several Staff witnesses express doubt about whether customers have benefited from past MEEIA programs,[4] indicating that either the benefits have not been sufficiently evaluated,[5] or complaining that evaluation of such benefits is "difficult."[6] Does this mean benefits have not accrued?

A. Absolutely not. The fact that evaluating energy efficiency is "difficult" is not new. But that does not mean that it cannot be done, has not been done, and/or is not worth doing. Understanding energy efficiency inherently requires comparing what actually has happened to a counter-factual scenario that asks what would have happened "but for" the impact of the programs. We have had a robust and transparent Evaluation, Measurement, and Verification ("EM&V") process that is annually approved by the Commission – further discussed by Company witness Neil Graser - associated with our

[4] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 13, ll. 4-6.
[5] File No. EO-2023-0136, Brad Fortson Direct Testimony, p. 7. ll. 1-6.
[6] File No. EO-2023-0136, Sarah Lange Direct Testimony, p. 6, ll. 9-11.

first three MEEIA cycles that clearly establishes the significant benefits that have accrued to customers in the form of meaningful reductions in customer energy consumption and peak demand, as well as favorable Total Resource Cost ("TRC") test results (i.e., benefits have exceeded costs according to the metric that Missouri's MEEIA law prescribes as the preferred cost-effectiveness test). It is true that the evaluation process does not extend so far as to create an entirely counter factual world that includes assessment of what hypothetical resources - resources that do not exist in reality today because of the success of the Company's first three cycles of MEEIA programs - might have been built (or be in the process of being built) in that counter factual world where we had not had MEEIA programs. But that does not mean more resources would not have been built or would not be in the process of being built if those MEEIA programs had not existed. In fact, it is entirely implausible to conclude that generation investment has not been and/or is not being deferred by the load reductions that have arisen from the Company's MEEIA programs of the last decade. The implication that "but for" past MEEIA programs the Company's existing and planned generation would be the same as it is today is wholly illogical and does not withstand scrutiny.

Q. Can you please put that point into context with some data?

A. Yes. Figures 1 and 2 below show the historical weather normalized[7] annual retail energy consumption and peak demands experienced in the Company's service territory. They also show a view of those measurements of load "reconstituted" for the effects of the Company's first three MEEIA cycles using evaluated data that has supported

[7] In addition to weather normalization, I have also adjusted historical loads by removing the impact of the Noranda aluminum smelter, which both began and terminated service with the Company during the time horizon shown in Figures 1 and 2, and which represented a disproportionately large share of load that would distort the underlying load growth trends.

Commission-approved EM&V results, and which considers measure lives and persistence of savings from each program year to determine what additional load would have existed at any given time "but for MEEIA." These figures create a very telling picture both of the efficacy of energy efficiency of altering the trajectory of load growth and of what the system load (and by extension, resource needs) would look like today with and without these past energy efficiency programs.

Figure 1 – 2004 – 2021 Annual Energy Consumption with and without MEEIA Programs

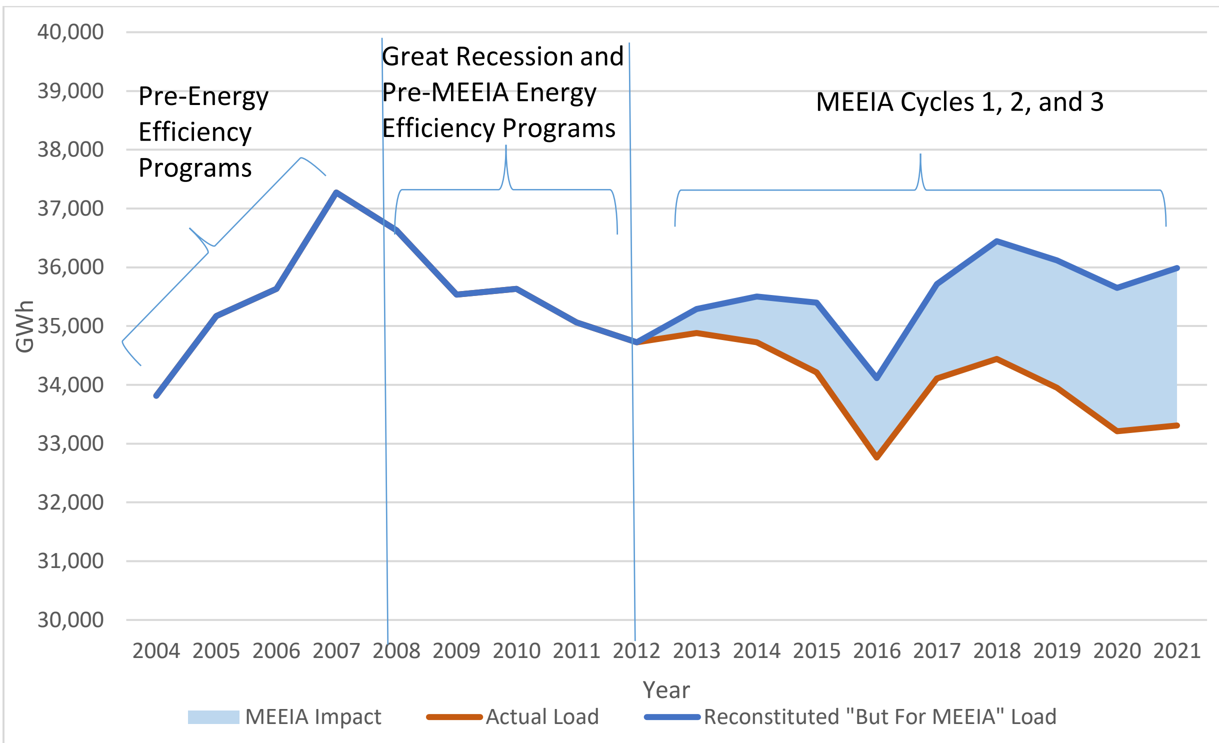
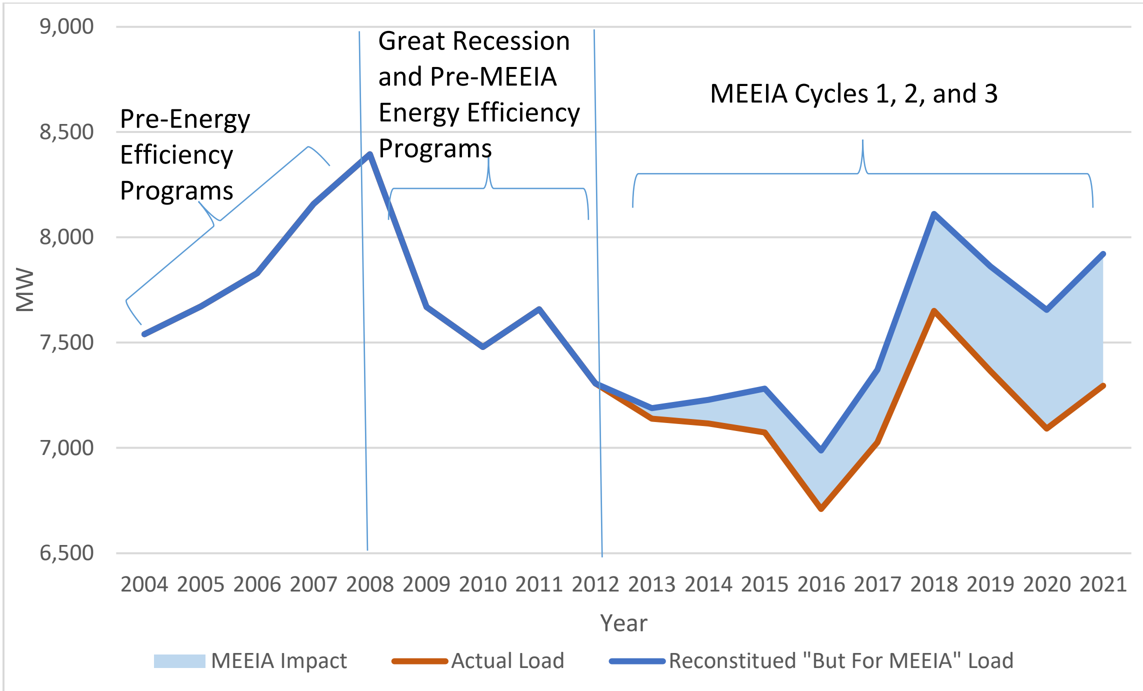


Figure 2 – 2004 – 2021 System Peak Load with and without MEEIA Programs



I have divided figures 1 and 2 into three discrete time periods to provide additional context for understanding the impact of MEEIA programs. The first period is what I have labeled as "Pre-Energy Efficiency Programs." I started this graph in 2004 due to the amount of historical information available in the database the Company maintains with respect to its load analysis in compliance with the Commission's IRP rules, but the trend that is evident in this first 4-year "era" is generally consistent with the long-term growth in electric usage that had existed prior to 2004 as well. During this 2004 – 2008 timeframe, annual energy consumption and peak demand grew at compound annual growth rates ("CAGR") of 2.0% and 2.7% respectively. Absent a change in load growth trajectories, it was clear that additional generation resources would need to be brought online to keep up with growing demand. However, in late 2008, the economy took a major hit with the welldocumented and well-known financial crisis and great recession that followed. Around that same time, the Company also initiated energy efficiency programs, although not under the umbrella of MEEIA, and not quite as large as subsequent MEEIA offerings. There were also impacts to the growth trajectory from certain federal appliance efficiency standards that would have modestly dampened load growth from the historical 2% level in play starting at this time as well.[8] Driven largely by the combined effect of these developments (and by far most significantly by the recession) load sharply declined and then temporarily leveled off. I have labeled this period as "Great Recession and Pre-MEEIA Energy Efficiency Programs" in the Figures above.

Beginning after 2012, in the period labeled as "MEEIA Cycles 1, 2, and 3," the Company's MEEIA programs began in earnest. It is clear from these graphs and the evaluated program impact numbers underlying them the substantial impact that MEEIA has had on the growth trajectory – which also directly creates avoided costs and impacts the amount of supply-side resources needed to serve customers (during the historical time period contemplated in the Figures, today, and in the future). Relative to 2012 loads, the experienced CAGRs in energy consumption and demand through 2021 were -0.4% and 0.0% respectively. Absent MEEIA, those trajectories would have been approximately 0.4% and 0.8% respectively – 0.8% higher annual growth in the case of both energy and peak demand. While a 0.8% difference may not sound like a lot, when applied to millions of Megawatt-hours ("MWh") or thousands of Megawatts ("MW") and compounded year in and year out for a decade or more, it is in fact game changing. Note that by the end of the period covered in the graph above, the actual annual energy consumption is *over 2.5 million*

[8] These effects were/are contemplated in the Company's IRP load forecasts, DSM potential studies, and in EM&V to differentiate them from the effects of the Company's programs.

MWhs less than it would be absent MEEIA's evaluated impacts and peak demand is *over 600 MWs lower* than it otherwise would have been.

Q. Would an additional 2.5 million MWhs of annual energy and 600 MWs of peak demand impact the resources needed to serve Ameren Missouri's customers?

A. Absolutely. Staff refers to the fact that the Company has identified an "energy need" arising from the recent and near-term retirement of coal-fired energy centers.[9] That energy need would be 2.5 million MWh higher *immediately* were it not for the success of the first three MEEIA cycles. For reference, consider the projects associated with the four CCNs I mentioned just above that the Company recently sought – three of which have already been granted by the Commission and the fourth of which is subject to certain conditions being fulfilled pursuant to a Stipulation and Agreement the Company entered with parties to the case – are projected to generate 1.2 million MWh of energy in their first full year of operation. The savings from MEEIA have offset more than double that amount of annual energy consumption. Said another way, to have the same energy position that we will have when these projects go into service under the assumption that MEEIA programs had not existed, we would have needed additional generation resources with sufficient expected energy output to more than double the energy output of projects that we have already pursued. While this example is certainly an over-simplification of what a completely developed "counter-factual" world would look like – the counter-factual mix of resources we would have needed with more than 600 MW of incremental peak demand and more than 2.5 million MWh of incremental energy to serve would have arisen from detailed and robust IRP-style analyses and would likely include dispatchable resource

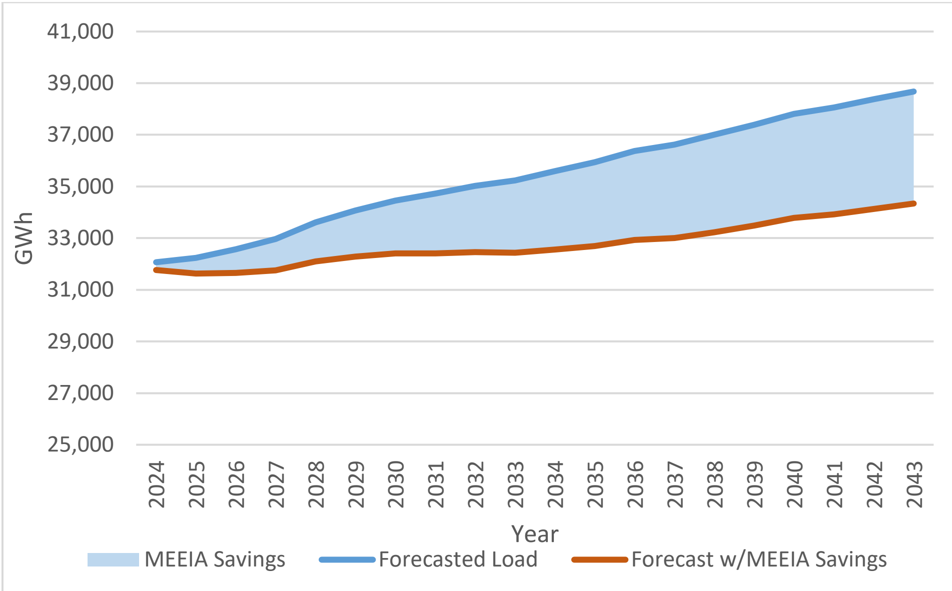
[9] File No. EO-2023-0136, Brad Fortson Direct Testimony, p. 12, ll. 3-32.

additions along with energy resources, it illustrates the obvious point that *resources unquestionably have been and are being avoided as a result of MEEIA programs*.

Q. Can the same be expected of additional MEEIA programs if the Commission approves the Company's application in this case?

A. Yes. Mr. Michels' rebuttal testimony presents evidence from the Company's IRP of the supply-side resources that are being avoided in the Company's PRP as a direct result of the inclusion of RAP level DSM programs. But just to provide similar context as I provided for historical program impacts in Figures 1 and 2 above, Figure 3 below shows the forecasted annual sales the Company would plan for under a world with, and without, future DSM programs. To be clear, once again, the shaded area represents incremental load that the Company would have to be prepared to serve – i.e., build or acquire resources to meet – if we do not go forward with MEEIA programs as Staff recommends. Note that in Figure 3, the annual loads forecasted for the Company to meet with supply-side resources is over 2 million MWh, or 6.3%, higher by just 2030.

Figure 3 - Forecasted Annual Energy Consumption with and without MEEIA Programs



Q. Is this a particularly precarious time to take the extreme step recommended by Staff to pause DSM efforts in the Company's PRP?

A. Yes. I'm sure the Commission knows what is going on with the historic generation transition that we are in the middle of and the attendant challenges in bringing on enough renewables to meet the need for cleaner resources, as well as the challenge in ensuring enough dispatchable capability to maintain reliability as aging and environmentally-pressured coal plants retire. I won't belabor that point again except to say that the much higher level of loads that we would have to serve under a "no-MEEIA" future would be that much more difficult to meet with an appropriate mix of timely-deployed supply-side resources.

But beyond that, one of the hottest topics emerging in the industry is the rapid increase in the forecasted growth rates in load to be served in the future. This is largely due to a boom in data centers being built to provide the capabilities to handle cloud-based computing services and Artificial Intelligence ("AI") applications, along with energy intensive cryptocurrency operations, but also includes other industrial loads that are increasingly being brought back onshore due to federal efforts to support manufacturing in the United States, as well as electrification of transportation and other end uses. In its Electricity 2024[10] report it released in January in which it discusses its forecast of energy trends through 2026, the International Energy Agency ("IEA") highlighted this trend, featuring in its executive summary a headline stating "Electricity consumption from data centres, artificial intelligence (AI) and the cryptocurrency sector could double by 2026."[11]

The expectations of the IEA are also consistent with other recent indications of significant upward change in growth forecasts within the industry. A recent Utility Dive article titled "PJM triples annual load growth forecast to 2.4% driven by data centers, electrification" highlights the stark reckoning with higher load growth occurring in the eastern U.S. I have little doubt that the Commission has probably heard this as a theme at regulatory conferences and industry webinars that it follows as well.

Q. Is Ameren Missouri seeing indicators of higher potential for growth like the rest of the industry?

A. Yes. In fact, given the uptick in inquiries from potential very large load customers that our economic development team was seeing at the time we prepared our 2023 IRP, the Company made an unusually late adjustment to its load forecast to begin to account for this trend. The load forecast for the IRP generally has to be completed early in the process of developing a plan, because it is early in the critical path of developing an

[10] International Energy Agency, Electricity 2024 – Analysis and forecast to 2026, January 2024.
[11] IEA's statement applies to worldwide electricity demand, but later in the report U.S. specific statements are included that highlight the rapid growth expected from data centers domestically as well.

IRP, as the composition of all of the candidate resource plans to be evaluated must be driven by their ability to meet the needs of those forecasted loads. But the Company made a relatively late adjustment to its forecast to account for the increasing probability that was becoming readily apparent of additional load to be served, given the level of interest in our service territory from entities with significant electric demand. That trend has only increased as we have continued to see higher and higher levels of inquiries from very large potential customers. We're already seeing a manifestation of this higher demand on our system today. In fact, since the beginning of 2023, ** [redacted] **

Q. Should an increasing load growth forecast impact the decision about whether to pursue future MEEIA programs?

A. Absolutely. Staff did not address the impact of the Company's future load growth in its testimony. While managing the generation transition and reducing (even if not eliminating, as Staff would seem to insist upon) the amount of additional supply-side resources that need to be built to replace the retiring fleet is an extremely compelling reason to pursue MEEIA savings on its own, the possibility of much higher load growth increases the urgency of managing the demand that we can manage. Energy efficiency and demand response can at least mitigate and provide some amount of insurance against the need to rapidly deploy even more supply-side resources as new demand emerges. It is incredibly short sighted for Staff to suggest what is already a bad idea in their proposal to pause DSM programming.

Q. Does the potential for higher load growth illustrate the fallacy of Staff's thinking about deferral or avoidance of supply-side resources?

A. Yes. I can already picture Staff's testimony if, in a few years, new customers have come on the system and the Company needs to propose new resources that are not already in its PRP. Staff's currently evident philosophy suggests that it would be likely to come in and say, "see MEEIA did not avoid anything," even if the driver of the new resources was new load that had nothing to do with what MEEIA could or should be expected to impact and was associated with economic activity that was good for Missouri, and even if there would have been even more resources needed had we not managed the existing load with effective DSM programs. Simply put, the world is constantly changing, and our planning must keep up with the changes, mitigate risks from the changes we can see potentially coming, and make the best decisions we can with the information we have at the time. At this time, the best information says that MEEIA programs are more essential than ever in managing a generation transition that is requiring investment in supply-side resources at the same time that we are seeing growth in the useful applications of electricity in our society and our service territory. That growth does not somehow mean that improving the efficiency of energy services is not worthwhile, but it in fact enhances the importance of doing so.

IV. STAFF'S OPPOSITION TO EARNINGS OPPORTUNITIES IS BAD POLICY AND INCONSISTENT WITH THE MEEIA LAW

Q. Staff claims that the Company should not be eligible for an earnings opportunity ("EO") associated with MEEIA because the Company is not foregoing any earnings by implementing the programs.[12] What is your reaction to this recommendation?

A. Staff's recommendation is wholly irrational, lacks grounding in the Company's actual IRP, and is inconsistent with the MEEIA law.

Q. How is Staff's opposition to an earnings opportunity inconsistent with the MEEIA law?

A. While I am not a lawyer and this issue will be addressed in the Company's initial brief, I can say that the MEEIA legislation itself requires:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. **In support of this policy, the commission shall**: (1) Provide timely cost recovery for utilities; (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and (3) **Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.**[13]

[12] File No. EO-2023-0136, Brad Fortson Direct Testimony, p. 10. ll. 7-9.
[13] Section 393.1075, RSMo (emphasis added).

Again, I am not a lawyer but I thought it relevant to highlight the clarity that the law provides related to the Commission's unqualified[14] obligation ("shall") to provide earnings opportunities for savings from cost-effective DSM programs like the one proposed by the Company in this case.

Q. Regardless of the legal question, why is Staff's proposal irrational and not grounded in the Company's actual IRP?

A. Staff characterizes the payment of an EO under MEEIA as "double compensation" when it occurs alongside investments in supply-side resources that the Company will also earn on by including those investments in rate base,[15] without regard for the fact that the Company's IRP clearly indicates a need for *both* MEEIA programs *and* supply-side investments to meet customers' needs in the most reliable and affordable way possible. Staff says that "[t]here is no way the result of this double compensation could lead to just and reasonable rates."[16]

There is so much wrong with Staff's characterization of the situation that it's hard to know where to begin. It is no more double compensation to provide earnings for both the supply-side and demand-side components of a portfolio of resources used to serve customers than it is to provide earnings on multiple supply-side investments (i.e., power plants) that make up a portfolio of resources that provide service to customers. Recall that the Company's IRP identified that, if the Company did not pursue the RAP level DSM in its PRP, it would need *two additional natural gas-fired power plants* within the planning

[14] On page 12 of Staff witness Luebbert's Direct Testimony, he claims that if no generation investment is avoided by a MEEIA cycle, then this statutory provision can be met even with no EO being granted, but he fails to square that position with the plain language in the statute that includes no such qualification on the requirement to provide timely earnings.
[15] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 4, ll. 3-9.
[16] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 4, ll. 78.

horizon[17]. As noted above, this approach is expected to cost customers an additional $4.197 billion on an NPVRR basis.[18] If the Company took that path and pursued only supply-side resources, it should go without saying that the Company would earn on *all* of the resources that it prudently put into service to serve customers – including earnings on the resources that it developed that are consistent with the Company's existing PRP as it looks today, as well as *additional earnings* on the *additional natural gas-fired plants* that it would have to build as a result of a decision not to offer MEEIA programs. I cannot imagine even Staff trying to refer to that as double compensation. Earning on all components of a resource portfolio, including supply- and demand-side resources, is no more double compensation than the Company currently earning on both the Labadie Energy Center and the Callaway Energy Center at the same time, because both are a needed part of the portfolio of resources it has invested in to serve customers. If the Company does not implement this next MEEIA cycle and instead invested in two more natural gas-fired cycle plants, the Company's earnings would be higher by including those two plants in rate base. Not building those plants, which is enabled by MEEIA programming, and therefore not earning on an investment in them, is the very definition of deferred or avoided investment and foregone earnings, completely irrespective of whether there is also other supply-side investment occurring that will help build the new fleet of resources that will replace the capabilities of the retiring coal fleet. There is a reason that energy efficiency and demand response programs are referred to as demand-side *resources*; they fill in for,

[17] In addition to the two additional natural gas-fired power plants in the alternative plan, a third natural gas-fired power plant – a combined cycle – would need to be accelerated by five years.

[18] File No. EO-2024-0020, Notice of Filing Correction to 2023 Integrated Resource Plan, Description of Correction and List of Revisions (Public, Confidential and Highly Confidential), Chapter 10 – Strategy Selection.pdf, page 50 Table 10.4 EVBI Analysis Results.

or substitute, for traditional supply-side investments that would otherwise need to be made. The General Assembly recognized this when it mandated that utilities be given an earnings opportunity to provide earnings the utilities otherwise would have received on incremental supply-side resources that the MEEIA programs displace.

Q. Staff claims that its position that no earnings opportunity should be afforded Ameren Missouri is supported by "lessons learned regarding Ameren Missouri generation ratebase."[19] Is Staff's analysis of historical generation rate base trends useful for assessing whether foregone earnings associated with MEEIA programs have been experienced in the past, or can be expected in the future?

A. No, not at all. Foregone earnings analyses, like many analyses associated with energy efficiency and demand response are complicated, in that they require the evaluation of a counter-factual scenario as I have mentioned previously. What earnings would have been manifest "but for" the program? Whether generation investment has increased or not over a particular period of time is not a relevant question. The relevant question is what level of investment in generation *would have been* experienced, and what investment would be expected to be experienced in the visible future, if not for the load reductions that have arisen from the existence of the programs - not how has net rate base changed over the last year or five years. Actual experienced rate base change is a poor and very blunt measure for analyzing this issue, as changes could be associated with, for example, environmental projects at plants that add rate base but do not change, or maybe even slightly reduce, capacity. In fact, in examining the table on page 13 of Mr. Luebbert's testimony, it is clear to me that rate base growth during the time horizon Staff examined

[19] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 13, l. 3.

had *nothing* to do with a failure of MEEIA to cause the avoidance of generation investment. This is clear because during most of the years shown on that table, the Company was generally not adding any significant new or expanded generation capacity *at all*. Rate base growth necessarily must have been investment needed to maintain existing facilities and/or comply with environmental regulations,[20] investments on which MEEIA would not and should not be expected to have any impact. And later in the time horizon reflected in Staff's table – specifically in 2020 – a noticeable jump in generation rate base occurred at a point in time where the Company was adding wind generation resources that were needed to comply with the Missouri Renewable Energy Standard ("RES"). Again, this is investment that would not and should not have been expected to have any meaningful interaction with MEEIA programming. While MEEIA savings can avoid some amount of renewable investment needed to meet the RES, the wind investments in 2020 were foundational investments in the Company's path to go from its relatively low historical level of renewables toward the 15% renewable requirement that applies to its entire retail customer base. So, there is no plausible way MEEIA programs could have been expected to avoid that foundational renewable investment, despite the fact that MEEIA can and does in fact reduce the total amount of renewable energy the Company needs under the RES on the margin.

All told, Staff's ratebase history table is useless in assessing the efficacy of past MEEIA programming on the avoidance or deferral of generation costs.[21] And that analysis is the crux of Staff's entire contention that generation is not being avoided or deferred by

[20] For example, significant rate base investment was required to comply with the US EPA's effluent limitation and coal combustion residual rules, including investment required whether or not the coal plants would continue operation.
[21] File No. EO-2023-0136, J Luebbert Direct Testimony, pp. 13-14.

MEEIA. It quickly becomes apparent that nothing in Staff's "lessons learned regarding Ameren Missouri generation ratebase" means that we do not have less generation than we would have "but for" MEEIA, and Staff's primary argument against an EO for the Company completely falls apart. As I discussed in the opening of my testimony, where I shared Figures 1 and 2 that illustrate the Company's experienced load as compared to what those loads would have looked like "but for" MEEIA, and observed the 2.5 million MWh and 600 MW differences directly attributable to the Company's MEEIA efforts of the last decade, it is in fact entirely implausible to conclude that significant additional generation investment has not already been avoided and/or deferred. In an environment where significant supply-side investment is needed in the future, such as we are experiencing in today's generation transition, it is similarly (or even more) implausible that future load reductions will not reduce the amount of incremental generation that will need to be built or acquired in the foreseeable future.

Q. Staff also claims that generation deferrals must be directly traceable to the impacts of a specific MEEIA cycle in order to qualify a utility for an earnings opportunity in that cycle.[22] Does that perspective justify Staff's recommendation that there be no EO for the Company associated with its proposed MEEIA cycle 4?

A. No, for a couple of reasons. First, Staff's claim is fully unsupported by the plain language of the MEEIA statute that I cited above. Staff infers a qualification of the statutory requirement for an earnings opportunity where no such qualification exists. But beyond that point, even if one accepted the goal of Staff's stated premise as being reasonable irrespective of the requirements of the law, it simply ignores both how energy

[22] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 12 l. 15 through p. 13, l. 2.

efficiency and demand response fits into a resource portfolio, and how the Company analyzed its foregone earnings in this docket in order to inform its recommended earnings opportunity.

Q. Is the policy in the MEEIA statute, that by its plain language indicates that utilities are allowed earnings opportunities without those earnings being explicitly tied to deferred investment, unusual?

A. No, not at all. They are actually quite common in the industry. Many states provide incentives to their utilities to achieve energy efficiency and demand response goals, and it is relatively rare, if it occurs at all, for those states to tie the incentives to specific deferred generation investment. It is certainly true that there are a number of states that provide incentives to utilities that do not even own generation, and therefore have no potential to forego earnings as a result of deferring generation. In its 2022 State Energy Efficiency Scorecard, the American Council for an Energy Efficient Economy ("ACEEE") found that 28 states had some form of performance incentives for electric DSM programs.[23]

Q. How does Staff's premise that each individual MEEIA cycle must individually result in the deferral or avoidance of generation ignore the way that energy efficiency and demand response fits into a resource portfolio?

A. Energy efficiency and demand response are valuable resources when sustained commitment and investment are made over time. The cumulative effects of such sustained investment are what ultimately creates the avoidance/deferral of supply-side resources, and the lower revenue requirements that are apparent in the Company's IRP

[23] Sagarika Subramanian, et al., 2022 State Energy Efficiency Scorecard, ACEEE Report (Dec. 2022), p. 48-49 https://www.aceee.org/research-report/u2206

associated with resource plans that take advantage of RAP level DSM. Witness Michels discusses this issue further in his rebuttal testimony.

The Company undertook a more detailed analysis of the efficacy of compounding the effects of DSM programs through sustained investment over time in its MEEIA 3 application filed with the Commission in File No. EO-2018-0211. The conclusion of that analysis can be summarized with the expression "the whole is greater than the sum of its parts." The effect of sustained investment in energy efficiency and demand response is greater than the standalone effect of any individual (shorter-term) MEEIA cycle. Without the compounding effect of savings that accumulate over time (across MEEIA cycles), the lower revenue requirements that arise from deferring and/or avoiding generation simply do not materialize in as meaningful of a way.

I have attached to my testimony Schedule SMW-R1, which is a 2-page excerpt from the Company's Energy Efficiency Plan that supported its MEEIA 3 application, which describes the analysis I just mentioned in a section titled "MEEIA Plan Synergies." To cite the key takeaway from these pages:

> To further illustrate the importance of the continuation of demand-side programs, Ameren Missouri also analyzed combinations of implementation cycles, e.g., implement Cycle 3 and no more demand-side programs afterwards, or implement Cycle 4 and no demand side programs before and after, or Cycles 4 and 5 alone, or Cycles 4, 5, and 6 without implementing Cycle 3. All of these different cycle combinations demonstrated that deployment of demand-side resources without interruption is the most effective way to achieve deferrals of new supply-side resources further into the future because skipping even one cycle results in the need of a CC earlier than what the need would be with all the cycles implemented.[24]

[24] File No. EO-2018-0211, Ameren Missouri2019-24 Energy Efficiency Plan, p. 62-63.

Company witness Michels further elaborates on the practical realities – i.e., the risks in a dynamic energy landscape - that make the notion of "sharpshooting" particular capacity needs with individual MEEIA cycle investments a wholly untenable approach.

Q. How does Staff's premise that each individual cycle must individually result in the deferral or avoidance of generation in order to justify an EO ignore how the Company analyzed its foregone earnings in this docket?

A. The Company's analysis in this docket did in fact only analyze potential generation deferrals associated with the specific savings in MEEIA cycle 4. I will return to this point to explain further in a moment.

Q. Staff says that the appropriate earnings opportunity for a utility should be determined by calculating the foregone earnings component of all deferred or avoided investment experienced by the utility as a result of its successful DSM programs[25]. Is this an appropriate standard?

A. Yes, I would say it is *an* appropriate standard, but not the only reasonable standard that could be relied upon to establish an EO. For example, in each past MEEIA cycle that has been approved by the Commission, the Company has performed such a calculation looking prospectively at expected deferrals and the foregone earnings associated with them. However, in none of those cases has Staff supported earnings opportunities consistent with those calculations, nor have the Company's eventually approved earnings opportunities matched that level in most cases. Table 1 below shows the results of the Company's foregone earnings analysis from each of its prior MEEIA cycle

[25] File No. EO-2023-0136, Sarah Lange Direct Testimony, p. 17., ll. 10-13, which reads: Under a well-designed earnings opportunity, the payment to shareholders for avoided investment (plus an allowance for income taxes) should be roughly identical on a risk-adjusted present value of the return on equity of a plant that would physically exist in the future (with an allowance for income taxes).

applications, and also the earnings opportunity that was ultimately approved for plan implementation.

Table 1 – MEEIA Cycle Foregone Earnings

Case	Foregone Earnings Quantification – Annual	Maximum Annual EO Authorized by Commission Order
EO-2012-0142	$10 Million[26]	$10 Million[27]
EO-2015-0055	$23.3 Million[28]	$13.1 Million[29]
EO-2018-0211	$35.5-48.5 Million[30]	$12.3 Million[31]

I must say I appreciate that Staff now suggests that fully making the Company whole for every dollar of foregone earnings it experiences is appropriate. In these past cycles, this perspective would have generally meant higher earnings opportunities than those that were actually available to the Company. That said, I believe the historical earnings available to the Company from MEEIA – despite being generally lower than the

[26] File No. EO-2012-0142, 2013-2015 Energy Efficiency Plan, p. 27.
[27] File No. EO-2012-0142, Stipulation and Agreement dated July 5, 2012, Appendix B, which called for a Shared Net Benefit approach to EO, and included a 3-year $30 million target incentive for max performance achieving 130% of targeted energy savings. The net shared benefits framework meant that if the programs created enough benefits, the actual experienced EO in MEEIA cycle 1 could exceed the targeted level.
[28] File No. EO-2015-0055, 2016-18 Energy Efficiency Plan, p. 40
[29] File No. EO-2015-0055, Stipulation and Agreement filed on March 16, 2017, which revised an earlier agreement authorizing a slightly smaller EO max opportunity.
[30] File No. EO-2018-0211, 2019-24 MEEIA Energy Efficiency Plan, p. 60
[31] File No. EO-2018-0211, Stipulation and Agreement filed on October 25, 2018, Appendix N – Max Payout from Column N of spreadsheet divided by 3 year term of the plan. Additional performance incentives were available to the Company for three one-year extensions of this MEEIA plan, all of which were lower than the quantification of foregone earnings in that case by a similar magnitude.

values the Company calculated as its full foregone earnings – have been sufficient to achieve the goal of the MEEIA law, which simply calls for a level of earnings opportunity that is sufficient to align the utility's incentives with helping its customers use energy more efficiently. Foregone earnings analysis is useful benchmarking for establishing a relevant EO to the utility to achieve such alignment, but ultimately a variety of benchmarks may also be relevant to consider. So long as the earnings opportunity is meaningful enough to align the utility's incentives with those of its customers, and so long as the level of that earnings incentive does not result in the MEEIA portfolio no longer being cost effective for customers,[32] the earnings is consistent with Missouri law and may be considered reasonable for the Commission to approve.

Q. Returning to the analysis performed by the Company for this case, how does the Company's foregone earnings analysis provide an appropriate benchmark to determine a relevant earnings opportunity for the Company associated specifically with the savings from the proposed MEEIA cycle 4?

A. The Company analyzed the peak load reductions that are projected to arise specifically from the proposed DSM portfolio *in this case*. Such peak load reductions directly reduce the amount of supply-side capacity the Company will need in the future to meet reliability standards in MISO and to reliably serve its load. To conservatively quantify a sufficient earnings opportunity associated with the load reductions from this portfolio, the Company developed a reasonable generic value of those MW of demand savings that reduce our peak load (and therefore capacity obligations) based on the implied earnings

[32] As discussed by witness Michels in his rebuttal testimony, the Company's IRP contemplates appropriate earnings opportunities associated with the various levels of DSM included in its various plans to ensure that the cost to customers of those incentives do not undermine the cost effectiveness of the DSM plan established by the IRP.

associated with MISO's valuation of the lowest cost supply-side capacity resource (a simple cycle gas combustion turbine) - it's Cost of New Entry ("CONE") determination. CONE is a capacity valuation that MISO uses to set the ceiling price for its annual capacity auction, based on the premise that CONE represents the *marginal cost* of new capacity and therefore it is the appropriate price signal for a capacity market that requires new entry in order to have enough supply-side resources to meet the need of the load to be served within its market. This is an objective, transparent, and relevant metric for establishing a generic representation of the earnings the Company would forego (i.e., the earnings component of the marginal cost of developing the lowest capital cost form of new capacity) associated with the peak load reductions that defer marginal capacity additions (at a minimum – they may also defer resource additions needed to meet an energy need that have a higher cost of capital than a simple cycle CTG, and therefore greater levels of foregone earnings as well).

Q. Why did the Company use a more generic approach to quantifying its foregone earnings associated with this MEEIA cycle?

A. Staff has recently demonstrated that they fail to understand a basic truth about foregone earnings analysis – that it is a projection taking place in an incredibly dynamic energy landscape that is certain to change as conditions change. This does not mean that a more specific foregone earnings analysis is not (and has not been) valuable – it is very relevant to the circumstances that apply to the determination of the existing incentives as utility decision makers see them at the time they enter into a commitment to pursuing a DSM portfolio. However, Staff has come to take the Company's foregone earnings analysis in a given MEEIA cycle as if it is a guarantee that the specific investment deferrals that formed the basis of that analysis are the exact deferrals that will occur, and that any generation being built may be considered evidence that such deferrals did not occur, irrespective of other changes in the planning environment that may dictate changes in the Company's PRP.[33] Certainly, the Company could have replicated analyses from past MEEIA cases to quantify the foregone earnings associated with the specific capacity deferrals that were identified in the IRP – in this case that would have been the two natural gas plants that would necessarily be a part of the Company's PRP if DSM programs were not pursued. And it could have replicated the "MEEIA Plan Synergies" analysis mentioned just above that was performed for the Company's MEEIA 3 application. Such analyses would have been a reasonable benchmark for establishing an EO in this case. But, rather than perpetuate Staff's misunderstanding of the uncertainty associated with the particulars of a foregone earnings analysis that is based on a snapshot in time, the Company chose to recognize that – whatever we project the capacity deferrals associated with a MEEIA cycle to be, the actual deferrals that take place are likely to be impacted by changes in the planning environment – i.e., they will be subject to change (their changing does not mean that they do not still exist in a meaningful way), and they will be a counter-factual that we will never definitively observe. Based on those circumstances, Staff will be likely to (erroneously) claim that such changes invalidate the premise of the EO that may be authorized in this case. So, the Company conceived of this more generic analysis as an alternative approach that is somewhat agnostic to which specific plant will be deferred from which year to which later year, but rather values a MW of deferral based on the earnings component associated with the marginal cost of capacity, which is an entirely

[33] In the rebuttal testimony of Sarah Lange in File No. EA-2023-0286 (the Company's application for four CCNs for new solar generating facilities), Staff took the position that the fact that the very specific generation deferrals that had been analyzed to determine the EO for MEEIA cycle 2 could not be proven to have occurred (a counter-factual that was never analyzed) meant that the EO from that cycle was inappropriate.

relevant and transparent benchmark that should be a meaningful indicator of the magnitude of foregone earnings for consideration by the Commission and by utility decision makers who will be evaluating whether to proceed with DSM programming.

V. STAFF'S FAC-RELATED CONCERNS ARE SEVERELY OVERBLOWN

Q. Staff spends considerable time and effort throughout several witnesses' testimonies, most notably that of J Luebbert,[34] describing effects that arise from the operation of the Company's FAC that they suggest may prevent benefits from MEEIA from accruing to all customers. Has Staff identified a fundamental flaw with the Company's MEEIA plan?

A. No. Staff has spent a great deal of effort in explaining phenomena within the FAC that have little practical effect on both the existence and distribution of MEEIA benefits. This is true for a variety of reasons. While Staff creates hypothetical examples of MEEIA/FAC interactions, it is left to only hypothesize that the effects it describes may meaningfully impact the existence or distribution of benefits. When considered carefully, both with a more complete understanding of the role of the FAC and with actual data to assess the likelihood of the outcomes Staff fears, it is evident that these concerns have little practical effect. There are (at least) three key reasons this is true:

1. Staff has made it clear that avoided investment in generation (and possibly also transmission and distribution infrastructure) is the true goal of MEEIA from its perspective. Staff's FAC-related concern only relates to avoided wholesale energy and capacity costs arising from MEEIA load reductions, which are real and significant benefits, but benefits Staff is largely relatively

[34] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 22 l. 5 through p. 31 l. 18.

dismissive of throughout its consideration of the Company's MEEIA application. The FAC-phenomena Staff discusses do not apply *at all* to the realization or distribution of benefits arising from deferred or avoided capital costs associated with investment in infrastructure. These type of capital costs make up a significant portion of the more than 4 billion in NPVRR benefits arising from continuation of DSM programs at the RAP level in the Company's IRP, relative to the plan that would have to be pursued absent continuation of such programming.

2. The phenomenon Staff describes that it claims *could* result in higher FAC rates for customers only occurs if the avoided wholesale market energy costs (reductions in purchased power expense or increases in off-system sales that arise from the lower load that must be served when MEEIA-related load reductions occur) are manifest at a price that is lower than the FAC tariff's "Base Factor". Fortunately, that is not expected to be the case on average *for any MEEIA measures*. Savings from all MEEIA programs are expected to result in market savings at average price levels that significantly exceed the level of the FAC Base Factor, meaning that MEEIA would result in increased credits or reduced charges through the FAC that provide benefits to all customers. (Hang tight, reader, I know this sounds complicated, but I will explain it below).

3. MEEIA impacts in the FAC are only a transient means of delivering benefits to customers, as MEEIA savings relatively quickly become embedded in

base rates, eliminating any role for the FAC to deliver and apportion those benefits.

Q. Please elaborate on each of these three points, starting with the first.

A. The first point above is relatively self-explanatory, but to restate it succinctly: many very real and very significant benefits from MEEIA do not flow through the FAC at all. Given my lengthy discussion in the previous section of my testimony, in addition to observations related to that point raised by witnesses Michels and Lozano, it should be clear that there are expected to be significant avoided generation investments attributable to the Company's MEEIA programming. Mr. Michels further discusses the avoided transmission and distribution ("T&D") investments that are also expected to be facilitated by the Company's MEEIA plan. The benefits of lower base rates due to the lack of return on and return of all of those avoided or deferred investments will not pass through the FAC, and therefore the mechanics of the FAC will have no bearing on the distribution of those benefits to customer classes and customers within those classes.

Q. Please turn to your second point above – that *all measures* in the Company's MEEIA plan should be expected to *lower* future FAC rates, starting by explaining the basic workings of the FAC itself.

A. This is a somewhat complex issue, and Staff witness Luebbert described the basic mechanics in a somewhat dense, but I think generally accurate, way. I will try to explain it in a somewhat less technical manner here.

The FAC, at its core, is a mechanism that is used to compare actual net energy costs (generally fuel and purchased power expense net of revenues from off-system sales of excess energy generated by the Company and sold into the wholesale market) to the net base energy costs that are reflected in the Company's base retail rates and are therefore presumed to have been recovered through customer bills. This comparison occurs for defined periods of time (referred to as Accumulation Periods "AP"), and the FAC subsequently allows the Company to recover from or return to customers 95% of any under- or over-recoveries of those differences between actual and base net energy costs over another period of time (referred to as the Recovery Period "RP"). This ensures that, other than the impact of 95% factor in the FAC formula,[35] the Company ultimately recovers no more and no less than its actual prudently incurred net energy costs. The FAC tariff mechanism for establishing the net energy costs that are presumed to have been recovered in base rates during any given AP for purposes of this comparison to actual net energy costs operates on a cost per kilowatt-hour ("kWh") basis. By that I mean, when rates are set in a general rate proceeding, we establish the Base Factor that Mr. Luebbert referenced in his direct testimony, which essentially represents what I would characterize as a quantification of the amount of net energy costs that are presumed to be recovered from customers associated with each kWh of energy sold under a retail tariff of the Company. When we get into an AP for which we want to compare actual and base net energy costs, we start by multiplying our actual retail sales[36] (total retail kWh sold) experienced in that AP by the Base Factor (the net base energy costs presumed to be recovered per kWh sold). The result

[35] This factor is often referred to as 95/5 sharing in an FAC, and has been a longstanding provision of Missouri FAC tariffs approved by the Commission. I would characterize the purpose of 95/5 sharing as a means by which the Commission has tried to align the incentives of the utility when it comes to fuel procurement and generation asset management with the interests of its customers (much like MEEIA aligns incentives with respect to energy efficiency). This is because the Company retains 5% of any net cost reductions it achieves and absorbs 5% of any net cost increase it experiences, giving it a direct financial incentive to manage those net costs.

[36] Note that this calculation occurs based on sales plus distribution losses that occur on the system, but a later adjustment associated with the FAC's Voltage Adjustment Factor brings the effect of this back such that the calculation can be considered relevant to metered customer sales levels.

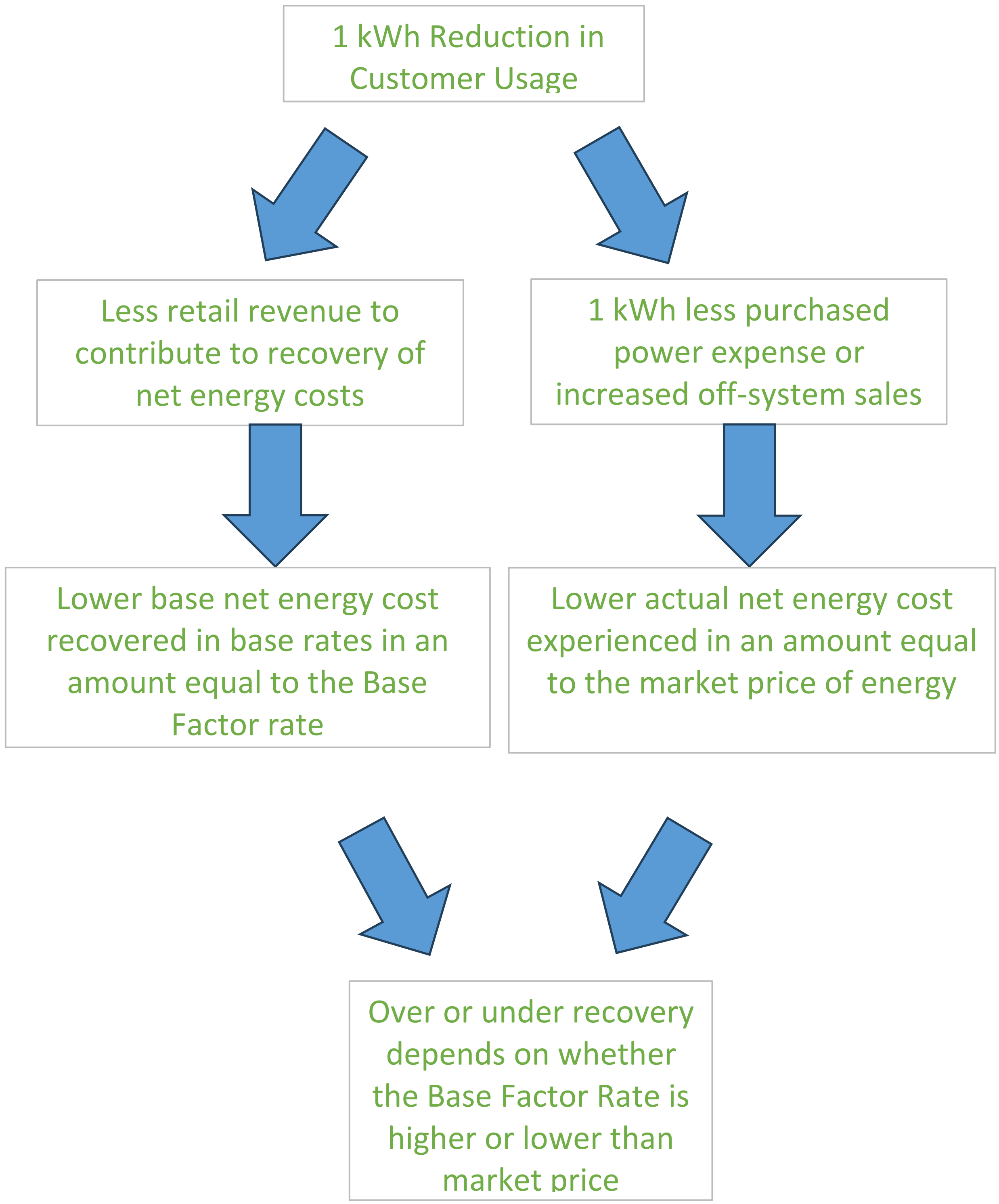
is a calculation of the amount of net energy costs that are presumed to have been recovered from customers during that AP. That amount – the amount recovered in the AP – is compared to the actual net energy costs experienced in the AP to determine whether an over- or under-recovery of those costs has occurred.

The fact that the mechanism deals with *net* energy costs – i.e., the fact that revenues from wholesale sales of energy generated by the Company to the market flow through the FAC – is important here. When the usage of a customer declines from the level it otherwise would have been for whatever reason (such as when the Company, through its MEEIA programs, provides an incentive that allows or causes a customer to reduce its usage), two effects occur that are captured in the FAC. First, retail sales of kWh made by the Company decline. That decline in retail sales causes the presumed recovery of net energy costs to be lower than it otherwise would (since costs that are presumed to have been recovered in base rates are determined by multiplying the Base Factor by the actual kWh of retail sales – fewer kWh of sales means less retail revenue and less net energy costs recovered). The second effect is that the Company, with less load to serve either:[37] 1) has to purchase less power from the market to cover its load, if the Company was otherwise short of economic energy from its own energy centers, or 2) has additional kWh available to sell to the market, if the Company already was "long," having more economic energy from its energy centers than it had load to serve). Either of these two effects – reduced purchases or increased sales – functionally reduce actual net energy costs based on the market price of energy. A

[37] A third effect could occur on a less frequent basis. If one of the Company's generating units was the marginal unit in the MISO market, it could be dispatched down due to the reduced load, and rather than avoiding energy purchases or increasing sales, the Company could avoid fuel cost associated with generating the energy.

summary of the effects of the reduced retail consumption arising from the successful implementation of energy efficiency measures is illustrated in Figure 4 below:

Figure 4 – Impact of a kWh of Reduced Retail Sales on FAC



I hope that Figure 4 helps to illustrate the mechanics of the effect Staff witness Luebbert was explaining. The upshot of this effect is that when a kWh is saved as a result of the implementation of an energy efficient measure, FAC rates will generally decline if the market price of energy is higher than the FAC's base factor rate, but will increase if the opposite is true and the market price of energy is below the base factor rate.

Staff observes that different energy efficient measures may save energy at different times, and therefore be subject to different market prices. A measure with a preponderance of savings during off-peak periods will generally be subject to lower market prices, and may therefore be more likely to increase the FAC rate (rather than decrease it) than another measure with more on-peak period savings.

Q. Can you provide any data that sheds light on the impact of market prices from different time periods on the avoided energy costs associated with different energy efficient measures?

A. Yes. I used hourly end use load shapes and hourly market prices from the Company's 2023 IRP to generate what is effectively a forecast of the average market price that will be realized by measures associated with different end uses – i.e., measure specific annual avoided energy costs. I would note that I used the *lowest* price scenario from the Company's IRP for this analysis in order to be as conservative in measuring this effect as possible (i.e., for all other price scenarios, the annual average end use energy prices would be even higher). Table 2 and Table 3 below show for the residential measure types and business measure types respectively the annual average avoided energy cost for each measure type.

Table 2 – Residential Measure-Specific Annual Avoided Energy Cost Forecast

Year	2025	2026	2027	2028
Refrigerator	$37.97	$35.35	$32.50	$32.89
Freezer	$39.09	$36.34	$33.38	$33.70
Elec Cook	$40.36	$37.30	$34.19	$34.41
Dishwasher	$41.57	$38.43	$35.18	$35.36
Miscellaneous	$37.85	$35.17	$32.34	$32.72
Dryer	$41.52	$38.32	$35.08	$35.15
Water Heat	$38.90	$35.93	$32.99	$33.26
Clothes Wash	$40.65	$37.48	$34.29	$34.36
TV	$38.72	$35.97	$33.05	$33.42
Lighting	$39.96	$37.01	$34.00	$34.41
Cooling	$43.02	$40.99	$37.49	$37.73
Heating	$40.48	$36.61	$33.52	$33.61

Table 3 –Business Measure-Specific Annual Avoided Energy Cost Forecast

Year	2025	2026	2027	2028
Refrigerator	$38.75	$35.98	$33.05	$33.37
Elec Cook	$41.83	$38.67	$35.39	$35.50
Miscellaneous	$38.96	$36.12	$33.17	$33.46
Outdoor Lighting	$34.76	$32.45	$30.01	$30.78
Water Heat	$42.29	$38.96	$35.66	$35.75
Ventilation	$38.21	$35.41	$32.56	$32.89
Office	$38.72	$35.91	$32.99	$33.30
Indoor Lighting	$42.29	$38.96	$35.66	$35.75
Cooling	$41.49	$39.57	$36.32	$36.57
Heating	$39.69	$35.92	$32.93	$33.08

Tables 2 and 3 illustrate that, while it is indeed true that there is a difference between the expected avoided costs from one measure to the next, depending on the end use it impacts and the time that those end uses tend to consume energy – as much as a $5 - $7/MWh difference between the lowest and highest avoided cost measures in any given year, the minimum avoided cost associated with any end use in any year of the proposed MEEIA 4 term is over $30/MWh.

Q. What is the current Base Factor in the FAC?

A. Stated in $/MWh units for consistency with Tables 2 and 3, the current Base Factor is $14.39/MWh in the summer and $13.28/MWh in the winter. Every single measure is expected to have an annual avoided energy cost that is ***more than double*** the FAC's current Base Factor. Now, it's certainly true that the Base Factor is updated in each rate case that the Company files, and that it is likely to be updated at least once, and perhaps multiple times, between now and the end of the proposed MEEIA 4 term. But I think it is highly unlikely that the base factor could or would more than double in a period of just a few years.

Q. What do you conclude with respect to the Staff's theory that some measures may cause increases in the FAC for all customers, rather than decreases?

A. It is, practically speaking, a complete non-issue. The mechanics of the FAC that Staff describes exist, and theoretically could produce the outcome Staff fears (on a transient basis, as I will discuss further below), but the current market price and base factor environment make that outcome incredibly improbable. I feel extraordinarily confident saying that MEEIA 4 savings will produce rate decreases for all customers in the FAC relative to what would occur without implementing MEEIA 4. (Just to get out in front of the claim I expect Staff to make in the future if FAC rates go up in some AP/RP during MEEIA 4 - whether FAC rates rise or fall in the future will be driven by many, many factors and is not a reflection on whether this phenomenon occurred. Whether MEEIA contributed to an increase or decrease in the FAC is a counter-factual that will never be observed without dedicated study, so any casual claim by Staff that rising FAC rates prove them right will be false).

Q. Please address the third reason why the FAC is not an impediment to the realization or distribution of benefits from MEEIA.

A. Staff portrays the situation as though *all* MEEIA avoided energy and capacity benefits pass through the FAC,[38] and therefore are subject to its mechanics (those described above, plus the cost/benefit allocation that inherently occurs in the FAC). This is inaccurate since the FAC is inherently a transient mechanism. By this I mean, it only captures costs and revenues that *change relative to the test year* of the most recent rate case that has occurred. When a customer first installs an energy efficient measure which reduces customer load and thereby the Company's actual net energy costs, those avoided energy costs indeed do pass through the FAC. However, as soon as that efficient measure has been in place during a test year of a rate case, the avoided costs that arise from the savings associated with that measure become reflected in base rates, and that measure stops having any meaningful impact[39] on the FAC from that point forward, for the entirety of the remaining measure life.

Q. How much of the typical measure's expected useful life will occur during time periods where its avoided cost impact will be felt in the FAC versus through base rates?

[38] File No. EO-2023-0136, J Luebbert Direct Testimony, p. 23, ll. 5-13, which includes no qualification related to the transient nature of net energy costs in the FAC while describing issues with MEEIA-FAC interaction.

[39] I say "meaningful impact" because the customer in question could change its consumption patterns at some point during the life of the measure, and the impact of the measure of just the change in utilization of the end use would again pass through the FAC. But the overall savings level of measures on average should not be expected to have a significant enough level of fluctuation over their useful lives to create meaningful variation in net energy costs that flow through the FAC mechanism.

A. Quite little of the impact will actually run through the FAC. The average measure life associated with a measure for the most recent program year evaluated under the Company's existing MEEIA programs (which I use as a proxy for expected measure life for those installed during the term of MEEIA 4) is 13.85 years. This means that from the date of measure installation, the customers' usage is expected to be lower (savings from the measure will occur) for that almost 14-year period of time, creating avoided costs for all of those years. Those avoided costs will reduce FAC rates until that measure has been in place at some point in the test year of a rate case, and will reduce *base rates* (but not the FAC) from that point forward. Over approximately the last decade, the Company has averaged almost exactly two years between rate cases. Since measures' adoption and installation should be expected to be relatively well spaced out across time, and unimpacted by the timing of rate cases, it is likely that some measures are installed right after an immediately preceding rate case and therefore "spend" about two years impacting the FAC, and other measures are installed late in a test year of an ongoing rate case and due to annualization of energy efficiency savings that is performed for rate cases "spend" only a few months impacting the FAC. This suggests that on average an energy efficient measure impacts the FAC for just over a year of its almost 14-year useful life. So, while Staff implies that all avoided cost benefits of energy efficiency are delivered to customers through the FAC, it is evident that roughly 90% of those benefits (perhaps a little more) are not transmitted through the FAC at all, but pass to customers through base rates established in general rate proceedings. As such, Staff's allegation that the mechanics and cost allocation impacts of the FAC are a significant barrier to the existence and allocation of benefits to all customers is dramatically overstated.

VI. STAFF'S CONCERNS ABOUT THE IMPACT OF TIME OF USE ("TOU") RATES ON THE DETERMINATION OF THE THROUGHPUT DISINCENTIVE ARE ALSO OVERSTATED, AND STAFF'S SOLUTION FAILS TO FULLY ALIGN THE UTILITY'S INCENTIVES WITH HELPING CUSTOMERS USE ENERGY MORE EFFICIENTLY AS THE MEEIA LAW REQUIRES

Q. Briefly, what is the Throughput Disincentive ("TD")?

A. When the Company incentivizes a customer to install an energy efficient measure and thereby use less electricity as a result, it is inherently encouraging that customer to buy less of the Company's primary product. It is broadly recognized – and it is certainly recognized within the MEEIA law in Missouri - that for it to be reasonable to expect electric utilities to encourage such activities that reduce their own sales, and thereby profitability, that utilities should be made whole for the negative financial impacts of those self-induced sales reductions. This aligns the utility's incentives with the interests of its customers in reducing their energy usage, and (along with the EO) turns energy efficiency into a win-win proposition for utilities and their customers.

Q. How does the Company's Demand-Side Investment Mechanism ("DSIM") address the throughput disincentive?

A. The Company's DSIM has a TD mechanism that effectively looks at measured and verified savings and recognizes each of those kWh as source of lost revenue for the Company and compensates the Company through Rider EEIC (which stands for Energy Efficiency Investment Charge and is the tariff mechanism that implements the Company's DSIM) for the portion of that lost revenue that contributes to fixed cost recovery (i.e., costs the Company incurs that are not avoided through the reduction in usage).[40]

Q. Has the TD mechanism in the Company's Rider EEIC been relatively consistent throughout prior MEEIA cycles?

A. Since the approval of the Company's second MEEIA cycle, which began in 2016, yes. The mechanism was structurally different in the first three-year MEEIA cycle that ran from 2013-2015. But from 2016 forward, the methodology has been quite consistent from cycle 2 to cycle 3 to what the Company has proposed in this application for its fourth MEEIA cycle.

Q. What is Staff's position regarding the continuation of the successful TD mechanism that has been utilized for over eight years?

A. Staff suddenly suggests that such mechanism is illegal.

Q. How can a mechanism that has been used for over eight years suddenly be considered illegal by Staff, who has entered into several past Stipulations and Agreements[41] that endorsed the use of this mechanism?

A. I don't know. It appears to me that Staff seems to be attempting to create confusion by conflating two different statutory provisions. Staff witness Lange points to the enactment of Subsection 386.266.3 RSMo in 2018 as making it unlawful "for the Commission to authorize a MEEIA mechanism to account for the impact on utility

[40] Some revenues that are lost are also offset by cost reductions. Ultimately, the discussion of the FAC's Base Factor earlier in my testimony is very useful for delineating between revenues that contribute to fixed versus variable costs. The Company's 2025-27 MEEIA Plan (Revised) filed in this case contains more detail on the mechanics of the determination of the marginal revenue foregone by the Company for each kWh of savings.

[41] File No. EO-2015-0055 Stipulation and Agreement filed on February 5, 2016.
File No. EO-2018-0211 Stipulation and Agreement filed on October 25, 2018.
File No. EO-2018-0211 Stipulation and Agreement filed on July 10, 2020.
File No. EO-2018-0211 Stipulation and Agreement filed on October 13, 2021.
File No. EO-2018-0211 Stipulation and Agreement filed on August 3, 2023.

revenues of increases or decreases in residential and commercial customer usage due to variations caused by supply-side programs for Ameren Missouri"[42] as a result of the Company's election to utilize Plant in Service Accounting ("PISA") deferrals associated with its capital investment program. I am advised by counsel that the Company is not seeking its DSIM under the authority created by the statutory provision that Staff cites above. We are seeking the DSIM under the authority of the MEEIA statute – specifically 393.1075 RSMo – the very same statute that has underpinned the existence of DSIMs and TD mechanisms for over a decade in this state. I am further advised by counsel that the passage of the provision cited by Ms. Lange did not expressly or by implication amend or repeal the authority that has existed under the MEEIA law for over a decade. The fact that Staff has entered into Stipulations and Agreements, and the Commission approved those agreements, authorizing the use of the current TD mechanism including occurrences of this *since the passage of the PISA law* further supports the conclusion that Staff's novel argument has no merit.

Q. Aside from any legal question, does Staff's position even make sense?

A. No, it does not. Staff's theory appears to be based on the premise that the option given to electric utilities to choose to decouple its revenues from its load if the utility would prefer to do so instead of electing to use PISA would, in the case of a utility that chose the decoupling route, mean that thereafter there would be no throughput disincentive arising from offering energy efficiency programs. And I agree with that. If a utility's revenues are fully decoupled from its loads, then the Commission would not need to also remove a throughput disincentive – because there would no longer be one – in order to

[42] File No. EO-2023-0136, Sarah Lange Direct Testimony, p. 22, ll. 12-15.

align the utility's interests with helping its customers save energy consumption. But the decoupling *option* in Section 386.266.3 is just that, an option, and if a utility does not choose it – and the statute does not mandate that the utility elect the option – then offering energy efficiency programs means there *remains* a throughput disincentive, meaning the Commission must still remove it to align those incentives. If the General Assembly had intended to do away with the Commission's duty to align incentives it would not have given utilities the option to elect decoupling; it would have required that they do so.

Q. Staff also proposes an alternative to the longstanding TD mechanism that has been used by the Commission and Missouri utilities for years, in spite of its legal argument. What is Staff's alternative?

A. Staff's alternative is to employ "an avoided revenue mechanism", which is essentially a decoupling mechanism for the residential and Small General Service ("SGS") rate classes.[43] In its simplest form, decoupling amounts to a revenue true-up to ensure that the amount of revenue a utility earns is equal to a pre-determined amount, usually an amount equal or related to the revenue requirement established in a general rate proceeding as the basis of setting rates. As I said, my definition is the "simplest form" of how to think about decoupling, but there are a lot of variations of decoupling with different ways of handling specific details. Staff provides many of the details of its decoupling proposal in Ms. Lange's testimony. However, it is not necessary to work through those details, because for both legal and practical reasons, the notion of deploying decoupling to address the throughput disincentive should not be pursued. For the legal reason, I am advised by counsel that the MEEIA statute does not authorize decoupling, and while the PISA law

[43] File No. EO-2023-0136, Sarah Lange Direct Testimony, pp. 24-26.

may do so, Staff is correct that the Company's election of PISA would prevent it from using the decoupling provision within that same statutory framework. But that is ultimately an issue for lawyers, not the witnesses in this case. I will focus on why decoupling fails to properly align the incentives of the Company with its customers' interest in using less of its product.

Q. Why does decoupling fail to properly align those incentives, as required by the MEEIA statute?

A. Put simply, the implementation of decoupling itself would result in negative financial impacts on the Company in an environment where it may experience any load growth at all "but for" its DSM programs. MEEIA does not impose a remedy like decoupling on utilities, it requires the Commission to find win-win outcomes (like the TD mechanism in use today) to align the Company's incentives, such that it can promote energy efficiency and help customers save money without financially harming itself.

Q. Why do you say that decoupling would result in negative financial impacts on the Company?

A. Figure 1 early in my testimony is a perfect illustration of why this is the case. Recall that in my discussion of Figure 1 I described the load growth trends that have existed since the Company began its MEEIA programs, and contrasted those with the "reconstituted" loads that illustrate what load growth would have been "but for" MEEIA. In that section, I identified that in the "MEEIA era" beginning in 2013, the Company's energy sales have declined at a CAGR of 0.4% per year over the time period reflected in Figure 1, but would have increased at 0.4% per year during the same time period without the impact of the programs. The TD mechanism has provided the Company with incremental revenues to restore its earnings to the level they would have been in a world with 0.4% per year growth. If the Company had been under decoupling during that time, its revenues (and earnings) would have been based on a world with zero growth.[44] Decoupling would have taken away any impact of negative load growth that would have arisen from implementation of MEEIA programs (about half of the impact of MEEIA over that timeframe), but it would have failed to restore the benefit of growth that would have existed without MEEIA (the other half of the impact of MEEIA during those years). In this way, decoupling still leaves a financial disincentive for the utility to pursue MEEIA programs.

Q. Why should the Company have a financial benefit from load growth?

A. For a couple of reasons. First and most simply, absent DSM programs, the Company already does have the opportunity to financially benefit from this load growth. Anything that takes away an existing benefit is a financial disincentive to doing that thing. In this case specifically, taking away the utility's financial benefit from load growth as a part of the framework through which it is expected to promote energy efficiency is not an alignment of incentives to pursue that energy efficiency. The Missouri legislature's approach to energy efficiency was explicit in that the plain language of the statute imposes a requirement on the Commission to align incentives, or as I would say, create win-win outcomes. This is good energy policy built into state law, and the Commission should not deviate from that requirement by adopting a framework that results in financial detriment to the utility as a result of its willingness to pursue DSM.

[44] Recall that decoupling effectively creates a true-up of revenue to the level of the revenue requirement approved in the last rate case, so growth (i.e. regulatory lag) since the last case gets eliminated in the true-up, where revenues are set to match the historical level approved in that last case.

Moreover, the fact that the utility benefits from load growth is entirely fair in a regulatory environment such as Missouri where rates are set based on an historical test year and the utility's earnings are subject to regulatory lag relative to that historical test year. Most of a utility's costs increase over time, especially when in an investment cycle like utilities are generally in right now, where aging infrastructure is being replaced, smart technologies being deployed, and generation fleets are transitioning. Utilities that are subject to historical test year rate making already start with the challenge of how to deal with the impact of increasing costs between rate cases. However, there is at least one part of regulatory lag that can help utilities mitigate that problem, at least to a degree – and that is load growth. Increasing revenues arising from load growth that may be realized between rate cases can at least partially offset the pressure of rising costs, giving the utility a better opportunity to recover its prudently incurred costs of providing service, or at least mitigating the extent to which it may not have that opportunity.

At this point, I have no doubt that Staff will bring up PISA, which was authorized by the Missouri general assembly to help address the negative financial impacts of regulatory lag on utilities that I discussed in the previous paragraph. But there are several reasons why PISA does not entirely eliminate regulatory lag, and the benefit of load growth is still not only reasonable, but necessary for the utility to have an opportunity to recover its prudently incurred costs of providing electric service. Those reasons include:

- PISA does nothing to address regulatory lag associated with Operations and Maintenance expenses of the utility, which are subject to the pressures of increasing costs;

- PISA only covers 85% of the regulatory lag in capital costs (as offset by accumulated depreciation), leaving the remaining 15% of investment subject to regulatory lag;
- PISA does not apply to all investments.
  - Notably, one of the investment categories that is not eligible for PISA treatment is investment in facilities (primarily distribution) that allow the utility to connect to new customer premises and generate new revenues (i.e., load growth). The obvious rationale for this provision is that such investment that generates new business creates new revenues that help address the regulatory lag associated with the costs of that investment. This is perhaps the clearest indication possible that the concept of *PISA explicitly contemplated that its application would be to a utility that is not decoupled* for revenue purposes (i.e., it was predicated on the assumption that new business would produce load growth that the utility would retain the benefit of in order to compensate that utility for the lag in recovery of those investments and therefore PISA need not apply to those investments), otherwise there would have been absolutely no rationale for this specific provision.

Q. Part of Staff's rationale for making this alternative proposal was that the existing TD mechanism, that has been successfully in use for years, is now "unworkable."[45] What is Staff's concern and your reaction to it?

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[45] File No. EO-2023-0136, Hari K. Poudel Direct Testimony, p. 10, l. 7.

A. Staff articulates concerns that arise from the deployment of TOU rates for the Company's residential customers, suggesting that lost revenues associated with these more complex rates cannot be valued accurately by the net margin rates that the Company has calculated based on a study of the legacy flat residential rate.[46] Staff's concerns, however, are significantly overblown, given the current level of adoption of TOU rates by the Company's customers. As of this writing, 4,660 residential customers out of a total of more than 1,080,000 are taking service on what I will call advanced TOU rates – those with significant differentials between on- and off-peak rates. Any perceived inaccuracy in the application of the current TD methodology that could potentially arise because of this small percentage of customers on these rates would be completely imperceptible in the TD calculation. And for the several hundred thousand customers on the Company's default "Evening/Morning Savers" TOU rate, first, it is true that the Company explicitly considered the Evening/Morning Saver customer bills in its net margin rate calculations. But it is also true that the time of use differentials are so small for that rate option that it is rare for customers to have a bill impact from application of that rate versus the legacy flat rate that significantly exceeds 1%, suggesting that any impact of the small differential in the Evening/Morning Savers rate on the applicability of the net margin rate would have a similarly imperceptible impact on the TD mechanism. The existing TD mechanism is still completely suitable for the environment today.

Q. If the Commission were concerned about the accuracy of TD calculations due to the emergence of TOU rates, is that an intractable problem for the current TD mechanism, as Staff suggests?

[46] To clarify, the Evening/Morning Savers rate that has several hundred thousand customers taking service on it at this time was explicitly contemplated in the Company's marginal rate study for this case.

A. No. Ms. Lange says that "the mechanism Staff proposes in this case eliminates the need to create dozens or hundreds of time-and measure-specific margin rates to continue to limp the 2014 mechanism along."[47] In fact, all that would be required to have very reasonable and accurate net margin rates for application suitable for even broad-based advanced TOU rate adoption would be to have for the residential class the exact same framework that we have used for years for the non-residential class TD mechanism – that is, to have end use specific margin rates that would be applied to savings created by measures associated with that specific end use. The fact that Staff recommends continuation of existing TD mechanism for the Large General Service, Small Primary Service, and Large Primary Service rate classes clearly indicates that end use net margin rates are not "unworkable" even for Staff, and also that the end use load shapes from the Company's IRP, which underlie the net margin rates for those classes which the Staff recommends continuation of the existing TD mechanism, are considered reliable enough by Staff to support net margin rate calculations. If Staff has no problem using this method for the larger non-residential classes, then it should have no problem using it for the residential class either.

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

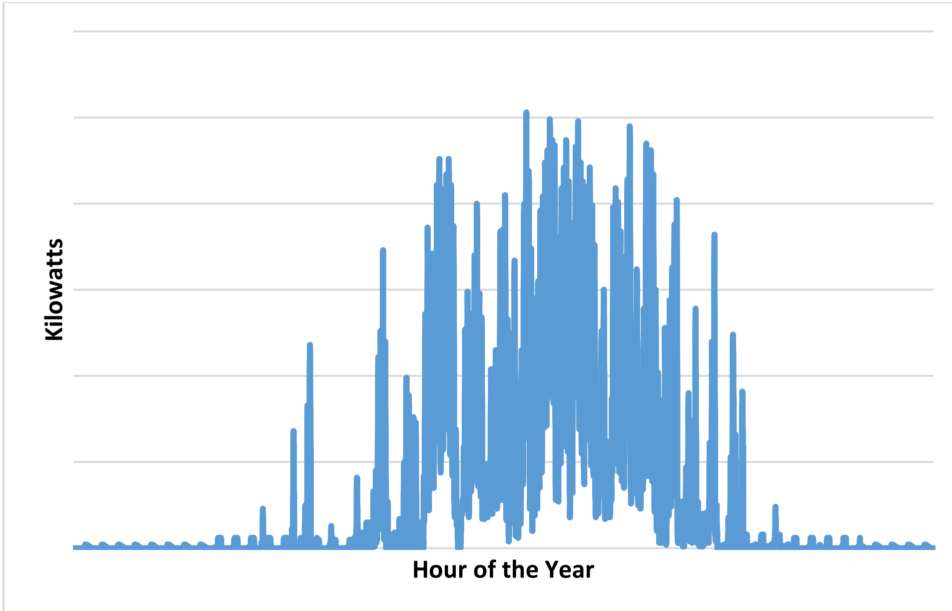
A. Yes. The calculation of the net margin rates is actually much easier for the TOU rates than it is for a block rate structure. For the analysis of marginal rates in a block rate structure, it is necessary[48] to simulate the bill impact of savings on all of the Company's more than 1 million residential customers, which is a computationally intensive (but

[47] File No. EO-2023-0136, Sarah Lange Direct Testimony, p. 27, ll. 13-15.

[48] I say necessary here, but I do believe that this exercise could be reasonably performed using a random sample of customers that is much smaller than the full residential population. That said, the Company has traditionally performed this analysis on the full population.

doable) exercise. That is because for each customer, a marginal kWh might have a different marginal price, depending on which block price is applicable to their last kWh of consumption. For TOU rates, every kWh within a given TOU period (e.g., peak period of 3-7 p.m. on summer non-holiday weekdays for the Company's Smart Saver and Ultimate Saver rates) has the exact same marginal value *for every customer taking service on that rate*. So, no computationally intensive simulations are needed – the marginal rate for those rate option and time period combinations is simply the rate stated in the tariff applicable to those time periods. What is needed is an end use load shape that tells us when savings occur for a given measure, so we know how much of the savings from a given measure to price at the marginal rate for each time period. And fortunately, we have those load shapes as developed in the Company's IRP. We have in fact used those load shapes for the non-residential TD mechanism for years. Figure 5 below shows the cooling end use load shape (i.e., the consumption pattern associated with residential air conditioning essentially):

Figure 5 - Residential Cooling End Use Load Shape



By aggregating the usage of this profile according to the hours of the year that occur during the on-peak and off-peak periods respectively, we can ascertain the percent of residential air conditioning usage that occurs during those different pricing periods,[49] and apply those ratios to the peak and off-peak prices to come up with an end use marginal rate, as illustrated in Table 4:

[49] In this example, the on-peak and off-peak periods are consistent with the definitions of the Overnight Saver rate, which has a peak period of 6 a.m. to 10 p.m. daily, and an off-peak period applicable to all other hours.

Table 4–Margin Rate – Residential Cooling End Use – Overnight Savers[50]

Month	On Peak Usage Pct (A)	Off-Peak Usage Pct (B)	On-Peak Rate (C)	Off-Peak Rate (D)	Marginal Rate (A x C + B x D)
Jan	66.3%	33.7%	$0.0910	$0.0555	$0.0790
Feb	66.3%	33.7%	$0.0910	$0.0555	$0.0790
Mar	89.5%	10.5%	$0.0910	$0.0555	$0.0873
Apr	88.0%	12.0%	$0.0910	$0.0555	$0.0867
May	85.7%	14.3%	$0.0910	$0.0555	$0.0859
Jun	76.0%	24.0%	$0.1617	$0.0644	$0.1384
Jul	76.6%	23.4%	$0.1617	$0.0644	$0.1389
Aug	75.7%	24.3%	$0.1617	$0.0644	$0.1381
Sep	79.7%	20.3%	$0.1617	$0.0644	$0.1420
Oct	83.0%	17.0%	$0.0910	$0.0555	$0.0850
Nov	88.7%	11.3%	$0.0910	$0.0555	$0.0870
Dec	66.3%	33.7%	$0.0910	$0.0555	$0.0790

This process would be replicated for each end use and for each residential time of use rate schedule. The Rider EEIC tariff could easily reflect all of the calculated rates for each end use/tariff combination. For the TD calculation in each month, a weighted average of the end use rates for each rate option would be calculated, weighted by the number of customers taking service on each rate in that month's billings, and the final total residential class net margin rate for that end use would be applied to the savings for the applicable measure in the Company's residential MEEIA portfolio.

Q. Could such a methodology be implemented in this case?

A. Yes. While I do not think it is necessary given the current level of TOU adoption, and other considerations I will mention in a moment, if the Commission is persuaded by Staff that TOU rates and their impact on the TD mechanism are a significant concern, the Commission could order the Company to calculate compliance tariff margin

[50] Please note that these are margin rates and would still need to be netted with the Base Factor from the FAC to be net margin rates suitable for use in TD calculations.

rates consistent with the example provided above. I have provided a spreadsheet template of this calculation as an electronic attachment to my testimony, Schedule SMW-R2. This template contains each of the Company's IRP end use residential load shapes, each of which would need to be run through the calculations in the template with the TOU peak and off-peak (and in the case of Smart savers, intermediate) schedules and rates entered as an input as each of these items as (clearly) defined in the respective rate option tariff sheets.[51] Following this procedure, appropriate margin rates would be calculated for input into the Rider EEIC tariff. The tariff could easily be revised in a compliance filing to include those net margin rates, as well as the formulaic language to calculate the weighted average residential margin rates using the number of customers billed each month on each rate option to weight the margin rates associated with those rate options for each end use.

Q. Staff also indicates that accurate EM&V is important for the proper functioning of the existing TD mechanism. Is that a problem?

A. No. Company witnesses Lozano and Graser discuss issues related with EM&V in detail. The savings results that are verified through the EM&V process are wholly adequate for TD calculations that reasonably address the throughput disincentive.

Q. Staff witness Poudel states, regarding the Company's calculation of net margin rates for use in the TD mechanism, that "[t]he net marginal rate is the difference between the wholesale cost of the energy for a given kWh sold at retail and the marginal retail rate for that kWh of energy. Due to the operation of Ameren

[51] For the limited purposes of this alternative proposal for this MEEIA cycle 4 application, the Company would agree to not include any estimation of the throughput disincentive associated with the demand charge included in the Ultimate Savers rate plan as a part of the marginal rate used in the throughput disincentive mechanism, making this template suitable for determining marginal rates for that rate option. Additional details of the calculation for marginal rates for the winter months for the Evening/Morning Savers rate option are included in Schedule SMW-R2.

Missouri's FAC, it may be more appropriate to calculate the net marginal rate as the difference between the FAC base factor and the value of the marginal retail rate for that kWh."[52] Please respond.

A. The first sentence in the quote above from Mr. Poudel is factually wrong. The Company already calculates the net margin rates exactly as Mr. Poudel recommends in the second sentence, as it has ever since the form of the net margin rate analysis used in all Ameren Missouri MEEIA applications since MEEIA cycle 2 was developed in 2014. As stated in the Company's original plan filing in this case:[53]

> Once the marginal revenue reductions have been calculated associated with each kWh of savings, **the marginal rate is reduced by a factor derived from the Company's FAC**. Due to the mechanics of the FAC, the portion of the foregone marginal revenue from each kWh of load reduction that was designed to cover net energy costs is subject to a reconciliation that allows the Company to recover 95% of the foregone net energy-related amount of revenue. As such, the marginal rate calculated above is adjusted to just reflect the portion of that revenue that contributes to the fixed (non-energy-related) cost recovery of the Company.[54]

Q. Witness Poudel makes several statements focusing on the precision of net margin rates and throughput disincentive recovery. Is the focus on increasing precision the most productive thing to focus on with respect to TD?

A. No. There is a difference between precision and accuracy. Accuracy – i.e., seeking a quantification of the throughput disincentive that is unbiased and therefore will not systematically cause an over- or under-recovery of the true throughput disincentive, should be the goal. Let's be clear about a few things here. First, let's acknowledge that all of the analysis around energy efficiency is, as I have discussed multiple times in this

[52] File No. EO-2023-0136, Hari K. Poudel Direct Testimony, p. 5, ll. 4-8.
[53] Note that the bolded reference in the quote below about "a factor derived from the Company's FAC" refers to the Base Factors, which Mr. Poudel recommends be utilized for this very purpose.
[54] 2025-27 MEEIA Plan (Revised), p. 69, emphasis added.

testimony, dealing with estimation of a counterfactual – something that did not happen. It is impossible for that estimation to be completely perfect - we cannot achieve perfect precision. But it can be accurate – free from bias, and thereby completely sufficient to form the basis of just and reasonable rates. The MEEIA statute requires the Commission to align the Company's incentives around energy efficiency, and to approve cost effective programs. It does not require the Commission to quantify the throughput disincentive precisely to the penny (nor could it because such a thing could never be accomplished). My point is that we should not spend an inordinate amount of time, money, or effort chasing the elusive goal of perfect precision. If parties have reasonable suggestions that can improve EM&V, we should pursue those improvements. But we shouldn't pretend that existing EM&V is not a good estimate that is reasonable to use for a variety of purposes, including valuing the throughput disincentive. If parties have reasonable suggestions for how the throughput disincentive calculation can be improved, we should pursue those improvements. But we shouldn't pretend that the existing calculations are not valid estimates that can be used to form the basis of just and reasonable rates that align the Company's incentives with helping customers use energy more efficiently, and are a part of a cost-effective and beneficial DSM portfolio. Not every improvement opportunity means that the existing method prior to making that improvement is or was not just and reasonable.

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 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA.	))))	File No. EO-2023-0136

AFFIDAVIT OF STEVEN WILLS

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

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

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

/s/ Steven Wills
Steven Wills

Sworn to me this 26th day of April 2024.

can generate earnings equal to the NPV of earnings that earlier deployment of CCs generate in the contingency plan with no DSM. The analysis indicated that, in order to make up for the forgone earnings from the deferred CCs, the RAP DSM would need to have an after-tax earnings annuity of $36.1 million (as tax rates changed, the annuity would need to be $31.1 million).

Since filing its 2017 IRP, Ameren Missouri updated its IRP analysis using its the MEEIA 2019-24 portfolio savings reflected in the plan. The timing of the CCs in the updated RAP portfolio plan changed very slightly with the deferral of the CC in 2034 to 2044, and the two CCs in 2037 to 2049 and 2054 (instead of 2055). The estimated annuity in order to eliminate the disincentive of forgone earnings for the utility from deployment of demand-side programs would be $30.65 according to this updated analysis (quite close in the earlier calculation $31.1 million). This analysis assumes all MEEIA plans within the full planning horizon are equally compensated for long-term forgone earnings opportunity.

MEEIA Plan Synergies

As stated above, Ameren Missouri selected a preferred plan that includes continued deployment of demand-side resources throughout the planning horizon (through 2037) where three CCs are deferred for many years. There is no doubt that the continued and uninterrupted deployment of demand-side programs and the combined effect from all the cycles is necessary achieve major deferrals of supply-side resources, as discussed further below.

As a screening analysis, Ameren Missouri analyzed the impact of 3-year MEEIA plan cycle by breaking its proposed 6-year plan into two 3-year periods. This demonstrated that neither 3-year implementation (MEEIA 2019-21 or MEEIA 2022-24) period by itself would result in any deferral of a new supply-side resource; in contrast, the 6-year implementation period does impact future supply-side resource timing. This preliminary screening analysis itself illustrates the value of an extended 6-year plan rather than two 3-year plans.

To further illustrate the importance of the continuation of demand-side programs, Ameren Missouri also analyzed combinations of implementation cycles,[22] e.g., implement Cycle 3 and no more demand-side programs afterwards, or implement Cycle 4 and no demand-side programs before and after, or Cycles 4 and 5 alone, or Cycles 4, 5, and 6 without implementing Cycle 3. All of these different cycle combinations demonstrated that deployment of demand-side resources without interruption is the most effective way to achieve deferrals of new supply-side resources further into the future because skipping even one cycle results in the need of a CC earlier than what the need would be with all

[22] Cycle 3: MEEIA 2019-24, Cycle 4: 2025-30, Cycle 5: 2031-36, Cycle 6:2037.

the cycles implemented. The table below summarizes the impact of MEEIA 2019-24 ("Cycle 3") combined with other cycles versus not implementing MEEIA 2019-24.

Table 10 – MEEIA 2019-24 Impact on Supply-Side Resource Deferral

Synergies	CC Deferral # of Years	NPV of EO $ Million	Gain from Cycle 3 CC Deferral	Gain from Cycle 3 NPV EO	Gain from Cycle 3 EO Annual
Cycle 3-4	12	$106	5	$39.5	$9
Cycle 4	7	$66			
Cycle 3-4-5	34	$266	13	$88.2	$20
Cycle 4-5	21	$178			
Cycle 3-4-5-6	39	$298	5	$32.2	$7
Cycle 4-5-6	34	$266			

The table shows if Cycle 3 (MEEIA 2019-24) is not implemented and Cycle 4 (MEEIA 2025-30) is implemented by itself, it would achieve a total number of 7 years of CC plant deferrals, and the resulting NPV of forgone earnings would be $66 million. On the other hand, if Cycle 3 is implemented and followed by Cycle 4, then the combined effect of these two cycles would be 11 years of deferrals for a total NPV of forgone earnings of $106 million. It is apparent that MEEIA 2019-24 adds 5 years of deferrals and an NPV of forgone earnings of $39 million or an annualized earnings opportunity ("EO") of $9 million over 6 years.

Similarly, if Cycle 3 (MEEIA 2019-24) is not implemented and Cycles 4 and 5 are implemented, they would achieve a total number of 21 years of CC deferrals with a resulting NPV of forgone earnings of $178 million. On the other hand, if Cycle 3 is implemented and followed by Cycles 4 and 5, then the combined effect of these three cycles would be 34 years of deferrals for a total NPV of forgone earnings of $266 million: MEEIA 2019-24 adds 13 years of deferrals and an NPV of forgone earnings of $88 million or an annualized earnings opportunity of $20 million over 6 years.

Finally, if Cycle 3 (MEEIA 2019-24) is not implemented and Cycles 4, 5 and 6 are implemented, they would achieve a total number of 34 years of CC deferrals with a resulting NPV of forgone earnings of $266 million. On the other hand, if Cycle 3 is implemented and followed by Cycles 4, 5, and 6 then the combined effect of these four cycles would be 39 years of deferrals for a total NPV of forgone earnings of $298 million: MEEIA 2019-24 adds 5 years of deferrals and an NPV of forgone earnings of $32 million or an annual earnings opportunity of $7 million over 6 years.

This analysis illustrates that even though Ameren Missouri does not have an immediate capacity need, implementing MEEIA 2019-24 is imperative in achieving longer periods of supply-side resource deferrals.