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Renewable Solutions  
Program Update, and  
Wildfire Mitigation  
Costs Tracker  
Witness: Steven M. Wills  
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**MISSOURI PUBLIC SERVICE COMMISSION**

**FILE NO. ER-2026-0291**

**DIRECT TESTIMONY**

**OF**

**STEVEN M. WILLS**

**ON**

**BEHALF OF**

**UNION ELECTRIC COMPANY**

**D/B/A AMEREN MISSOURI**

**St. Louis, Missouri  
June, 2026**

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**DIRECT TESTIMONY**

**OF**

**STEVEN M. WILLS**

**FILE NO. ER-2026-0291**

**I. INTRODUCTION**

1

2 **Q. Please state your name and business address.**

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

6 **Q. What is your position with Ameren Missouri?**

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

8 **Q. Please describe your educational background and employment**  
9 **experience.**

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



1           A.     The primary purpose of my Direct Testimony is to provide a detailed  
2 assessment of the impact of large loads on the revenue requirement in this case, and otherwise  
3 address large load issues including an evaluation of Senate Bill 4's ("SB 4") requirement that  
4 large load customers' "rates will reflect the customers' representative share of the costs incurred  
5 to serve the customers and prevent other customer classes' rates from reflecting any unjust or  
6 unreasonable costs arising from service to such customers"<sup>2</sup>.

7           I also:

- 8           A.     Provide updates on tariff changes related to large load customers coming onto  
9                   our system;
- 10          B.     Provide an update on the Renewable Solutions Program;
- 11          C.     Request to discontinue an old credit reporting requirement from File No. ET-  
12               2014-0076 that is no longer experimental;
- 13          D.     Address a local public hearing notice commitment made in File No. ER-2024-  
14               0319;
- 15          E.     Request a tracker for wildfire mitigation costs to comply with the Wildfire  
16               Mitigation Plan required by the Commission in File No. OW-2025-0314; and
- 17          F.     Address stipulation commitments arising from File No. EA-2023-0386 for three  
18               new energy centers that will be reflected in rate base in this case.

19          **Q.     What are your key conclusions related to the impact of large load**  
20 **customers on the rates the Company is proposing to establish in this case?**

21          A.     The rates proposed in this case are *millions of dollars* lower than they otherwise  
22 would have been as a result of the Electric Service Agreements ("ESAs") that the Company has

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<sup>2</sup> RSMo 393.130.7

1 entered into to provide permanent service to large load customers starting in 2027. Existing  
2 customers will benefit from these large loads in the form of lower rates set in this case even  
3 before the large load customers actually initiate service on the system. This means that under  
4 proposed rates in this case, the requirements of SB 4 will be met. See Table 1, below, (which I  
5 will discuss in greater detail later in my testimony), that demonstrates that over the two years  
6 following the effective date of new rates in this case, non-large load rates will be lower than  
7 they otherwise would have been by more than approximately \$21 million.

8 **Table 1 – Impact of Large Loads ("LL") (\$Millions)<sup>3</sup>**

	Total	Res	SGS	LGS	SPS	LPS	Lighting
Revenue Requirement Increase Excluding LL Impacts	\$353.5	\$322.9	\$20.2	\$8.4	-\$7.4	-\$9.1	\$18.5
LL Costs in Revenue Requirement (+)	\$2.8	\$1.6	\$0.3	\$0.4	\$0.2	\$0.2	\$0.1
LL Revenues Offsetting Revenue Requirement (-)	\$13.4	\$6.8	\$1.5	\$2.7	\$1.1	\$1.1	\$0.2
Revenue Requirement Increase Including LL Impacts	\$342.9	\$317.7	\$19.0	\$6.1	-\$8.3	-\$10.0	\$18.4
<b>Net Impact of LL Customers on Rev. Requirement</b>	<b>-\$10.6</b>	<b>-\$5.2</b>	<b>-\$1.2</b>	<b>-\$2.2</b>	<b>-\$0.9</b>	<b>-\$0.9</b>	<b>-\$0.1</b>
<b>Base Rate Bill Impact Over 2-Years</b>	<b>-\$21.2</b>	<b>-\$10.4</b>	<b>-\$2.5</b>	<b>-\$4.5</b>	<b>-\$1.8</b>	<b>-\$1.8</b>	<b>-\$0.3</b>

9

10 **III. OVERVIEW OF THE LARGE LOAD LANDSCAPE**

11 **Q. Please provide a contextual overview of the large load landscape in**  
12 **Missouri and of the industry generally.**

13 A. As anyone following the utility industry is aware, the emergence of what is  
14 generally being referred to as large load customers – customers whose electric usage is orders  
15 of magnitude larger than almost all existing or historic customers on the system – has been  
16 reverberating throughout the industry and even society. Largely the result of massive growth of  
17 data centers that are providing artificial intelligence ("AI"), cloud computing, or other advanced

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<sup>3</sup> Class allocations based on the Class Cost of Service Study performed by Company witness Thomas Hickman. Actual class allocations of rate increase as proposed are sponsored by Company witness Nick Bowden. Total large load revenue requirement impact is the same irrespective of class allocation. Also, totals in the bottom line of this table may vary from the result implied in the line above it due to rounding.

1 data services, the industry is seeing electric demand growth of an historic scale. To put the  
2 growth in context, while the Company's load has been relatively flat for a couple of decades, in  
3 just the next five years we expect to see growth in annual electricity sales of over 60%! By the  
4 end of 2029, these new end users are expected to consume more than half as much electricity  
5 as the rest of the customers in the Company's service territory that covers most of Eastern  
6 Missouri.

7 Growth at this scale, and the significant economic benefits that arise from such massive  
8 investments in local communities, is causing the industry to invest in new or accelerated sources  
9 of power generation to meet the growing demand. The Company is no exception to this trend.  
10 Even the mainstream media is increasingly covering the "data center" topic and opinions are  
11 widespread that the potential exists for this growth, and the power system investment needed to  
12 support it, to drive up electric costs for all customers. I emphasize that these opinions are just  
13 that; opinions, and that while the potential exists for this growth to drive up electric costs for all  
14 customers, that does not mean that this potential reflects the reality of what will actually occur.

15 Many states – with Missouri as one of the leaders on this front – have passed or  
16 contemplated legislation to address this phenomenon. Indeed, in early 2025, the Missouri  
17 General Assembly proactively passed, and the governor signed, SB 4, which included  
18 provisions requiring electric utilities like Ameren Missouri to adopt tariffs to address the  
19 emerging demand to ensure that large load customers, inclusive of data centers, pay their  
20 representative share of the costs incurred to serve them and also prevent other customer classes'  
21 rates from reflecting any unjust or unreasonable costs arising from their service.

1           In short order, both Ameren Missouri<sup>4</sup> and Evergy's Missouri<sup>5</sup> operating companies  
2 filed large load tariff frameworks. And by the end of 2025, the Commission had approved  
3 similar frameworks, thoughtfully designed to meet SB 4's requirements (via tariff terms and the  
4 Commission's ongoing oversight and ability to allocate costs) so that the potential I referenced  
5 earlier will not be the reality, all while still positioning Missouri to attract the significant  
6 economic benefits of large loads, for the two largest electric utilities in the state. As a result of  
7 the large load additions and the protections reflected in SB 4, the Company's customers will  
8 experience approximately \$21 million in lower base rate bills over the next two years.

9           **Q.     Please provide an overview of the Company's large load tariff framework.**

10          A.     The large load tariff approved by the Commission for the Company contains  
11 the rates and other terms and conditions that apply to large load customers that seek service in  
12 Ameren Missouri's service territory. The tariff requires a significant contractual commitment  
13 from prospective customers in order to provide the certainty needed to make large investments  
14 in new or accelerated generation. This commitment ensures that a financially responsible  
15 customer will be there to pay for the costs associated with the investments, preventing the costs  
16 of that investment from being shifted to existing customers. In order to initiate service, a large  
17 load customer, defined as a customer with an expected demand greater than 75 Megawatts  
18 ("MW") served at transmission voltage (greater than 115 kilovolts), must enter into an ESA that  
19 includes the following minimum commitments:

- 20                 • An initial rate that is higher than other large industrial customers in the  
21                     Company's service territory currently pay, which is subject to update by the  
22                     Commission in all future rate cases to ensure it covers the cost of service;

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<sup>4</sup> File No. ET-2025-0184.

<sup>5</sup> Evergy Metro and Evergy West's large load tariff case was assigned File No. EO-2025-0154.

- 1           • A long-term commitment in the form of a contract term of at least 12 years, and  
2           up to 17 years when including an optional up to 5-year ramp period;
- 3           • A commitment to pay demand charges for 80% of the requested demand  
4           *whether the customer uses any power or not*, for the term of the agreement;
- 5           • Credit and collateral provisions ensuring financial responsibility upfront for up  
6           to two years of minimum bills;
- 7           • Significant termination fees of 5 years (or more under certain circumstances) of  
8           minimum bills if the customer seeks to exit its contractual commitment early;  
9           and
- 10          • Payment of additional charges to cover the full cost of incremental market  
11          capacity purchases where the customer desires to initiate service before the  
12          Company can bring new generation online to cover the demand and instead  
13          purchases capacity for the customer from a third party or the market.

14          Additionally, the Commission also approved the following four voluntary riders that  
15          large load customers may participate in to support their clean energy ambitions, and which  
16          generate additional revenue to offset the general revenue requirement for the benefit of all  
17          customers:

- 18          • Rider RSP-LLC (Renewable Solutions Program – Large Load Customers),  
19          which allows customers to financially support new renewable generation and  
20          receive the renewable attributes associated with the energy centers that they  
21          support;

- 1           • Rider CCAP (Clean Capacity Advancement Program), which allows customers  
2           to financially support new battery energy storage investments, which can help  
3           to reliably integrate renewable energy onto the system;
- 4           • Rider NEC (Nuclear Energy Credit), which allows customers to purchase  
5           carbon free energy attributes from the Company's existing Callaway Energy  
6           Center; and
- 7           • Rider CEC (Clean Energy Choice), which allows customers to partner with the  
8           Company to pay for more customized or innovative changes to the Company's  
9           generation mix in exchange for clean energy attributes from the new resources  
10          supported by the program.

11          **Q.     Have any large load customers applied for service under the large load**  
12          **tariff framework?**

13          A.     Yes. As of the filing of this testimony, the Company has executed ESAs to serve  
14          over 2.8 Gigawatts ("GW") of large load customer demand by the end of 2029. No customers  
15          that make up that total have initiated service at this time, but demand is expected to begin  
16          materializing in 2027 and ramp up over the next few years.

17          **IV.    LARGE LOAD CUSTOMERS ARE REDUCING RATES FOR ALL**  
18          **OTHER CUSTOMERS IN THIS FILING**

19          **Q.     Do the rates proposed in this case for Service Classification 14(M)<sup>6</sup>**  
20          **(the large load class) meet the requirements of SB 4?**

21          A.     Yes, and then some. As I stated in my introductory comments, proposed  
22          rates for all other customer classes are millions of dollars lower than they would have been

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<sup>6</sup> Consistent with the Commission's order in File No. ET-2025-0184, the large load customer provisions of existing Service Classification 11(M) will become a standalone rate class, labelled Service Classification 14(M), when new rates from the case take effect.

1 without the above-referenced ESAs. Other customers' base rate bills are expected to be  
2 approximately \$21 million lower over the next two years as a result of the large load class.

3 **Q. How have you assessed whether large loads are paying their**  
4 **representative share based on the terms and conditions of the large load tariff and**  
5 **proposed rates in this case?**

6 A. They are paying their representative share based upon either of the two  
7 common ways to measure the cost of serving a customer or customer class like large load  
8 customers: based either on the results of an embedded cost of service study or based upon  
9 the results of an incremental cost of service study. I think the spirit of SB 4 calls for an  
10 incremental view – i.e., if the incremental revenues paid by large load customers do not  
11 cover the incremental costs that are caused by large load customers, everyone else's rates  
12 will go up. If they do cover their incremental costs with incremental revenues, everyone  
13 else's rates will be the same or lower than they otherwise would be. I think it's pretty self-  
14 evident that SB 4 was passed looking at the issue through this lens – will other customers'  
15 rates be impacted by (go up or down as a result of) large load customers? And therefore an  
16 incremental view is by far the most relevant to assessing compliance with SB 4 and the  
17 impacts on existing customers.

18 That said, under either an embedded cost view or incremental cost view, large load  
19 rates that will be set in this case are sufficient to cover the cost the utility will incur to serve  
20 them once they come onto the system, meaning large load customers are not being  
21 subsidized by other customers, which in the end is the obvious purpose of SB 4. Since  
22 embedded cost of service is foundational to the process necessary to develop utility rates

1 that recover the embedded revenue requirement and the Company sponsors such a study  
2 (in the testimony of witness Thomas Hickman), I will at least touch on both perspectives.

3 **Q. What insight does the Company's embedded cost of service study,**  
4 **sponsored by witness Hickman, provide about large load rates?**

5 A. Mr. Hickman's embedded class cost of service study that we have used to  
6 propose the rates in this case demonstrates that large load rates easily cover the embedded  
7 cost of serving customers like large loads. I say customers "like" large loads deliberately.  
8 Since there is no large load demand or energy – the factors on which the revenue  
9 requirement is allocated - present in the historical test year used to develop this case, the  
10 large load class simply could not be included in the embedded class cost of service study  
11 to measure its embedded cost of service. If there is no presence of large load demand or  
12 energy consumption in the test year, there is no way to allocate historical test year costs to  
13 them, etc. However, we can prove that had there been large load customer costs or revenues  
14 present in this case at the revenue requirement level that has actually been requested, the  
15 large load rate class rates they would pay easily cover the embedded cost of serving them.

16 **Q. How can you prove that to be the case?**

17 A. There *is* a class present in the class cost of service study that provides a very good  
18 representation of the embedded cost of serving large load customers – the 11(M) Large  
19 Primary Service ("LPS") class, and specifically the transmission voltage level subclass of  
20 that class.<sup>7</sup>

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<sup>7</sup> As a result of resolution of an issue in a past Ameren Missouri rate case related to Rider B, the Company has structured its rates in this case with voltage subclasses and separately studied those subclasses in its class cost of service study in this case for the first time. See the Direct Testimony of Thomas Hickman.

1           This is true for a couple of reasons. First, the embedded cost of service is by far  
2 most significantly influenced by two characteristics of a class of customers: its load factor  
3 and the voltage at which service is provided. Load factor is important because it is by its  
4 definition the relationship between demand (the maximum rate of electricity consumption  
5 by a customer or class at a point in time) and energy (the total amount of electricity  
6 consumed by a customer or class over time). Since demand and energy are the two most  
7 significant allocation factors in a class cost of service study, the load factor relationship of  
8 demand and energy is highly influential in the results of the study for each class. Second,  
9 voltage is significant because it is a determinant of whether and to what extent some  
10 categories of cost even apply to a customer/customer class at all – i.e., the costs of the  
11 secondary distribution system must be allocated to customers that take service at secondary  
12 voltages but not to customers that take service at higher voltages, whose electricity never  
13 passes through any secondary voltage distribution components, and who therefore cannot  
14 be said to have any causative effect on secondary distribution costs.<sup>8</sup> Since the LPS  
15 transmission subclass is made up of high load factor customers served at transmission  
16 voltage – much like the large load class, the LPS transmission subclass results from the  
17 class cost of service study represent a very good proxy for the embedded cost of service of  
18 large load customers. If anything, I strongly expect using this as a proxy is conservative  
19 and that a large load class-specific study (when those customers have been present and  
20 operating during a test year) would produce an even lower relative cost of service. This  
21 expectation is based on the fact that the load factor of the LPS transmission subclass in the

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<sup>8</sup> I discuss later in my testimony some very minor distribution costs that the Company has identified associated with large load service – but those costs are being addressed through the tariff provision that requires upfront payment for the costs of interconnection and will therefore not impact the general revenue requirement in a manner that would warrant any allocation of distribution costs to large load customers.

1 CCOS study is 72.1%<sup>9</sup> and large loads are anticipated to have load factors closer to 85%.  
2 As I mentioned earlier, the load factor is a strong indicator of the total cost of service on a  
3 \$/kWh basis, and higher load factors are indicative of a lower average cost per kWh to  
4 serve (i.e., the higher load factor large loads should be expected to have a lower embedded  
5 cost per kWh cost to serve than the LPS transmission subclass).

6 **Q. What does the LPS transmission subclass result from witness**  
7 **Hickman's class cost of service study suggest about the embedded cost of serving the**  
8 **large load class relative to the class's rates being proposed in this case?**

9 A. The rates are more than sufficient to cover the large load class's  
10 representative share of costs. If you look at the LPS transmission class's allocated share of  
11 the embedded cost revenue requirement in witness Hickman's study and divide by the  
12 annual consumption of the LPS transmission subclass, it translates to a cost per kilowatt-  
13 hour ("kWh"), and therefore the need for an all-in average rate of at least 5.4 cents per  
14 kWh.<sup>10</sup> Application of the proposed 14(M) rate to billing parameters of an illustrative large  
15 load customer with an 85% load factor (as we expect to be typical for large load  
16 customers<sup>11</sup>), results in an average all-in rate of 6.8 cents per kWh. Given the fact that the  
17 14(M) rate produces an all-in kWh cost 26% higher than the embedded cost per kWh of

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<sup>9</sup> I derived this value from Mr. Hickman's workpaper titled "MO ECOSS\_2026 Final.xlsx", taking the LPS transmission annual energy consumption at generation from the tab "A.F.1—4NCP" in cell J12, dividing by 8760 hours in a year to get the average hourly demand, and then dividing that result by the class NCP found in the same workpaper on the tab "A.F.1—4NCP-Step 1" in cell J58.

<sup>10</sup> I derived this value by dividing the total class revenue responsibility for the LPS transmission subclass from Mr. Hickman's workpaper "MO ECOSS\_2026 Final.xlsx" on the tab "SCH 2" in cell L4 by the total class energy from Dr. Bowden's rate design workpaper titled "ER-2026-0291 Rate Design Workpaper Direct Final.xlsx" on the tab "ScheduleB" using the sum of cells C321 and C323.

<sup>11</sup> This expectation is based on conversations I have personally participated in with many prospective hyperscale data center customers.

1 serving high load factor, transmission subclass customers, it is easy to conclude that large  
2 load customers are paying their fair share from an embedded cost perspective.

3 That said, what is much more interesting and aligned with what I believe is clearly  
4 the focus of SB 4 and the general public is the incremental view that will demonstrate  
5 directly the impact of large load customers on existing customers' rates, which I detail  
6 below.

7 **Q. Please summarize the results of the incremental view prior to**  
8 **explaining how you developed the analysis that supports it.**

9 A. The results of the incremental impact analysis required an evaluation of both  
10 incremental costs and revenues arising from large load service. Those results were shown  
11 in Table 1 in the introduction to my testimony, which illustrated that the rate increase in  
12 this case is \$10.6 million dollars less than it otherwise would be. That relative reduction in  
13 rates is the juxtaposition of the incremental costs totaling \$2.8 million that I will detail  
14 below against a discrete adjustment to the revenues in the case of \$13.4 million that I will  
15 also walk through later in this section. The net effect is \$10.6 million of net revenue that  
16 offsets other costs in the revenue requirement responsibility of all customers.

17 **Q. How did you approach determining the incremental cost of serving the**  
18 **large load class?**

19 A. What is of greatest interest in this case in order to determine the impact of  
20 large load customers on existing customers is identifying incremental costs of large loads  
21 that will impact the revenue requirement in this case – the revenue requirement that will  
22 establish the rates applicable to all customers' service going forward starting in June 2027.  
23 I have worked with internal teams to identify any capital projects that are being undertaken

1 to serve large load customers (i.e., investments that would not exist but for large loads and  
2 which therefore represent incremental costs that have the potential to drive up the revenue  
3 requirement) that either went into service in the test year or are expected to go into service  
4 by the true-up date and are therefore included in the pro forma adjustment to rate base used  
5 to build the revenue requirement presented by Company witness Stephen J. Hipkiss.

6       There are no such projects in the historical test year. However, I have identified a  
7 small number of capital projects expected to go into service by the true-up date (through  
8 December 31, 2026) that are being undertaken to enable future large load service and are  
9 not being paid in advance by a large load customer under the terms of a construction  
10 agreement (i.e., if the customer is paying upfront for the construction, its revenue  
11 requirement impact on other customers will be zero since the contribution in aid of  
12 construction ("CIAC") paid by the large load customer fully offsets the value of plant in  
13 service that would otherwise go into the rate base). Schedule SMW-D1 contains an  
14 itemized list of the identified projects and their expected costs and revenue requirement  
15 impacts. The total amount of investment expected in projects that are being undertaken to  
16 serve large loads and which are not subject to 100% CIAC is \$9.6 million. Based on  
17 application of depreciation rates expected to apply to these investments (a weighted average  
18 depreciation rate of 9.92%<sup>12</sup>), the rate of return of 7.506% as calculated for this case by  
19 witness Mitchell Lansford, and the Company's total state and federal income tax rate of  
20 23.65%, the total incremental capital-related revenue requirement of large load customers  
21 in this case is \$1.8 million.

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<sup>12</sup> This depreciation rate is higher than most plant accounts that include most infrastructure investments due to the presence of a digital project with a shorter life that results in a 20% amortization rate for that project.

1           **Q.     You indicated that these projects are associated with the pro forma**  
2 **adjustment made by witness Hipkiss to reflect plant expected to go into service prior**  
3 **to the true-up date. How certain is the estimate used to create that pro forma**  
4 **adjustment?**

5           A.     It is always the case that actual costs at the true-up will vary to some degree  
6 from the estimates used in the pro forma adjustment at the beginning of the case. That is  
7 the very reason we have a true-up. The mechanism exists in order to ensure that we get the  
8 most accurate reflection of actual investments reflected in rates, rather than a preliminary  
9 or budgetary estimate. That said, I have a high degree of confidence that we have a  
10 materially accurate estimate for costs associated with projects undertaken to serve large  
11 load customers. We have carefully evaluated the universe of projects we are undertaking  
12 as a result of the ESAs that have been signed. It is quite unlikely that there are any projects  
13 that could get initiated after the point that this case is filed, but that are large enough to  
14 significantly impact the revenue requirement and also will go into service prior to the end  
15 of the year.

16           And as for the projects we did identify, undoubtedly the precise project costs will  
17 have some variance to the budget as is always the case, but it would take a quite extreme  
18 variance that I believe to be highly unlikely to change the costs in any way that would alter  
19 my basic conclusions about large load service. For example, a 10% variance in the totality  
20 of project costs would result in only an approximately \$180 thousand dollar impact to the  
21 total revenue requirement impact of large loads.

1           **Q.    Are there any transmission network upgrades included in these**  
2 **projects and how does the Company's large load framework ensure large load-related**  
3 **transmission investments are not resulting in rate impacts?**

4           A.    There is one relatively small transmission project included in the total I  
5 described previously. Since the costs of *all* of the large load projects reflected in the  
6 revenue requirement in this case is covered by the revenue imputation I will discuss shortly,  
7 it should go without saying that the transmission project – as a subset of that total – is more  
8 than covered as well.

9           In the future, there may be larger transmission network upgrade projects that are  
10 undertaken as a result of large load additions. As I discussed in the large load tariff case  
11 (File No. ET-2025-0184), the portion of the bundled rate for large load service designed to  
12 cover transmission costs, based on the scenario I analyzed in that case with 2 GW of large  
13 load demand, is expected to cover the revenue requirement impact of transmission projects  
14 with a capital cost of at least \$800 million. The fact that we now have ESAs for 2.8 GW of  
15 demand with a faster ramp up than was assumed in that analysis means that there is even  
16 more large load revenue to cover potential future revenue requirement impacts of large  
17 load-related transmission investment.

18           In future cases and in order to validate that existing customers are not picking up  
19 the responsibility for those transmission costs, the Company expects to be able to identify  
20 all of those transmission investments that are in the revenue requirement and conduct an  
21 analysis like the one I have done in this case to assess the incremental costs and revenues  
22 of the transmission investments arising from large load service. To the extent that large  
23 load revenues do not fully cover those costs, any excess costs would be directly assigned

1 to the large load class and built into the rates proposed for that class so that they would  
2 then fully cover the transmission costs.

3 The Company is also aware of a recent Federal Energy Regulatory Commission  
4 ("FERC") action related to large load impacts on wholesale transmission rates. To the  
5 extent that the FERC proceeding results in any new directives related to transmission cost  
6 allocation, the Company will comply with that directive and take it into consideration in  
7 its future analysis to ensure that the Company's other retail customers are still protected  
8 from responsibility for costs arising from large load-related transmission investments.

9 **Q. Have you identified any incremental operations and maintenance**  
10 **("O&M") costs that impact the revenue requirement associated with large loads?**

11 A. Yes, a limited amount. As of the filing of this case and as expected as of the  
12 true-up date, we have identified six employees that are primarily working to support large  
13 load issues. Two work in a department newly created to directly manage large load  
14 customer issues. Four work in an economic development team that is primarily focusing  
15 on handling business development with prospective large load customers. It is strongly  
16 arguable that this latter group should not be considered a cost of the large load class, as  
17 they focus on prospective customers and do little to provide service directly to existing  
18 large load customers. They really are engaged in business development that benefits all  
19 customers, our communities, and our state. That said, out of an abundance of caution in  
20 trying to conservatively estimate large load costs, and given that the nature of their work  
21 is heavily focused on large load customers generally, I have included the cost of this team  
22 in the category of incremental O&M that is in the revenue requirement as a result of large  
23 loads. To further take an overly conservative view of this issue, I have also assumed that

1 all of these employees' time is charged to operations and maintenance expense, while in  
2 reality there is almost certainly some amount of their time that is charged to capital projects  
3 (and which therefore are already accounted for in the revenue requirement associated with  
4 capital projects, suggesting this analysis is conservative by potentially double counting a  
5 small amount of cost).

6 Company witness Hipkiss provided me with an average annual cost per employee  
7 (including benefits) of \$153,576 and I applied it to the headcount of six employees that are  
8 working primarily on large load issues to arrive at a total incremental O&M cost associated  
9 with large load service in the revenue requirement in this case of \$0.9 million.

10 Adding the incremental capital-related costs and O&M costs associated with large  
11 load service that are included in the revenue requirement in this case, the total potential  
12 impact on existing customers – i.e., the full incremental impact of large load customers on  
13 this revenue requirement – is \$2.8 million, which again, is ultimately much more than fully  
14 offset by revenues I will discuss next<sup>13</sup>.

15 **Q. Why do you say that is the "potential" impact, and how does this result**  
16 **factor into your conclusion that rates in this case will be *lower* as a result of large load**  
17 **service rather than higher?**

18 A. The incremental costs are only one side of the equation needed to determine  
19 the impact of large load customers on the rates to be established in this case. One must  
20 compare the incremental costs included in the revenue requirement to the incremental  
21 *revenues* arising from large load customers that *offset* the revenue requirement in order to  
22 see the full picture of large load impacts on existing customers' rates.

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<sup>13</sup> The \$2.8 million total revenue requirement cost impact does not equal the sum of the capital and O&M cost impacts of \$1.8 million and \$0.9 million respectively due to rounding.

1           **Q.     Are there any large load revenues included in the test year or expected**  
2 **as of the true up date in this case?**

3           A.     No. But that said, the Company is proposing a discrete adjustment to the  
4 requested revenue requirement calculation in this case to reflect known and measurable  
5 large load revenues that will start after the true-up date but roughly commensurately with  
6 the dates rates take effect in this case. That adjustment will result in setting rates in this  
7 case as if there are incremental revenues.

8           **Q.     Please discuss the background of the use of discrete adjustments in**  
9 **Missouri regulatory proceedings.**

10          A.     In the Commission's *Order Regarding Test Year* issued on July 31, 2024 in  
11 Missouri American Water Company's rate case ("MAWC case"), File No. EW-2024-0320,  
12 the Commission stated:

13                 As an alternative to the adoption of a future test year, MAWC requests the  
14 Commission allow inclusion in its revenue requirement and rates discrete  
15 adjustments to certain rate base and expense items beyond the requested true-up  
16 date, through the operation of law date.

17                 On July 2, the Commission issued its Order Directing Notice, Establishing Time to  
18 Intervene, Setting Time to Respond, and Consolidating Cases, which, among other  
19 things, gave parties until July 26 to respond to MAWC's motion.

20                 On July 26, the Staff of the Commission (Staff) filed its Response to MAWC's  
21 Motion to Establish Test Year in which it stated that it does not oppose the historical  
22 test year and true-up period proposed by MAWC, but opposes the use of a future  
23 test year. Should the Commission decide against the use of a future test year, Staff  
24 is not opposed to the use of discrete adjustments, but requests that all parties be  
25 permitted to present such adjustments beyond the true-up period to present a more  
26 complete picture of MAWC's operations at the operation of law date.

27                 On July 26, the Office of the Public Counsel (OPC), Missouri Industrial Energy  
28 Consumers (MIEC), the Consumers Council of Missouri, Midwest Energy  
29 Consumers Group (MECG), AARP, the City of St. Joseph, Missouri, and the City  
30 of Riverside, Missouri filed a Joint Response to Motion to Establish a Future Test  
31 Year (Joint Response). The Joint Response asks the Commission to deny MAWC's

1 motion and order the use of an historic test year with true-up, rather than a future  
2 test year. The Joint Response acknowledges that the Commission has permitted  
3 discrete adjustments in past cases and requests that, should the Commission do so  
4 in this case, that the Commission allow all parties to propose such adjustments.

5 After reviewing the filings and arguments made by the parties, the Commission  
6 concludes that the historic test year with adjustments should be adopted.

7 The Company's request to include known and measurable large load revenues that  
8 will exist after the true-up date but at the time rates take effect from this case is consistent  
9 with the Commission's order in the MAWC case. The Company also requested a discrete  
10 adjustment to rate base associated with a significant construction project in its most recent  
11 natural gas rate review, File No. GR-2024-0369 ("Gas Case"). While that case was settled  
12 via Stipulation and Agreement that did not explicitly address the Company's request for a  
13 discrete adjustment, there was testimony exchanged in that case between the Company and  
14 Staff that I think provides some relevant context for the Company's request to make a  
15 discrete adjustment in this circumstance.

16 **Q. Please summarize that relevant testimony.**

17 A. In his Direct Testimony in the Gas Case, Staff witness Young provided two  
18 criteria that Staff considers in order to determine the need for a discrete adjustment in a utility  
19 rate case. The first is whether the adjustment is known and measurable. The second is that the  
20 timing should not skew the matching principle in relation to other cost of service items. Witness  
21 Young also references a prior Commission order related to discrete adjustments and the  
22 retirement of the Asbury generating plant in a past Empire District Electric Company rate case,  
23 File No. ER-2019-0374 ("the Asbury order"). The criteria identified by the Commission related  
24 to the inclusion of discrete adjustments include determinations that the adjustment:

25 1) is known and measurable;

1           2) promotes the proper relationship of investment, revenues and expenses; and  
2           3) is representative of the conditions anticipated during the time the rates will be in  
3           effect.<sup>14</sup>

4    In the Asbury order, the Commission further stated the following:

5                        When setting rates, the choice of method to adjust the test year for known and  
6                        measurable changes is a factual determination within the Commission's expert  
7                        discretion. The Commission is not required to recognize and incorporate all  
8                        known and measurable events outside the test year **so long as the results are**  
9                        **rates that are just and reasonable.**<sup>15</sup> [emphasis added]

10           **Q.       Does the Company's proposed discrete adjustment meet the Commission's**  
11           **three criteria?**

12           A.       Yes. I would also first note that, unlike the discrete adjustments proposed in the  
13    MAWC case or by the Company in the Gas Case, the proposed discrete adjustment in this case  
14    is to impute additional *revenue*, which will *offset* the revenue requirement and therefore in fact  
15    *lower the amount of rate increase pursued by the Company*. In the other two examples I cited,  
16    the utilities' proposals were related to investments or expenses, increasing the overall requested  
17    rate increase. While there is no policy reason that discrete adjustments that lead to increases or  
18    decreases in requested rates should be treated with a different standard,<sup>16</sup> — the fact that the  
19    adjustment in this case is to lower rates for all customers leads me to believe that it should  
20    perhaps be less controversial for those parties advocating for consumers' interests. Again,  
21    though, that is only interesting, but should not be determinative of the policy considerations the  
22    Commission uses to evaluate the discrete adjustment proposals generally.

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<sup>14</sup> File No. GR-2024-0369, Matthew Young Direct Testimony, p. 6, ll. 2-8.

<sup>15</sup> File No. ER-2019-0374, *Amended Report and Order*, p. 113, issued July 23, 2020.

<sup>16</sup> Rather, the goal should be to fairly evaluate each proposed adjustment in order to set a revenue requirement that is just and reasonable, aligns with the factors that the Commission has articulated as supportive of discrete adjustments, and affords the Company an opportunity to recover its prudently incurred costs and earn a reasonable return on its investments.

1           In reviewing the three criteria cited above in the Gas Case, it is clear that this discrete  
2 adjustment is appropriate.

- 3           • Known and measurable – the Company has entered into ESA's with large load  
4 customers with defined start dates, contract capacity values, and minimum bills,  
5 which are a function of those contract capacity values. Minimum bills for  
6 customers under executed ESAs are known and measurable.<sup>17</sup>
- 7           • Promotes the proper relationship of revenues and expenses – As I discussed  
8 previously, I have identified revenue requirement items that are caused by the  
9 existence of large load customers that result in an incremental increase in the  
10 revenue requirement in this case of \$2.8 million. In the grand scheme of large  
11 load service relating to multiple GW of eventual load, these are very small  
12 amounts. But given their presence in the revenue requirement, it is also  
13 appropriate to incorporate an initial, but relatively small in the scheme of  
14 eventual large load operations, revenues that are known and measurable to exist  
15 at approximately the time rates take effect to recognize the proper relationship  
16 between the small level of both "startup" costs and "startup" revenues that will  
17 be incurred when rates take effect.
- 18          • Is representative of conditions expected to exist at the time rates are in effect –  
19 again, the ESAs are signed and service (or, at least, minimum billing under the  
20 contracts) will be initiated by June 1, 2027 – the operation of law date for this  
21 case – for all currently effective ESAs as of the writing of this testimony.

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<sup>17</sup> Projections of actual demands or energy consumption are not known and measurable at this time, as the actual ramping up of large loads are subject to a variety of considerations and risks, including legal challenges to certain projects, construction schedules, and business plans of entities that are outside the control of the Company.

1                   Minimum bills are contractually required by that time, and those minimum bills  
2                   will exist when rates take effect.

3                   There really is no question when observing the three criteria the Commission has  
4 articulated in the past that this discrete adjustment is appropriate and reasonable to make as an  
5 offset to the revenue requirement in this case.

6                   **Q.     What is the value of the discrete adjustment that you propose be**  
7 **included in this case?**

8                   A.     I propose inclusion of additional large load base rate revenues of \$10.1  
9 million. I quantified this value based on an annualization of the level of minimum bill  
10 revenue that will exist during the month when rates take effect from this case. I utilized the  
11 contract capacity expressed in the ramp schedule of each executed ESA for the month of  
12 June 2027 – the operation of law date in this case – times the 80% minimum demand charge  
13 to establish the "billing determinant" for the adjustment. I then calculated annualized bills  
14 for the customer based on that known and measurable billing determinant by multiplying  
15 that demand level by the summer demand charge for four months of the annualization  
16 calculation and by the non-summer demand charge for the eight non-summer months of  
17 the annualization calculation.<sup>18</sup> This calculation is shown in Schedule SMW-D2.

18                   Beyond the base rate revenues, I also propose to establish a base amount of RSP-  
19 LLC revenues for the RSP tracker associated with large load service and include that base  
20 amount as an additional offset to the revenue requirement in this case. The RSP-LLC base  
21 amount I have calculated based on the known and measurable contract demand under the

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<sup>18</sup> Note that I necessarily had to calculate the large load revenue as an input to the revenue requirement and rate change in this case being calculated, so rather than using the proposed 14(M) rates in this case to calculate the revenue, I used a preliminary estimate of the large load rate based on an assumed 10% increase from currently approved rate levels.

1 program and the solar production profile otherwise used to model generation production in  
2 this case by Company witness Michael Flannagan is \$3.3 million. Taken together, the base  
3 rate and RSP-LLC revenue discrete adjustments total \$13.4 million.

4 **Q. So, what is the total impact of large load customers on the change in**  
5 **revenue requirement requested by the Company in this case when considering both**  
6 **the incremental costs caused by large loads and the incremental revenues derived**  
7 **from large loads that will offset that revenue requirement?**

8 A. Table 1 above shows that amount. The net effect of the incremental impacts  
9 of large loads on the change in revenue requirement in this case is a decrease of \$10.6  
10 million. Absent large loads, the Company would have requested a \$10.6 million larger rate  
11 increase. Existing customers are benefiting in this case in the form of lower total rates by  
12 that amount as a direct result of large loads. Assuming a two-year rate case cadence as has  
13 been fairly typical for the Company, customers' base bills should be expected to be  
14 approximately \$21 million lower in total for the two-year period beginning June 2027 as a  
15 result of large load customers.

16 **Q. When those large load customers start taking service in 2027, their**  
17 **actual load will cause additional incremental energy and capacity costs to be incurred**  
18 **by the Company to meet the customers' load needs. How are those costs considered**  
19 **in this case, and are the proposed rates sufficient to cover them?**

20 A. Those costs are not reflected in the revenue requirement in this case because  
21 they have not been incurred as of the test year or true-up date and are not known and  
22 measurable. So those costs are not impacting the rates established in this case. That said, it  
23 is a useful exercise to expand the incremental cost of service analysis beyond those items

1 that are included in this revenue requirement to reflect estimated additional energy and  
2 capacity expense that are incremental costs that the Company will incur in serving these  
3 loads, along with corresponding retail revenues it will earn, in order to further demonstrate  
4 that the rates for large load service *are* sufficient to cover a reasonable expectation of those  
5 costs – meaning the rates established in this case are sufficient for the test in SB 4 that  
6 requires large loads to pay their representative share of costs incurred. I will demonstrate  
7 this by comparing the all-in revenue per megawatt-hour ("MWh") that will be realized  
8 when large loads actually begin consuming energy and pay their resulting bills to the all-  
9 in cost of their service factoring in the incremental revenue requirement I identified above  
10 attributable to the large load class as well as the estimated incremental energy and capacity  
11 expense at the market prices for those commodities.

12 **Q. Why is this comparison producing the appropriate figures to determine**  
13 **if the large load customers' rates are covering or more than covering the incremental**  
14 **cost to serve them?**

15 A. No new generation that is being accelerated for large load service will be  
16 reflected in the revenue requirement used to establish customer rates until at least the *next*  
17 electric rate review of the Company; to be clear, there are no costs for any such generation  
18 in this case. Therefore, the incremental impacts on the costs that will be relevant for  
19 comparison to the rate paid by the customer is the market price – since every MWh  
20 consumed by a new large load will either displace a MWh of generation that could have  
21 been sold off-system at the market price, or it will cause the Company to purchase an  
22 additional MWh at the market price.<sup>19</sup> That makes a cost of service calculation which

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<sup>19</sup> Either way, the opportunity cost of providing a MWh of large load (or any other) retail service in between rate cases is the market price of that power.

1 factors in the market value of power the appropriate cost to compare large load customers  
2 to until such time that new generation is brought online that was added or accelerated to  
3 serve the large loads, at which time the cost of that generation should be figured into the  
4 calculation. Said another way, this analysis replicates exactly what would happen if these  
5 customers began consuming energy in earnest prior to the true-up date in this case and  
6 therefore did impact the revenue requirement with additional energy and capacity costs. In  
7 that circumstance, we would annualize the total load of the customers into the retail loads  
8 used in the production cost modeling work of witness Flanagan and additional net energy  
9 cost would be reflected in this case based on the market prices used for that production cost  
10 modeling in this case. Corresponding additional retail revenues would be annualized into  
11 the revenue side of the case as well.

12 **Q. Your utilization of market energy and capacity costs was premised on**  
13 **the notion that no new generation was being added to serve large loads in this case.**  
14 **Why do you say that, given that the Company is proposing to include the cost of three**  
15 **new solar generation facilities – the Bowling Green, Vandalia, and Split Rail Solar**  
16 **Energy Centers – in the revenue requirement in this case?**

17 A. Those facilities were already planned, proposed, and approved by the  
18 Commission prior to the Company having any large load customer ESAs, or even any  
19 expectations to serve a material amount of large load customers. Each of these facilities  
20 received approval of a Certificate of Convenience and Necessity ("CCN") from the  
21 Commission in File No EA-2023-0286 in an order dated March 21, 2024. The CCN case  
22 was filed on June 16, 2023.

1           These projects fulfilled generation needs identified in prior Integrated Resource  
2 Plans<sup>20</sup> that included no consideration of new large loads. It was not until filing a  
3 Notification of Change in Preferred Resource Plan on February 28, 2025 that the Company  
4 began articulating to the Commission what its resource needs would look like in a large  
5 load future. The Split Rail, Vandalia, and Bowling Green projects were absolutely  
6 undertaken to meet existing customers' needs and not in order to integrate *any* large load  
7 demand.

8           **Q.       Please return to the discussion of the analysis you have conducted to**  
9 **assess the adequacy of the large load rate to cover the incremental costs that large**  
10 **loads will cause to be incurred.**

11           A.       I would further note that, in my analysis of what large loads are paying  
12 relative to the cost they are causing, I will also recognize additional sources of revenue  
13 contribution that they will make beyond base rate retail revenues. I have already directly  
14 addressed one of those sources – Rider RSP-LLC, for which I estimated \$3.3 million of  
15 revenue which has been imputed into the revenue requirement in this case. The other  
16 sources of revenue are payments that large load customers will make under any applicable  
17 interim capacity provisions of their ESAs, and other riders including Rider SUR  
18 (Securitization), the Fuel Adjustment Clause ("FAC"), and the Renewable Energy Standard  
19 Rate Adjustment Mechanism ("RESRAM").

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<sup>20</sup> At the time of filing, the Company's PRP was reflected in its Notification of Change in Preferred Resource Plan filed on June 22, 2022.

1           **Q.     Please describe the interim capacity payments you referenced.**

2           A.     The Company's large load tariff approved by the Commission includes a  
3 provision whereby large load customers pay the full incremental market cost for capacity  
4 that the Company procures from the market if such capacity is needed to enable service to  
5 them before the Company's own system capabilities allow that service (because otherwise,  
6 service to them would be delayed). Despite the fact that the base retail rate being charged  
7 to large load customers is in part designed to cover fixed costs of generation (meaning the  
8 customer is implicitly paying something for generating capacity already in its base rate),  
9 the tariff includes this precautionary measure in this tight capacity market allowing the  
10 Company to pass on the *full incremental cost* of market purchases to support interim  
11 capacity *on top of* the retail rate. As such, this interim capacity payment acts as another  
12 source of revenue to cover the incremental cost of capacity that will be incurred to serve  
13 large loads.

14           **Q.     Please discuss the interaction of large loads with applicable riders.**

15           A.     Large loads will be subject to Riders SUR, FAC, and RESRAM.<sup>21</sup> While  
16 Rider FAC and RESRAM operate effectively as balancing mechanisms to ensure proper  
17 recovery of costs that are otherwise recovered in base rates and can therefore fluctuate  
18 between charges and credits of different sizes depending on the circumstance, the  
19 securitization rider deals with a discrete category of costs that large load customers will  
20 now contribute to the recovery of that otherwise would have been legally mandated to be  
21 paid by existing customers. The Company securitized approximately \$476 million

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<sup>21</sup> For purposes of this discussion, I am presuming that large load customers will exercise their legal right to opt out of Rider EEIC charges associated with Missouri Energy Efficiency Investment Act demand side programs.

1 associated with the retirement of the Rush Island Energy Center. The recovery of those  
2 costs, together with interest payments that bring the total nominal cost to \$673 million, is  
3 legally non-bypassable for all retail load of Ameren Missouri. Given that, absent large  
4 loads, existing customers would have borne the entire \$673 million, every dollar  
5 contributed by a large load customer to recovery of the securitization balance is a dollar  
6 that will be saved by existing customers. Based on the ramp schedules reflected in current  
7 ESAs, the contract demands of those customers, and an assumed 85% load factor, I  
8 estimate that the currently signed ESAs are likely to result in large loads covering  
9 approximately \$206 million of securitization costs (including interest payments) to the  
10 benefit of existing customers over time (and approximately \$4 million of benefit during  
11 the first year that rates from this case are in effect).

12 In rates charged under Riders FAC and RESRAM, there will initially be no  
13 incremental costs of large load customers, but large load customers will pay toward the  
14 recovery of any costs that may be flowing through those riders at the time they initiate  
15 service. That is because all of the rider rates discussed use historical accumulation periods  
16 (costs that have already been incurred) but forecasted billing units (expectations of the load  
17 subject to the rate in a future recovery period) to develop rates. So, for an illustrative  
18 example, if there are \$100 of costs associated with a recent four-month historical  
19 accumulation period that need to be recovered in the FAC and the Company has 1,000  
20 MWh of expected retail load in the next future recovery period prior to consideration of  
21 large loads, the FAC charge to all customers will be \$0.10 per MWh without large loads.  
22 If a new load comes onto the system and is forecasted to add 100 MWh during the same  
23 recovery period, the new rate would be \$100 divided by 1,100 MWh of load including the

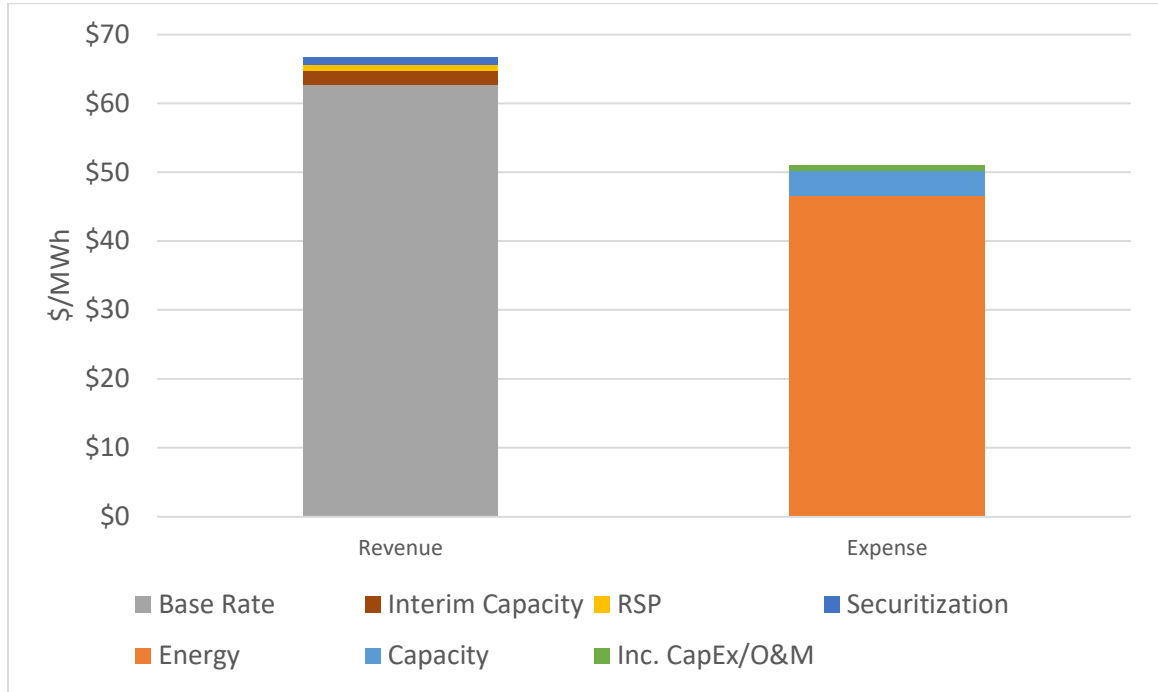
1 new load in the rate denominator, or \$0.09 per MWh. So initially, as large loads are  
2 included in forecasted kWh used to establish rates under these mechanisms, they will  
3 participate in the recovery of historical costs (or return of benefits, in the event that either  
4 rider has a credit rather than a charge at the time) associated with a period prior to their  
5 initiation of service – benefitting existing customers (presuming the mechanisms are in the  
6 state of a charge rather than a credit, which they tend to be more often than not).

7 I have modeled expected payments of large load customers under base retail rates  
8 as well as each of these mechanisms to develop an "all-in" rate that large load customers  
9 are expected to pay. However, given the uncertain initial rate level of the "balancing riders"  
10 (i.e., the FAC and RESRAM), I exclude any forecast of the contribution large loads will  
11 make through those mechanisms. I compare the all-in rate paid to the all-in incremental  
12 cost that I expect to arise from large load service (including the incremental revenue  
13 requirement in this case along with incremental energy and capacity market costs) to  
14 demonstrate that the provisions of SB 4 are met – i.e., large loads will pay rates covering  
15 their representative share of costs (and then some) when they initiate service in 2027 under  
16 the rates proposed in this case.<sup>22</sup> Figure 1 below shows the comparison of the expected "all-  
17 in" cost to serve large loads to the all-in revenue from them, based on conditions that will  
18 be in effect when rates take effect in 2027.

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<sup>22</sup> A small – so small I would even say trivial – amount of large load revenues will be realized early in 2027, prior to rates from this case taking effect.

1 **Figure 1 – All-in Cost and Revenue per MWh for Large Load Service for 12-Month  
Period When Rates Take Effect**



2

3 **Q. Much discussion occurred about the impact large load customers will**  
4 **have on the FAC during the Company's large load tariff case. Will large load**  
5 **customers have an impact on the FAC?**

6 A. Yes. As I mentioned, initially, large loads will pay charges under the FAC  
7 before they have any possibility to cause any costs to be recovered in the mechanism. So,  
8 presuming the FAC is a charge and not a credit, large loads will initially provide benefits  
9 by paying a share of costs that were incurred to serve existing customers prior to them even  
10 taking service. However, eventually, higher purchased power costs (or lower off-system  
11 sales revenues) resulting from large load service will flow through the FAC. That will not  
12 occur on any observable scale until 2028.<sup>23</sup>

<sup>23</sup> A small – so small I would even say trivial – amount of costs will impact the FAC prior to 2028.

1           **Q. Does that suggest a subsidy of large load customers by other**  
2 **customers?**

3           A. No, it is not a sign that existing customers are subsidizing large load  
4 customers. To understand why, let's go back to Figure 1. As discussed earlier, Figure 1  
5 demonstrates that large loads are paying for the incremental cost of their service, including  
6 any market power costs that are within the FAC – and then some. To put a finer point on it  
7 using figures that underlie Figure 1, the large load tariff rates large load customers are  
8 paying (including interim capacity, RSP revenues, and securitization) reflect \$67 per  
9 MWh. The cost per MWh for energy and capacity to serve these loads along with the  
10 incremental capital investment and O&M reflected in the revenue requirement in this case  
11 is \$51 per MWh, meaning the large load customer rate is producing a margin of \$16 per  
12 MWh. Since the large load customer rates produce revenues that more than cover the cost  
13 to serve them, they can't be said to be subsidized by other customers. A subsidy could only  
14 occur if their rates were too low – and they didn't cover the cost to serve them – and then  
15 that shortfall is made up by raising the rates of other customers. That did not happen in this  
16 case; there is no subsidy.

17           **Q. You mentioned above that other customers would be impacted via the**  
18 **FAC, right?**

19           A. I did, and that is true, but those FAC impacts do not represent unjust or  
20 unreasonable costs borne by existing customers as a result of large load service as  
21 contemplated by SB 4. That is because the charges, again, are not a subsidy. Instead, they  
22 *are a function of regulatory lag*, in this case what is sometimes called "positive" regulatory  
23 lag to signify that it reflects a temporary benefit to the utility between rate cases, whereas

1 "negative" regulatory lag reflects a temporary detriment to utilities between rate cases.  
2 That there could very well be positive and negative regulatory lag was fully accounted for  
3 in the Stipulation and Agreement implemented in the Company's large load tariff case, File  
4 No. ET-2025-0184. And how it was accounted for was to adopt a revenue sharing  
5 mechanism to reasonably address *all* sources of regulatory lag – positive and negative -- in  
6 a balanced manner. That balanced treatment of regulatory lag already agreed to by key  
7 regulatory stakeholders certainly cannot be said to be an unjust or unreasonable outcome.  
8 That mechanism provides for large load revenues that, *in combination with the normal*  
9 *operation of the FAC* under Missouri's established rate making paradigm, created excess  
10 levels of positive regulatory lag that are above and beyond the level of *negative* regulatory  
11 lag already being borne concurrently by the Company to be returned to existing customers.  
12 While one can imagine other ways to address FAC impacts that may occur in this  
13 circumstance, the approved mechanism reflects the recognition that there could be negative  
14 regulatory lag from a non-large load customer perspective through FAC impacts, while  
15 also recognizing that there could be positive regulatory lag impacts for the Company due  
16 to large load customers coming onto the system and by approving the Stipulation,  
17 determined that this mechanism appropriately dealt with that issue.

18 **V. LARGE LOAD TARIFF UPDATES**

19 **Q. Are there any updates to the large load tariff that was approved by the**  
20 **Commission last year that you are proposing in this case?**

21 A. Yes, I will highlight the changes to the tariff that are being filed with this  
22 case in this section of my testimony. Redlined versions of each of the tariff sheets

1 referenced in this section of my testimony are included in Schedule SMW-D3. Changes  
2 affect the following sheets, and each will be discussed further below:

- 3           • Sheets 61.5-61.19 – Elimination of Large Load provision from the 11(M)  
4           tariff
- 5           • Sheets 62-62.14 – Creation of Service Classification 14(M)
- 6           • Sheets 74-74.1 – Updates to Rider CCAP
- 7           • Sheet 74.4 - Updates to Rider CEC
- 8           • Sheets 74.7-74.8 – Updates to Rider NEC
- 9           • Sheets 74.11, 74.13 – Updates to Rider RSP-LLC
- 10          • Sheets 122-123 – Updates to large load provisions of the Distribution  
11          System Extensions tariff

12           The first change is simply the location of the large load tariff rates, terms, and  
13 conditions in the overall tariff book. In the large load tariff case (File No. ET-2025-0184),  
14 the large load tariff provisions were adopted within the existing Service Classification  
15 11(M) – Large Primary Service tariff sheets, as a new subclass with provisions applicable  
16 to those meeting the large load definition. However, the Stipulation and Agreement that  
17 the Commission approved also indicated that the large load tariff would be moved into a  
18 new standalone rate class in the Company's next electric rate case. This is that case, and  
19 the Company proposes to create Service Classification 14(M) – Large Load Customer  
20 Service, which, except as otherwise noted later in this section of my testimony, is identical  
21 to the large load subclass provisions previously housed in the 11(M) schedule. This  
22 approach was originally necessary because the FAC, by its own terms and conditions, only  
23 applied to the rate classes that were specified within it. I am advised by counsel that the

1 FAC cannot be modified outside of a general rate case, so we were unable to add a new  
2 service classification (e.g., 14(M)) to the FAC's applicability statement in between rate  
3 cases. So we are doing that now.

4 **Q. What other changes are made to the currently effective terms of the**  
5 **large load tariff?**

6 A. There are a few minor changes that I would characterize as clarifications or cleanup  
7 items, including:

- 8 • Improving language around the "Term of Use" provision in order to avoid the  
9 potential for a reader to conflate the term of use as defined in the tariff with the  
10 term of a large load customer's ESA;
- 11 • Updating the Rate Application section of the tariff to reflect that it applies to all  
12 load additions meeting the applicability standards on or after January 4, 2026. The  
13 provision originally referred to the "effective date of this tariff". But given that the  
14 tariff revisions will have a new and different effective date, it is appropriate to  
15 specifically delineate the applicability date of the tariff to the original effective date  
16 of this tariff; and
- 17 • Clarifying that the Company will specify both the supply *and meter* voltage of  
18 service provided under this tariff. This obviates the need to apply Rider C  
19 adjustments to large load customers and simplifies administration and billing;
- 20 • Replicating language from the tariff's Termination provisions within the  
21 Permissible Capacity Reduction provisions to ensure consistency and clarity  
22 around the Company's obligations to mitigate capacity reduction fees; and

- 1       • Clarifying that the Cost Stabilization Rider is an additional demand charge and  
2           therefore applies to kilowatts of demand rather than kilowatt-hours of energy.

3           **Q.    Are there any other large load-related tariff changes you wish to**  
4 **discuss?**

5           A.    Yes. However, these changes are not housed in the large load tariff (Rate  
6 14(M)) itself. Rather, the first change is found in the Distribution System Extensions tariff.  
7 The provision relates to any required modifications or enlargements to the Company's  
8 system that are required to provide large load service. This section of the tariff was  
9 amended prior to the Company filing its large load tariff case in order to establish  
10 conditions needed to take the actions needed to ready its system to provide large load  
11 service.

12           Through the experience we have gained dealing with this interconnection process,  
13 we have learned about types of circumstances that were not addressed as clearly as we are  
14 now proposing to address them. Specifically, we are now clarifying that the terms of  
15 paragraph M (Modification or Enlargement of System for High Voltage Service or Large  
16 Load Customer Service, at Sheet Nos. 122-123) apply not just when a customer takes  
17 service, but when the Company reasonably anticipates them taking service. This is an  
18 important distinction because the Company may enter a construction agreement prior to  
19 the execution of an ESA under which service can commence. But the customer that has  
20 signed a construction agreement is subject to payment under the terms of the agreement  
21 irrespective of whether they eventually sign an ESA and begin taking retail service from  
22 the Company.

1           Additionally, we added language to account for the potential for large load  
2 customers to be responsible for payments related to any distribution system investments  
3 made as a part of their interconnection process. This was not originally anticipated to be  
4 necessary, since such customers will all take service at transmission voltages and therefore  
5 presumably would not utilize the distribution system, and therefore would not cause the  
6 incurrence of any distribution level costs. But subsequently we have identified  
7 circumstances where distribution costs may be incurred related to a large load project, and  
8 we are clarifying that the umbrella of interconnection-related costs that large load  
9 customers must pay upfront includes any distribution costs.

10           The nature of potential distribution costs that we have identified as potentially  
11 arising from large load customers being served at transmission voltage relate to  
12 construction power or other non-permanent sources of power being provided prior to the  
13 full transmission interconnection project being completed, and also power to ancillary  
14 loads (e.g., water pumping), where the power consumption is not occurring directly at the  
15 large load customer's premises, but where the investment needed in the distribution system  
16 to serve the ancillary load is directly a result of needs of the large load customer. This  
17 change is consistent with my understanding of the intent of SB 4 and provides additional  
18 protections to existing customers from costs that may be caused by large load customers.

19           Finally, we discovered minor cleanup issues in some of the large load voluntary  
20 riders. First, in the Rider RSP-LLC tariff filed in File No. ET-2025-0184, we had  
21 inadvertently omitted language relating to the application of financial security  
22 requirements (which appeared in Rider NEC and CCAP), so we have added language to  
23 Rider RSP-LLC. Similarly, while the large load tariff (now in 14(M)) delineated the efforts

1 the Company would take to mitigate an Exit or Early Termination Fee, we inadvertently  
2 failed to include that same delineation regarding the Capacity Reduction Fee but have done  
3 so now. Also, for each of the large load riders (RSP, CCAP, NEC, and CEC), we have  
4 added Rate Schedule 14(M) to the applicability provisions, since when those riders were  
5 initially conceived, large load customer service existed under Schedule 11(M) and it is  
6 being moved to 14(M) in this case.

7 **VI. UPDATE ON RENEWABLE SOLUTIONS PROGRAM**

8 **Q. What is the Renewable Solutions Program?**

9 A. The RSP was approved by the Commission in File No. EA-2022-0245,  
10 under which interested customers can subscribe to receive the output of new renewable  
11 energy generation facilities in order to meet their individual sustainability goals. Under the  
12 program, subscribers are still subject to all charges under the standard Company retail tariff  
13 applicable to their service classification, but also pay an additional amount under the RSP  
14 program tariff in exchange for the title to the renewable energy credits ("RECs") from a  
15 particular facility. The monthly amount customers pay is the net impact of a charge – the  
16 Renewable Resource Charge under which the customer pays a fixed monthly amount based  
17 on the kilowatts of capacity to which they are subscribed – and a credit - the Renewable  
18 Benefits Credit which is based on the output of customers' subscribed portion of the  
19 renewable resource (determined as a pro rata share of total generation from the facility in  
20 the month based on the share of the resource's capacity that is dedicated to that customer's  
21 subscription) in that month times a tariffed rate. The net of the charge and credit is expected  
22 to be a charge in most months (any given month is dependent on the output of the resource)  
23 and will provide incremental revenue for the Company that offsets the need for some

1 amount of additional base rate revenues to pay toward covering the revenue requirement  
2 of the Program resources. In this manner, the RSP directly benefits non-subscribers by  
3 enhancing the affordability of new renewable generation sources that support the Program  
4 while also providing energy and capacity to serve all of our customers. As I will detail  
5 further below, the RSP is providing a net benefit to all customers in this case by offsetting  
6 \$9.4 million of the Company's revenue requirement.

7 **Q. In the Company's last electric rate review (File No. ER-2024-0319), the**  
8 **Company included a base amount of Program revenue in the revenue requirement**  
9 **associated with subscriptions to the Boomtown and Cass County Solar Energy**  
10 **Centers ("Boomtown" and "Cass County", respectively) and established that value**  
11 **as a base amount against which to track Program revenues as a means of ensuring all**  
12 **revenues from the Program would benefit customers with lower rates, as proposed**  
13 **by the Company and required by the Commission's order approving the Program.**  
14 **Does your testimony reflect the Program revenues associated with those facilities**  
15 **again?**

16 A. Yes. The Boomtown and Cass County subscriptions continue to provide  
17 service to Program participants and generate net revenues that will offset the revenue  
18 requirement in this case for the benefit of all customers.

19 **Q. Are any additional Program resources expected to be in service by the**  
20 **true-up date in this case?**

21 A. Yes. There are three solar facilities – the Vandalia, Bowling Green, and  
22 Split Rail Energy Centers ("Vandalia", "Bowling Green", and "Split Rail", respectively)  
23 being added to the Program in this case. The Vandalia and Bowling Green facilities, each

1 of which is fully subscribed by interested customers and which collectively represent a  
2 distinct phase of the RSP (distinct from Phases I and II, which were associated with the  
3 aforementioned Boomtown and Cass County facilities) with unique pricing. Vandalia and  
4 Bowling Green are both in service, resulting in new revenues under the Program. The third  
5 facility – Split Rail – has approximately 11 MW of RSP subscriptions and is expected to  
6 be providing RSP service to customers by the true-up date in this case as the fourth phase  
7 of RSP.<sup>24</sup> I have estimated expected annualized first year net revenues from these Program  
8 phases going forward, along with an annualized level of ongoing revenues under the  
9 Boomtown and Cass County phases I and II, and provided them to Company witness  
10 Stephen Hipkiss for purposes of making a pro forma adjustment to the Company's  
11 operating revenues that offset the revenue requirement used to establish base retail rates as  
12 well as to establish a base amount for the RSP revenue tracker.

13 **Q. How did you estimate the annual level of net revenues expected as of**  
14 **the true up date?**

15 A. Each of the Boomtown and Cass County facilities is nominally 150 MW  
16 and is fully subscribed, and each of the Vandalia and Bowling Green facilities is  
17 approximately 50 MW<sup>25</sup> and is fully subscribed. The Split Rail facility has 11 MW of  
18 subscriptions. Therefore, I calculated the total monthly revenues associated with the  
19 Renewable Resource Charge by multiplying 150,000, approximately 50,000, or 11,020 kW  
20 as appropriate for the facility (e.g., 150 MW converted into kW by multiplying by 1,000  
21 kW/MW) by the Renewable Resource Rate associated with the applicable Program year

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<sup>24</sup> Part of Split Rail's capacity is also being utilized for the RSP-LLC Program as referenced earlier in my testimony related to large load impacts on the case. Additional subscriptions may be received related to Split Rail and if so, those will be reflected in the true up in this case.

<sup>25</sup> To be precise, Vandalia's subscriptions total 50,400 kW and Bowling Greens' total 50,500 kW.

1 for each phase. I then multiplied the monthly revenues by 12 in order to determine the  
 2 annual revenues. I also estimated the total annual credits under the Renewable Benefits  
 3 Credit provision of the tariff for each Program phase. To do this, I received expected annual  
 4 energy production estimates from Company witness Flanagan and multiplied the total kWh  
 5 of production by the applicable year Renewable Benefits Rate for the respective phase. The  
 6 net revenues I calculated for each Program phase are provided in Table 2 below:

7 **Table 2 – RSP Net Revenues by Program Phase**

<b>Boomtown RSP Subscriber Net Revenue</b>	
Subscriptions (kW)	150,000
Renewable Resource Rate (\$/kW-Month)	\$8.48
Months	12
<b>Total RRC Revenue</b>	<b>\$15,264,000</b>
Annual Production (kWh)	333,473,420
Renewable Benefits Credit (\$/kWh)	\$0.0408
<b>Total Renewable Benefit Credit Cost</b>	<b>\$13,605,716</b>
<b>Net Subscriber Revenue</b>	<b>\$1,658,284</b>
<b>Cass County RSP Subscriber Net Revenue</b>	
Subscriptions (kW)	150,000
Renewable Resource Rate (\$/kW-Month)	\$10.60
Months	12
<b>Total RRC Revenue</b>	<b>\$19,080,000</b>
Annual Production (kWh)	338,050,180
Renewable Benefits Credit (\$/kWh)	\$0.0420
<b>Total Renewable Benefit Credit Cost</b>	<b>\$14,198,108</b>
<b>Net Subscriber Revenue</b>	<b>\$4,881,892</b>
<b>Vandalia RSP Subscriber Net Revenue</b>	
Subscriptions (kW)	50,400
Renewable Resource Rate (\$/kW-Month)	\$9.97
Months	12

Total RRC Revenue	\$6,029,856
Annual Production (kWh)	118,979,850
Renewable Benefits Credit (\$/kWh)	\$0.0400
Total Renewable Benefit Credit Cost	\$4,759,194
Net Subscriber Revenue	<b>\$1,270,662</b>
<b>Bowling Green RSP Subscriber Net Revenue</b>	
Subscriptions (kW)	51,500
Renewable Resource Rate (\$/kW-Month)	\$9.97
Months	12
Total RRC Revenue	\$6,161,460
Annual Production (kWh)	118,979,850
Renewable Benefits Credit (\$/kWh)	\$0.0400
Total Renewable Benefit Credit Cost	\$4,759,194
Net Subscriber Revenue	<b>\$1,402,266</b>
<b>Split Rail RSP Subscriber Net Revenue</b>	
Subscriptions (kW)	11,020
Renewable Resource Rate (\$/kW-Month)	\$9.08
Months	12
Total RRC Revenue	\$1,200,739
Annual Production (kWh)	25,608,555
Renewable Benefits Credit (\$/kWh)	\$0.0400
Total Renewable Benefit Credit Cost	\$1,024,342
Net Subscriber Revenue	<b>\$176,397</b>
<b>Total Net Subscriber Revenue</b>	<b>\$9,389,502</b>

1           **Q.     Are actual net revenues under the Program subject to tracking?**

2           A.     Yes. As a part of the Company's original RSP proposal, the Company was  
3 committed to ensuring that all Program net revenues would be used to enhance affordability  
4 for all customers – meaning that the Company proposed that it should not experience  
5 beneficial regulatory lag on these revenues but would track all Program net revenues and  
6 use them to offset future revenue requirements. The Commission ultimately ordered such  
7 tracking. The Program net revenues that I calculated just above<sup>26</sup> are proposed for inclusion  
8 as an offset to the revenue requirement in this case and should therefore also become the  
9 base amount for tracking future Program net revenues against when rates arising from the  
10 case are in effect, in order to ensure that all net Program revenues benefit all customers.

11           **Q.     What factors will lead to variability in Program net revenues in the**  
12 **future?**

13           A.     There are three major factors that can impact the net revenues over time.  
14 First, additions of new Program phases between rate cases as new resources and  
15 subscriptions are added to the Program can increase revenues, should they occur. Next,  
16 variability in the output of Program resources will result in corresponding variability in  
17 the Renewable Benefits Credits earned by subscribers, which impacts the net revenues  
18 generated by the Program. Finally, the Renewable Resource Rate and Renewable  
19 Benefits Credits are subject to pre-determined annual updates for each Program year, as  
20 stated in the RSP tariff associated with each Program phase.<sup>27</sup> Additionally, while there

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<sup>26</sup> Additional RSP-LLC net revenues are separately discussed above and are also included as an offset to the revenue requirement and in the tracker base amount.

<sup>27</sup> The Split Rail phase of the Program (Phase IV) is not reflected in a Commission approved tariff yet, but the pricing has been established through the subscription process associated with the already-approved Phase III (i.e., Phase III and Phase IV subscriptions were solicited and priced in a single event). The Company will file the Program Phase IV tariff sheet later this year reflecting the pricing.

1 are Program safeguards against subscribers exiting the Program - including transferability  
2 provisions and potential termination fees if subscriptions cannot be transferred - events  
3 around changes in individual subscriber circumstances could impact the timing and  
4 amount of future Program net revenues.

5 **VII. REQUEST TO DISCONTINUE OLD CREDIT REPORTING**  
6 **REQUIREMENT FROM FILE NO. ET-2014-0076**

7 **Q. Please describe the relief the Company is requesting related to credit**  
8 **reporting requirements.**

9 A. In a 2014 docket (File No. ET-2014-0076), the Company requested that the  
10 Commission approve changes to its tariff sheet governing the practice of assessing deposits  
11 for residential customers. Specifically, consistent with Commission rule 20 CSR 4240-  
12 13.030, the Company proposed to use customer credit scores as a part of the criteria for  
13 determining whether a deposit would be assessed. In resolution of that case, the Company  
14 and several parties reached a Stipulation and Agreement that was approved by the  
15 Commission. That Stipulation and Agreement essentially approved the changes requested  
16 by the Company on an experimental basis and required the Company to file quarterly  
17 reports with the Commission related to deposits. Such reporting was required to continue  
18 for as long as the program was still considered experimental. However, the settlement also  
19 called for the Company to be able to request a removal of the experimental designation of  
20 the program in a future rate case. The Company is making that request – to remove the  
21 experimental designation and cease its reporting obligations - in this case.

22 **Q. Why is it appropriate to terminate the experimental designation of the**  
23 **Program at this time?**

1           A.     We have been operating under the new credit scoring provisions that were  
2 approved for well over a decade, and I am unaware of any disputes or concerns that have  
3 been raised by any parties or customers related to the practice. Certainly, a decade of  
4 successful experience under the new provisions is adequate to move forward with the tariff  
5 changes on a permanent basis. It is simply no longer an experiment. It is our standard  
6 operating practice at this point and no longer warrants an experimental designation.

7                                   **VIII. LOCAL PUBLIC HEARINGS NOTICES**

8           **Q.     In the Company's last electric rate review, File No. ER-2024-0319, the**  
9 **Company agreed to include in direct testimony in its next electric rate review a**  
10 **proposal to provide as many customers as possible either a text or email for local**  
11 **public hearings. Do you have such a proposal?**

12           A.     Yes. Ameren Missouri intends to inform all residential and business  
13 customers of the local public hearings coordinated by the Missouri Public Service  
14 Commission as part of the electric rate review request proceedings no later than ten days  
15 before the local public hearings. The Company will use the following methods to  
16 notify all customers of the local public hearings: bill insert for paper bill customers, digital  
17 bill insert posted on a rate review customer-facing landing page on Ameren.com for  
18 paperless bill customers, and digital notification (email or text message) for customers who  
19 opt-in to be contacted via their preferred method.

20           **Q.     In order to program and post the notices as described in the prior**  
21 **answer, when does the Company need the actual notice content as approved by the**  
22 **Commission?**

1           A.     In order to program and post the notices as described above, the Company  
2 needs the notice content approved by the Commission at least 60 days in advance of the  
3 first local public hearing.

4                   **IX.     WILDFIRE MITIGATION TRACKER REQUEST**

5           **Q.     Why is the Company requesting a tracker related to costs associated**  
6 **with developing and implementing a wildfire mitigation plan?**

7           A.     There are a variety of circumstances where there is very good policy  
8 justification for the use of trackers. Such circumstances may include the existence of very  
9 volatile or significant costs that are outside of the utility's control and which may reduce or  
10 even eliminate the utility's opportunity to recover its prudently earned costs and earn a  
11 reasonable return on its investment. Another such circumstance is the implementation of  
12 new laws, rules, regulations, or business requirements that cause a new category of costs  
13 that did not exist previously and which are not obviously offset by any other costs being  
14 reduced or going away, and which therefore are not represented in the historical test year  
15 revenue requirement. Such costs that a utility is required to incur as imposed by new legal  
16 or regulatory requirements or emerging issues, similar to volatile and significant costs  
17 outside of the utility's control, can impair the utility's ability to recover those costs and  
18 therefore earn a reasonable return on its investments.

19           Wildfire is an emerging topic in the industry as we have seen utilities in California,  
20 Hawaii, and elsewhere experience significant wildfire-related events that have had serious  
21 impacts not only on the local communities, but also on the operations and finances of the  
22 local utilities. Related to this emerging topic, the Commission initiated a working docket,  
23 File No. OW-2025-0314, in which it collected information from utilities about their state

1 of wildfire readiness and risk, and subsequently issued an order on February 6, 2026  
2 requiring all electric and gas utilities to develop a Wildfire Mitigation Plan and provide a  
3 copy to Staff by December 31, 2026 and provide quarterly updates starting March 31, 2026.

4 **Q. What is required of Missouri utilities under the order?**

5 A. The following components are required to be included in electric utility  
6 Plans:

- 7 • A risk assessment of the service territory;
- 8 • A list of resources that will be used for monitoring and providing advance  
9 warning of wildfire threats;
- 10 • The use of mitigative measures to reduce the threat of facility exposure,  
11 including the use of vegetation management and inspections as a  
12 mitigative measure;
- 13 • Identification of and plan of action for current system or geographic  
14 vulnerabilities;
- 15 • Inclusion of emergency response and communications plans, and training  
16 on such plans; and
- 17 • Damage assessment following a wildfire event.

18 **Q. What level of costs does the Company anticipate incurring in**  
19 **compliance with this rule?**

20 A. There is still quite a bit of uncertainty related to the level of costs that will  
21 be incurred. That is a good reason in and of itself to implement a tracker. If the costs end  
22 up being relatively large, it will be important for the Company to have the opportunity to  
23 recover those costs. If they end up not being as significant as they might be, then the

1 customer impact of the tracker will be small. Either way, the tracker provides an  
2 appropriate opportunity to ensure that the cost of compliance with the order will be fairly  
3 accounted for in the ratemaking process.

4 Cost categories where we anticipate the potential for significant new costs may  
5 include new data services for condition monitoring, new software, additional full-time  
6 employees to staff monitoring activities, and increased vegetation management and/or  
7 infrastructure inspections (i.e., either higher frequency or greater scope of activities, or  
8 both, than current Commission rule requirements). We have no history of these costs to  
9 establish a basis for their inclusion in this revenue requirement, but it is appropriate for the  
10 Company to have the opportunity to recover them nonetheless.

11 **Q. Are there any analogous circumstances where the Commission has**  
12 **utilized trackers?**

13 A. Yes. When the Vegetation Management Rule was first initiated, electric  
14 utilities were allowed to track new costs. See 20 CSR 4240-23.030(10):

15 "(10) In the event an electrical corporation incurs expenses as a result of this  
16 rule in excess of the costs included in current rates, the corporation may submit a  
17 request to the commission for accounting authorization to defer recognition and  
18 possible recovery of these excess expenses until the effective date of rates resulting  
19 from its next general rate case, filed after the effective date of this rule, using a  
20 tracking mechanism to record the difference between the actually incurred expenses  
21 as a result of this rule and the amount included in the corporation's rates, or if there  
22 is no identifiable amount included in the corporation's rates, the amount reflected  
23 in the appropriate uniform system of accounts account for vegetation management  
24 on the corporation's books for the test year (as updated) from the corporation's last  
25 rate case will be used to determine the amount included in current rates. In the event  
26 that such authorization is granted, the next general rate case must be filed no later  
27 than five (5) years after the effective date of this rule. Parties to any electrical  
28 corporation request for accounting authorization pursuant to this rule may ask the  
29 commission to require the electrical corporation to collect and maintain data (such  
30 as actual revenues and actual vegetation management expenses) until such time as  
31 the commission addresses ratemaking for the deferrals. The commission will

1 address the ratemaking of any costs deferred under these accounting authorizations  
2 at the time the electrical corporation seeks ratemaking in a general rate case."

3 While there is no Commission rule expressly addressing a wildfire mitigation  
4 tracker, the policy rationale that underlies the vegetation management rule provision I just  
5 cited can be nearly identically applied to this circumstance.

6 Also, in Spire's most recent gas rate case, File No. GR-2025-0107, parties stipulated  
7 and the Commission approved an "Advanced Leak Detection Tracker" related to a new  
8 federal regulation that is also very analogous to the wildfire mitigation facts without any  
9 Commission rule requiring or expressly authorizing such a tracker.

10 "The Signatories agree that the Company will implement an Advanced Leak  
11 Detection tracker to track costs incurred to ensure compliance with the pending  
12 federal Leak Detection and Repair regulation. Internal labor costs will be  
13 excluded."<sup>28</sup>

14 Similar to the examples that I cited above related to the vegetation management  
15 rules and the leak detection regulations, the emergence of the wildfire issue and the new  
16 costs that may arise from compliance with the Commission's related order warrant a tracker  
17 in order to ensure that the utility has an opportunity to recover these new costs that are not  
18 contemplated in its historic test year revenue requirement.

19 **X. SOLAR STIPULATION COMPLIANCE**

20 **Q. Is the Company including in rate base in this proceeding investment**  
21 **associated with new renewable generation resources?**

22 A. Yes. The Company expects to have placed into service, prior to the true-up  
23 date in this case, three new solar energy centers for which the Commission has granted

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<sup>28</sup> File No, GR-2025-0107, *Stipulation and Agreement*, p. 4, issued September 3, 2025

1 CCNs in the last year and a half – the Vandalia Energy Center ("Vandalia"), the Bowling  
2 Green Energy Center ("Bowling Green"), and the Split Rail Energy Center ("Split Rail").

3 **Q. Are there any conditions associated with those CCN approvals that you**  
4 **will be addressing?**

5 A. Yes. The approval of the CCN for each of these facilities was subject to  
6 certain conditions that were agreed to by the Company and certain parties to the CCN case  
7 (File No. EA-2023-0286) as a part of a Stipulation and Agreement resolving the issues in  
8 that case ("Solar Stipulation"). Some of those conditions require information to be provided  
9 in the first case in which the investments in these facilities are requested to be included in  
10 the Company's rate base, which is this case.<sup>29</sup> I will address these conditions from the Solar  
11 Stipulation in this section of my testimony.

12 **Q. What is the first condition from the Solar Stipulation that you will**  
13 **discuss?**

14 A. The Solar Stipulation required that the treatment of tax credits arising from  
15 the facilities be determined in a future rate proceeding under the Inflation Reduction Act  
16 ("IRA") tracker established in File No. ER-2022-0337. The status of the tax credits varies  
17 by facility. For Vandalia, the Company has already sold Investment Tax Credits ("ITC's")  
18 to a third party and tracked the proceeds of that sale. For Bowling Green and Split Rail,  
19 such transactions are not yet complete but are anticipated by the true-up date in this case.  
20 As such, the Company has included an expectation of the sale of ITCs from all three  
21 facilities in its estimate of the IRA tax credits that will be included in the tracker, subject

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<sup>29</sup> These commitments also apply to the another project for which a CCN was approved in the Solar Stipulation, but that other project was placed in service prior to the true-up date in the Company's last rate case, so this is not its first inclusion in a rate case.

1 to true-up. The Company, per the testimony of Company witness Stephen J. Hipkiss,  
2 proposes to amortize the regulatory liability associated with that deferral as it exists at the  
3 true-up date over a period of two years as an offset to its revenue requirement in this case.

4 **Q. Please address the second condition from the Solar Stipulation.**

5 A. The Solar Stipulation required that, if the capital cost of the facility exceeds  
6 **\*\* \_\_\_ \*\*** of the cost modeled by the Company for the project in the case where the CCNs  
7 for the facilities were approved, the Company would provide certain information  
8 explaining why the Company proceeded with the acquisition of the facility. For Vandalia  
9 and Bowling Green, which went into service during the test year, I can provide a final  
10 assessment of this condition.<sup>30</sup> As such, I can confirm that neither project exceeded the  
11 threshold at which additional information is required. While, at the time of this writing, the  
12 Split Rail acquisition has not closed and the resource has not been placed into service, and  
13 therefore the final total capital cost of the facility has not been determined, it is currently  
14 not anticipated that the cost will exceed the threshold from the Solar Stipulation. Therefore,  
15 there are no additional requirements related to that provision of the Solar Stipulation for  
16 any of the facilities at this time.

17 **Q. What is the next condition from the Solar Stipulation you will address?**

18 A. Paragraph 5(c) of the Solar Stipulation included the five items below, which  
19 the Company agreed to address in the first rate case in which the Company's investment in  
20 the facilities was proposed to be included in the Company's rate base.

21 (1) satisfaction of the in-service criteria (addressed below) and  
22 documentation that those criteria have been met to the extent possible at the  
23 time of that direct filing;

---

<sup>30</sup> Technically, a small amount of additional investment is expected prior to the true-up date in this case. An estimate of those incremental investment amounts is reflected in the numbers referred to and reported herein.

1           As of the filing of this case, the Vandalia and Bowling Green facility have been  
2 placed in service, and the in-service criteria documentation has been provided to Staff on  
3 December 12, 2025 and April 1, 2026 respectively. Split Rail has not been placed in-service  
4 yet at this time. Documentation of the in-service criteria will be provided to Staff once the  
5 facility is placed into service, prior to the final inclusion of the investment in Split Rail  
6 being reflected in the trued-up rate base.

7           (2) an explanation of the capital costs incurred;

8           The capital costs reflected in the determination of the revenue requirement  
9 associated with Vandalia in this case is \*\*\* \_\_\_\_\_ \*\*\*. The capital costs reflected in  
10 the determination of the revenue requirement associated with Bowling Green in this case  
11 is \*\*\* \_\_\_\_\_ \*\*\*. As of this writing, the acquisition of Split Rail has not been closed  
12 and the facility has not been placed into service, so final capital costs are not known with  
13 certainty. The Company has included a pro forma adjustment to the rate base underlying  
14 its filed revenue requirement in this case for the investment expected in Split Rail by the  
15 true-up date. That pro forma adjustment reflected an expected investment in the facility of  
16 \*\*\* \_\_\_\_\_ \*\*\*.

17           (3) an explanation of the tax treatments to be pursued;

18           As noted above, the Company has sold or anticipates selling by the true-up date the  
19 ITCs earned associated with each of the three facilities. Because the Internal Revenue  
20 Service has recently issued guidance that indicates that ITCs under the IRA will not be  
21 subject to normalization requirements when transferred to a third-party entity in exchange  
22 for cash considerations, claiming ITCs has greater economic value than claiming  
23 production tax credits ("PTCs"), which could be chosen in lieu of ITCs. The Company's

1 analysis of each of the three projects demonstrated a lower net present value of revenue  
2 requirement for the project as a whole when electing ITCs and transferring those to third  
3 parties.

4 (4) an explanation of the property tax treatment to be pursued;

5 Each of the three facilities is the subject of a Chapter 100 financing agreement with  
6 the counties in which they are located, and are therefore subject to payments in lieu of taxes  
7 rather than property taxes.

8 (5) an explanation of all related expenses and offsetting revenues and a discussion  
9 of the factors that will impact those expenses going forward as estimated at the time  
10 of filing.

11 Expenses associated with the facilities include depreciation expense, the return on  
12 the Company's net investment in the facility at the Company's weighted average cost of  
13 capital ("WACC") plus applicable income taxes, land lease costs, interconnection costs,  
14 property taxes, facility maintenance costs, and the cost of property insurance. The factors  
15 impacting these expenses going forward will be capital market conditions that impact  
16 interest rates and the Company's WACC, income tax rates, and general inflation as it  
17 impacts our other categories of operations and maintenance ("O&M") expense. The pro  
18 forma test year amounts of O&M expense associated with Vandalia, Bowling Green, and  
19 Split Rail reflected in the revenue requirement in this case respectively are \$233,000,  
20 \$250,000, and \$2,964,919.

21 Offsetting revenues will include revenues generated by the sale of energy and  
22 capacity into the MISO market, in addition to revenues generated by customer  
23 subscriptions to each facility under the RSP, which was discussed in more detail in an  
24 earlier section of my testimony. Estimated energy revenues and capacity revenues for each

1 facility included as an offset to net energy costs in the Company's revenue requirement in  
2 this case are shown in Table 4 below.

3 Table 4 – Energy and Capacity Market Revenues Included in Net Energy Costs

	<b>Energy</b>	<b>Capacity</b>
Vandalia	\$4,442,404	\$1,914,442
Bowling Green	\$4,442,404	\$1,991,019
Split Rail	\$26,029,700	\$11,486,651
Total	\$34,914,507	\$15,392,112

4 Factors influencing future levels of these offsetting revenues include the level the  
5 production (energy) and accreditation (capacity) of the facilities, as well as changes in  
6 energy and capacity market prices in the future. Although not technically a revenue,  
7 expenses associated with each facility are also be offset by ITCs as discussed in more detail  
8 above.

9 **Q. Does this conclude your Direct Testimony?**

10 A. Yes, it does.



Project	Amount to go in service by			Depreciation Rate	Annual Depreciation Expense	Rate Base Return @ 7.506% WACC	Equity Return Component	Tax Gross Up on Equity Return	Rate Base Return w/ Tax Gross Up	Total RR Impact
	true up by Project	Plant Acct in RR	\$ Per Plant Acct in RR							
	166,282	362	166,282	1.85%	3,076	12,481.16	8,862.51	2,745	15,226	18,303
	0	N/A			N/A	N/A	-	-	-	-
	1,247,089	355	810,608	3.65%	29,587	60,844.22	43,203.73	13,383	74,227	103,814
		356	436,481	2.37%	10,345	32,762.27	23,263.55	7,206	39,968	50,313
	(33,618)	353	(33,618)	2.03%	(682)	(2,523.40)	(1,791.80)	(555)	(3,078)	(3,761)
	15,856	364	7,928	4.33%	343	595.06	422.53	131	726	1,069
		365	7,928	2.33%	185	595.06	422.53	131	726	911
	3,822,268	303	3,822,268	20%	764,454	286,899.46	203,719.07	63,104	350,003	1,114,457
	135,739	364	67,869	4.33%	2,939	5,094.28	3,617.30	1,120	6,215	9,154
		365	67,869	2.33%	1,581	5,094.28	3,617.30	1,120	6,215	7,796
	1,477,647	364	738,824	4.33%	31,991	55,456.11	39,377.79	12,198	67,654	99,645
		365	738,824	2.33%	17,215	55,456.11	39,377.79	12,198	67,654	84,868
	1,236,911	364	618,456	4.33%	26,779	46,421.28	32,962.42	10,210	56,632	83,411
		365	618,456	2.33%	14,410	46,421.28	32,962.42	10,210	56,632	71,042
	1,237,113	364	618,556	4.33%	26,783	46,428.84	32,967.79	10,212	56,641	83,424
		365	618,556	2.33%	14,412	46,428.84	32,967.79	10,212	56,641	71,053
	302,585	364	151,292	4.33%	6,551	11,356.00	8,063.57	2,498	13,854	20,405
		365	151,292	2.33%	3,525	11,356.00	8,063.57	2,497.75	13,853.76	17,378.87
<b>Total</b>	<b>\$ 9,607,872</b>		<b>\$ 9,607,872</b>		<b>\$ 953,494</b>	<b>\$ 721,167</b>	<b>\$ 512,080</b>	<b>\$ 158,621</b>	<b>\$ 879,788</b>	<b>\$ 1,833,282</b>

Wtd Avg Depreciation Rate 9.92%

ER-2026-0291

Schedule SMW-  
D2 is Highly  
Confidential  
Highly Sensitive  
in its Entirety

Due to EFIS not supporting Highly Confidential  
Highly Sensitive information, please contact  
MORegParalegals@ameren.com for further  
assistance.

UNION ELECTRIC COMPANY

ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 61.5

CANCELLING MO.P.S.C. SCHEDULE NO. 6

1st Revised

SHEET NO. 61.5

APPLYING TO MISSOURI SERVICE AREA

\* THIS SHEET RESERVED FOR FUTURE USE

\*Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)

\* LARGE LOAD CUSTOMER SERVICE RATE

RATE BASED ON MONTHLY METER READINGS

Table with 2 columns: Description and Rate. Rows include Customer Charge (\$ 412.66), Low-Income Pilot Program Charge (\$ 291.99), and Reactive Charge (44.81¢).

Standard Rates

Summer Rate (June through September)

Table with 2 columns: Description and Rate. Rows include Energy Charge (4.06¢) and Demand Charge (\$ 22.43).

Winter Rate (October through May)

Table with 2 columns: Description and Rate. Rows include Energy Charge (3.71¢) and Demand Charge (\$ 10.66).

Alternate 4 Season Demand and Time-of-Use Energy Rates ("Alternate Rates")

Summer Rate (June through August)

Table with 2 columns: Description and Rate. Rows include On Peak kWh (6.16¢), Off Peak kWh (3.24¢), and Demand Charge (\$ 22.43).

Fall Rate (September through November)

Table with 2 columns: Description and Rate. Rows include On Peak kWh (4.13¢), Off Peak kWh (2.98¢), and Demand Charge (\$ 9.16).

Winter Rate (December through February)

Table with 2 columns: Description and Rate. Rows include On Peak kWh (3.87¢), Off Peak kWh (3.75¢), and Demand Charge (\$ 17.58).

Spring Rate (March through May)

Table with 2 columns: Description and Rate. Rows include On Peak kWh (3.60¢), Off Peak kWh (2.89¢), and Demand Charge (\$ 9.16).

DATE OF ISSUE December 5, 2025 DATE EFFECTIVE January 4, 2026

ISSUED BY Michael Moehn Interim Chairman & President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 61.5

CANCELLING MO.P.S.C. SCHEDULE NO. 6

1st Revised

SHEET NO. 61.5

APPLYING TO \_\_\_\_\_

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~~\*Indicates Addition.~~

DATE OF ISSUE December 5, 2025

DATE EFFECTIVE January 4, 2026

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd)

All months refer to calendar months.

Time-of-Use Periods for Alternate Rate Seasons:

- \_\_\_\_\_ Spring - March Through May
- \_\_\_\_\_ Summer - June through August
- \_\_\_\_\_ Fall - September through November
- \_\_\_\_\_ Winter - December through February

On-Peak/Off-Peak Energy Charge Periods applicable herein are:

- \_\_\_\_\_ All Seasons (Summer, Fall, Winter, Spring)
- \_\_\_\_\_ On-Peak hours - 9:00 A.M. to 9:00 P.M., All days
- \_\_\_\_\_ Off-Peak hours - 9:00 P.M. to 9:00 A.M., All days

On-Peak/Off-Peak Demand Charge Periods for both Standard and Alternate Rates applicable herein are:

- \_\_\_\_\_ All Seasons
- \_\_\_\_\_ On-Peak hours - 6:00 A.M. to 10:00 P.M., All days
- \_\_\_\_\_ Off-Peak hours - 10:00 P.M. to 6:00 A.M., All days

Service Voltage for Large Load Customer Service: 115 kV or greater

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC) Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM) Applicable to all metered kilowatt-hours (kWh) of energy.

Securitized Utility Tariff Rider (Rider SUR) Applicable to all metered kilowatt-hours (kWh) of energy.

Cost Stabilization Rider (Rider CSR) Applicable to all metered kilowatt-hours (kWh) of energy.

Tax Adjustment Any license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

Payments Large Load Customer bills are due and payable within thirty (30) days from date of bill and become delinquent thereafter.

Term of Use One (1) year, terminable thereafter on three (3) days' notice.

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

1. RATE APPLICATION

~~Service under this rate is required for (i) any new facility beginning service after the effective date of the tariff sheets for Large Load Customer Service (the "Effective Date") with a peak load forecast reasonably expected to be equal to or in excess of a monthly maximum demand of seventy-five megawatts (75 MW) at any time during the Term or Extension Term; or (ii) any existing customers, who expand such that, after the Effective Date, have a monthly maximum demand that is reasonably expected to exceed their pre-existing demand by seventy-five megawatts (75 MW), then this rate shall be applicable to the expansion load.~~

~~For the purpose of determining applicability of this rate, Company may exercise its discretion to aggregate premises served at a distribution voltage premises based on factors including, but not limited to, multiple premises with common owner(s) or a common parent company, or multiple premises sharing one or more of the following: common ownership, common local electrical infrastructure, physical layout, character of service, end use, and common control.~~

2. CHARACTER OF SERVICE SUPPLIED

~~Company will specify and supply service at a voltage of 115 kV or greater where the customer will own or otherwise bear financial responsibility for construction and operation of the distribution substation. Large Load Customer operations shall comply with Company's End User Connection Procedures — Requirements for the Connection of Customer Load to the Ameren Transmission System (the "End User Requirements"), which are adopted by Company or on its behalf by Ameren Services Company, as such End User Requirements may be revised from time-to-time.~~

~~LLCS customer premises (also referred to herein as a facility) shall generally mean a single point of interconnection, though the Company and customer may use multiple meters if determined appropriate. The Company maintains full discretion to evaluate whether multiple meters or premises may or may not be aggregated for purposes of the application of this rate, and in its sole reasonable discretion may require multiple meters or premises, including premises served at distribution voltages, to be considered an aggregate load that shall take service under this rate.~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

3. METERING EXPANSION LOAD

~~For customer facilities taking service under this rate due to expansion, the Company may install metering equipment necessary to measure the incremental load subject to this rate. The Company reserves the right to make the determination of whether such load will be separately metered or sub-metered. If the Company determines that the nature of the expansion is such that either separate metering or sub-metering is impractical or economically infeasible, the Company will determine, based on historical usage, what portion of the Customer's load in excess of the monthly baseline, if any, will be subject to this rate and the LLCS Service Agreement.~~

4. BILLING DEMAND

~~The billing demand in any month will be the highest demand established during on peak hours or fifty percent (50%) of the highest demand established during off peak hours, whichever is highest during the month, but in no event less than eighty percent (80%) of the Contract Capacity specified in the LLSC Service Agreement ("Minimum Billing Demand").~~

5. REACTIVE CHARGE

~~The charge specified in this rate shall be applicable to the kilovars by which the customer's average metered kilovars exceed the customer's kilovars at an average power factor of ninety percent (90%) lagging during the billing period. Such average kilovar billing units shall be determined in accordance with the following formula:~~

$$\text{kVar} = \left( \frac{\text{kVarh}}{\text{kWh}} - 0.4043 \right) (\text{kW})$$

~~where:~~

~~kVar = kilovar billing units~~

~~kVarh = metered kilovar hours~~

~~kWh = metered kilowatt-hours~~

~~kW = metered kilowatts~~

~~0.4043 = kilovar requirement at a 90% lagging power factor.~~

~~Where in the Company's judgment application of the above formula would not be appropriate to full or partial self generation customers, an alternative agreement, between Company and customers, for the payment of reactive supply facilities may be substituted for said formula.~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

6. ALTERNATE 4 SEASON DEMAND AND TIME OF USE ENERGY RATES

~~At customer's election made in the manner specified below, the Alternate Rates will be used for billing a customer's energy consumption in lieu of the Standard Rates for energy and demand, except that, any customer that expects to operate at an annual load factor lower than seventy-five percent (75%), or that fails to maintain a load factor of 75% during the term of the LLCS Service Agreement determined as provided for below, shall, post the Ramp Period provided for in Section 9 of this rate, be subject to mandatory application of the Alternate Rates in lieu of the Standard Rate[s] for energy and demand.~~

~~To elect service under time-based energy charges, a customer must, at any time during the Term or any Extension Term in their LLCS Service Agreement, give written notice to the Company sixty (60) days or more prior to the date the customer's notice is to take effect. The election shall take effect on the first day of the calendar month following 60 days after the notice was given.~~

~~Whether a customer failed to maintain a load factor of 75% for any given year shall be determined by the Company based on a review of that year's energy consumption and demand data, with such review to occur annually based on the most recently completed year of the Term or Extension Term. Should the Company's review determine that the customer failed to maintain of load factor of 75% for the year in question, Company will notify the customer in writing that prospective billings will be based on time based energy and demand charges until such time as customer maintains a load factor of 75% for a full year as determined in the annual review process described above.~~

7. CUMULATION OF SERVICES

~~For a Large Load Customer that, in Company's judgment, requires multiple points of service for an individual premises, the individual meters will be combined prior to determining the demand applicable to billing.~~

8. ELECTRIC SERVICE AGREEMENT

~~Customers receiving service under this rate are required to enter in a written service agreement (the "LLCS Service Agreement") that specifies certain provisions of their electric service, including Contract Capacity. Which of Riders CEC, RPS-LLC, CCAP, and NEC that are applicable to customer's service will be specified in an exhibit attached to the LLCS Service Agreement, which may be periodically amended subject to the mutual agreement of the Company and customer to reflect customer's participation in such Company offered programs. LLCS Service Agreements must be consistent with approved tariffs applicable to Large Load Customers.~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

9. SERVICE TERM

~~Customers to which this rate applies shall take service for a minimum term that includes up to five (5) years of an optional transitional load ramp period ("Load Ramp" or "Ramp Period") plus twelve (12) years (the "Term"). The Term shall commence on the date permanent service begins, or as set forth in the LLCS Service Agreement. During the transitional Ramp Period, the customer's maximum load may be lower than seventy-five megawatts (75 MW). Specific details of the customer's Load Ramp may be addressed in the LLCS Service Agreement. Unless otherwise mutually agreed in the LLCS Service Agreement, the LLCS Service Agreement will automatically extend for periods of five years ("Extension Term") at the end of the Term or any Extension Term, unless either party to the LLCS Service Agreement provides at least thirty-six (36) months' written notice to the other party prior to the end of the Term or any Extension Term or its intent not to renew the LLCS Service Agreement, or of its intent to renew the LLCS Service Agreement for the Extension Term at a reduced Contract Capacity. A customer providing notice of non-extension will remain subject to the Exit Fee and Early Termination Fee based upon the remainder of the Term or Extension Term to the extent applicable under the customer's LLCS Service Agreement, provided that so long as timely written notice is given and the notifying customer continues its service for the remaining Term or Extension Term, as applicable, no Exit Fee or Early Termination Fee shall apply. Service shall remain in effect throughout the Term and any Extension Term unless cancelled, modified, or terminated in writing and pursuant to the terms of Schedule LLCS or the LLCS Service Agreement, or the customer changes to another applicable Company rate schedule pursuant to the terms of this rate.~~

10. CONTRACT CAPACITY

~~The LLCS Service Agreement will include a Contract Capacity schedule specifying the customer's forecasted annual peak load requirement for the post Ramp Period of the Term during on peak hours. The Contract Capacity schedule shall also specify the peak load requirement for each quarter during the Load Ramp during on peak hours, if any. The LLCS Service Agreement will set out expected off-peak demand if off peak demand is expected to be greater than Contract Capacity. Unless otherwise agreed by the parties, the Contract Capacity during any Extension Term shall be the same as the Contract Capacity for the last year of the Term immediately preceding Term or Extension Term, as applicable.~~

DATE OF ISSUE December 5, 2025 DATE EFFECTIVE January 4, 2026

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

11. MAXIMUM DEMAND

~~Customer has an affirmative obligation to provide an updated peak demand forecast for each quarter of the upcoming year to provide the best current estimate of its peak demand by September 1st of each year. Customer is not authorized to exceed its Contract Capacity in any period, except (i) if the customer specifically requests authorization from Company to exceed the Contract Capacity for a limited time period, and (ii) Company verifies that such exceedance will not result in any reliability impacts. Company will provide Staff notification of any approved exceedance within five (5) business days after the approval is given, and of any cost impacts of any approved exceedance within forty-five (45) days.~~

12. PERMISSIBLE CAPACITY REDUCTION

~~A customer taking service under this rate may request to reduce the Contract Capacity during the Term or any Extension Term, with the effective date of any such reduction occurring at any time in the Term by up to twenty (20) percent of the Contract Capacity ("Permissible Capacity Reduction"), in total, without charge for such reduction. To do so, the customer must provide the Company at least twenty four (24) months' prior written notice.~~

~~In addition, the customer may request to reduce its Contract Capacity beyond the Permissible Capacity Reduction, with the effective date of any such reduction occurring at any time after the first five (5) years of the Term by giving the Company at least twenty four (24) months' written notice prior to the beginning of the year for which the reduction is sought, subject to payment of a Capacity Reduction Fee. The Capacity Reduction Fee shall be calculated as two times the difference between (a) the nominal value of the Minimum Monthly Bill using the Contract Capacity specified in the customer's ILCS Service Agreement minus (if applicable) the Permissible Capacity Reduction, times the number of months remaining in the Term or Extension Term, or for sixty (60) months, whichever is lesser, and (b) the nominal value of the Minimum Monthly Bill following such a reduction in capacity, times the number of months remaining in the Term or Extension Term, or for sixty (60) months, whichever is lesser. For avoidance of doubt, nothing in this Paragraph 12 limits the right of the customer to reduce its Contract Capacity upon thirty six (36) months' written notice before the end of the Term or Extension Term as permitted by Section 9.~~

~~The Company will use reasonable efforts to mitigate the Capacity Reduction Fee amount owed by the customer. The Company shall invoice the customer no earlier than ninety (90) days prior to the date the customer has indicated the capacity reduction will occur for any unmitigated amounts of the Capacity Reduction Fee based on the calculation described above, provided that to the extent the Company is able to sell the difference between the Minimum Demand at the~~

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**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

Original

SHEET NO. 61.11

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

APPLYING TO \_\_\_\_\_

**MISSOURI SERVICE AREA**

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DATE OF ISSUE December 5, 2025

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~~SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)~~

~~12. PERMISSIBLE CAPACITY REDUCTION (Cont'd.)~~

~~original Contract Capacity and the Minimum Demand at the reduced Contract Capacity post such a capacity reduction into the Midcontinent Independent System Operator capacity market, Company shall refund the proceeds of such capacity sales (net of all wholesale market costs to do so) to customer annually for a period equal to the lesser of (i) the remainder of the Term or Extension Term, as applicable, or (ii) sixty (60) months post the date such a capacity reduction occurred, and provided further that the total refunds to customer shall not exceed the Capacity Reduction Fee.~~

~~The customer shall pay the Capacity Reduction Fee within thirty (30) days of the date it receives an invoice from the Company for the fee. To the extent the customer seeks to reduce its Contract Capacity on less notice, and the Company can reasonably reassign Contract Capacity to another large load customer, the Company in its sole reasonable discretion may agree to a variance from these provisions. Any notice to reduce capacity is irrevocable once given by the customer unless the Company in its sole reasonable discretion determines that it can accommodate a revocation of such notice. Any capacity reduction is permanent for the Term and any Extension Term, and any request by the customer to reinstate such capacity will be subject the interconnection process described in Section P of the Distribution System Extensions provisions of the Company's General Rules and Regulations.~~

~~13. TERMINATION~~

~~In order to terminate before the end of the Term or any Extension Term, the customer must deliver a written notice (a "Termination Notice") to Ameren Missouri not less than twenty four (24) months prior to the effective date of the termination specified in the Termination Notice (the "Termination Date"). If a customer terminates its service under its Service Agreement pursuant to this Section 13 during the Ramp Period, the customer shall pay to Ameren Missouri an Exit Fee (the "Exit Fee") in an amount equal to the nominal value of the applicable Minimum Monthly Bill multiplied by the number of months in the remaining term of the Load Ramp period plus sixty (60) calendar months.~~

~~If the customer terminates its service under its LLCS Service Agreement pursuant to this Section 13 after the Ramp Period, the Customer shall pay to Ameren Missouri an Exit Fee in an amount equal to the nominal value of the applicable Minimum Monthly Bill multiplied by the lesser of (x) a period of sixty (60) calendar months or (y) the number of months in the remaining Term or Extension Term (such lesser period, the "Termination Fee Period").~~

~~An additional fee shall apply if the customer seeks to terminate with less than twenty four (24) months' notice (the "Early Termination Fee"). In such case, the Early Termination Fee shall be equal to two (2) times the nominal value of~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

13. TERMINATION (Cont'd.)

~~the applicable Minimum Monthly Bill times the number of months less than the twenty-four (24) months' notice required for termination. The Large Load Customer shall pay to Ameren Missouri the Exit Fee and, if applicable, the Early Termination Fee promptly, and in any event not more than thirty (30) days, after the Termination Date, by wire transfer of immediately available federal funds to an account located in the United States as Ameren Missouri may specify by notice.~~

~~Commencing on the date of delivery of the Termination Notice, Company shall use commercially reasonable efforts to mitigate the amount of the Exit Fee, which efforts are expressly limited to (i) during the Termination Fee Period, Company selling wholesale capacity (net of all wholesale market costs to do so), up to the Minimum Demand in the applicable Midcontinent Independent System Operator markets or via bilateral transactions, at such times and in such amounts as Company may determine, and (ii) until the Termination Date, Company seeking LLCS customers to whom it would provide bundled retail electric service, up to the Minimum Demand, to one or more other Large Load Customers (if available) pursuant to an LLCS Service Agreement with such customers. For purposes hereof, the "Refund Amount" is the aggregate net amount received by Company in connection with clauses (i) and (ii) in the preceding sentence. Within thirty (30) days after December 31 of each calendar year during the Termination Fee Period, Company shall pay to the customer the portion of the Refund Amount received by Company during such calendar year, by wire transfer of immediately available federal funds to an account located in the United States as the customer may specify by notice; provided that in no event shall the Refund Amount exceed the Termination Fee. If customer qualifies for a different rate schedule (other than Company Service Classifications 2(M), 3(M), 4(M) and the non-Large Load Customer Service provisions of 11(M)), it may elect to change to such schedule so long as it meets the requirements therein.~~

14. INTERIM CAPACITY ADJUSTMENT

~~If the Company determines that the customer's load cannot be served by the Company's existing system capabilities, the Company may enter into specific market contract agreements to provide the necessary capacity requirements of the customer until sufficient system capacity may be supplied by the Company. The customer and the Company must mutually agree on the terms for the interim capacity procured by the Company pursuant to an Interim Capacity Agreement. The customer shall be subject to an additional demand charge calculated according to the terms of the Interim Capacity Agreement, with customer responsible for the full costs thereof and the terms of the Interim Capacity Agreement.~~

DATE OF ISSUE December 5, 2025

DATE EFFECTIVE January 4, 2026

ISSUED BY Michael Moehn Interim Chairman & President

St. Louis, Missouri

NAME OF OFFICER

TITLE

ADDRESS

APPLYING TO MISSOURI SERVICE AREA

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\*Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

15. MINIMUM MONTHLY BILL

~~Customers taking service under this rate shall be subject to a Minimum Monthly Bill which shall consist of the sum of each of the following charges and shall apply in addition to any energy-based charges paid by customer:~~

- ~~i. Demand Charge (with minimum monthly demand set at 80 percent of the Contract Capacity ("Minimum Demand"));~~
- ~~ii. Customer Charge (metering, billing, customer support);~~
- ~~iii. Low-Income Pilot Program Charge~~
- ~~vi. Other Demand-Based Riders approved by the Commission in the future; and~~
- ~~v. The Cost Stabilization Rider, with minimum monthly demand set at the Minimum Demand.~~

16. COST STABILIZATION RIDER

~~Schedule LLCS customers eligible to receive service under the Company's Economic Development Rider will be subject to the Cost Stabilization Rider ("CSR"), an adjustment clause designed to ensure recovery of costs incurred to serve customer to which this rate applies. The CSR shall be applied consistent with the Missouri Economic Development Rider statute. The CSR shall be calculated based on comparing the customer's estimated base rate revenue and estimated final bill revenue prior to applying Rider CEC. Estimated base rate revenue shall be the revenue produced by all applicable base rate and riders other than Riders CEC, RSP-LLC, CCAP, and NEC and the estimated final bill revenue shall be the base rate revenue plus any applicable rate discounts, such as an approved economic development rate. Should the customer's estimated final bill revenues fall below the customer's estimated base rate revenue, an amount, expressed in a dollar per kW (\$/kW) charge, will be added to the customer billing through this charge. The CSR shall be customer specific and memorialized in the LLCS Service Agreement. This comparison shall be completed annually. The CSR shall not be subject to any related Economic Development Rider discount. Making the CSR non-bypassable ensures that customers are substantially covering the cost to serve them in their tariffed rates or any other voluntary riders in which the customer enrolls.~~

~~The CSR shall not be subject to any related Economic Development Rider discount.~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

17. CUSTOMER CREDITWORTHINESS

- ~~(1) For a customer falling within the category reflected in subsection (6) below: (1) The customer, or (2) the entity who owns the facility where the customer takes service and assumes all financial obligations associated with the facility under this rate and the LLCS Service Agreement, or (3) an entity who otherwise assumes all financial obligations associated with the facility under this rate and the LLCS Service Agreement, must be reasonably creditworthy as determined in the Company's sole reasonable discretion. As such, the Company retains discretion to evaluate the creditworthiness and credit support of the entity who assumes all contractual obligations under this rate and the LLCS Service Agreement, and to require reasonable assurances if necessary to address customer creditworthiness.~~
- ~~(2) The Company will require Schedule LLCS customers to provide collateral in an amount equal to two (2) years of Minimum Monthly Bills, as calculated by the Company (the "Collateral Requirement").~~
- ~~(3) A customer together with a Guarantor, which can include its ultimate parent, corporate affiliate, a tenant, or any other entity with a financial interest in the customer ("Guarantor") that guarantees the Collateral Requirement under Schedule LLCS and the LLCS Service Agreement (i) has a credit rating of at least A- from Standard & Poor's ("S&P") and A3 from Moody's, (ii) and if rated A- or A3 has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, and (iii) has liquidity greater than ten (10) times the collateral requirement as of the end of applicable period (and which must be shown by providing financial statements and a chief financial officer or a third party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the period) (collectively, "60% Eligibility Requirements") will be exempt from sixty (60) percent of the Collateral Requirement, with the sixty (60) percent discount not to exceed \$175 million. "Period" for public companies shall be the interval for reporting required by the Securities and Exchange Commission, for all other companies "Period" shall be each calendar quarter.~~
- ~~(4) A customer that does not have an A- credit rating from S&P and A3 rating from Moody's, but (together with a Guarantor that guarantees the Collateral Requirement under Schedule LLCS and the LLCS Service Agreement) (i) has at least a BBB+ credit rating from S&P and Baal credit rating from Moody's, (ii) has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, and (iii) has liquidity greater~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

17. CUSTOMER CREDITWORTHINESS (Cont'd.)

~~(4) Cont'd.)~~

~~than ten (10) times the Collateral Requirement as of the end of the applicable quarter (as determined in the Company's reasonable discretion, and which must be shown by providing quarterly financial statements and a chief financial officer or a third party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the quarter) (collectively, "50% Eligibility Requirements") will be exempt from fifty (50) percent of the Collateral Requirement, with the fifty (50) percent discount not to exceed \$150 million.~~

~~(5) A customer that does not have an A- credit rating from S&P and A3 rating from Moody's, but (together with a Guarantor that guarantees the Collateral Requirement under Schedule LLCS and the LLCS Service Agreement) (i) has at least a BBB- credit rating from S&P and Baa3 credit rating from Moody's, (ii) has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, and (iii) has liquidity greater than ten (10) times the Collateral Requirement as of the end of the applicable quarter (as determined in the Company's reasonable discretion, and which must be shown by providing quarterly financial statements and a chief financial officer or a third party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the quarter) (collectively, "40% Eligibility Requirements") will be exempt from forty (40) percent of the Collateral Requirement, with the forty (40) percent discount not to exceed \$125 million.~~

~~(6) A customer that does not have an A- credit rating from S&P and A3 rating from Moody's, but (together with a Guarantor that guarantees the Collateral Requirement under this rate and the LLCS Service Agreement) either (i) has at least a BBB- credit rating from S&P and Baa3 credit rating from Moody's, and has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, or (ii) has liquidity greater than ten (10) times the Collateral Requirement as of the end of the applicable quarter (as determined in the Company's reasonable discretion, and which must be shown by providing quarterly financial statements and a chief financial officer or a third party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the quarter) (collectively, "25% Eligibility Requirements") will be exempt from twenty five (25)~~

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**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

Original

SHEET NO. 61.16

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

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**MISSOURI SERVICE AREA**

~~percent of the Collateral Requirement, with the twenty five (25) percent discount not to exceed \$75 million.~~

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

17. CUSTOMER CREDITWORTHINESS (Cont'd.)

- ~~(7) The 60% Eligibility Requirements, the 50% Eligibility Requirements, the 40% Eligibility Requirements, and the 25% Eligibility Requirements are collectively referred to as the "Discount Eligibility Requirements."~~
- ~~(8) The Collateral Requirement must be provided at the time of executing the LLC Service Agreement.~~
- ~~(9) Any collateral provided to satisfy the Collateral Requirement shall not accrue interest while held by the Company.~~
- ~~(10) The Company will, in its sole reasonable discretion, after the customer has achieved their peak load for at least three (3) years, annually consider reducing the customer's collateral obligation over the course of its contract period, on a schedule generally corresponding to the reduction of risk to the Company and its customers. The Company will consider the customer's performance criteria, which includes, but is not limited to the customer's: (i) financial condition, (ii) load performance, (iii) payment history, (iv) credit rating, and (v) any default history.~~
- ~~(11) The amount of the Collateral Requirement under the foregoing calculation will be recomputed quarterly based upon the customer's rolling twenty-four (24)-month load forecast as of the first date of the next quarter, and the customer shall provide the recomputed amount if greater than the current amount held. The Company shall notify a customer if the customer no longer meets the applicable Discount Eligibility Requirements, including if the customer has been placed on credit watch, if applicable to such eligibility.~~
- ~~(12) The Collateral Requirement must be provided in one or more of the following Forms, provided, that the Company shall have the right to choose the acceptable form of collateral among those listed below for any customer that qualifies for a Discount of twenty five percent (25%) or less:
 
  - ~~a. A guarantee from the customer's Guarantor for the applicable Collateral Requirement, so long as the Guarantor meets the applicable Discount Eligibility Requirement, provided that the dollar amount of the Collateral Requirement that may be provided under the guarantee is subject to credit review by the Company. The guarantee must be in a format acceptable to and approved by the Company, and must include (i) if the Guarantor's creditworthiness is considered for determining the Discount Eligibility Requirements, a commitment from the Guarantor to pay the Collateral Requirement if the customer fails to make such payments (without a dollar limit), and (ii) a provision that automatically increases the dollar amount of collateral covered by the~~~~

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**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

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SHEET NO. 61.17

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

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~~guarantee if either the customer or Guarantor no longer satisfies the applicable Discount Eligibility Requirement, or,~~

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~~SERVICE CLASSIFICATION NO. 11(M)~~  
~~LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)~~

17. ~~CUSTOMER CREDITWORTHINESS (Cont'd.)~~

~~(12) Cont'd.)~~

~~b. A standby irrevocable Letter of Credit ("Letter of Credit") for the applicable Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the customer or its Guarantor, with a credit rating of at least A- from S&P and A3 from Moody's and a minimum of \$2 billion in assets. Such security must be issued for a minimum term of three hundred sixty (360) days. The customer must cause the renewal or extension of the security for additional consecutive terms of three hundred sixty (360) days or more no later than thirty (30) days prior to each expiration date of the security. If the customer no longer satisfies the applicable Discount Eligibility Requirement, it must increase the amount covered by the Letter of Credit within ten (10) days. If the security is not renewed, extended, or increased as required herein, the Company will have the right to draw immediately upon the Letter of Credit and/or demand cash collateral in the amount of the required increase and be entitled to hold the amounts so drawn or received as security until the customer has either (i) come back into compliance with the requirements for use of a Letter of Credit or, (ii) if required by the Company, has provided an alternative form of collateral consistent with this rate. The Letter of Credit must be in a format acceptable to and approved by the Company; or~~

~~e. A cash deposit for the applicable Collateral Requirement.~~

~~(13) In case of an uncured breach by the customer of the LLC Service Agreement, an uncured breach of the Guarantor under the parent guaranty, or any notice of termination or refusal to continue the Letter of Credit by the issuing bank, the Company may draw on the applicable collateral, as further set forth in the LLC Service Agreement.~~

~~(14) If, at any time after Customer's initial delivery of the collateral the customer fails to comply with the Collateral Requirement, the Company may thereafter pursue any and all rights and remedies at law or in equity, and may take any other action consistent with the LLC Service Agreement, this rate, and the Company's General Rules and Regulations, including but not limited to suspension or curtailment of service.~~

~~(15) To the extent the Company draws on a cash deposit provided by a customer, the Company draws funds from a Letter of Credit or Guarantee, or the Company receives a cash Exit Fee, the Company will defer the amount received minus any amount used to pay for services rendered, together with the Company's weighted average cost of capital, as a regulatory liability to be addressed in the next general ratemaking proceeding.~~

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MO.P.S.C. SCHEDULE NO. 6

Original

SHEET NO. 61.18

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

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SERVICE CLASSIFICATION NO. 11(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

18. LARGE LOAD CUSTOMER RIDERS

~~In addition to the applicability of Riders FAC, EEIC, SUR, and RESRAM to service provided to Large Load Customers, the following additional Riders shall apply to Large Load Customer's service under an applicable LLCS Service Agreement if selected by the Large Load Customer pursuant to such applicable LLCS Service Agreement:~~

- ~~1. Renewable Solutions Program Large Load Customers Program (Rider RSP-LLC)~~
- ~~2. Clean Capacity Advancement Program (Rider CCAP)~~
- ~~3. Nuclear Energy Credit Program (Rider NEC)~~
- ~~4. Clean Energy Choice Program (Rider CEC)~~

~~Notwithstanding any provisions of Rider RESRAM to the contrary, a Large Load Customer shall not be subject to RESRAM charges if it participates in Rider RSP-LLC or any other voluntary rider offered by Company and thereby receives or is reasonably projected to receive renewable attributes supporting its load at a level that is greater than or equal to the then applicable "RES portfolio requirement" as defined in 20 CSR 4240-20.100(1)(R). For Large Load Customers with such participation agreements, the Large Load Customer's entire load that is supported with renewable~~

~~attributes it receives or is reasonably projected to receive that are sufficient to cover the applicable "RES portfolio requirement" as defined in 20 CSR 4240-20.100(1)(R) will be subtracted from the calculation of "total retail electric sales" as defined in 20 CSR 4240-20.100(1)(W). RESRAM charges shall still apply to such a Large Load Customer to the extent the renewable attributes it receives or is reasonably projected to receive do not reach the then applicable "RES portfolio requirement". For purposes of this Section 8, "renewable attributes" means Renewable Energy Credits, as defined in 20 CSR 4240-20.100(1)(N), that the Large Load Customer has retired or had retired on its behalf through such programs. Large Load Customers participating in Rider RSP-LLC or other voluntary riders offered by Company for which renewable attributes are produced will be evaluated for this exemption annually or more frequently if a customer's participation to such program(s) changes. Such annual or more frequent evaluations shall be used by the Company to demonstrate compliance with the accelerated renewable buyer provisions of Section 393.1030.2(5), RSMo.~~

19. GENERAL RULES AND REGULATIONS

~~In addition to the above specific rules and regulations, all of the Company's General Rules and Regulations shall apply to the supply of service under this rate.~~

DATE OF ISSUE December 5, 2025 DATE EFFECTIVE January 4, 2026

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MO.P.S.C. SCHEDULE NO. 6 87th Revised SHEET NO. 62

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APPLYING TO MISSOURI SERVICE AREA

**SERVICE CLASSIFICATION NO. 1411 (M)**  
**LARGE LOAD CUSTOMER SERVICE RATE**

**RATE BASED ON MONTHLY METER READINGS**

Customer Charge - per month	\$ <del>456.85</del> <del>12.66</del>
Low-Income Pilot Program Charge - per month	\$ <del>101.26</del> <del>291.99</del>
Reactive Charge - per kVar	<del>49.61</del> <del>4.81</del> ¢

**Standard Rates**

Summer Rate (June through September)

Energy Charge - per kWh	4. <del>49</del> <del>06</del> ¢
Demand Charge - per kW of Billing Demand	\$ <del>24.83</del> <del>2.43</del>

Winter Rate (October through May)

Energy Charge - per kWh	<del>4.11</del> <del>3.71</del> ¢
Demand Charge - per kW of Billing Demand	\$ <del>11.80</del> <del>0.66</del>

**Alternate 4 Season Demand and Time-of-Use Energy Rates ("Alternate Rates")**

Summer Rate (June through August)

Energy Charge - per kWh	
On-Peak kWh	6. <del>82</del> <del>16</del> ¢
Off-Peak kWh	3. <del>59</del> <del>24</del> ¢
Demand Charge - per kW of Billing Demand	\$ <del>24.83</del> <del>2.43</del>

Fall Rate (September through November)

Energy Charge - per kWh	
On-Peak kWh	4. <del>57</del> <del>13</del> ¢
Off-Peak kWh	<del>3.30</del> <del>2.98</del> ¢
Demand Charge - per kW of Billing Demand	\$ <del>10.14</del> <del>9.16</del>

Winter Rate (December through February)

Energy Charge - per kWh	
On-Peak kWh	<del>4.28</del> <del>3.87</del> ¢
Off-Peak kWh	<del>4.15</del> <del>3.75</del> ¢
Demand Charge - per kW of Billing Demand	\$ <del>19.46</del> <del>7.58</del>

Spring Rate (March through May)

Energy Charge - per kWh	
On-Peak kWh	3. <del>99</del> <del>60</del> ¢
Off-Peak kWh	<del>3.20</del> <del>2.89</del> ¢
Demand Charge - per kW of Billing Demand	\$ <del>10.14</del> <del>9.16</del>

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MO.P.S.C. SCHEDULE NO. 6 ~~3rd<sup>rd</sup>~~ Revised SHEET NO. 62.1

CANCELLING MO.P.S.C. SCHEDULE NO. 6 ~~2nd<sup>nd</sup>~~ Revised SHEET NO. 62.1

APPLYING TO MISSOURI SERVICE AREA

**SERVICE CLASSIFICATION NO. 1411(M)**  
**LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)**

**RATE BASED ON MONTHLY METER READINGS (Cont'd)**

All months refer to calendar months.

Time-of-Use Periods for Alternate Rate Seasons:

- Spring - March Through May
- Summer - June through August
- Fall - September through November
- Winter - December through February

On-Peak/Off-Peak Energy Charge Periods applicable herein are:

All Seasons (Summer, Fall, Winter, Spring)

- On-Peak hours - 9:00 A.M. to 9:00 P.M., All days
- Off-Peak hours - 9:00 P.M. to 9:00 A.M., All days

On-Peak/Off-Peak Demand Charge Periods for both Standard and Alternate Rates applicable herein are:

All Seasons

- On-Peak hours - 6:00 A.M. to 10:00 P.M., All days
- Off-Peak hours - 10:00 P.M. to 6:00 A.M., All days

Service Voltage for Large Load Customer Service: 115 kV or greater

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC) Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM) Applicable to all metered kilowatt-hours (kWh) of energy.

Securitized Utility Tariff Rider (Rider SUR) Applicable to all metered kilowatt-hours (kWh) of energy.

Cost Stabilization Rider ~~(Rider CSR)~~ Applicable to all metered kilowatt-~~hours~~ (kWh) of demand energy.

Tax Adjustment Any license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

Payments Large Load Customer bills are due and payable within thirty (30) days from date of bill and become delinquent thereafter.

Term of Use With respect to General Rules and Regulations, V. Billing Practices, Change of Rate, and for purposes of switching between the Standard Rates and Alternate Rates of this Service classification 14(M), the customer shall remain on

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**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 ~~3rd~~<sup>2nd</sup> Revised SHEET NO. 62.1

CANCELLING MO.P.S.C. SCHEDULE NO. 6 ~~2nd~~<sup>1st</sup> Revised SHEET NO. 62.1

APPLYING TO MISSOURI SERVICE AREA

~~either such Standard Rates or the Alternative Rates for a term of not less than one (1) year, terminable thereafter on three (3) days' notice.~~

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MO.P.S.C. SCHEDULE NO. 6 ~~3rd<sup>rd</sup>~~ Revised SHEET NO. 62.2

CANCELLING MO.P.S.C. SCHEDULE NO. 6 ~~2nd<sup>nd</sup>~~ Revised SHEET NO. 62.2

APPLYING TO MISSOURI SERVICE AREA

**SERVICE CLASSIFICATION NO. 1411(M)**  
**LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)**

**1. RATE APPLICATION**

Service under this rate is required for (i) any new facility beginning service after January 4, 2026 (the original effective date of the tariff sheets for Large Load Customer Service) (the "Effective Date") with a peak load forecast reasonably expected to be equal to or in excess of a monthly maximum demand of seventy- five megawatts (75 MW) at any time during the Term or Extension Term; or (ii) any existing customers, who expand such that, after the Effective Date, have a monthly maximum demand that is reasonably expected to exceed their pre-existing demand by seventy-five megawatts (75 MW), then this rate shall be applicable to the expansion load.

For the purpose of determining applicability of this rate, Company may exercise its discretion to aggregate premises served at a distribution voltage premises based on factors including, but not limited to, multiple premises with common owner(s) or a common parent company, or multiple premises sharing one or more of the following: common ownership, common local electrical infrastructure, physical layout, character of service, end use, and common control.

**2. CHARACTER OF SERVICE SUPPLIED**

Company will specify and supply and meter service at a voltage of 115 kV or greater where the customer will own or otherwise bear financial responsibility for construction and operation of the distribution substation. Large Load Customer operations shall comply with Company's End User Connection Procedures - Requirements for the Connection of Customer Load to the Ameren Transmission System (the "End User Requirements"), which are adopted by Company or on its behalf by Ameren Services Company, as such End User Requirements may be revised from time-to-time.

LLCS customer premises (also referred to herein as a facility) shall generally mean a single point of interconnection, though the Company and customer may use multiple meters if determined appropriate. The Company maintains full discretion to evaluate whether multiple meters or premises may or may not be aggregated for purposes of the application of this rate, and in its sole reasonable discretion may require multiple meters or premises, including premises served at distribution voltages, to be considered an aggregate load that shall take service under this rate.

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MO.P.S.C. SCHEDULE NO. 6 ~~2nd<sup>1st</sup>~~ Revised SHEET NO. 62.3

CANCELLING MO.P.S.C. SCHEDULE NO. 6 1st Revised SHEET NO. 62.3

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**3. METERING EXPANSION LOAD**

For customer facilities taking service under this rate due to expansion, the Company may install metering equipment necessary to measure the incremental load subject to this rate. The Company reserves the right to make the determination of whether such load will be separately metered or sub-metered. If the Company determines that the nature of the expansion is such that either separate metering or sub-metering is impractical or economically infeasible, the Company will determine, based on historical usage, what portion of the Customer's load in excess of the monthly baseline, if any, will be subject to this rate and the LLCS Service Agreement.

**4. BILLING DEMAND**

The billing demand in any month will be the highest demand established during on-peak hours or fifty percent (50%) of the highest demand established during off-peak hours, whichever is highest during the month, but in no event less than eighty percent (80%) of the Contract Capacity specified in the LLSC Service Agreement ("Minimum Billing Demand").

**5. REACTIVE CHARGE**

The charge specified in this rate shall be applicable to the kilovars by which the customer's average metered kilovars exceed the customer's kilovars at an average power factor of ninety percent (90%) lagging during the billing period. Such average kilovar billing units shall be determined in accordance with the following formula:

$$kVar = \left( \frac{kVarh}{kWh} - 0.4843 \right) (kW)$$

where:

kVar = kilovar billing units

kVarh = metered kilovar-hours

kWh = metered kilowatt-hours

kW = metered kilowatts

0.4843 = kilovar requirement at a 90% lagging power factor.

Where in the Company's judgment application of the above formula would not be appropriate to full or partial self-generation customers, an alternative agreement, between Company and customers, for the payment of reactive supply facilities may be substituted for said formula.

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ISSUED BY Michael Moehn Interim Chairman & President St. Louis, Missouri  
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MO.P.S.C. SCHEDULE NO. 6 ~~3rd<sup>rd</sup>~~ Revised SHEET NO. 62.4

CANCELLING MO.P.S.C. SCHEDULE NO. 6 ~~2nd<sup>nd</sup>~~ Revised SHEET NO. 62.4

APPLYING TO MISSOURI SERVICE AREA

**SERVICE CLASSIFICATION NO. ~~1411~~(M)**  
**LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)**

**6. ALTERNATE 4 SEASON DEMAND AND TIME-OF-USE ENERGY RATES**

At customer's election made in the manner specified below, the Alternate Rates will be used for billing a customer's energy consumption in lieu of the Standard Rates for energy and demand, except that, any customer that expects to operate at an annual load factor lower than seventy-five percent (75%), or that fails to maintain a load factor of 75% during the term of the LLCS Service Agreement determined as provided for below, shall, post-the Ramp Period provided for in Section 9 of this rate, be subject to mandatory application of the Alternate Rates in lieu of the Standard Rate[s] for energy and demand.

To elect service under time-based energy charges, a customer must, at any time during the Term or any Extension Term in their LLCS Service Agreement, give written notice to the Company sixty (60) days or more prior to the date the customer's notice is to take effect. The election shall take effect on the first day of the calendar month following 60 days after the notice was given.

Whether a customer failed to maintain a load factor of 75% for any given year shall be determined by the Company based on a review of that year's energy consumption and demand data, with such review to occur annually based on the most recently completed year of the Term or Extension Term. Should the Company's review determine that the customer failed to maintain of load factor of 75% for the year in question, Company will notify the customer in writing that prospective billings will be based on time-based energy and demand charges until such time as customer maintains a load factor of 75% for a full year as determined in the annual review process described above.

**7. CUMULATION OF SERVICES**

For a Large Load Customer that, in Company's judgment, requires multiple points of service for an individual premises, the individual meters will be combined prior to determining the demand applicable to billing.

**8. ELECTRIC SERVICE AGREEMENT**

Customers receiving service under this rate are required to enter in a written service agreement (the "LLCS Service Agreement") that specifies certain provisions of their electric service, including Contract Capacity. Which of Riders CEC, RPS-LLC, CCAP, and NEC that are applicable to customer's service will be specified in an exhibit attached to the LLCS Service Agreement, which may be periodically amended subject to the mutual agreement of the Company and customer to reflect customer's participation in such Company-offered programs. LLCS Service Agreements must be consistent with approved tariffs applicable to Large Load Customers.

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2nd Revised

SHEET NO. 62.5

CANCELLING MO.P.S.C. SCHEDULE NO. 6

1st Revised

SHEET NO. 62.5

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)  
LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

9. SERVICE TERM

Customers to which this rate applies shall take service for a minimum term that includes up to five (5) years of an optional transitional load ramp period ("Load Ramp" or "Ramp Period") plus twelve (12) years (the "Term"). The Term shall commence on the date permanent service begins, or as set forth in the LLCs Service Agreement. During the transitional Ramp Period, the customer's maximum load may be lower than seventy-five megawatts (75 MW). Specific details of the customer's Load Ramp may be addressed in the LLCs Service Agreement. Unless otherwise mutually agreed in the LLCs Service Agreement, the LLCs Service Agreement will automatically extend for periods of five years ("Extension Term") at the end of the Term or any Extension Term, unless either party to the LLCs Service Agreement provides at least thirty-six (36) months' written notice to the other party prior to the end of the Term or any Extension Term or its intent not to renew the LLCs Service Agreement, or of its intent to renew the LLCs Service Agreement for the Extension Term at a reduced Contract Capacity. A customer providing notice of non-extension will remain subject to the Exit Fee and Early Termination Fee based upon the remainder of the Term or Extension Term to the extent applicable under the customer's LLCs Service Agreement, provided that so long as timely written notice is given and the notifying customer continues its service for the remaining Term or Extension Term, as applicable, no Exit Fee or Early Termination Fee shall apply. Service shall remain in effect throughout the Term and any Extension Term unless cancelled, modified, or terminated in writing and pursuant to the terms of Schedule LLCs or the LLCs Service Agreement, or the customer changes to another applicable Company rate schedule pursuant to the terms of this rate.

10. CONTRACT CAPACITY

The LLCs Service Agreement will include a Contract Capacity schedule specifying the customer's forecasted annual peak load requirement for the post-Ramp Period of the Term during on-peak hours. The Contract Capacity schedule shall also specify the peak load requirement for each quarter during the Load Ramp during on-peak hours, if any. The LLCs Service Agreement will set out expected off-peak demand if off-peak demand is expected to be greater than Contract Capacity. Unless otherwise agreed by the parties, the Contract Capacity during any Extension Term shall be the same as the Contract Capacity for the last year of the Term immediately preceding Term or Extension Term, as applicable.

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SHEET NO. 62.6

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. 1411(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**11. MAXIMUM DEMAND**

Customer has an affirmative obligation to provide an updated peak demand forecast for each quarter of the upcoming year to provide the best current estimate of its peak demand by September 1st of each year. Customer is not authorized to exceed its Contract Capacity in any period, except (i) if the customer specifically requests authorization from Company to exceed the Contract Capacity for a limited time period, and (ii) Company verifies that such exceedance will not result in any reliability impacts. Company will provide Staff notification of any approved exceedance within five (5) business days after the approval is given, and of any cost impacts of any approved exceedance within forty-five (45) days.

**12. PERMISSIBLE CAPACITY REDUCTION**

A customer taking service under this rate may request to reduce the Contract Capacity during the Term or any Extension Term, with the effective date of any such reduction occurring at any time in the Term by up to twenty (20) percent of the Contract Capacity ("Permissible Capacity Reduction"), in total, without charge for such reduction. To do so, the customer must provide the Company at least twenty-four (24)-months' prior written notice.

In addition, the customer may request to reduce its Contract Capacity beyond the Permissible Capacity Reduction, with the effective date of any such reduction occurring at any time after the first five (5) years of the Term by giving the Company at least twenty-four (24) months' written notice prior to the beginning of the year for which the reduction is sought, subject to payment of a Capacity Reduction Fee. The Capacity Reduction Fee shall be calculated as two times the difference between (a) the nominal value of the Minimum Monthly Bill using the Contract Capacity specified in the customer's LLCS Service Agreement minus (if applicable) the Permissible Capacity Reduction, times the number of months remaining in the Term or Extension Term, or for sixty (60) months, whichever is lesser, and (b) the nominal value of the Minimum Monthly Bill following such a reduction in capacity, times the number of months remaining in the Term or Extension Term, or for sixty (60) months, whichever is lesser. For avoidance of doubt, nothing in this Paragraph 12 limits the right of the customer to reduce its Contract Capacity upon thirty-six (36) months' written notice before the end of the Term or Extension Term as permitted by Section 9.

The Company will use reasonable efforts to mitigate the Capacity Reduction Fee amount owed by the customer, which efforts being expressly limited to Company selling wholesale capacity (net of all wholesale market costs to do so), up to the Minimum Demand in the applicable Midcontinent Independent System Operator markets or via bilateral transactions, at such times and in such amounts as Company may determine. The Company shall invoice the customer no earlier than ninety (90) days prior to the date the customer has indicated the capacity reduction will occur for any unmitigated amounts of the Capacity Reduction Fee

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SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**12. PERMISSIBLE CAPACITY REDUCTION (Cont'd.)**

based on the calculation described above, provided that to the extent the Company is able to sell the difference between the Minimum Demand at the original Contract Capacity and the Minimum Demand at the reduced Contract Capacity post-such a capacity reduction into the Midcontinent Independent System Operator capacity market, Company shall refund the proceeds of such capacity sales (net of all wholesale market costs to do so) to customer annually for a period equal to the lesser of (i) the remainder of the Term or Extension Term, as applicable, or (ii) sixty (60 months) post-the date such a capacity reduction occurred, and provided further that the total refunds to customer shall not exceed the Capacity Reduction Fee.

The customer shall pay the Capacity Reduction Fee within thirty (30) days of the date it receives an invoice from the Company for the fee. To the extent the customer seeks to reduce its Contract Capacity on less notice, and the Company can reasonably reassign Contract Capacity to another large load customer, the Company in its sole reasonable discretion may agree to a variance from these provisions. Any notice to reduce capacity is irrevocable once given by the customer unless the Company in its sole reasonable discretion determines that it can accommodate a revocation of such notice. Any capacity reduction is permanent for the Term and any Extension Term, and any request by the customer to reinstate such capacity will be subject the interconnection process described in Section P of the Distribution System Extensions provisions of the Company's General Rules and Regulations.

**13. TERMINATION**

In order to terminate before the end of the Term or any Extension Term, the customer must deliver a written notice (a "Termination Notice") to Ameren Missouri not less than twenty-four (24) months prior to the effective date of the termination specified in the Termination Notice (the "Termination Date"). If a customer terminates its service under its Service Agreement pursuant to this Section 13 during the Ramp Period, the customer shall pay to Ameren Missouri an Exit Fee (the "Exit Fee") in an amount equal to the nominal value of the applicable Minimum Monthly Bill multiplied by the number of months in the remaining term of the Load Ramp period plus sixty (60) calendar months.

If the customer terminates its service under its LLCS Service Agreement pursuant to this Section 13 after the Ramp Period, the Customer shall pay to Ameren Missouri an Exit Fee in an amount equal to the nominal value of the applicable Minimum Monthly Bill multiplied by the lesser of (x) a period of sixty (60) calendar months or (y) the number of months in the remaining Term or Extension Term (such lesser period, the "Termination Fee Period").

An additional fee shall apply if the customer seeks to terminate with less than twenty-four (24)-months' notice (the "Early Termination Fee"). In such case, the Early Termination Fee shall be equal to two (2) times the nominal value of

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SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**13. TERMINATION (Cont'd.)**

the applicable Minimum Monthly Bill times the number of months less than the twenty-four (24)-months' notice required for termination. The Large Load Customer shall pay to Ameren Missouri the Exit Fee and, if applicable, the Early Termination Fee promptly, and in any event not more than thirty (30) days, after the Termination Date, by wire transfer of immediately available federal funds to an account located in the United States as Ameren Missouri may specify by notice.

Commencing on the date of delivery of the Termination Notice, Company shall use commercially reasonable efforts to mitigate the amount of the Exit Fee, which efforts are expressly limited to (i) during the Termination Fee Period, Company selling wholesale capacity (net of all wholesale market costs to do so), up to the Minimum Demand in the applicable Midcontinent Independent System Operator markets or via bilateral transactions, at such times and in such amounts as Company may determine, and (ii) until the Termination Date, Company seeking LLCS customers to whom it would provide bundled retail electric service, up to the Minimum Demand, to one or more other Large Load Customers (if available) pursuant to an LLCS Service Agreement with such customers. For purposes hereof, the "Refund Amount" is the aggregate net amount received by Company in connection with clauses (i) and (ii) in the preceding sentence. Within thirty (30) days after December 31 of each calendar year during the Termination Fee Period, Company shall pay to the customer the portion of the Refund Amount received by Company during such calendar year, by wire transfer of immediately available federal funds to an account located in the United States as the customer may specify by notice; provided that in no event shall the Refund Amount exceed the Termination Fee. If customer qualifies for a different rate schedule (other than Company Service Classifications 2(M), 3(M), 4(M) and the non-Large Load Customer Service provisions of 11(M)), it may elect to change to such schedule so long as it meets the requirements therein.

**14. INTERIM CAPACITY ADJUSTMENT**

If the Company determines that the customer's load cannot be served by the Company's existing system capabilities, the Company may enter into specific market contract agreements to provide the necessary capacity requirements of the customer until sufficient system capacity may be supplied by the Company. The customer and the Company must mutually agree on the terms for the interim capacity procured by the Company pursuant to an Interim Capacity Agreement. The customer shall be subject to an additional demand charge calculated according to the terms of the Interim Capacity Agreement, with customer responsible for the full costs thereof and the terms of the Interim Capacity Agreement.

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SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**15. MINIMUM MONTHLY BILL**

Customers taking service under this rate shall be subject to a Minimum Monthly Bill which shall consist of the sum of each of the following charges and shall apply in addition to any energy-based charges paid by customer:

- i. Demand Charge (with minimum monthly demand set at 80 percent of the Contract Capacity ("Minimum Demand"));
- ii. Customer Charge (metering, billing, customer support);
- iii. Low-Income Pilot Program Charge
- vi. Other Demand-Based Riders approved by the Commission in the future; and
- v. The Cost Stabilization Rider, with minimum monthly demand set at the Minimum Demand.

**16. COST STABILIZATION RIDER**

Schedule LLCS customers eligible to receive service under the Company's Economic Development Rider will be subject to the Cost Stabilization Rider ("CSR"), an adjustment clause designed to ensure recovery of costs incurred to serve customer to which this rate applies. The CSR shall be applied consistent with the Missouri Economic Development Rider statute. The CSR shall be calculated based on comparing the customer's estimated base rate revenue and estimated final bill revenue prior to applying Rider CEC. Estimated base rate revenue shall be the revenue produced by all applicable base rate and riders other than Riders CEC, RSP-LLC, CCAP, and NEC and the estimated final bill revenue shall be the base rate revenue plus any applicable rate discounts, such as an approved economic development rate. Should the customer's estimated final bill revenues fall below the customer's estimated base rate revenue, an amount, expressed in a dollar per kW (\$/kW) charge, will be added to the customer billing through this charge. The CSR shall be customer-specific and memorialized in the LLCS Service Agreement. This comparison shall be completed annually. The CSR shall not be subject to any related Economic Development Rider discount. Making the CSR non-bypassable ensures that customers are substantially covering the cost to serve them in their tariffed rates or any other voluntary riders in which the customer enrolls.

The CSR shall not be subject to any related Economic Development Rider discount.

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APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**17. CUSTOMER CREDITWORTHINESS**

- (1) For a customer falling within the category reflected in subsection (6) below: (1) The customer, or (2) the entity who owns the facility where the customer takes service and assumes all financial obligations associated with the facility under this rate and the LLCS Service Agreement, or (3) an entity who otherwise assumes all financial obligations associated with the facility under this rate and the LLCS Service Agreement, must be reasonably creditworthy as determined in the Company's sole reasonable discretion. As such, the Company retains discretion to evaluate the creditworthiness and credit support of the entity who assumes all contractual obligations under this rate and the LLCS Service Agreement, and to require reasonable assurances if necessary to address customer creditworthiness.
- (2) The Company will require Schedule LLCS customers to provide collateral in an amount equal to two (2) years of Minimum Monthly Bills, as calculated by the Company (the "Collateral Requirement").
- (3) A customer together with a Guarantor, which can include its ultimate parent, corporate affiliate, a tenant, or any other entity with a financial interest in the customer ("Guarantor") that guarantees the Collateral Requirement under Schedule LLCS and the LLCS Service Agreement (i) has a credit rating of at least A- from Standard & Poor's ("S&P") and A3 from Moody's, (ii) and if rated A- or A3 has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, and (iii) has liquidity greater than ten (10) times the collateral requirement as of the end of applicable period (and which must be shown by providing financial statements and a chief financial officer or a third-party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the period) (collectively, "60% Eligibility Requirements") will be exempt from sixty (60) percent of the Collateral Requirement, with the sixty (60) percent discount not to exceed \$175 million. "Period" for public companies shall be the interval for reporting required by the Securities and Exchange Commission, for all other companies "Period" shall be each calendar quarter.
- (4) A customer that does not have an A- credit rating from S&P and A3 rating from Moody's, but (together with a Guarantor that guarantees the Collateral Requirement under Schedule LLCS and the LLCS Service Agreement) (i) has at least a BBB+ credit rating from S&P and Baal credit rating from Moody's, (ii) has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, and (iii) has liquidity greater

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APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

17. CUSTOMER CREDITWORTHINESS (Cont'd.)

(4) Cont'd.)

than ten (10) times the Collateral Requirement as of the end of the applicable quarter (as determined in the Company's reasonable discretion, and which must be shown by providing quarterly financial statements and a chief financial officer or a third-party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the quarter) (collectively, "50% Eligibility Requirements") will be exempt from fifty (50) percent of the Collateral Requirement, with the fifty (50) percent discount not to exceed \$150 million.

(5) A customer that does not have an A- credit rating from S&P and A3 rating from Moody's, but (together with a Guarantor that guarantees the Collateral Requirement under Schedule LLCS and the LLCS Service Agreement) (i) has at least a BBB- credit rating from S&P and Baa3 credit rating from Moody's, (ii) has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, and (iii) has liquidity greater than ten (10) times the Collateral Requirement as of the end of the applicable quarter (as determined in the Company's reasonable discretion, and which must be shown by providing quarterly financial statements and a chief financial officer or a third-party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the quarter) (collectively, "40% Eligibility Requirements") will be exempt from forty (40) percent of the Collateral Requirement, with the forty (40) percent discount not to exceed \$125 million.

(6) A customer that does not have an A- credit rating from S&P and A3 rating from Moody's, but (together with a Guarantor that guarantees the Collateral Requirement under this rate and the LLCS Service Agreement) either (i) has at least a BBB- credit rating from S&P and Baa3 credit rating from Moody's, and has not been placed on credit watch by either such rating agency if either the customer's credit rating by such agency is equal (and not greater to) to the foregoing rating, or (ii) has liquidity greater than ten (10) times the Collateral Requirement as of the end of the applicable quarter (as determined in the Company's reasonable discretion, and which must be shown by providing quarterly financial statements and a chief financial officer or a third-party certified public accountant certification accompanying such financial statements, no later than forty-five (45) days after the end of the quarter) (collectively, "25% Eligibility Requirements") will be exempt from twenty-five (25) percent of the Collateral Requirement, with the twenty-five (25) percent discount not to exceed \$75 million.

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APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

17. CUSTOMER CREDITWORTHINESS (Cont'd.)

- (7) The 60% Eligibility Requirements, the 50% Eligibility Requirements, the 40% Eligibility Requirements, and the 25% Eligibility Requirements are collectively referred to as the "Discount Eligibility Requirements."
- (8) The Collateral Requirement must be provided at the time of executing the LLCs Service Agreement.
- (9) Any collateral provided to satisfy the Collateral Requirement shall not accrue interest while held by the Company.
- (10) The Company will, in its sole reasonable discretion, after the customer has achieved their peak load for at least three (3) years, annually consider reducing the customer's collateral obligation over the course of its contract period, on a schedule generally corresponding to the reduction of risk to the Company and its customers. The Company will consider the customer's performance criteria, which includes, but is not limited to the customer's: (i) financial condition, (ii) load performance, (iii) payment history, (iv) credit rating, and (v) any default history.
- (11) The amount of the Collateral Requirement under the foregoing calculation will be recomputed quarterly based upon the customer's rolling twenty-four (24)-month load forecast as of the first date of the next quarter, and the customer shall provide the recomputed amount if greater than the current amount held. The Company shall notify a customer if the customer no longer meets the applicable Discount Eligibility Requirements, including if the customer has been placed on credit watch, if applicable to such eligibility.
- (12) The Collateral Requirement must be provided in one or more of the following Forms, provided, that the Company shall have the right to choose the acceptable form of collateral among those listed below for any customer that qualifies for a Discount of twenty-five percent (25%) or less:
  - a. A guarantee from the customer's Guarantor for the applicable Collateral Requirement, so long as the Guarantor meets the applicable Discount Eligibility Requirement, provided that the dollar amount of the Collateral Requirement that may be provided under the guarantee is subject to credit review by the Company. The guarantee must be in a format acceptable to and approved by the Company, and must include (i) if the Guarantor's creditworthiness is considered for determining the Discount Eligibility Requirements, a commitment from the Guarantor to pay the Collateral Requirement if the customer fails to make such payments (without a dollar limit), and (ii) a provision that automatically increases the dollar amount of collateral covered by the guarantee if either the customer or Guarantor no longer satisfies the applicable Discount Eligibility Requirement; or,

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APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

17. CUSTOMER CREDITWORTHINESS (Cont'd.)

(12) Cont'd.)

- b. A standby irrevocable Letter of Credit ("Letter of Credit") for the applicable Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the customer or its Guarantor, with a credit rating of at least A- from S&P and A3 from Moody's and a minimum of \$2 billion in assets. Such security must be issued for a minimum term of three hundred sixty (360) days. The customer must cause the renewal or extension of the security for additional consecutive terms of three hundred sixty (360) days or more no later than thirty (30) days prior to each expiration date of the security. If the customer no longer satisfies the applicable Discount Eligibility Requirement, it must increase the amount covered by the Letter of Credit within ten (10) days. If the security is not renewed, extended, or increased as required herein, the Company will have the right to draw immediately upon the Letter of Credit and/or demand cash collateral in the amount of the required increase and be entitled to hold the amounts so drawn or received as security until the customer has either (i) come back into compliance with the requirements for use of a Letter of Credit or, (ii) if required by the Company, has provided an alternative form of collateral consistent with this rate. The Letter of Credit must be in a format acceptable to and approved by the Company; or
- c. A cash deposit for the applicable Collateral Requirement.

(13) In case of an uncured breach by the customer of the LLCS Service Agreement, an uncured breach of the Guarantor under the parent guaranty, or any notice of termination or refusal to continue the Letter of Credit by the issuing bank, the Company may draw on the applicable collateral, as further set forth in the LLCS Service Agreement.

(14) If, at any time after Customer's initial delivery of the collateral the customer fails to comply with the Collateral Requirement, the Company may thereafter pursue any and all rights and remedies at law or in equity, and may take any other action consistent with the LLCS Service Agreement, this rate, and the Company's General Rules and Regulations, including but not limited to suspension or curtailment of service.

(15) To the extent the Company draws on a cash deposit provided by a customer, the Company draws funds from a Letter of Credit or Guarantee, or the Company receives a cash Exit Fee, the Company will defer the amount received minus any amount used to pay for services rendered, together with the Company's weighted average cost of capital, as a regulatory liability to be addressed in the next general ratemaking proceeding.

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Original

SHEET NO. 62.14

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. ~~1411~~(M)

LARGE LOAD CUSTOMER SERVICE RATE (Cont'd.)

**18. LARGE LOAD CUSTOMER RIDERS**

In addition to the applicability of Riders FAC, EEIC, SUR, and RESRAM to service provided to Large Load Customers, the following additional Riders shall apply to Large Load Customer's service under an applicable LLCS Service Agreement if selected by the Large Load Customer pursuant to such applicable LLCS Service Agreement:

1. Renewable Solutions Program - Large Load Customers Program (Rider RSP LLC)
2. Clean Capacity Advancement Program (Rider CCAP)
3. Nuclear Energy Credit Program (Rider NEC)
4. Clean Energy Choice Program (Rider CEC)

Notwithstanding any provisions of Rider RESRAM to the contrary, a Large Load Customer shall not be subject to RESRAM charges if it participates in Rider RSP-LLC or any other voluntary rider offered by Company and thereby receives or is reasonably projected to receive renewable attributes supporting its load at a level that is greater than or equal to the then applicable "RES portfolio requirement" as defined in 20 CSR 4240-20.100(1)(R). For Large Load Customers with such participation agreements, the Large Load Customer's entire load that is supported with renewable

attributes it receives or is reasonably projected to receive that are sufficient to cover the applicable "RES portfolio requirement" as defined in 20 CSR 4240-20.100(1)(R) will be subtracted from the calculation of "total retail electric sales" as defined in 20 CSR 4240-20.100(1)(W). RESRAM charges shall still apply to such a Large Load Customer to the extent the renewable attributes it receives or is reasonably projected to receive do not reach the then applicable "RES portfolio requirement". For purposes of this Section 8, "renewable attributes" means Renewable Energy Credits, as defined in 20 CSR 4240-20.100 (1)(N), that the Large Load Customer has retired or had retired on its behalf through such programs. Large Load Customers participating in Rider RSP-LLC or other voluntary riders offered by Company for which renewable attributes are produced will be evaluated for this exemption annually or more frequently if a customer's participation to such program(s) changes. Such annual or more frequent evaluations shall be used by the Company to demonstrate compliance with the accelerated renewable buyer provisions of Section 393.1030.2(5), RSMo.

**19. GENERAL RULES AND REGULATIONS**

In addition to the above specific rules and regulations, all of the Company's General Rules and Regulations shall apply to the supply of service under this rate.

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RIDER CCAP

CLEAN CAPACITY ADVANCEMENT PROGRAM

PURPOSE/AVAILABILITY

The purpose of the Clean Capacity Advancement Program ("CCAP" or "Program") is to provide customers taking service under Service Classification 11(M) or Service Classification 14(M) a capacity product that enables storage of clean energy.

DEFINITIONS

CCAP Agreement: An agreement between the Company and the eligible customer, setting forth the specific terms of such customer's participation in the Program, including the participating account.

Large Load Customer Electric Service Agreement ("ESA"): As defined in the Large Load Customer Service provisions of Service Classification No. (14+M).

ESS Support Charge: The ESS Support Charge shall be calculated monthly as a participating customer's monthly ESS Support Level multiplied by the ESS Support Rate as specified in the CCAP Agreement.

Energy Storage Systems ("ESS"): An asset that stores electrical energy and then releases electrical energy onto the electric grid providing increased reliability and other energy and capacity services.

ESS Support Level (kW): Subject to the terms of applicable CCAP Agreement, the ESS Support Level is calculated as the summation of the total nameplate capacity for any Program Resources supported by the participating customer in question or portion thereof. To the extent that Program Resource capacity supported by a given customer is comprised of multiple resources that begin commercial operation at different times, the participating customer's ESS Support Level will be updated as appropriate to reflect the total nameplate capacity supported by the customer that are commercially operational at any point in time. The CCAP Agreement will reflect the ESS Support Level along with projected annual in-service dates for Program Resources from which capacity will be supported by the customer as specified in the CCAP Agreement.

ESS Support Rate (\$/kW-mo): Participating customers shall pay a dollar per kilowatt-month (\$/kW-mo.) rate as specified in the applicable CCAP Agreement. The rate shall be applied to the participant's ESS Support Level.

Large Load Customers: Customers to which the Large Load Customer Service provisions of Service Classification No. 14+

(M) apply.

Program Resources: Any new Company-owned commercially operational ESS supported in whole or in part by a participating customer under the Program for a term outlined in the customer's CCAP Agreement.

\*Indicates Addition.

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**RIDER CCAP**

**CLEAN CAPACITY ADVANCEMENT PROGRAM (Cont'd.)**

**MONTHLY BILL**

All applicable charges provided for under, and other applicable terms and conditions of, Service Classification No. 11(M), or Service Classification 14(M) and any ESA under which a Large Load Customer takes service, shall continue to apply and will continue to be based on actual metered energy use during the customer's normal billing cycle.

Customers that participate in the Program will see an additional charge, the ESS Support Charge, added to their bill for the in-service capacity being supported as specified in the CCAP Agreement.

Charges resulting from this Rider CCAP shall not be eligible for any economic development discount(s) that could otherwise apply to Company's Service Classification No. 11(M) or Service Classification 14(M) customers.

All charges arising from Program participation are subject to any applicable license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority with appropriate jurisdiction.

**OTHER PROGRAM PROVISIONS AND TERMS**

1. A customer's participation in the CCAP is specific to the accounts specified in the applicable CCAP Agreement. A customer's participation in the CCAP is specific to the Program Resources specified in the applicable CCAP Agreement. Allocation of customer's CCAP participation across enrolled accounts will be determined by Company and the customer as specified in the applicable CCAP Agreement.
2. With respect to Large Load Customers, if at the time the CCAP Agreement is signed a Large Load Customer does not have an account number established for an account reasonably expected by Company to exist at some point over the Term or Extension Term of an ESA, Company may input a placeholder on the CCAP Agreement which will be updated after said account number is established.
3. If, prior to the end of the term of participation, a participating customer premises that constitutes a separate account is relocated to another location within the Company's service territory, the customer's participation shall continue at the customer's same ESS Support Level at the new account established at the new location.
4. Failure by a participating customer to pay its bill when due, including that part of the bill reflecting charges for participation in the CCAP, shall constitute a failure to pay a bill due for services in accordance with the Company's General Rules and Regulations.
5. A customer's participation in the CCAP is not a security and does not represent an ownership interest in any of the Program Resources.
6. Any customer participating in the CCAP or who formerly participated in the CCAP waives all rights to any billing adjustments or other relief arising from a claim that the Large Load Customer's service would be or would have been at a lower cost had the Customer not participated in the CCAP.

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RIDER CEC

CLEAN ENERGY CHOICE PROGRAM

PURPOSE/AVAILABILITY

The Clean Energy Choice Rider (the "Program") provides Service Classification 11(M) or Service Classification 14(M) with a means to influence the Company's generation resource portfolio. Within the Company's Integrated Resource Planning Process ("IRP"), the eligible customer may request one or more Clean Energy Resources be deployed in place of or in addition to one or more resources selected in the Company's Preferred Resource Portfolio. If the Company determines that it should include customer's requested generation as part of a Clean Energy Preferred Resource Plan, the Requesting Customer shall cover costs associated with its specific request for clean resources. The specific terms of the Requesting Customer's obligation must be reflected in a mutually agreed upon Clean Energy Choice Agreement and will be subject to Commission approval as outlined below.

DEFINITIONS

For purposes of this Program, the following definitions apply:

Clean Energy Resource: A resource that does not contribute any net carbon emissions to the atmosphere, which shall include but not be limited to distributed energy resources such as demand side management, energy efficiency, and battery storage.

Clean Energy Preferred Resource Plan: A separate resource plan that would call for the addition of one or more generation resources pursuant to a Requesting Customer's request. The Company retains all discretion in preparing the Clean Energy Preferred Resource Plan to ensure the Clean Energy Preferred Resource Plan meets the Company's requirements to provide safe and reliable service. The execution of the Clean Energy Preferred Resource Plan shall be subject to approval by the Commission, including approval by the Commission of the Requesting Customer's funding obligations for the subject Clean Energy Resource, and obtaining all appropriate regulatory approvals, and in a manner deemed satisfactory to the Company in its sole discretion.

Integrated Resource Planning Process: The Company's integrated process to consider and analyze demand-side resources, supply-side resources, and renewable energy resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of Company electric energy and capacity resources, governed by the Commission's Resource Planning rules and applicable statutes.

Large Load Customers: Customers to which the Large Load Customer Service provisions of Service Classification No. 14+(M) apply.

Preferred Resource Plan: This refers to the resource plan selected by the Company as its Preferred Resource Plan as part of its IRP.

\*Indicates Addition.

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**RIDER NEC**

**NUCLEAR ENERGY CREDIT PROGRAM**

**PURPOSE/AVAILABILITY**

The purpose of the Nuclear Energy Credit Rider program ("Program") is to allow Service Classification 11(M) or Service Classification 14(M) Customers that have elected to participate in the Program to subscribe to receive NECs that are associated with Company-owned nuclear energy resources in amounts not to exceed the customer's Annual Usage. The Company shall track NECs assigned to each customer annually until (if applicable) a registry for NECs that is similar to a Renewable Energy Credit registry such as the North American Renewable Registry is used based on initial Midcontinent Independent System Operator ("MISO") settlements of Company-owned or sourced nuclear resources, as the initial settlement values may be adjusted as part of MISO's resettlement process. Under the Program, a customer may agree to receive NECs for an agreed upon term as specified in the customer's NEC Agreement.

**DEFINITIONS**

For purposes of this Program, the following definitions apply:

Customer's Annual Usage: Customer's actual metered energy usage over the twelve (12) most recent monthly billing periods for which data is available, or, if deemed more appropriate by the Company, Customer's expected metered energy usage over twelve (12) monthly billing periods as determined by the Company. Customer's Annual Usage shall be established at the time the NEC Agreement is executed by Customer and Company. In the case where the participant is a Large Load Customer, Customer's Annual Usage may vary by year depending on the Large Load Customer's Ramp Period usage.

Large Load Customer Service Agreement ("ESA"): As defined in the Large Load Customer Service provisions of Service Classification No. 14+M.

Large Load Customer: Customers to which the Large Load Customer Service provisions of Service Classification No. 14+M apply.

NEC Agreement: A written contract executed by the Company and a customer setting forth the specific terms of the customer's subscription under this Program including the accounts covered by the subscription. The NEC Agreement shall reflect the quantity of NECs to which the customer is subscribing, subject to the terms and conditions set forth in this tariff and the NEC Agreement.

Nuclear Energy: Electricity that is generated using Company-owned nuclear energy resources.

Nuclear Energy Credits ("NECs"): Attributes from one megawatt-hour (MWh) of electricity generated from a Company-owned nuclear energy resource.

Nuclear Energy Credit Charge ("NEC Charge"): The NEC Charge shall be calculated monthly as a customer's monthly quantity of NECs multiplied by the NEC Rate as specified in the NEC Agreement.

\*Indicates Addition.

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RIDER NEC

NUCLEAR ENERGY CREDIT PROGRAM (Cont'd.)

DEFINITIONS (Cont'd.)

Nuclear Energy Credit Rate ("NEC Rate"): A dollar per megawatt hour (\$/MWh) rate applicable to a customer's monthly quantity of NECs as specified in the NEC Agreement.

Ramp Period: As specified in a Large Load Customer's ESA.

MONTHLY BILL

All charges provided for under, and other terms and conditions of, the applicable provisions of Service Classification No. 11(M) or Service Classification 14(M), and any applicable ESA under which a Large Load Customer takes service, shall continue to apply and will continue to be based on actual metered energy use during the Customer's normal billing cycle.

All charges arising from Program participation are subject to any applicable license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority with appropriate jurisdiction.

Charges resulting from this Rider NEC shall not be eligible for any economic development discount(s) that could otherwise apply to Company's Service Classification No. 11(M) or Service Classification 14(M) customers.

Customers that participate in the Program will see an additional charge added to their bill for the NECs, the NEC Charge.

OTHER PROGRAM PROVISIONS AND TERMS

1. A Customer's participation in the NEC is specific to the accounts specified in the applicable NEC Agreement. An Allocation of Customer's NEC participation across enrolled accounts will be determined by Company and the Large Load Customer as specified in the applicable NEC Agreement.
2. In the case of a Large Load Customer, if at the time the NEC Agreement is signed a Large Load Customer does not have account number established for an account reasonably expected by Company to exist at some point over the Term of the ESA, Company may input a placeholder on the NEC Agreement which will be updated after said account number is established.
3. If, prior to the end of the term of a given subscription, a customer premises that constitutes a separate account is relocated to another location within the Company's service territory, the customer's subscription shall continue to be enrolled in the Program at the customer's same NEC quantity at the new account established at the new location.
4. Failure by a Customer to pay its bill when due, including the NEC Charge, shall constitute a failure to pay a bill due for services in accordance with the Company's General Rules and Regulations.

\*Indicates Addition.

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RIDER RSP LLC

RENEWABLE SOLUTIONS PROGRAM - LARGE LOAD CUSTOMERS

PURPOSE/AVAILABILITY

The purpose of the Renewable Solutions Program - Large Load Customers ("RSP LLC" or "Program") is to allow Large Load Customers that have elected to participate in the Program pursuant to the Large Load Customer's ESA, to subscribe to receive renewable energy service ("RE Service") from existing or new renewable wind and/or solar generation resource capacity available to the Large Load Customer under the Program.

DEFINITIONS

Commercial Pricing Node: The point where any transmission-interconnected renewable energy from a Program Resource will be injected into the wholesale energy market.

Large Load Customer Service Agreement ("ESA"): As defined in the Large Load Customer Service provisions of Service Classification No. (14+M).

Large Load Customer: Customers to which the Large Load Customer Service provisions of Service Classification No. 14+(M) apply.

Large Load Customer's Annual Usage: Large Load Customer's actual metered energy usage over the twelve (12) most recent monthly billing periods for which data is available, or, if deemed more appropriate by the Company, Large Load Customer's expected metered energy usage over twelve (12) monthly billing periods as determined by Company. A Large Load Customer's Annual Usage shall be established at the time the RSP LLC Agreement is executed by the Large Load Customer and Company. A Large Load Customer's Annual Usage may vary by year depending on the Large Load Customer's Ramp Period usage.

Metered RE Production: This is the total energy production of the Program Resources or portion thereof available to the Large Load Customer under the applicable Renewable Solutions Program - LLC Agreement ("RSP LLC Agreement") at a point in time, as measured at the Commercial Pricing Node(s) where the power is injected into the wholesale energy market or by dedicated generation meters at the point of interconnection with the distribution system where resource output offsets power that would have otherwise been procured in the wholesale energy market. This value is expressed as the metered production of energy (measured in kilowatt-hours ("kWh")). Each Program Resource shall be separately metered.

Program Resources: Any new Company-owned commercially operational wind or solar generation resources available in whole or in part to a Large Load Customer participating in the Program. Once commercially operational, new renewable generation facilities or a portion thereof will be available to provide service to the Large Load Customer in question for a term outlined in the Large Load Customer's RSP LLC Agreement.

Ramp Period: As specified in the Large Load Customer's ESA.

\*Indicates Addition.

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RIDER RSP LLC

RENEWABLE SOLUTIONS PROGRAM - LARGE LOAD CUSTOMERS (Cont'd.)

DEFINITIONS (Cont'd.)

RSP LLC Agreement: A written contract executed by the Large Load Customer and Company setting forth the specific terms of such customer's subscription under the Program, including the accounts covered by the subscription.

SUBSCRIPTION

An eligible Large Load Customer may subscribe to RE Service associated with Program Resource capacity, where the projected energy production from which is less than or equal to 100% of the Large Load Customer's Annual Usage, subject to the availability of Program Resource capacity and to the terms of the Large Load Customer's RSP LLC Agreement. The RSP LLC Agreement will reflect the Large Load Customer's RE Service Level along with projected annual in-service dates for Program Resources from which capacity will be subscribed by the Large Load Customer as specified in the RSP LLC Agreement.

MONTHLY BILL

All charges provided for under, and other terms and conditions of, the Large Load Customer Service provisions of Service Classification No. 14+(M), and the ESA under which the Large Load Customer takes service, shall continue to apply and will continue to be based on actual metered energy use during the Large Load Customer's normal billing cycle.

Large Load Customers that participate in the Program will see additional charge(s) and credit(s) (i.e., the Renewable Resource Charge(s) and the Renewable Benefits Credit(s)) added to their bill for in-service capacity subscribed to by them associated with the most recent calendar month as of the time the bill is produced. Renewable Resource Charge(s) and Renewable Benefits Credit(s) reflect the Large Load Customer's procurement of renewable energy from the Company in an amount equal to the Large Load Customer's RE Service Level.

Charges resulting from this Rider RSP-LLC shall not be eligible for any economic development discount(s) that could otherwise apply to Company's Service Classification No. 14+(M) customers.

All charges and credits arising from RE Service under the Program are subject to any applicable license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority with appropriate jurisdiction.

\*Indicates Addition.

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**GENERAL RULES AND REGULATIONS**

**III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)**

**L. MODIFICATION OR ENLARGEMENT OF DISTRIBUTION SYSTEM**

Except when Modification Or Enlargement Of System For High Voltage Service below, applies, modifications or enlargements of Company's distribution system associated with additional electrical load of existing non-residential Customers shall be performed at no cost to Customer provided the estimated Extension Allowance exceeds the estimated Extension Cost from the proposed distribution system modifications or enlargements. Where the estimated Extension Allowance is less than Company's estimated Extension Cost from the proposed modification or enlargement costs, an Extension Charge may be required prior to the commencement of construction by Company.

Where modifications or enlargements of Company's distribution system are performed at the request of any existing Customer and no additional Marginal Revenue is anticipated therefrom, Customer shall pay, in advance, the total estimated costs associated with such changes.

**\*M. MODIFICATION OR ENLARGEMENT OF SYSTEM FOR HIGH VOLTAGE SERVICE OR LARGE LOAD CUSTOMER SERVICE**

Where Company provides High Voltage Service (see General Rules and Regulations, II. Characteristics of Service Supplied), for load expected to be 50 MW or larger, the Customer will be responsible for the full amount of the Extension Cost for facilities which are dedicated to serving the load of the Customer. For purposes of this Section, "Extension Cost" shall have the meaning given it in General Rules and Regulations, III. Distribution System Extensions, except that there shall be no Extension Allowance and provisions that would otherwise cover a portion of the Extension Cost with an Extension Allowance shall not apply.

Where Company reasonably expects to provide service to a customer ~~taking service under the Large Load Customer Service provisions of~~ Service Classification 14+(M), such customer shall pay all costs of distribution or transmission facilities that the Company determines are necessary to provide safe and adequate electric service (whether before or after customer's permanent service commences) to customer's premises while maintaining the integrity of the Company's electric system, and to serve any ancillary loads that directly support customer's ongoing operations at its premises, other than any transmission facilities classified as network upgrades by the Midcontinent Independent System Operator's Open Access Transmission Tariff, ~~that the Company installs to extend service to such a customer~~. Such a customer must complete payment for the facilities extension or make suitable arrangements for installment payments and execute all required agreements associated with the facilities requested extensions as a condition for any construction to commence.

\*Indicates Addition.

APPLYING TO MISSOURI SERVICE AREA

**GENERAL RULES AND REGULATIONS**

**III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)**

\* **M. MODIFICATION OR ENLARGEMENT OF SYSTEM FOR HIGH VOLTAGE SERVICE OR LARGE LOAD CUSTOMER SERVICE (Cont'd)**

The Company shall not be obligated to proceed to modify or enlarge Company's system or acquire resources or otherwise provide High Voltage Service or service under the Large Load Customer Service provisions of Service Classification ~~14~~(M) until the Customer executes appropriate agreements relating to determining system improvements or resource acquisitions needed to provide the service, and any other agreements provided for by the Service Classification tariff sheets under which the Company shall provide Customer's electric service.

\*\* **N. RELOCATION OF THE DISTRIBUTION SYSTEM**

Company may, at its sole discretion, upon Customer's request, relocate any distribution facilities providing service to Customer and/or other parties to a right-of-way acceptable to Company, on or off Customer's premises, following the payment by Customer of the Company's total estimated cost of said relocation. Additionally, at the Company's discretion, it may relocate any distribution facilities based upon safety, reliability, or operational needs at the cost of the Company.

In the presence of physical conflicts associated with any new construction or enlargement of Customer's premises or electrical load, Company may, at its sole discretion, upon Customer's request, relocate any distribution facilities to a right-of-way acceptable to Company on or off Customer's premises, following the payment by Customer of the Company's estimated net cost of relocating its distribution facilities. The net cost of relocation referred to herein excludes any costs estimated by Company to be associated with the supply of any additional electrical requirements of Customer, absent the relocation of any distribution facilities.

When Company agrees to relocate existing overhead facilities with an underground installation, the Customer will be responsible for all costs associated with the undergrounding of facilities including spare conduits, manholes, and other structures or equipment required to replace the to-be-vacated overhead right-of-way considering present and future needs as determined by Company.

\*Indicates Change. \*\*Indicates Reissue.

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