Exhibit No.: 006
Issue(s): Efficient Electrification
Witness: Steven M. Wills
Type of Exhibit: Direct Testimony
Sponsoring Party: Union Electric Company
File No.: ET-2018-0132
Date Testimony Prepared: February 22, 2018

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ET-2018-0132

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

p. 37, 38, and 39

CORRECTIONS MARKED BY NANCY DIPPELL, SENIOR REGULATORY LAW JUDGE
ND

St. Louis, Missouri
February, 2018

UE/Ameren Exhibit No. 6
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File No. ET-2018-0132

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DIRECT TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ET-2018-0063

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. What is your position with Ameren Missouri?

A. I am the Director of Rates & Analysis.

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.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony provides an overview of a portfolio of two new programs and one revised program that are all designed to promote efficient utilization of the Company's electric system for the benefit of all customers. I will give a brief history of the events and

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

considerations that led to this filing, provide a high level overview of the tariff sheets that govern each program, and introduce additional Company witnesses who will address each one in more detail. I will also discuss the substantial economic and other benefits of the proposals incorporated in this filing and provide analysis of the expected financial impacts of them on customers and the Company. Finally, I will describe the Company's proposed means of cost recovery for the two new programs.

Q. What proposals are addressed by this filing?

A. As I previously stated, the Company is proposing two new programs, as well as revisions to one existing program. The two new proposed programs are: the Electric Vehicle ("EV") Charging Infrastructure Incentive Program ("Charge Ahead – Electric Vehicles") and the Business Solutions program ("Charge Ahead – Business Solutions"). Together, Ameren Missouri refers to these as its "Charge Ahead" programs. This filing also includes revisions to the existing Distribution System Extensions program commemorated in Section III of the Company's General Rules and Regulations, and other tariff sheets related to the Company's distribution system line extension policies. New and revised tariffs, as appropriate, accompany this filing.

Q. Please identify the Company witnesses that will address each program.

A. My testimony contains information relevant to both of the Charge Ahead programs and the distribution system extension revisions. Company witness Michael W. Harding addresses details associated with the proposed changes to the distribution extension policies, Company witness Patrick E. Justis addresses issues related to the Charge Ahead – Electric Vehicles, and witness David K. Pickles, an employee of ICF, Inc. ("ICF"), describes the Company's work in developing the study of efficient electrification potential of certain end uses in Ameren Missouri's service territory that forms the basis of the Charge Ahead – Business Solutions program.

Q. Please elaborate on the overarching goal of these programs.

A. This filing proposes a portfolio of programs reflected in new and revised tariff sheets designed to enhance the utilization of the electric grid in a manner that reduces overall rate levels for existing customers while simultaneously creating a number of benefits. These include reducing overall energy consumption across fuels on a total BTU[2] basis, reducing emissions, and/or enabling expansion of customer operations on equitable terms that may improve the efficient utilization of the Company's distribution system. These new terms for customer expansions may also generate ancillary economic development benefits in the Company's service territory. As I describe later in my testimony, the distribution extension policy revisions are designed to align the terms and conditions under which customers connect new load to the Company's system more closely with the incremental costs and benefits that the new load will bring to the system. In a similar manner, the Charge Ahead programs seek to provide incentives to promote new loads based on the net benefits those loads provide to existing customers. These benefits arise from the characteristics of these loads whereby they enhance utilization of existing infrastructure and improve system load factors, ultimately lowering the unit cost of energy on Ameren Missouri's system for all customers. As a further benefit, the new electric usage promoted by the Charge Ahead programs will displace other forms of fossil fuel energy consumed by internal combustion engines, lowering participating customers' overall energy costs, and resulting in meaningful emissions reductions that improve air quality and reduce greenhouse gases in the atmosphere.

[2] British Thermal Unit, which is a measure of the heat content of fuels or energy sources.

Q. Are the revisions and programs proposed in the Company's filing interdependent such that the Commission must approve or reject them all together?

A. No. Each of the programs stands on its own merit and can operate independently of the other. However, the Company strongly believes that the benefits of approving all three are compelling and encourages the Commission to authorize the line extension policy changes and both new Charge Ahead programs together.

III. REGULATORY CONTEXT

A. Distribution Line Extensions

Q. Why is the Company proposing a new line extension policy at this time?

A. The context for the Company's decision to propose this revision begins in the working docket initiated by the Commission in the second half of 2015 to explore infrastructure utilization issues (File No. EW-2016-0041). In its order initiating that docket, the Commission signaled its keen interest in this topic by saying:

> ...the Commission remains interested in exploring whether existing electric utility infrastructure is detrimentally underutilized, whether that underutilization can be identified geographically and quantified, **whether there are rate design mechanisms or other tariff provisions that may incentivize more efficient use of existing infrastructure to the benefit of both customers and companies**, and whether there are public policy considerations the Commission should consider in weighing the value of any such mechanisms or provisions. (Emphasis added.) (File No. EW-2016-0041, Aug. 26, 2015 *Order Directing Staff to Investigate and Opening a Repository File.)*

The infrastructure efficiency working docket included a workshop along with opportunities for various parties to provide comments and share relevant information. The dialogues, discussions, and conclusions of that workshop were summarized in a Staff report filed on December 11, 2015. The primary recommendation that Staff included in the report, which arose from the investigation, discovery, and dialogues of the workshop as a means to promote efficient utilization of infrastructure, was summarized in the report's conclusion:

> Staff recommends that to the extent the Commission is interested in a model extension policy that more aligns with cost-causation without restricting new growth, that consideration of a design similar to GMO's tariff be considered in that it more fully considers the incremental costs a customer causes to a system in determining how much, if any, customer advance is required. By considering these costs, a customer causing new utility investment is more likely to bear some offset to that investment than under other approaches that do not consider incremental costs. (File No. EW-2016-0041, December 11, 2015, *Staff Investigation and Report*, p. 28.)

Q. Have there been additional actions taken on this topic since the working docket was concluded?

A. Yes. In its final comments responding to the Staff's report in that docket, Ameren Missouri expressed its shared interest in furthering the goals of the workshop, but also suggested that if its line extension policies were to be changed in response to the recommendation, it ought to be done thoughtfully with sufficient study to determine the potential impacts on our customers and the communities we serve. In the context of the Stipulation and Agreement settling its subsequent general rate case (File No. ER-2016-0179), Ameren Missouri committed to performing just such a study to evaluate a line extension policy designed similar to that of KCP&L - Greater Missouri Operations Company ("KCPL-GMO"). Specifically, the Stipulation stated that the Company would perform the study described in the rebuttal testimony of Company witness William R. Davis, which he characterized as follows:

> Ameren Missouri is willing to conduct a twelve-month historical study comparing the revenue requirement impact of its existing line extension policy to a line extension policy modeled after that in effect for KCP&L-GMO. Such a study could be completed by June 2018, and would include the Company's recommendation about whether its line extension policies should be changed. That recommendation would be based on the revenue requirement analysis as well as an assessment of other factors like customer understanding and expected impact on efficient utilization of existing facilities. (File No. ER-2016-0179, Davis Rate Design Rebuttal, p. 29, l. 7-13.)

Q. Has the study described by Mr. Davis been completed?

A. Yes. The details of the study are described in Mr. Harding's direct testimony.

Q. What is the Company's recommendation based on its findings?

A. As Mr. Harding will elaborate, the Company agrees with Staff's recommendation in File No. EW-2016-0041 that the KCPL-GMO line extension methodology more fully considers the incremental costs and benefits associated with the connection of new load to the system than the Company's existing line extension policy. The KCPL-GMO methodology specifically contemplates the characteristics of the new load and the marginal revenues and costs that will be received and incurred by the Company as a result of serving that new load. It also takes into consideration the annual revenue requirement impact of any new construction that must be undertaken to serve the new load. These factors – the marginal revenues and costs incurred and the revenue requirement impact of new plant constructed – are the determinants of how the addition of the load will impact overall rate levels for existing customers. As such, the KCPL-GMO methodology provides a better and more sophisticated framework to encourage new or growing customers to add load to the grid in an economically efficient manner that benefits all customers. Mr. Harding is sponsoring a revised line extension policy that embodies the same methodological framework as the KCPL-GMO policy.

B. Charge Ahead – Electric Vehicles Program

Q. Please provide some additional historical regulatory context for the Company's Charge Ahead - Electric Vehicles program proposal.

A. EV charging issues have been in front of this Commission in contested dockets at least twice, in which utilities sought to own EV charging infrastructure. Ameren Missouri sought Commission authority to build six charging islands across the I-70 corridor in File No. ET-2016-0246. Kansas City Power and Light Company ("KCP&L") sought rate recovery of charging infrastructure it had already constructed within its service territory in each of its last two electric rate proceedings. In both instances, the utility proposals were rejected by the Commission primarily over jurisdictional concerns. The Commission asserted that electric vehicle chargers do not meet the definition of "electric plant," and therefore are not subject to Commission jurisdiction. In neither case, however, did the Commission weigh in on the critical policy question of whether utility involvement in overcoming market barriers to the development of EV charging infrastructure is in the public interest.

The policy question remains an important one, and in fact, is a subject of discussion in the ongoing Emerging Issues workshop being conducted by the Commission (File No. EW-2017-0245). This matter explores a number of trending topics in the industry that are significantly impacting utility operations and business models. The Emerging Issues workshop was initiated by the Commission at Staff's request with a directive to participants to explore five issues, one of which is: "What is the Commission's role in promoting a competitive market for plug-in electric vehicles?" (File No. EW-2017-0245, March 24, 2017, Staff's *Agenda and Request for Workshop Docket*. Attachment A.)

The written comments and in-person discussion at the May 18, 2017, workshop provide evidence that, across a broad array of stakeholders and even Commissioners, there is a great deal of interest in and support for the development of new and creative solutions to jump-start investment in the needed EV charging infrastructure in Missouri. In fact, although there is no transcript of that discussion, my recollection of Chairman Hall's comments include his suggestion to consider line extension policies among other means of stimulating charging infrastructure development, such as examining "make-ready" models. Commissioner Rupp has also made supportive comments regarding the need to develop EV charging, including in his dissenting opinion in Ameren Missouri's first EV charging case.

Q. Does the Company's filing reflect its belief that utility involvement in EV charging is a necessary component of the development of EV markets in Missouri?

A. Yes, that is correct. Mr. Justis will expound on the significant need for and benefits to be derived from utility involvement in the development of EV charging infrastructure.

Q. How does this filing relate to the Company's initial EV charging case?

A. While one way for utilities to become involved in EV charging would have been for utilities to own and operate EV charging infrastructure as the Company previously proposed, the Charge Ahead - Electric Vehicles program proposed in this docket addresses the same issue in a new and different manner. The Charge Ahead - Electric Vehicles program takes into account the Commission's position that it lacks jurisdiction over utility-owned EV charging stations, but at the same time, recognizes the important role utilities must play in the deployment of this needed infrastructure.

C. <u>Charge Ahead – Business Solutions Program</u>

Q. Is there any similar context of events that establish the backdrop for the proposed Charge Ahead - Business Solutions program?

A. While programs like the proposed Charge Ahead - Business Solutions program have not been discussed in specific Missouri utility proceedings or in a Commission workshop process, the program does have some similarities to other programs with which the Commission is familiar. Specifically, I am referring to the energy efficiency programs that Missouri utilities, including Ameren Missouri, operate under the framework of the Missouri Energy Efficiency Investment Act ("MEEIA"). The Commission is very familiar with the goals, structures, and cost effectiveness metrics of the Missouri utilities' MEEIA programs. Among the benefits of the Charge Ahead - Business Solutions program is its contribution to the achievement of certain goals that it shares with energy efficiency programs, except extended to cover energy sources beyond electricity, and it can be characterized according to the same or similar cost effectiveness metrics. Mr. Pickles of ICF testifies on behalf of the Company regarding the policy rationale for the program and the customer and environmental benefits that can be derived from it. I will also provide more information about the proposed structure of the specific program proposed in this filing and the cost effectiveness of that proposal.

IV. ECONOMICS OF DISTRIBUTION LINE EXTENSIONS

Q. Please discuss the economic principles that underlie the distribution line extension policy changes that you are proposing.

A. At their core, the proposed changes are designed to increase the efficiency with which the Company's infrastructure is utilized, for the benefit of all customers and in furtherance of the Commission's stated objectives that initiated the infrastructure efficiency working docket (File No. EW-2016-0041), which I previously mentioned. This is important, because electric utilities are capital intensive businesses that invest significant sums of money in permanent infrastructure, such as substations, .transformers, poles and wires that stand ready to serve customers 24 hours a day, 365 days a year. Those significant investments in turn create fixed costs that must be covered by rate revenues from customers. That is to say, once the system has been constructed prudently to meet anticipated customer demand, regardless of how much electricity customers actually use, many of the costs incurred by the utility are fixed for years or decades to come. However, the rates charged for service are substantially based on the volumes of electricity consumed [expressed to customers on a cents per kilowatt-hour ("kWh") basis]. While there are some costs like fuel expense that vary with energy production, many of the costs reflected in that cents per kWh rate are those fixed infrastructure costs that I just described.

Those costs persist regardless of usage fluctuations. For a given infrastructure investment, then, the variable rates charged to recover the fixed costs of the system can be markedly different depending on the amount of energy delivered over it.

Q. Please provide an example of the power of infrastructure utilization in establishing rate levels.

A. Consider the load characteristics of two different types of customers. Figure 1 below shows the load shape of the Company's residential class for a given year. Figure 2 below shows the load shape of the industrial segment of the Company's Small Primary Service class. I have shaded the graphs such that the light blue colored space represents "underutilized" infrastructure, whereas the light grey space represents the actual utilization of infrastructure on an hour-to-hour basis to meet customer demand. That is to say that the light blue shading extends up from the actual customer demand (represented by the darker blue line) at a given point in time to the level of the class' peak demand for which capacity is generally planned and built. The light blue, therefore, represents capacity that sits idle at a particular point in time.

Figure 1: Residential Load Shape

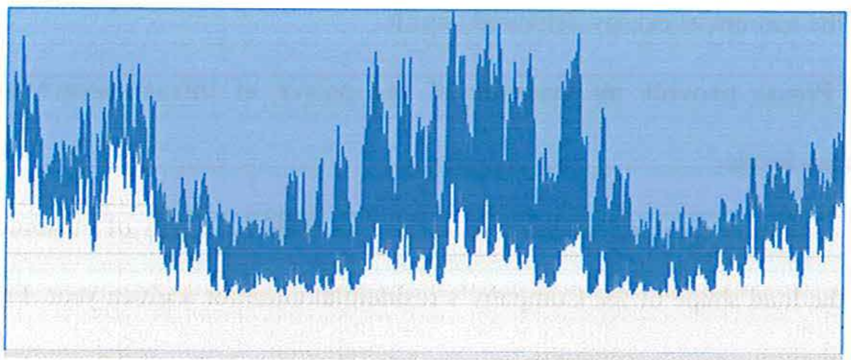
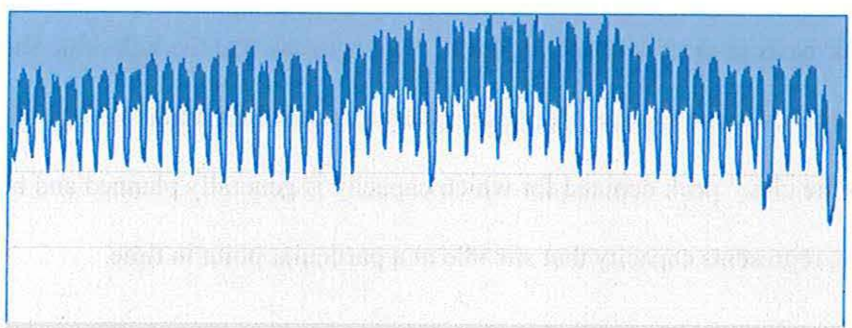


Figure 2: Industrial Small Primary Load Shape



Notice the striking difference between the percent of the area of the two charts that has been shaded in light blue to identify underutilized or idle infrastructure. The residential class in this year had a load factor[3] of 41.6%, meaning that *on average* across the course of the year, less than half of the demand-related capacity for which the infrastructure was built and which is needed to meet these customers' peak demand is in use. The Industrial SPS class has a load factor in this year of 69.9%, meaning that *on average* over the course of the year, over two-thirds of the demand-related capacity needed to meet these customers' peak demand is in use.

[3] Load factor is the ratio of average demand to peak demand, which characterizes how consistently a customer or group of customers utilize system capacity designed to meet their peak demand.

Q. How does this concept relate to the distribution line extension changes proposed in this filing?

A. If we can improve the utilization of the infrastructure that is in place (i.e., reduce the light blue areas), we can lower rates. This is because customers' load characteristics have significant implications for the rates applicable to them. As I discuss further below, the Charge Ahead - Electric Vehicles and Charge Ahead - Business Solutions programs proposed in this filing also improve utilization of that infrastructure.

Q. Please elaborate.

A. Assume for a moment that the revenue requirement associated with certain infrastructure needed to serve 100 Megawatts ("MW") of demand is $10 million. At the 69.9% load factor of the industrial customers reflected in Figure 2, the rate needed to recover the revenue requirement is approximately 1.6 cents/kWh:

$$\frac{\$10{,}000{,}000}{100\text{MW x } 8{,}760\left(\frac{Hours}{Year}\right) x\ 69.9\%\ Load\ Factor\ x\ 1{,}000\ (\frac{kWh}{MWh})} = \$0.016/kWh$$

At the 41.6% load factor of the residential customers reflected in Figure 1, the rate is 2.7 cents/kWh or 68% higher:[4]

$$\frac{\$10{,}000{,}000}{100\text{MW x } 8{,}760\left(\frac{Hours}{Year}\right) x\ 41.6\%\ Load\ Factor\ x\ 1{,}000\ (\frac{kWh}{MWh})} = \$0.027/kWh$$

[4] The $10 million revenue requirement and 100 MW example is intended to be illustrative and is not necessarily representative of any particular investment or infrastructure. However, while the cents/kWh rate level would potentially vary, the 68% differential between the applicable rate for the two load characteristics would continue to be true for any given level of investment and capacity sizing for assets constructed to meet the class peak demand.

While the point of the distribution line extensions policy (and the other programs included in this filing) is not to delve into the differences in class cost of service that arise from differing class load shapes, the foregoing figures demonstrate that, as utilization of a fixed asset increases, there is a powerful impact created, which serves to lower the variable rate incurred by customers. The programs and tariff revisions that are the subject of this filing are all designed to increase utilization of the Company's system which will have the effect of lowering unit costs and ultimately rates for all customers.

Q. Please explain more specifically how the line extension methodology proposed by the Company promotes efficient utilization of the grid.

A. As I just described, efficient utilization of infrastructure results in lower unit costs (cents/kWh) of energy to customers. The proposed line extension policy changes are specifically designed to determine whether unit costs that will be reflected in rates to existing customers will be positively or negatively impacted when the Company makes the necessary investments to serve a new load. In effect, the "Extension Allowance" term in the tariff describes the amount of money the Company could invest to serve the new load without causing any increase in existing customers' rates. Application of this principle is designed to ensure that the incremental costs of new investment required to serve expanding loads are borne by the customer(s) that causes them. As such, if existing customers' rates are expected to go up as a result of an extension of service to a new customer (i.e. the Extension Cost exceeds the Extension Allowance), that new customer will have to make a financial contribution in aid of construction up to the point where the negative impact on other customers is alleviated. However, if the net effect of the Company serving the new load will drive other customers' rates down (i.e. the Extension Allowance exceeds the Extension Cost), that new customer will not have to pay anything up-front to connect the new load to the grid.

There are three fundamental determinants of whether (or how much) customers will have to pay for line extension under this policy, two of which directly relate to efficient grid utilization. The first is the load factor of the customer seeking the line extension relative to the load factor of the rate class that they will take service from – i.e., how efficiently the customer uses infrastructure largely determines how much margin a customer will contribute to fixed cost recovery under a given rate structure. Customers who use infrastructure more efficiently than others, and therefore contribute more margin per kWh consumed, will realize more benefits in the line extension process.

The second determinant is the amount of investment needed in order to connect the new customer. Customers locating in close proximity to existing circuits with excess capacity will not require as much investment on their behalf as customers who need a long extension or who will force capacity upgrades on already heavily loaded circuits. Said another way, customers who make greater use of existing "under-utilized" infrastructure will connect to the grid on more favorable terms than those who require significant construction of new lines, or upgrades of local capacity.

The third fundamental factor that determines the terms on which new load will be added under this policy is simply the current level of incremental energy and related marginal costs relative to the embedded cost of energy and related costs in rates. But this factor is outside of the control of customers connecting to the system, whereas load factor and choice of location on the system are characteristics or decisions of the customers themselves.

Q. Is there a familiar way to gauge this kind of impact?

A. Yes, there is. It is useful to think of this type of line extension policy, which considers the expected rate impact of utility investment directed at a specific customer or group of customers on all other customers, as an analog to the Rate Impact Measure ("RIM") test cost effectiveness metric commonly used in the evaluation of energy efficiency programs. The RIM test is a measure that best captures the effect of programs on *non-participants* whose own usage will not be impacted by the program's measures, because it is formulated to determine whether an investment in a measure will ultimately cause rate levels to go up or down. But it can similarly be used to analyze load additions for their impacts on "non-participants," in this case, all pre-existing customers and pre-existing loads of expanding customers. The RIM is expressed as a ratio of benefits to costs such that a RIM score of 1.0 means that the expected benefits and costs of the measure or program being analyzed match exactly. When the RIM equals exactly 1.0, no overall rate impacts are anticipated as a result of that measure or program. RIMs greater than 1.0 mean that for every dollar of cost associated with the program or measure being evaluated, more than one dollar of benefits is anticipated, and overall rate levels are expected to go down. Conversely, a RIM less than 1.0 means that there are fewer benefits than costs, and an increase in rates is anticipated as a result of implementation of programs or measures. The RIM calculation as applied to energy efficiency generally contemplates benefits, including the net avoided costs of energy, capacity, and transmission and distribution ("T&D") associated with a load reduction. The cost side of the RIM equation includes any program costs incurred to achieve the load reduction (i.e. incentives and administrative costs), along with the lost retail margins associated with participating customers' load reductions that otherwise would contribute to the recovery of fixed infrastructure costs of the overall electric system. However, when applied to load additions, some of the categories of costs and benefits are reversed. Benefits of *added* load include additional margins derived from the retail bill assessed to the customer responsible for the new load. Costs of the added load include incremental energy, capacity, and T&D costs incurred to serve the load. In addition, as in the case of energy efficiency, program costs must be taken into account. In my analogy where the RIM is related to the marginal cost line extension methodology, the revenue requirement associated with the line extension itself would represent the program costs. This RIM framework analogy will be useful for relating the beneficial effects of the proposed line extension policy and the beneficial impacts of the Charge Ahead programs.

Q. Are there any unique features of the Company's proposed line extension tariff changes that further promote economically efficient load additions?

A. Yes. The Company has incorporated an innovative feature into the line extension methodology, referred to as the Non-Residential Existing Infrastructure Incentive ("NEII"). Mr. Harding's direct testimony addresses this provision in more detail. The intent of the NEII is to encourage highly beneficial load additions that are expected to provide significant downward pressure on existing customers' rates. The marginal cost line extension approach itself is very good at distinguishing between projects that are beneficial and therefore can be undertaken at no upfront cost to the new customer vs. those that require a customer contribution in order to alleviate rate impacts that would otherwise be felt by existing customers. What that approach doesn't do is differentiate between multiple beneficial projects that have different magnitudes of benefits. A customer who provides $1 of marginal revenue that exceeds their marginal cost is treated the same as a customer providing $1 million of marginal revenue that exceeds their marginal cost. The NEII seeks to provide that differentiation, whereby strongly beneficial projects, as evidenced by the Extension Allowance exceeding the Extension Cost by predetermined threshold, can receive incentives in the form of rate discounts during their first three years of service. To extend the RIM analogy from my previous answer, this differentiates between the type of project that would have a RIM test result barely exceeding 1.0 (where benefits slightly exceed costs) and a project that has RIM benefits that are multiple times the cost (RIM of, for example, 3 or 4 or even higher). As I mentioned previously, conditions where the Extension Allowance greatly exceeds the Extension Cost will either occur due to very favorable load characteristics of the new customer, or due to the new customer making significant use of existing, potentially "under-utilized," infrastructure, or both of the above. Providing a rate discount to these projects will give customers an incentive to locate their operations at sites with low extension costs, and will reward them for providing system benefits. This provision further strengthens the economic signal in the proposed line extension policy to promote economically efficient expansion of service on the Company's system.

V. ECONOMICS OF THE CHARGE AHEAD - ELECTRIC VEHICLES PROGRAM

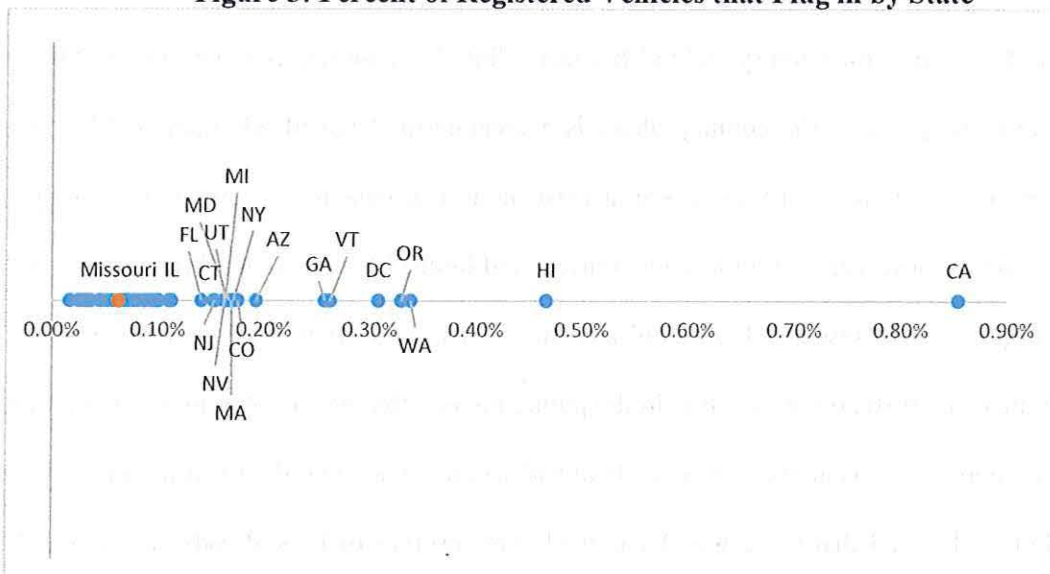
Q. Please discuss the rationale of the Company's proposed Charge Ahead - Electric Vehicles program.

A. The basis of the need for, and appropriateness of, utility involvement and investment in the development of EV charging infrastructure is twofold. First, new EVs purchased by Ameren Missouri customers represent new electric loads that are coming and will continue to come onto the system, which have a specific infrastructure need (i.e. charging). The development of that infrastructure is lagging, and as Mr. Justis testifies further, will likely continue to lag without direct utility support. As a result, the utility should fill its traditional role as a developer of infrastructure to meet the needs of its customers and the public. Second, by ensuring that the infrastructure is developed, more EV adoption than would otherwise occur is likely to be spurred. Just as the utility and its customers stand to benefit from the effects of the kinds of efficient electrification discussed by Mr. Pickles in his direct testimony, there are similar benefits from greater EV adoption.

Q. Please elaborate on these factors that suggest utilities should take an active role in the development of EV charging infrastructure.

A. Mr. Justis' direct testimony demonstrates that plug-in vehicle offerings from auto manufacturers are increasing rapidly and are likely to result in significant growth in consumer interest in EVs across the country and in Missouri. While EV adoption remains slow in Missouri relative to many parts of the country, there is a meaningful level of adoption of EVs in our service territory and we are likely to see at least modest growth in EV ownership among our customers for the foreseeable future. These current and future EV owners need practical charging options to get the greatest benefits of utilizing their EVs. And given the broad benefits of EV adoption that Mr. Justis describes, it is in the public interest that we are able to ensure that more and more interested consumers have a practical and secure choice in EVs. Ensuring that choice is available broadly, and that those who have availed themselves of EVs already can utilize them fully, requires the development of more charging infrastructure. However, Mr. Justis also describes the factors that are causing a significant lag in the deployment of this infrastructure and the critical importance of the utilities' role in ensuring that this infrastructure gap is closed. Third party charging providers simply will not focus their efforts and investments in markets like Missouri - without incentives to do so - for years to come due to low EV adoption rates relative to other markets. Figure 3 below shows a scatter plot of the adoption rates of EVs by state with Missouri highlighted. Note that Missouri, represented by the orange dot, is in the middle of a pack of the slowest group of states to adopt EVs. Missouri's EV adoption level of 0.06% of registered vehicles significantly lag a large group of states with more than triple the adoption rate (and more than 12 times in the case of California). It should be pointed out that the states with higher adoption rates are not in that position by accident. In many of these jurisdictions you will find some of the most supportive policies toward EVs, including a number of states that have already begun working and continue to work with and through utilities to promote charging infrastructure.

Figure 3: Percent of Registered Vehicles that Plug in by State[5]



Fortunately, where third parties are not prepared to enter the market, utilities are typically well-suited to take on the role of meeting infrastructure challenges like this, where significant large scale investment is needed for the benefit of both individual customers and the public at large, just as it has been the case for decades in other areas of the utility business.

Q. Please elaborate further on the efficient electrification effects that may arise from utility involvement in this area.

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[5] Data from autoalliance.org/resource-center. Vehicle registrations as of December 2016.

A. Utilities and their customers are positioned to benefit economically from the proliferation of EVs and their ability to improve utilization of fixed assets when charging is done in off-peak time periods. EVs are a flexible load that can charge during periods when demand on the system is low. When this occurs, the retail revenues derived from charging significantly exceed the marginal cost of serving the EV load, which in turn drives down retail rates for all customers. This is the power of efficient infrastructure utilization that I discussed earlier in my testimony. The availability of charging infrastructure that would be promoted by the Charge Ahead – Electric Vehicles program would be a very significant step in removing one of the key barriers to consumer adoption of EVs, which in turn would increase EV adoption and the resulting effects of efficient electrification arising from increasing numbers of EVs on the road.

This confluence of factors - the public need for infrastructure investment that I described above and the significant potential to increase utilization of existing capacity on the electric system that can integrate the resultant load in a manner that is beneficial to existing utility customers - suggests that it is squarely in the public interest for utilities to participate in the development of this infrastructure. Through initiatives like the Charge Ahead - Electric Vehicles program proposed by Ameren Missouri, electric utilities and this Commission can play a key role in stimulating the transformation of the transportation sector toward electric powered vehicles in order to improve infrastructure utilization while also helping achieve the emissions reductions, consumer choice, and other benefits detailed in Mr. Justis' testimony.

Q. Please summarize how the proposed Charge Ahead - Electric Vehicles program would work.

A. While based on the Commission's order in the Company's first EV charging case the Company cannot own EV charging infrastructure and provide it as a tariffed service, the

Company can play the important role of improving EV charging infrastructure by offering incentives to existing and prospective customers, much like it does when it offers incentives to customers to acquire energy efficiency measures. In the latter case, the benefits arise from avoiding future infrastructure investments by the Company; in the former case, as discussed earlier, the benefits arise from better utilization of the infrastructure the Company has already put in place. The Company's proposal, as further outlined in Mr. Justis' direct testimony, includes a $10 million budget over five years for incentives directed to a number of market segments to pay for the charging equipment itself as well as other costs, such as line extension costs and site development, or "make-ready" costs, in order to stimulate customer and third-party development of charging infrastructure. The program includes an additional proposed $1 million budget for marketing and related program activities.

Q. Is the earlier discussion of the proposed line extension policy changes useful in understanding the first rationale you suggested for the proposed Charge Ahead - Electric Vehicles incentives (i.e. to facilitate the development of infrastructure to meet the needs of new EV load coming onto the system)?

A. Yes. EV's brought into the service territory represent new load - just like the addition of a new customer or expansion of service to an existing customer does under the line extension policy. However, this new EV load is not stationary and therefore must be served electrically by a network of charging infrastructure across the territory, rather than by a single discrete distribution system extension. Therefore, unlike a traditional line extension serving a stationary new load, the investments needed in charging infrastructure are not "one for one." By this I mean that we do not build (or incentivize) one charging station and serve one new EV from it. Each charging station may be used by multiple EVs, and each EV may use multiple charging stations. The investments in charging stations are not necessarily directed at the premises of the owner of the new load (the EV), but rather at host locations that stand to potentially serve many EVs. But while these differences from the traditional line extension investments exist, there is also a similarity between line extensions and incentives for EV charging infrastructure. The EV charging incentives included in the Charge Ahead program still represent an incremental investment made by the Company to develop physical infrastructure in support of its customers' (the EV owners') use of the electric system to meet their needs for expansion of service. And like extensions made under the marginal cost approach being proposed for line extension, this expansion of service can take place in a manner that is economically efficient, with beneficial rate impacts for all customers.

As I mentioned previously, the line extension methodology is designed to, in essence, determine how much money the Company could invest in serving any new load without negatively impacting the rates of existing customers. It ensures that the costs of incremental investment made to serve new or expanding loads are borne by the causer of those costs while also in many cases improving the utilization of existing infrastructure. This principle remains true whether the incremental investment occurs at a discrete premises hosting a new load or through incentives to promote a distributed network of infrastructure that supports new loads. So for the potential new load associated with EV charging, the line extension methodology can be used to answer the same question it does for other customer expansions: given the load that can be reasonably expected from EVs, how much of the needed incentives for charging infrastructure could be supported by the margin revenues that will be derived from new EV-related load, while ensuring that some level of benefits from the whole EV ecosystem (i.e. the net of the added margin from EV load and the costs incurred by the utility to incentivize charging infrastructure investments) remain for all customers in the form of lower rates? Application of the "extension allowance" formulaic framework from the line extension tariff can be used to discern the answer to that question.

Q. The Company is not proposing to own the EV charging infrastructure itself, correct?

A. That is correct,[6] the Company is not proposing to own and operate charging stations. But for purposes of understanding the economics of EV charging infrastructure investment, it is useful to examine, as we did for investments for distribution line extensions, what level of investment EV revenues could support using the "extension allowance" methodology. That analysis appears immediately below.

Q. Please explain the analytical steps needed in order to apply the "extension allowance" methodology to the load associated with a new EV.

A. The determination of the "extension allowance" associated with a new load under the marginal cost line extension methodology begins by calculating the expected annual retail margin that will be derived from serving that load. To make that calculation for an EV, the annual electric consumption of that EV must be estimated. To accomplish this, the Company acquired vehicle registration data for EVs in its service territory to determine the types of vehicles and associated battery capacities that are in use.[7] We assumed typical driving distances of 40 miles total per day and vehicle efficiency of three miles per kWh. This results in a typical

[6] Because incentives can be directed toward line extension costs and, in other limited circumstances, utility owned infrastructure, some subset of the $10 million investment in incentives may go toward assets the utility owns, but they would be the type of assets that are routinely owned by the Company and fit squarely within the Commission's interpretation of "electric plant". The Company is not proposing to own the chargers themselves.

[7] Plug-in hybrid electric vehicles ("PHEV") were also included in the population, which tend to have smaller battery capacities. The total daily charging needs calculated from the population of EVs reflects a weighted average of the all-electric vehicles, for which all miles driven are obviously electric powered, and PHEV, for which it is assumed the electric capacity is utilized first prior to using gasoline as a backup. As a result, of the 40 miles assumed to be driven per day by owners of EVs and PHEVs, approximately 34 miles are assumed to be powered by electricity.

EV having annual consumption of approximately 4,090 kWh per year. Priced at the Company's current residential rate (where the large majority of charging is expected to occur), the annual revenues associated with one EV are $379 (shown in Table 1 below).

Table 1: Retail Revenue Forecast for Charging One EV

	kWh Consumption	Retail Rate	Total Retail Revenue
Summer	1,367	$0.1261	$172
Winter	2,723	$0.0759	$207
Total	4,090	$0.0927	**$379**

The incremental costs of serving the EV load and associated losses and reserves are estimated based on an energy cost of $0.0245/kWh (shown in Table 2 below), which is the market value of energy used to establish rates in the Company's last general rate case (File No. ER-2016-0179), and a capacity cost of $25.29/MW-Day (shown in Table 3 below), which is the historical three-year average of the MISO capacity price (net of Zonal Deliverability Benefits) in the Company's resource adequacy pricing zone. Charging is expected to occur at 6.6 kW (typical level 2 charging rates), with 20% of vehicles assumed to charge during peak times.[8] The result of applying these assumptions to a vehicle with 4,090 kWh of annual consumption is a marginal cost to serve of $120 per year, leaving a margin to contribute to recovery of EV charging infrastructure-related costs (or incentives) of $259 per year ($379 revenue - $120 incremental cost)[9] (shown in Table 4 below).

[8] A U.S. Department of Energy study titled "Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors – Experiences from Six Smart Grid Investment Grant Projects," published in Dec. 2014 reported on p. 11 under results for charging behavior studies, "IPL found that approximately 76% of the electricity used for charging occurred during off-peak periods, an additional 4% occurred during mid-peak, and the remaining 20% occurred during peak periods."

[9] The line extension margin calculation also includes an incremental cost of "network and infrastructure support costs," which represents incremental operations and maintenance ("O&M") costs incurred to maintain newly constructed facilities, handle customer service and billing for new customers that connect through line extension, etc. Since the Company does not anticipate the load added by an EV being charged at a residential premises to change the level of costs of this nature that will be incurred in serving the customer, no infrastructure and support costs have been included in this analysis.

Table 2: Incremental Energy Expense for EV Charging Load

Col. 1 kWh	Col. 2 Losses	Col. 3 Market Energy	Col 4. Energy Expense (Col. 1 x (1 + Col. 2) x Col. 3)
4,090	5.49%	$0.0245	**$106**

Table 3: Incremental Capacity Expense for EV Charging Load

Col. 1 Demand per Vehicle w/Level 2 Charging (kW)	Col. 2 On-Peak Charging %	Col. 3 Losses + Reserves	Col 4. Market Capacity ($/MW-Day)	Col. 5 Days	Col. 6 Capacity Expense (Col. 1 x Col. 2 x (1 + Col. 3) x Col. 4 x Col. 5)
6.6	20%	13.72%	$25.29	365	**$14**

Table 4: Incremental Margin for EV Charging Load

Col. 1 Retail Revenue	Col. 2 Energy Expense	Col. 3 Capacity Expense	Col 4. Total Margin (Col. 1 - Col. 2 - Col. 3)
$379	$106	$14	**$259**

Once the annual margin contribution of the new load has been established, the next step is to determine the annual revenue requirement impact of an investment to serve the new EV load. For every dollar invested on behalf of a new EV's load, the annual revenue requirement is made up of the depreciation (or amortization in the case of a regulatory asset, which will be discussed further later in my testimony) expense associated with the asset, and the cost of capital and associated income taxes incurred while financing the investment.[10] Because the financing costs decline over time as the original capital investment is depreciated, the annual revenue

[10] Again, line extension includes a provision for incremental property taxes, but because the Company is proposing to not own the majority of the physical assets associated with the Charge Ahead - Electric Vehicle program, incremental property taxes have not been included in this analysis.

requirement impact declines over time. For purposes of the line extension methodology, the Company is proposing to use the average revenue requirement impact of new investment over the first five years of its life. Considering EV charging equipment is expected to have a useful life of approximately ten years and the pre-tax cost of capital for Ameren Missouri is approximately 9.73%,[11] the Company estimates that, on average, over the first five years of the life of the assets supported by the incremental margin from an EV on the system, the annual revenue requirement would be approximately 17.8% of the value of the investment (shown in Table 5 below). That is to say, for every dollar invested in EV charging infrastructure (or incentives to promote it), the revenue requirement that would be reflected in rates would be approximately 17.8 cents on average over five years.

Table 5: Annual Revenue Requirement as a % of New Investment

Year	Depreciation/Amortization	Undepreciated Investment	Pre-Tax Cost of Capital	Total Annual Revenue Requirement as a % of New Investment
1	10%	100%	9.73%	19.73%
2	10%	90%	9.73%	18.76%
3	10%	80%	9.73%	17.78%
4	10%	70%	9.73%	16.81%
5	10%	60%	9.73%	15.84%
Average				**17.78%**

To calculate the "extension allowance" that would be supported by a new EV's load, the annual margin ($259) is divided by the annual carrying cost factor (17.8%) resulting in an "extension allowance" of $1,459 per vehicle.

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[11] This factor is based on tax rates in effect prior to the recent passage of federal tax reform. These are the tax rates on which current rates were based, the use of which promotes consistency with the calculation of marginal revenues in this analysis. The factor should be updated when rates and the resulting revenues reflecting federal tax reform are in place.

Q. Please summarize what this illustration shows.

A. This detailed example demonstrates the economic value of the addition of each new residential EV that will be charged on the Ameren Missouri system, whether enabled by investment in Company-owned EV charging assets as the Company proposed in its first EV charging case or, as here, enabled by incentives paid by the Company to others to develop charging assets. In both cases, the utility's involvement in the deployment of EV charging contributes to overcoming barriers to EV adoption and, as the illustration shows, the economic value of each such vehicle on the system supports nearly $1,500 of Company investment in incentives without any negative net impact on its other customers. In fact, Company incentives below that level would bring other customers *net benefits* in the form of lower rates.

Q. Mr. Justis explained that consumer interest in EV adoption is likely to increase significantly going forward, and much higher EV sales should result if encouraged by supportive polices like the Company's proposed Charge Ahead - Electric Vehicles program. What is a reasonable projection of EVs in the service territory in the future and what would that imply for investment levels that can be made to serve this new load while being fully supported by the expected margins?

A. For this purpose, I am using the base forecast of EV adoption from the Company's recently filed 2017 Integrated Resource Plan ("IRP"). The IRP included three growth scenarios for EVs – low, base, and high. And it is worth pointing out at this time, that recent observations suggest that 2017 adoption is generally in line with the pace suggested by the base forecast, so it remains the most likely case in the Company's view. Looking forward to the level of vehicles contemplated over the first decade of the proposed program, the Company's base forecast suggests almost 25,000 electric vehicles will be in the service territory by 2028.

Multiplying this vehicle total by the $1,459 per vehicle in supported investment calculated previously, shows that Ameren Missouri could spend almost $35 million over that timeframe to promote the development of infrastructure needed to serve this new load and the overall effect on rates of the combined impact of EVs and the associated incentives for infrastructure would be neutral.

Q. How does that $35 million figure compare to the proposed Charge Ahead – Electric Vehicles program?

A. The Company's proposal includes an investment of just $11 million to jump start the development of this infrastructure and to promote the program and EV technology, which will contribute positively to the adoption of EVs and play a significant role in driving the associated benefits, while leaving considerable value for customers in the form of lower unit rates for electricity.

Q. Why is it appropriate to look at EV adoption in the service territory over the next 10 years to determine a reasonable investment in the Charge Ahead – Electric Vehicles program?

A. There are a number of reasons that this time horizon makes sense. First, ten years is likely to be in line with the useful life of much of the charging equipment that would be deployed as a result of the program. Second, as I will discuss later, the Company is proposing to defer and amortize its investments over a seven year time frame. So the recovery of the costs of the incentives offered by the Company from a five year program, plus a seven year amortization period would extend well beyond the ten years contemplated by the Company's analysis. Finally, the proliferation of EVs will play out over a period of many years, so the determination of the appropriate level of Company investment in the form of incentives to support EV charging infrastructure should not be shortsighted by just considering the benefits of the EVs already on the road or coming in just the next couple of years. Instead, it should reflect the structural shift in the transportation sector that will create benefits that multiply over time.

Q. Given the considerable uncertainty in the ultimate adoption rate of vehicles, please discuss the range of outcomes that could be realized based on the high, base, and low adoption forecasts included in the 2017 IRP.

A. First, I would reiterate that the current adoption already appears to be in line with the base case and approval of the Charge Ahead – Electric Vehicles program will make higher levels of adoption even more likely to occur in the future. So I would suggest that there is a greater probability of experiencing outcomes in line with the higher end of the range that I calculate, rather than the lower end under any scenario where the Company's proposed investments in support of EV charging infrastructure are being made. I calculate the range of EVs and associated investment levels that are supported in Table 6 below, where I show the average EVs expected in the service territory over the ten-year period beginning with the initiation of the program, and also the total EV's expected in the service territory at the end of the ten-year period for each of the 2017 IRP adoption scenarios. For each of these EV levels, I multiply the total EV's by $1,459 (the value previously determined to reflect that amount of investment that is supported by an incremental EV charging on the system) to calculate a range of investment levels that may be supported by EV margin contributions under different future adoption scenarios. Table 6 demonstrates that, even at the lowest and least likely estimate of adoption, the $11 million EV Charging program proposed by the Company is in line with the amount that is economically justified by the charging margins that would be provided by the forecasted level of EVs. And in the best cases, the EV ecosystem creates significant value for all customers through lower expected rates, given the fact that the Company's program invests only a fraction of what EV charging margins would be capable of supporting. The excess margins above the level necessary to pay for the Charge Ahead – Electric Vehicles program would simply create lower rates for all customers because of the increasing utilization of existing infrastructure to serve the new load.

Table 6: Projected EVs Across 2017 IRP Adoption Scenarios and Charging Investment Supported by Them

	Low Adoption		Base Adoption		High Adoption	
	10 Yr Avg Projection	2028 Projection	10 Yr Avg Projection	2028 Projection	10 Yr Avg Projection	2028 Projection
EVs in Ameren Missouri's Service Territory	7,268	11,346	11,813	24,516	22,864	48,638
Investment Supported by EV Margins ($Millions)	$10.6	$16.6	$17.2	**$35.8**	$33.4	$71.0

Q. Are the forecasted vehicle levels from the 2017 IRP, on which you based these calculations, reasonable?

A. Yes. While any forecast of adoption of new technologies has uncertainty, the levels of investments by car makers in new EV production, the policies being put into place to support transportation electrification in many states and countries, and the considerable momentum that is already building in many markets virtually ensure that EVs will have a much more prominent place in the transportation mix of the future. Just to highlight the bullish view that many entities have on the future of EVs, nationally and globally, I will cite a few organizations' public projections or assumptions regarding market growth.

- Bloomberg New Energy Finance's Electric Vehicle Outlook 2017 projects over 10% of U.S. new car sales to be EVs by 2025 and that nearly 5% of the fleet on the road globally will be EVs by 2028.

- The International Energy Agency's Global EV Outlook 2017 projects between 40 and 70 million EVs on the road globally by 2025, a more than twenty-fold increase over the 2 million such vehicles as of 2016.
- A U.S. Department of Energy September 2017 analysis of EV-related infrastructure needs considered a base scenario of a 20% market share of EVs in 2030, with sensitivities ranging from 10% to 30%.

These projections and scenarios paint a picture of tremendous potential for growth in EVs relative to the 0.06% of cars that utilize EV technology in Missouri (per Figure 3 from earlier in my testimony). If barriers to adoption are fully addressed, the high case IRP forecast and beyond are increasingly plausible EV adoption scenarios. This is particularly true considering the forces pushing for EVs nationally and globally, and the potential Missouri has, if supportive policies are in place, to move from being one of the slowest adopting states (again see Figure 3) toward the level of those states that are already embracing this technology more rapidly.

Q. That potential for high levels of adoption under the right circumstances brings a good opportunity to discuss the second rationale you provided at the outset of this section of testimony for the Company's investment in EV charging. You suggested that it would provide rate benefits to all customers if enough new vehicles entered the service territory as a result of the Charge Ahead – Electric Vehicles program. Given the margin each new vehicle contributes to the recovery of the fixed costs of the system, how many incremental new vehicles would have to result from the program for rates to be lower as a result of the program?

A. Given the $11 million proposed budget, and the roughly $1,500 investment that I previously calculated could be supported by each car, simple division suggests that approximately 7,500 new cars over the life of the program would need to be added to the system for the incremental effect of the program to result in rate benefits *directly* arising from the program for all customers.

Q. Is it reasonable to believe that more than 7,500 new vehicles will result from the Charge Ahead – Electric Vehicles program?

A. Absolutely. While I believe it will be very hard to infer the precise motivations behind different EV owners' decisions to purchase their cars, such that it is unrealistic to "count the cars" that resulted from the program, it is clear that addressing the barriers to EV ownership which Mr. Justis identified can move the needle on local EV adoption. There are numerous studies that support this conclusion.[12] Consider one more time the regional differences in adoption illustrated in Figure 3 above. As I mentioned when first introducing that scatter plot, many states that have supportive policies in place already have adoption of EVs that is three or more times the level in Missouri, with some states significantly above that. That further suggests that removing barriers for local residents can be very impactful in promoting adoption. Recall for a moment the difference between the Company's base and high adoption forecast for EVs in the 2017 IRP. The high case 2028 vehicle total of almost 49,000 is nearly double the base case projection for the same year. If the Company's program is responsible for shifting the local adoption trajectory from the base to high case, which is reasonable given the observations about differing regional adoption levels already cited, well above the 7,500 cars that I just calculated would come onto the roads in Ameren Missouri's service territory. Under this very plausible outcome, the direct benefits of the Company's Charge Ahead – Electric Vehicles investments

[12] See "Evaluating Methods to Encourage Plug-in Electric Vehicle Adoption" prepared by Plug In America for CalETC, October 2016, page 21-22. https://pluginamerica.org/wp-content/uploads/2016/11/PEV-Incentive-Review-October-2016.pdf

would more than pay for the costs of incentives reflected in customer rates. As a final data point suggesting the effectiveness of charging infrastructure development on vehicle adoption, see the discussion included in the testimony of Mr. Justis that describes the impact that KCP&L's Clean Charge Network has had on vehicle adoption in the Kansas City area.

Q. You previously drew an analogy from the line extension methodology to the energy efficiency cost effectiveness RIM metric. What is the calculated RIM value for the proposed Charge Ahead - Electric Vehicles program?

A. I have performed that calculation using charging load characteristic assumptions described previously, incremental cost curves from the 2017 IRP,[13] and a vehicle population that is based on the base case 2017 IRP adoption forecast.[14] The combination of the Charge Ahead – Electric Vehicles program and the load added associated with EVs, viewed together, result in a RIM of 1.19. This suggests that for every dollar that the Company invests through the Charge Ahead – Electric Vehicles program, electric vehicles will provide $1.19 in benefits that lower rates for Ameren Missouri's customers.

[13] I drew the analogy between the line extension methodology and the RIM test, but for this comparison, I will clarify notable differences between these two calculations. The line extension policy incorporates an estimate of current incremental energy and capacity costs. The RIM test incorporates forward curves that forecast future levels of energy and capacity costs, and also applies discount rates to all of the future costs and revenues, which makes the timing of the vehicle additions relevant to the RIM calculation. As such, the favorable RIM result for EVs tests additional sensitivities to those factors.

[14] In traditional energy efficiency program applications, the RIM applies only to measures that are directly attributable to the program incentives. As I mentioned previously in testimony, the complex factors that go into a car buying decision and the fact that the Company's program is removing one of a number of barriers to such adoption, make such program attribution extremely challenging to infer. For this RIM test, I am including the benefits associated with all EVs on the road in the base adoption scenario, and costs associated with all of the incentives and other costs expected to be incurred by the program. Applying the attribution concept in order to arrive at the minimum number of incremental vehicles that would have to come on to the system as a direct result of the Charge Ahead – Electric Vehicles program for the RIM test to exceed 1.0 suggests that, depending on the timing of those vehicles, between approximately 7 and 10 thousand EVs would be sufficient to produce a favorable RIM. This range is comparable to the roughly 7,500 vehicles I previously calculated that would be necessary to support the $11 million of program costs using the line extension methodology.

Q. The results of the RIM test are sensitive to the assumptions around charging behavior, particularly how much charging occurs during peak conditions that may drive the need for incremental capacity. How much would the RIM results change if the peak demand assumptions are too low and what actions is Ameren Missouri taking to promote charging in the off-peak period to ensure the greatest benefits possible accrue to all customers?

A. Recall that I assumed that 20% of EVs would be charging during system peak conditions. That estimate would have to be too low by more than 40% for the RIM calculated with the other assumptions outlined above to reach 1.0, at which point other customers are still neutral to the program.

That said, the Company believes it is unlikely that charging will be more concentrated during peak conditions than its initial assumption. Rather, it is more likely that as appropriate education, rate design options, and demand response options are rolled out, customers will be encouraged to do even more of their charging off-peak, creating even more system benefits through utilization of otherwise idle infrastructure capacity. As Mr. Justis discusses, the Company will be working to raise awareness about the benefits of EVs and that will include educating customers about the benefits of using vehicle timers to conveniently charge during off-peak hours when possible. In addition, the Unanimous Stipulation and Agreement approved in the Company's last general rate proceeding (File No. ER-2016-0179) included a commitment by the Company to make modifications in its next general rate proceeding to the Company's residential Time of Use rate offering with a goal of, among other things, encouraging off-peak vehicle charging. And it is very likely that, if and when the Company is able to make the investments necessary to upgrade its metering infrastructure to smarter meters, even more cost effective rate design and demand response options will be available to promote additional off-peak charging. These future developments, which will further encourage off-peak charging, will only serve to enhance the potential value of EVs as a means to drive efficient infrastructure utilization in the future.

VI. ECONOMICS OF THE BUSINESS SOLUTIONS PROGRAM

Q. Please give an overview of the proposed Charge Ahead - Business Solutions program.

A. The Charge Ahead - Business Solutions program has a number of similarities to the more traditional electric energy efficiency programs offered by the Company, except that it considers efficiency across a broader array of energy sources. Specifically, this program seeks to encourage adoption of electric end use measures where those measures are cost effective and displace consumption of gasoline, diesel, or propane. Mr. Pickles testifies at greater length about the numerous categories of benefits that can arise from such programs, which include significant emissions reductions and the attendant environmental benefits that go along with those. Of course, with respect to the Company's electric customers, an important benefit is the efficient utilization of the grid promoted by this program and the attendant benefits that will accrue in the form of lower rates than would otherwise exist.

The program design includes incentives paid to commercial and industrial customers who adopt such measures, including forklifts, truck stop electrification, truck refrigeration units, and airport ground support equipment. The Company is proposing prescriptive incentive levels for each measure based on primary market research performed by ICF. In his testimony, Mr. Pickles provides an overview of the research that ICF performed as a part of the potential study. It included interactions with customers and equipment vendors in Ameren Missouri's service territory in order to help the Company understand the current marketplace and develop incentive levels that are cost effective and reasonably anticipated to drive measure adoption.

Q. How would the Company administer the incentives associated with the Charge Ahead - Business Solutions program?

A. The Company expects to hire a third-party implementation contractor to market the program to customers, process incentive applications, pay the resulting awards to customers, and maintain a database of relevant program information to be used to create accounting records of the program and other reporting and analysis as needed. The third-party administration costs would be considered program costs and included in the cost recovery solution adopted for the overall program.

Q. What are the benefits to non-participating customers associated with a program designed to direct funds to specific customers?

A. Consistent with the other aspects of this filing, the benefits manifest themselves in the form of lower rates for all customers over time. This is reflected in the RIM test results. Mr. Pickles calculated the RIM test results based on primary market research that informed anticipated measure uptake, detailed analysis of end use consumption patterns, projected incremental costs, and other assumptions, as described in more detail in his testimony. The RIM associated with the program recommended by ICF and proposed by Ameren Missouri is ~~1.63~~ 1.81; meaning that every dollar spent in the program is expected to produce $~~1.63~~ 1.81 in benefits that ultimately lower rates for all customers. This benefit is possible because of the characteristics of the loads contemplated for the program, which either use power primarily during off-peak periods or with very high load factors. ICF developed detailed load shapes of each measure and

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compared them with Ameren Missouri system load characteristics in order to verify the expected benefits in the form of efficient system utilization.

Q. What other evidence of cost effectiveness did ICF evaluate as a part of its analysis of this program?

A. Again, Mr. Pickles' testimony contains more details on this topic. But the measures were tested according to the Participant Cost Test ("PCT") to verify that the program is expected to be beneficial to those customers that adopt measures, and the modified Total Resource Cost ("TRC"). The TRC is the primary cost effectiveness metric used to analyze energy efficiency programs in Missouri, as it looks at cost effectiveness in the most comprehensive way. The TRC considers all incremental costs and benefits of the program, irrespective of who they accrue to. A TRC greater than 1.0 suggests that the program is cost effective overall. In this case, the TRC has been "modified" from the traditional definition used in energy efficiency analyses, in that it has been adapted to incorporate savings associated with diesel or propane fuels that are avoided by the electrification of the subject end uses, as well as reduced maintenance costs associated with electric equipment relative to internal combustion engines. This is appropriate for such a program because its overall economic impacts include significant alternate fuel savings and maintenance savings for participating customers.

Q. What were the results of the PCT and modified TRC tests?

A. A PCT result was calculated for each individual measure and ranged from just above 1.0 for airport ground power units all the way up to ~~4.7~~ 3.1 for truck stop electrification. This suggests favorable participant outcomes that should be sufficient to drive measure adoption. Corrected

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The modified TRC test result for the overall program is ~~3.47~~ 3.39, which means that for every dollar spent on the program, ~~$3.47~~ 3.39 in benefits are expected to result, including avoided cost of diesel and propane fuels.

Q. Are there other benefits beyond the favorable economics associated with this program?

A. Yes. Like the Charge Ahead – Electric Vehicles program, the Charge Ahead - Business Solutions program will drive significant emissions reductions – including ground level emissions that in some cases are indoor emissions directly impacting workers, such as in a warehouse setting. Benefits also include reduced noise and improved productivity. Mr. Pickles testifies at greater lengths about the full suite of benefits to be derived from the Charge Ahead - Business Solutions program.

Q. Please describe the details of the proposed program.

A. As I mentioned previously, incentives offered to customers would be prescriptive, based on market intelligence gathered by ICF, at levels designed to entice participation while maintaining RIM cost effectiveness. The specific measure level incentives recommended by ICF and proposed by the Company are shown in Table 7 below:

Table 7: Business Solutions Program Proposed Incentives

Measure	Incentive per unit
Forklift – Conventional	$1,500
Forklift - Rapid Charge	$1,700
Truck Refrigeration Units	$1,600
Truck Stop Electrification	$1,200
Airport Pushbacks	$1,900
Airport Tug/Tow Tractors	$900
Airport Belt Loaders	$800
Airport GPUs	$15,600

Q. What type of reporting would the Company provide to the Commission on the results of the program?

A. Along with any request to recover program costs in the context of a rate case, the Company would provide a detailed report of the measures that were successfully promoted through the program by month and by customer class, the total incentives paid, total program marketing costs, program administration costs, the estimated incremental load added to the system as a result of the program, and the estimated RIM test associated with the program. Additional detailed records of customer participation and individual incentives awarded would be available for review on request in a rate case, also.

Q. How would additional program rules and regulations be communicated with customers, regulators, and other stakeholders?

A. When an implementation contractor is hired, specific eligibility requirements, application processes, incentive payment processes, restrictions and limitations will be developed. The Company will formally share these rules and regulations with Staff and interested stakeholders and take input on them. Final rules will be posted on a website that is accessible to customers and documented in the program tariff.

VII. COST RECOVERY FOR THE CHARGE AHEAD PROGRAM

Q. What investment levels is the Company proposing for the Charge Ahead program?

A. Ameren Missouri proposes an approximately five-year term for each sub-program, beginning upon approval of the program by the Commission and extending through 2023, with budget caps of $11 million and $7 million for the Electric Vehicles and Business Solutions programs, respectively. The rationale for the magnitude of the Electric Vehicles program budget is grounded in the discussion in Section V of my testimony above, where I explained that, depending on the Electric Vehicle adoption, $11 million is approximately the amount that likely could be spent on EV charging infrastructure before it would offset the benefits likely to be provided by expected vehicle charging revenues given the lowest and least likely adoption scenarios. The $11 million would also leave significant margin from EVs to drive rates down under the majority of, and highest probability, scenarios. It is useful to think of the $11 million proposal as an attempt to re-invest some of the margins that will be derived from the charging load of Ameren Missouri customers who own EV's in a manner that is intended to: (1) provide infrastructure that specifically benefits the EV owners who are paying for their creation and (2) demonstrate the type of supportive policies that will reduce barriers and accelerate the mainstream adoption of EVs in a manner that grows beneficial EV charging load, which will magnify the RIM benefits that will occur. It is also important to observe that the Company's proposal, under the overwhelming majority of adoption scenarios anticipated, leaves considerable RIM value (in the highest case, up to $60 million of additional investment could be contemplated and fully supported by EV margins) to provide downward pressure on all customers' rates. It is possible that some of this value created by charging revenues may also be used over time in order to offer EV owners rate design (e.g., TOU) or demand response incentives to charge off-peak. Incidentally, the $11 million figure proposed by the Company for the Electric Vehicles charging program is also in line with the size of similar programs that have been approved for and/or proposed by utilities in Utah and Ohio, which I will discuss further below. A Massachusetts utility has a pending proposal to spend almost two and a half times that amount on charging infrastructure.

The $7 million budget for the Business Solutions program is based on the cost-effective and achievable potential for the measures selected for the program as identified by ICF through its primary market research and analysis.

Q. Should the cost of the programs be recovered from customers in rates?

A. Yes. Recall the significant benefits to all customers that these programs are expected to create through their favorable RIM test results. These results suggest that approval of programs with costs recovered in rates will create significantly more value in terms of future rate reductions arising from efficient utilization of the grid than the costs that would be borne by customers. Further, as previously discussed, there are a number of other non-financial benefits that make these programs in the public interest, including significant emissions reductions and the attendant environmental benefits. Additionally, these programs provide a supportive framework for creating an atmosphere where any and all of Ameren Missouri's customers can access the valuable benefits of electric vehicle transportation, of which they otherwise may not feel comfortable availing themselves.

Further, it is noteworthy that utilities, Commissions, and a broad array of utility stakeholders across the country have begun recognizing exactly what I have discussed in this testimony – that it is in the public interest to provide these types of incentives with cost recovery occurring in customer rates. Mr. Justis mentions in his testimony a number of utility programs designed to promote EV charging that have been proposed or approved in other jurisdictions. While California and its utilities have led in this space due to aggressive EV targets included in state policy, we are now seeing programs proposed or approved in states like Ohio, Utah, and Massachusetts as well. The specifics of the programs in these three states in particular are quite similar to the proposal Ameren Missouri is making in this filing. The utilities involved in the programs I am referencing – AEP Ohio, Rocky Mountain Power, and National Grid – all have programs premised on utilities providing incentives to third parties to develop independently owned and operated EV charging services. The Rocky Mountain Power program has already been approved. The AEP Ohio program is pending Commission approval after being supported by a stipulation and agreement endorsed by a broad coalition of stakeholders, and the National Grid proposal is in line with articulated state policy goals of Massachusetts and would therefore appear likely to get considerable traction.

Q. How are the cost recovery mechanisms designed for the programs you mentioned above?

A. Rocky Mountain Power in Utah is approved to provide $10 million in EV charging incentives over five years. Two million dollars per year will be added to customer rates through a simple percentage markup to all customer classes' bills to achieve recovery of the targeted incentives.

The stipulation and agreement entered into by AEP Ohio and a wide variety of stakeholders allows that utility to recover the $10 million in costs proposed as a part of that program through its "Smart Cities Rider." Costs recovered include the incentives paid to third parties along with a 5% adder to contribute to recovery of the utility's costs of administering the program.

National Grid has also proposed recovery of the $24 million costs of its program in near real time through an adjustable rider mechanism. It also proposes that the company be eligible for a $1.25 million earnings incentive for successful achievement of program goals.

Q. What mechanism do you propose to achieve cost recovery of the program incentives and associated costs for Ameren Missouri?

A. The cost recovery models of the programs I mentioned just above are all premised upon the ability of utilities and the Commissions that regulate them to adjust rates outside of rate cases for programs like this. I am advised by counsel that such a mechanism is likely not allowed in Missouri due to the prohibition against single-issue ratemaking. Therefore, the Company proposes to defer program incentives and certain associated administrative costs to a regulatory asset, and is seeking from the Commission an order granting the authority to make the regulatory deferral accounting entries necessary to do so. An amortization of the costs deferred to the regulatory asset would be included in revenue requirement in subsequent rate cases. While this proposal is born somewhat out of necessity due to the inability to change rates outside of a rate case, I believe that there are some unique customer advantages of this mechanism that I will discuss later.

Q. Since the Company will be deferring the dollars it spends and will have to finance those deferred sums until the amortization occurs, will the unamortized balance of the regulatory asset be included in rate base in future rate cases where the amortization expense is reflected in revenue requirement to assure a "return on" the funds deployed?

A. That is not the Company's proposal. Rather, the Company proposes to finance its investment through the regulatory lag associated with the revenue growth that these programs are expected to generate. These programs will result in relative increases in load (versus what would otherwise exist, but not necessarily overall load growth) between rate proceedings that will generate positive regulatory lag to the benefit of the Company. As a result of this lag, the

Company will effectively earn a return on the investments it makes without ever having to include the deferred sums in rate base.

Q. Please elaborate on the Company's proposal for financing the investments it makes in Charge Ahead incentives.

A. The Company believes that it is fair to use the favorable regulatory lag arising from this program to offset costs – the real financing costs the Company will incur to defer the incentives of the Charge Ahead program – that customers would otherwise be experiencing in rates when the unamortized balance is included in rate base. In this manner, the regulatory lag impacts are effectively returned to customers (by offsetting financing costs they would otherwise bear) to keep all parties neutral to the regulatory lag impacts of the program.

The Company has modeled the expected impacts of the regulatory lag revenues associated with the Charge Ahead programs and incorporated them up front into the cost recovery framework proposed for these programs. As I previously alluded to, the Company proposes that the program be structured such that the expected value of the benefits of regulatory lag associated with the revenue growth derived from the programs make the Company whole for the financing costs associated with the deferral of the program costs to a regulatory asset.

Q. How does the Company's proposed use of regulatory lag to finance the regulatory asset provide additional benefits to the programs?

A. Because the Company's recovery of financing costs associated with the regulatory asset will be tied to its ability to create benefits that will ultimately be shared amongst all customers once rates are reset, the incentives of the Company are aligned with its customers' interest to maximize the value of those benefits. The Company will have an inherent incentive to pursue the most new electric load possible for a given level of out-of-pocket costs of the incentives offered. If the Company fails to move customers to take actions they otherwise would not have taken in the amounts the program is designed to achieve, the Company will also fail to earn a return on the unamortized balance of the regulatory asset generated by Charge Ahead incentive deferrals.

Q. How have you estimated the impacts of regulatory lag associated with the programs?

A. The Company has modeled the regulatory lag using the margin rates contained in Rider EEIC (which were developed for a similar purpose, i.e. determining the regulatory lag revenue impact of energy efficiency programs), estimates of new load associated with the programs over time, and assumptions of rate case frequency and magnitude to determine the benefits the Company is likely to realize from regulatory lag associated with these programs. The modeling assumes rate cases filed every 2 years resulting in 4% increases in margin rate. Both assumptions are quite reasonable given actual recent historical rate case experience. The load additions that create the regulatory lag revenues related to the Business Solutions program are a direct output of the modeling performed by ICF for the potential study as discussed by Mr. Pickles. For the Electric Vehicles program, we assume the revenue growth is equal to the load that would be expected to be served through, or in the case of multi-family, directly enabled by, the charging stations incented by the program. The Company assumes a one-for-one charger to vehicle ratio for every level 2 charger promoted by the program, and a 5% utilization of corridor charging sites.[15] The estimated incremental sales volumes subject to regulatory lag for the two programs are shown in Table 8 below:

Table 8: Incremental Load from Charge Ahead Programs (MWh)

	2019	2020	2021	2022	2023 and Beyond
EV Charging Program	887	1,425	1,227	1,554	6,953
Electrification Program	2,995	5,999	8,759	11,737	11,737
Total	3,882	7,424	9,986	13,291	18,690

The regulatory lag margins associated with the volumes shown in Table 8 are shown in Table 9 below:[16]

Table 9: Incremental Margin from Charge Ahead Programs ($Thousands)

Program	NPV	2019	2020	2021	2022	2023	2024	2025	2026	2027 and Beyond
EV Charging	$1,424	$37	$122	$163	$263	$223	$252	$177	$213	$647
Electrification	$3,819	$91	$335	$601	$1,201	$1163	$1,186	$398	$48	$15
Total	$5,243	$128	$457	$765	$1,465	$1,385	$1,437	$575	$261	$662

As Table 9 shows, the net present value of the regulatory lag revenues associated with the Charge Ahead program using the Company's weighted average cost of capital of 6.18% is $5.2 million.

[15] The majority of the level 2 charger incentives in the Company's proposal are for multi-family residential settings. The Company would expect a charger at such a premises to be dedicated to a specific resident and serve one vehicle at a time, but that over time multiple tenants may utilize the same parking spot with the former tenant carrying that vehicle on to another location. As such we estimate that 3 EVs may be enabled over time by a single multi-family charger. Those future multi-family EV additions result in additional incremental revenue being attributed to the program beyond the program term. Workplace chargers would be likely to be dedicated to a single car parked in that spot throughout the work day, so we assume each charger will serve the load equivalent of one additional car. Other public level 2 charging, for which utilization data is not available, we assume will be utilized in similar amounts to the workplace charging utilization just discussed for this purpose. The 5% utilization of charging corridor facilities is based on conversations that Mr. Justis describes in his testimony with a number of entities in the charging business pursuant to a Request for Information ("RFI") issued by the Company.

[16] Despite the fact that the program is only proposed to run five years which would take it from 2019 through 2023, the revenue impacts extend beyond that because of the multi-family load additions discussed in footnote 15 and also because the revenue impacts that are the subject of this modeling are an artifact of regulatory lag, which would continue until there was a rate case test year that reflected all of the load associated with the program. This is why regulatory lag impacts are shown beyond the nominal end of the program term.

Q. Please explain how this estimate of the positive regulatory lag associated with the program works with the amortization of program costs to provide an appropriate and balanced overall cost recovery solution for the Charge Ahead program.

A. Recall that the Company proposes to defer the incentives and certain program administrative costs to a regulatory asset for recovery in a subsequent rate case. The Company will incur financing costs until such time that the regulatory asset is amortized in rates. I have conducted an analysis to determine the length of time that the Company could finance the projected regulatory asset given the margins that will be created by the effect of regulatory lag on the Company's revenues, given the assumptions reflected in the analysis presented above. The longer the amortization period, the more financing costs will be incurred, but also the less immediate rate impact will be felt by customers. The Company's 6.18% after-tax weighted average cost of capital, which is consistent with the after tax cost of capital that would be earned if the regulatory asset was included in rate base and also with the discount factors used to calculate Present Value of Revenue Requirements in the Company's IRP,[17] serves as a "hurdle rate" for it to make an investment like that represented by this program. If a given amortization period for the regulatory asset coupled with the effects of regulatory lag on margins result in an internal rate of return for the project that meets or exceeds the hurdle rate, it is an investment that the Company should desire to make on behalf of shareholders. Given the RIM benefits of both programs and assuming the internal rate of return earned by the Company on the investment is not excessive, customers should also look favorably on the Company undertaking the program. Table 10 below shows the result of a financial analysis of the program based on a seven year amortization of program costs in rates. The Company proposes that this amortization period,

[17] This after-tax cost of capital is updated to reflect the effect of Federal tax reform, since the financial analysis is forward looking and the tax impacts that result from the program will be incurred at the new Federal rates.

coupled with the arrangements already discussed regarding the margin from regulatory lag, would represent a cost recovery solution that fairly balances customer and Company interests.

Table 10: Charge Ahead Program Financial Analysis

($ in Millions)	2019	2020	2021	2022	2023	2024	2025	2026
Program Budget (Incentives + Admin)	$4.4	$4.2	$3.1	$3.4	$2.8	$0.0	$0.0	$0.0
Regulatory Asset Balance	$4.4	$8.6	$10.9	$13.1	$14.0	$11.9	$9.4	$6.9
Amortization Expense	$0.0	$0.0	$0.8	$1.2	$1.8	$2.2	$2.4	$2.6
Program Revenues (Base Rate Recovery)	$0.0	$0.0	$0.8	$1.2	$1.8	$2.2	$2.4	$2.6
Regulatory Lag Margin Estimate	$0.1	$0.5	$0.8	$1.5	$1.4	$1.4	$0.6	$0.3
Pre-Tax Earnings	$0.1	$0.5	$0.8	$1.5	$1.4	$1.4	$0.6	$0.3
Income Taxes	$0.0	$0.1	$0.2	$0.4	$0.4	$0.4	$0.1	$0.1
Net Income	$0.1	$0.3	$0.6	$1.1	$1.0	$1.1	$0.4	$0.2
Net Cash Flow	($4.4)	($3.8)	($1.7)	($1.1)	$0.1	$3.2	$2.8	$2.7

	2027	2028	2029	2030	2031	2032	2033
Program Budget (Incentives + Admin)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Regulatory Asset Balance	$4.3	$2.6	$1.3	$0.5	$0.1	($0.0)	($0.0)
Amortization Expense	$2.6	$1.8	$1.3	$0.7	$0.4	$0.1	$0.0
Program Revenues (Base Rate Recovery)	$2.6	$1.8	$1.3	$0.7	$0.4	$0.1	$0.0
Regulatory Lag Margin Estimate	$0.2	$0.2	$0.1	$0.1	$0.0	$0.0	$0.0
Pre-Tax Earnings	$0.2	$0.2	$0.1	$0.1	$0.0	$0.0	$0.0
Income Taxes	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0
Net Income	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0
Net Cash Flow	$2.7	$1.9	$1.4	$0.8	$0.4	$0.1	$0.0

Net Present Value	$0.1
Internal Rate of Return	6.37%
After-Tax Weighted Average Cost of Capital (Hurdle)	6.18%

Q. Please explain Table 10.

A. The first line of Table 10 shows the program costs (i.e. incentives for both sub-programs, third party administrative costs for the Business Solutions program, and marketing and related costs for the Electric Vehicles program) that would be incurred to run the program. We have assumed a spending pattern across the five years of the program. The higher level of program expenses in the first two years relative to the last three are a result of front loading the incentives associated with the corridor charging program. As explained in Mr. Justis' testimony, this program would include a Request for Proposals ("RFP") to construct corridor charging sites. Once that competitive bidding process is complete, it is expected that the corridor sites would be built and incentives paid early in the program in order to get the minimum practical network of long distance charging in place as soon as possible to remove this market barrier to vehicle adoption.

The next line in Table 10 is the regulatory asset balance, which grows as program costs accumulate, and diminishes after assumed rate cases conclude and amortization of the balance takes place. This line can be derived by looking at the program cost line above and the amortization expense line below it.

The third line is the amortization expense. Again, as soon as a rate case is assumed to conclude, one-seventh of the then-current regulatory asset is reflected in the amortization expense until it is either reset again in a rate case due to its reflection of more expenses that have accumulated, or it is fully amortized.

The next line shows program revenues recovered from all customers in base rates. It is exactly equal to the line above (amortization expense) because recovery of program costs through amortization is the only direct impact of the program on rates.[18] These two lines (Amortization Expense and Program Revenues (Rate Recovery)) offset each other to show that the program revenues and costs are equal and have no impact on the Company's earnings.

The next line, Regulatory Lag Margin Estimate, is the output of the earlier modeling I described to quantify the impact of that effect on the Company's earnings, which you will recall is the means the Company is using to finance the regulatory asset over time.

The following line summarizes the effects of the costs and revenues above into a pre-tax earnings value that would be realized by the Company. Notice that it is exactly equal to the regulatory lag revenue margin estimate, because program costs and revenues perfectly offset and the Company is left with the benefits of the regulatory lag margins as pre-tax earnings to offset its cost of capital. The next two lines just show the income tax expense that is expected and the after-tax net income resulting from the program.

The final line, labeled Net Cash Flow, is the key for evaluating the internal rate of return of the program relative to the hurdle rate for investment, the company's cost of capital. The net cash flow line sums the program costs from the first line (because the Company would spend the cash as the incentives are paid and start financing them) and income tax expense, because that is the only other negative cash flow generated by the program, and nets these values against the sum of the program revenue (rate recovery) and the regulatory lag margins, because these items will provide the positive cash flow to the Company to recover the program costs and the cost of capital. From this Net Cash Flow, the internal rate of return ("IRR") of the program can be calculated, which is the ultimate determinant of whether the cost recovery solution is reasonably balanced. Using this model, I evaluated different scenarios for the amortization period of

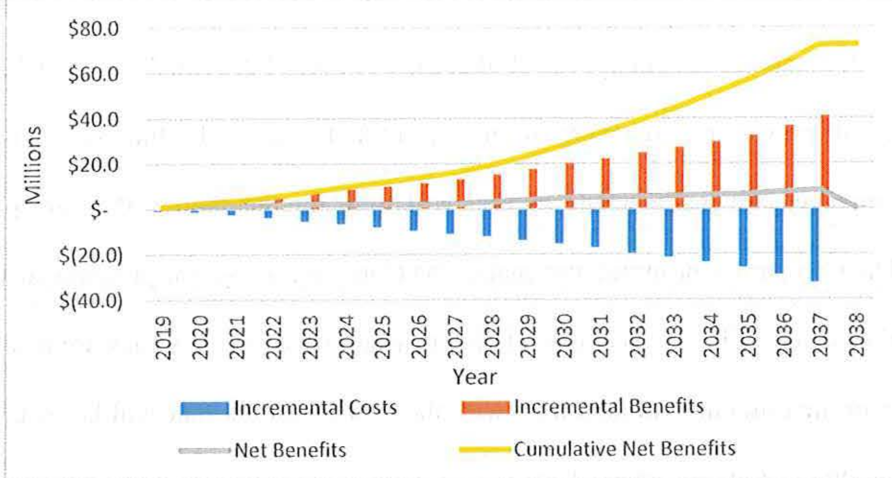
[18] I am characterizing the RIM benefits and incremental energy and capacity expense as indirect impacts for this purpose.

program costs, and the seven year amortization was the shortest amortization period where the IRR achieved the hurdle rate. This can be interpreted to mean that shorter amortization periods would fail to produce a situation where the Company was able to fully recover its cost of capital associated with financing the program, and longer amortization periods would unnecessarily increase customer costs to achieve a higher rate of return than the Company needs in order to agree to expend its limited capital on the program.

Q. Earlier you mentioned that, although this amortization solution was developed out of necessity because of the lack of access to a rider, the solution has other benefits to customers. Please explain that comment further now that the financial impacts of the program have been estimated and explained.

A. The RIM test results discussed earlier verify that the Net Present Value of rates is expected to be lower with the program than without, but recovery of all program costs immediately through a rider or similar mechanism would have caused an initial increase in rates to all customers, which would produce lower rates associated with the efficient electrification impacts over time. That's not to say that a program structured as such would not ultimately be in those customers' interests, but the fact that the program cost recovery is deferred under the Company's proposal until such time that the rate benefits provided by the added load are being realized is a nice feature that tends to sync up the costs and benefits and provide a smoother pattern of rate impacts to customers. Figure 4 below graphically depicts the expected rate impacts over time, including both the direct impacts of the program (i.e. cost recovery) and the indirect impacts (i.e. full RIM costs and benefits including incremental energy and capacity as well as the effects of the retail margin of new load that spreads fixed costs over more usage and results in lower unit costs).

Figure 4: Charge Ahead Rate Impacts by Year



Notice in Figure 4 that the expected benefits associated with Electric Vehicle loads and the Business Solutions measures exceed the expected program costs (direct costs as well as incremental supply expense) in every single year of the program, from inception through the end of the amortization of program costs. Also, the trajectory of the net impacts is very smooth. From year to year, favorable rate impacts build gradually and smoothly. If program cost recovery were not deferred, there would be more variability in the annual pattern of rate impacts, likely including some years early in the program with higher rates as a result. Again, that would not mean the program, if it were structured as such, was not a good thing in the long run for customers. It just demonstrates how the structure of the Company's proposal enhances the net benefit stream by pushing cost recovery out of the early years in a manner that syncs those costs and benefits up very effectively. Figure 4 also illustrates another powerful point, which is that the overall nominal net benefit associated with EV and Electrification loads exceeds $70 million cumulatively over time.

Q. How does this cost recovery solution compare with some of those you described that have been adopted or proposed for utility programs in other jurisdictions?

A. It compares favorably. Recall that the examples I provided from, Utah, Ohio, and Massachusetts all provide rate recovery of program costs through rider-like mechanisms so that the utilities involved are made whole in near real time for the money they are putting into incentives. The Company's proposal also makes the Company whole for program costs it incurs, but fairly balances the delay in recovery relative to what these other utilities are able to realize, with a return on investment commensurate with the cost of capital that will be incurred, which these other utilities will not incur because they are not financing program costs for any appreciable period of time. Recall also that National Grid in Massachusetts proposed to earn an incentive on top of its near real time cost recovery, and AEP Ohio is potentially getting a 5% premium to the direct costs of incentives to cover program administration, but which may contribute to the utility earning if the program is run more efficiently than that. I would also point out that in California, utilities are including the costs of EV charging infrastructure in rate base and earning on it that way.

So while many jurisdictions allow near real time cost recovery, it is still relatively common for utilities to have the potential to generate earnings from these types of programs. The fact that the earnings the Company would recognize are: 1) funded by regulatory lag of benefits that will ultimately accrue to all customers, aligning the incentives of the Company with its customers; and 2) fairly compensate the Company for financing costs it will incur while deferring the impact of program costs on customer rates, makes the Company's proposal to earn on its program compare favorably to these other solutions.

VIII. SUMMARY AND CONCLUSIONS

Q. Please provide a recap of the benefits of the portfolio of proposals included in the filing and on the significant effort the Company put into structuring the program in a manner that fairly balances the interests of customers and the Company.

A. Recall that each proposal – the revised line extension policy, the Charge Ahead – Electric Vehicles program, and the Charge Ahead - Business Solutions program – has the effect of promoting cost effective new loads on the system that are expected to improve the efficiency with which the grid is utilized, ultimately reducing the unit costs of such infrastructure. This can have a powerful effect on rates, keeping them as low as possible given the fixed costs that the Company must have an opportunity to recover. But beyond these benefits, there is the added fact that the proposals are good for the environment due to materially reduced emissions from internal combustion of fossil fuels, good for customers in that they provide increased choice, productivity, and local air quality, and generally in the public interest because they provide a missing piece to the puzzle that will enable transformations otherwise gaining momentum. The Company has made thoughtful and innovative recommendations in how the proposals and cost recovery of them are structured to align incentives of customers and the Company, minimize upfront rate impacts of the costs, and comprehensively address a broad suite of issues that can positively impact customers. The Company believes this is a well-balanced proposal that is clearly in the public interest and reasonably calculated to significantly advance forward-thinking energy policies in the state of Missouri.

Q. How is this a forward thinking initiative that would advance energy policy in Missouri?

A. Recall my discussion earlier of the ongoing Emerging Issues Workshop (File No. EW-2017-0245), and that this docket represents the interest of the Staff and Commission in addressing the emergence of significant changes in the industry that are fundamentally changing the way utilities operate and impacting their business models. This program addresses one of the key questions in that workshop head on – the Commission's role in ensuring a competitive marketplace for EVs – in a manner that allows the utility to perform its traditional role – i.e. participate in developing needed infrastructure for the benefit of customers – while stimulating, rather than stifling, the competitive landscape for charging services provided by third parties. Further, the emissions reductions that will result from electrification address the central struggle that really underlies much of the innovation that is driving the transformation of utilities – how to cost effectively reduce the impact of the energy system on the environment. Finally, loads like vehicle charging and off-peak or high load factor commercial and industrial applications are the types of flexible loads that may significantly help integrate Distributed Energy Resources over time – another key theme of the Emerging Issues Workshop.

Q. Considering all of these factors, what is your recommendation to the Commission?

A. The Company's program is innovative, forward-thinking, and in customers' and the general public interest for all of the reasons just discussed. The programs and associated cost recovery are fairly balanced between customers and the Company and thoughtfully crafted to enhance the value created by the program. I recommend that the Commission recognize that the significant benefits of the programs make their implementation in the public interest, and that the details of the Company's proposal are appropriate, by approving the tariff sheets included in this filing to take effect on a timely basis so that the customers of Ameren Missouri and the state of

Missouri can begin realizing the benefits of the Charge Ahead program and of the distribution line extension policy changes that the Company is proposing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program.	))))	File No. ET-2018-0132

AFFIDAVIT OF STEVEN M. WILLS

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

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

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as the Director of Rates & Analysis.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 57 pages and Schedule(s) N/A, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Steven M. Wills
STEVEN M. WILLS

Subscribed and sworn to before me this 21st day of February, 2018.

Cathleen A. Dehne
Notary Public

My commission expires
March 7, 2021

CATHLEEN A DEHNE
Notary Public – Notary Seal
St. Louis City – State of Missouri
Commission Number 17119727
My Commission Expires Mar 7, 2021