BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Establishment of a Working Case Regarding FERC Order 2222 Regarding Participation Of Distributed Energy Resource Aggregators in Markets Organized by Regional Transmission Organizations and Independent System Operators.	)))))	File No. EW-2021-0267

AMEREN MISSOURI'S RESPONSE TO
OPPORTUNITY FOR ADDITIONAL COMMENTS

COMES NOW Union Electric Company d/b/a Ameren Missouri (the "Company" or "Ameren Missouri"), and in response to the Commission's May 24, 2023, *Order Regarding Opportunity for Additional Comments, Order Scheduling Workshop, and Notice of LBNL Report (the "Order"),* states as follows:

INTRODUCTION

Ameren Missouri appreciates the Commission's invitation to comment on the Commission's continued evaluation of a possible modification of its prior order prohibiting aggregators of retail customers ("ARC") from aggregating Demand Response ("DR") resources for commercial and industrial customer demand response ("DR") resources. Further, the Company also appreciates the work the Commission has done, with and through the Lawrence Berkely National Laboratory ("LBNL"), to research issues related to ARC DR aggregation and activities and approaches in other states and the coming implementation of FERC Order 2222, which contemplates aggregation of a broader range of distributed energy resources ("DER"). The LBNL report clearly identifies a number of issues that are critical to address with respect to aggregation of DR or DER - issues that are consistent with many of the Company's concerns previously voiced when the Commission earlier (on August 4, 2021) offered an opportunity to address six specific questions related to DR aggregation by ARCs for commercial and industrial

(“C & I”) customers.[1] The Company’s answers to those questions, including the significant concerns it expressed regarding modifying the prohibition prior to addressing the many issues ARC aggregation presents, remain equally applicable today.

Before addressing the specific questions posed in the Order, it is important to put those questions in the proper context given the important role the state's utilities already play in delivering robust cost-effective DR programs to their customers, and the many benefits that arise from direct utility involvement in the DR process. Simply stated, DR is already being used as a resource in the state, irrespective of the prohibition on aggregation of DR by ARCs. Case in point: the Company currently has active DR programs for both Residential and Business customers, with approximately 84 and 54 MW of DR capability in those respective segments, for a total of about 135 MW of peak load reductions. The Company's programs provide opportunities for its retail customers to earn predictable incentives in exchange for their willingness to provide load reductions that can benefit the system and all of the Company's retail customers served by it, both economically and with respect to reliability. These programs are an invaluable part of the Company's resource planning and resource adequacy efforts, which benefits all customers. DR from Company programs can be utilized to meet the Company's capacity obligations in the MISO market and reduce its retail customer base's exposure to wholesale market prices for capacity, which as recently as last year reached MISO's Cost of New Entry, approximately $236/MW-Day. The reduction in MISO market capacity costs, or excess MISO market capacity revenues earned, arising from Company DR programs flow through the Company's Fuel Adjustment Clause (“FAC”) in a manner that benefits all retail customers, including non-participants, in the form of lower net energy costs.

[1] Ameren Missouri’s Response to Order Opening Working Case, EFIS Item No. 21.

All of that said, to the extent that ARCs also provide unique capabilities that have their own advantages over utility administered programs, the Company's programs can, and already do in certain cases, leverage many of those capabilities of aggregators to engage customer participation, while maintaining oversight by the Commission and under terms authorized in the Company's Commission-approved tariffs. A final benefit of Company programs – or use of aggregators through the utility and its programs – is that it obviates the many other issues, such as those identified and discussed in the LBNL report, that must be addressed in each state for aggregation to properly function.

The point is that from the standpoint of the Commission, the utility, and the non-participating utility customers – i.e., almost all customers – it is not at all clear that third-party market DR aggregation now would drive significant improvements to the state's DR portfolio. DR is here, it is available to customers, third-party aggregation is used in utility programs already and it is all working well without any changes required. The question is really when to enable third-party DR Aggregation.

This brings us back to those issues that are critical to address prior to removing the prohibition on ARC activity in DR (i.e., prior to implementation of Order 2222), which the Company discussed in its answers to the Commission's August 2021 questions. To summarize some of the key points from that filing, there are a number of policy and practical considerations that should be fully addressed prior to *any* move by the Commission to remove the prohibition on ARC activity, including:

- A thorough review of existing Commission rules and utility tariff provisions and programs should be conducted with an eye toward impacts of ARC activity and the prospect of customers' switching between programs and aggregators.

- Rules and tariff provisions should be put into place that provide retail consumer protections, ensuring the Commission established a means to provide jurisdiction over ARC relationships with retail customers in a manner that addresses retail customer complaints and disputes with ARCs.
- Clear guidance on enrollment and switching protocols between utility programs and ARCs, or between two ARCs should be established.
- Processes and procedures to avoid of double counting or double compensation of DR services should be developed.
- Efforts to define and codify the rights and responsibilities of both the electric utilities and their customers regarding the interaction between the normal and routine operation and maintenance of the distribution and transmission systems and the customers' ability to transact with the wholesale market via an ARC should occur.
- Communication protocols between utilities, ARCs, the RTOs, and the Commission as necessary, should be established that allow for the exchange of customer data and information in a way that protects data privacy and addresses cybersecurity risks.

All of the above issues are reflected in the LBNL report, but none have been addressed to-date.[2] Each of them warrants careful consideration by the Commission prior to it taking action to remove its prohibition on direct ARC activity in wholesale energy markets in Missouri.

---

[2] While beyond the scope of this Response, Ameren Missouri recognizes that Voltus has offered comments in this docket suggesting that all will be well if the prohibition is lifted regardless of the Commission having addressed these issues. Ameren Missouri strongly disagrees. That some limited DR aggregation may have occurred in 2 of 17

Next, the Commission should also consider the context of necessary activities to prepare for the implementation by the RTOs/ISO's of FERC Order 2222. It would be unwise to open-up DR markets to ARC activity without considering all of these issues and developing adequate rules, but also without considering how any rules adopted will or may need to be oriented in the future given the broad view of DER activities that are expected to be subject to aggregation in the near- to intermediate-term given Order 2222. A consistent and holistic approach to Order 2222 and DER aggregation (including DR) generally should a be guiding principle of the Commission's actions to avoid the significant potential for duplication of effort, including the need to rework or resolve conflicts between rules that might otherwise be established for DR aggregation, but which do not contemplate issues that may be implicated by broader forms of DER aggregation. Lifting the prohibition can most effectively be handled simultaneously with Order 2222 implementation. As such, the Company strongly recommends to the Commission that it systematically work through Order 2222 compliance considerations <u>and</u> lifting the prohibition at the <u>same time</u> rather than taking any specific action with regards to lifting the prohibition on DR aggregation individually.

RESPONSES TO SPECIFIC COMMISSION QUESTIONS[3]

A. <u>Size Limitations for Demand Response (DR) eligibility</u>:

1. What impact could any of these limits[4] have on implementation of a modified opt-out

---

traditionally regulated MISO states (Oklahoma and Kansas) and one state whose regulatory structure (and thus issues posed by aggregation) is much different than Missouri (i.e., Michigan) without major problems does not change the fact that all of these issues need to be addressed *in Missouri*. To note just two examples, Voltus suggests there "is no cybersecurity threat" yet NERC has issued an entire report (https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf) that suggests otherwise. Voltus has also indicated that "demand response does not impact management of the distribution system or undermine utility planning," yet those statements can't be accurate given that there is no enforceable regulatory regime in place in Missouri that would give utilities the visibility they need into ARC aggregation to account for the aggregation on its system, and in its planning.

[3] The Commission's questions are italicized.

[4] Listed in the Order as 0 kW, 10kW, 100kW, 300 kW, and other for large customers.

as applied to C & I customers in terms of reliability, participation or the need for additional regulations?

The question implies that there may be some specific limit at or below which third-party DR aggregation would not impact the system. However, the issue is more complex than that and questions about the size of DR resources must be framed for what we expect to happen in the future rather than focusing on a specific limit.

The expectation is that aggregations for DR (and DER) are going to significantly increase over time. As DR aggregations scale-up to hundreds, or even thousands of MWs, the impact of <u>simultaneous operation</u> of these resources at scale could create significant impacts on the grid. As the scaling occurs, there are two issues to consider for DR and DER aggregation.

First – Visibility. Both Ameren Missouri and MISO must have visibility to all resources. This includes the resource's geographic location, electrical location in the network, and expected and actual operation. This will include modeling data as NERC has defined in its reliability guidelines. Today, there are no enforceable rules that ensure the needed visibility.[5]

Second - Program Requirements. The current penetration of DR has not required concepts of phasing in and out (effectively ramping) of calls for these products. If an aggregation scales to either a significant percentage of a single feeder or substation facility, and over time, becomes a significant percentage of total load, we will need to ensure that aggregations are operated to incorporate this concept of ramping or phasing. This approach would support higher eventual limits for participation by ensuring only a portion of the committed capacity is exercised instantaneously. If we consider this approach in advance of consideration of lifting the prohibition, and in conjunction with the eventual implementation of Order 2222, we can pre-

[5] This also implicates the question of state jurisdiction to create and enforce such rules.

empt future problems and help ensure the reliability of the grid going forward and to create more effective resources for the benefit of all customers. But again, there are no enforceable rules to ensure that the ramping/phasing concept is incorporated.

2. *Should the Commission establish different size limits for different utilities based on customer classes?*

Subject to the foregoing considerations, the concept reflected in the LBNL report of phasing in implementation across various customer classes (and thereby sizes) has merit and deserves consideration, if and when demand response aggregation is opened up in the state.

3. *Should these size limits apply to a single location, or should a single customer be permitted to aggregate multiple locations to meet the threshold?*

To clarify, some large customers do form their own 'aggregator' which in turn then aggregates their locations. However, from the program perspective, the aggregator (third-party or self-administered) is responsible for the aggregation of multiple sites. In this context, if and when third-party DR aggregation is allowed, it would be reasonable for size limits to be based on aggregation of multiple locations to meet any established threshold.

4. *How many in terms of numerical value and as a percentage of the C & I customer classes and any specific sub-classes and what types of customers (with and without aggregated load) would be included within the proposed thresholds?*

Based on customer billing demand, the following customer count totals and percentages would meet the respective size thresholds contemplated by the Commission's question for the Company's Large General Service (LGS), Small Primary Service (SPS), and Large Primary Service (LPS) classes:

LGS: total customer 10,555

- 10 kW: 10,493 or 99.5%

- 100 kW: 7,122 or 67.5%
- 300 kW: 2,055 or 19.5%
- 1 MW: 137 or 1.3%

SPS: total customer 656

- 10 kW: 654 or 99.7%
- 100 kW: 622 or 94.8%
- 300 kW: 519 or 79.1%
- 1 MW: 287 or 43.8%

LPS: total customer 62

- 10 kW: 62 or 100%
- 100 kW: 62 or 100%
- 300 kW: 62 or 100%
- 1 MW: 62 or 100%
- 5 MW: 55 or 89%

Billing demand data is not available for the Small General Service (SGS) class from which to estimate the proportion of the class or total customer count at various thresholds, but based on tariff applicability, all customers in the SGS should be below the 100-kW threshold.

5. *Should there be a maximum aggregated size limit?*

As discussed in the Company's response to Question A.1., prior to removing the prohibition, the Commission, utilities, and stakeholders should evaluate the requirements for visibility and program definition in conjunction with the addition of DER's through Order 2222 before discussing an aggregated size limit.

B. <u>Dispute Resolution</u>:

1. *As to utilities with affiliates in states that allow ARCs:*

   a. *How are relationships between utilities and ARCs managed?*

As a preliminary but important matter, there are no enforceable rules in place respecting disputes involving DR aggregation today. There remain serious, unresolved jurisdictional questions in terms of state authority over ARCs, and whatever dispute resolution processes exist could only exist, today, via RTO tariffs and in the case of MISO, such processes do not exist. Even if they did, dispute resolution would really be under the purview of FERC and not the state since such provisions would only be in the RTO's tariff. MISO's proposed Order 2222 tariff provisions do contain (for DER aggregation) dispute resolution provisions that include RERRA's but those are not yet effective and will be defined with all stakeholders in the implementation process of Order 2222. As discussed throughout this Response, this is yet another reason why the prohibition on ARC DR activity should not be modified except as part of the implementation of DER aggregation generally.

For Ameren Illinois, resolving disputes has thus far been a matter of bilateral discussions between the ARC and the utility, but these discussions are not guided by or aided by any enforceable rules for utility involvement beyond verifying the maximum load capabilities for individual customer locations included in proposed aggregations. This process has made it clear that implementation of third- party aggregation without adequate consideration by the Commission of what the rules should be and how the process should work is not an appropriate path forward. There should be clarity in the expectations of all parties and a formal structure to govern the process.

b. What types of disputes arise, and how frequently?

Some examples of issues that have arisen in Ameren's Illinois jurisdiction include:

- One recent issue of contention has been regarding the ARC's desire to have the utility allocate/release energy efficiency load reductions to the customer so the customer can be directly credited with or compensated for load reduction. Ameren Illinois includes all energy efficiency load reduction in its load data provided to

MISO, so that all retail customers – who pay for the cost of the programs - benefit from the energy efficiency investments that result in those load reductions. Ameren Illinois has opted not to release the energy efficiency load reductions and have had a few customers threaten to not implement proposed energy efficiency programs due to this position.

- Recent Ameren Illinois experience highlights the fact that dual registration of resources will be an emerging issue. This year, 6,000 of Ameren Illinois' residential customers that were enrolled in the Ameren Illinois' Peak Time Rewards demand response program also enrolled in an ARC's demand response program. This creates a variety of difficult issues, indicating that going forward we must have a shared data resource between the ARC's, ISOs and utilities (and other necessary stakeholders) to be able to effectively manage customer participation in programs and ensure that no customers are allowed to dual register a resource in multiple programs through multiple ARC's. It is the Company's understanding that similar issues have arisen in Kansas.

Both of these examples clearly point out that the lack of clearly defined process and rules has made implementation and management very difficult. Neither issue would have occurred if appropriate structures were in place prior to implementing third party aggregation.

c. How are disputes resolved?

In Ameren Illinois' experience, these issues are addressed through discussions with the affected parties but here are no actual and enforceable rules or processes to govern the process.

2. As to the ARCs:[6]

[6] Ameren Missouri assumes this question is directed to ARCs only.

a. *How do they manage relationships with utilities?*

b. *What types of disputes arise, and how frequently?*

c. *How are disputes resolved?*

3. *As to MISO and SPP:*[7]

a. *What types of disputes arise related to third-party demand response, and how frequently?*

b. *How are those disputes typically resolved?*

c. *What disputes, if any, have been resolved by the state utility commission or other state regulatory authority?*

C. Double Counting/Dual Participation:

1. *Should the Commission clarify whether a C & I customer can participate only in the wholesale market or only in the retail market? How should this clarification be made?*

Yes. It is important to have sufficient rules and tariff mechanisms to prevent double counting or double compensation of DER's, while allowing legitimate dual participation where the multiple services can be provided by a DER that do not overlap or result in double counting or double compensation. Advanced Energy Economy ("AEE") and GridLab brought together utilities and AEE members to build consensus around key distribution system issues to facilitate DER participation in wholesale markets. This report/presentation can be found at: https://gridlab.org/wp-content/uploads/2022/01/AEE-GridLab-FERC-O.2222-Campaign-Final-Report.pdf

[7] Ameren Missouri assumes this question is directed to the RTOs only.

On pages 56-68 of the report, the issue of multiple use and double counting is discussed and provides a very good starting point for this conversation. In general, resources should be utilized for their ‘highest and best use’. On any given day, their use in a retail (distribution utility) program might be more valuable than their use in a wholesale market program and the resource should be allowed to participate in both programs with appropriate rules in place to ensure dual compensation is not awarded for any single call on the resource. Further, some utility retail programs already provide retail compensation to DERs for wholesale services and attributes. Utility programs and tariffs must be carefully reviewed to determine dual participation eligibility that does not result in double compensation. Importantly, we must have a shared data resource between the ARC’s, ISOs, and utilities (and other necessary stakeholders) to be able to effectively manage customer participation in programs and ensure that no customers are allowed to dual register a resource in multiple programs through multiple ARCs or through their utility and an ARC. The rules for this type of participation and the coordination between the retail and market program would have to be fully defined prior to allowing dual participation.

2. *If dual participation in the wholesale and retail markets for different services is allowed, how would improper double counting be identified and avoided?*

It is necessary to clearly define both the rules of participation and compensation to ensure double counting is avoided in these programs. Retail programs and tariffs must be carefully reviewed to determine the extent to which they compensate customers for wholesale services or might have significant operational overlap with wholesale market activity occurring through an ARC. In addition, switching rules for customers switching between various programs and providers, and relating to the duration of participation once they have signed up, must be established. Further, the administrative burden to accomplish this could be significant if there is not an effective shared data resource between utilities, the ISO, aggregators, and customers.

3. *What specific internal processes and procedures would utilities need to implement to address double counting under the requirements and procedures imposed by MISO or SPP?*

It is difficult to propose specific processes and procedures prior to MISO and SPP defining their programs and utilities interacting with Commission to determine if they will have additional retail programs. However, the AEE/GridLab report provides significant context to be able to address this issue when final FERC rulings are issued and the programs at both the wholesale and retail level are better defined.

D. Data Governance:

1. *Do existing utility tariffs include provisions related to customer data privacy?*
   a. *What revisions related to third-party demand response aggregation, if any, would be necessary?*

A consistent, common data privacy rule for customer data is needed for anyone who has access to this data. At a minimum, the state requirements for data privacy for customers need to be defined and any third-party aggregators must meet these requirements through a legally binding mechanism during their approval process to be an aggregator of customers in the state of Missouri. No such process is in place today.

2. *What customer information is generally shared between the utility and the ARC?*

The information shared is dependent on both the class of the customer and the program it is enrolled into. Information exchanged between utilities and ARCs needed to validate registration may include at least the following items:

> Local Balancing Authority (LBA) name, Load Serving Entity (LSE) name, RERRA name, CP Node name, customer account number, meter identification number, maximum level of participation, address, resource type, effective date, termination date, number of sites, number of meters, measurement and verification methodology, firm service level, tested or untested resource status.

a. *What information, if any, is public information?*

The only information that should be public is the aggregate load for an ARC.

3. *How do ARCs protect customer information?*

We have serious concerns in this area, including our affiliate's experience in Illinois where customer account information is shared in Excel files via email without any binding data privacy/cybersecurity protocols in place. This creates significant risk of loss of data and potential corruption of files. A much better method for data sharing between necessary stakeholders must be developed before ARC activity occurs.

4. *How do ARCs protect their systems from cybersecurity threats?*

NERC released a white paper in December 2022, Cyber Security for Distributed Energy Resources and DER Aggregators. This paper should be considered for recommendations or requirements and can be found here:

https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf

For example, the NERC paper notes that there should be a:

> **"Proactive Understanding of DER and DER Aggregator Cyber Security Risks**: Industry stakeholders should actively engage in understanding the risk

> posed with growing levels of DERs and the introduction of DER aggregators. Cyber security risks exist throughout the product lifecycle: equipment design, testing, commissioning, and operation. Understanding the aggregate risks posed by DERs and DER aggregators and how to mitigate them will better posture the BPS for reliable operation of DERs."

There will still be concerns about this issue even if strict guidelines are created. Who will ensure that every ARC's system meets these requirements? There are literally hundreds of systems in use for ARC's, utilities and ISO's and this process will be daunting to secure and share the data.

5. *Would adoption of Green Button or similar alternative facilitate timely and accurate demand response registration?*

Over time, the green button initiative will support the registration process. Initially, the data set will not have historical data required to establish the DR capability. Depending upon program requirements for historical data, it could be 1-3 years to have adequate data sets to support the registration process.

   a. *Are there any implementation constraints related to adopting Green Button or similar alternative?*

Pursuant to the Stipulation and Agreement in File No. ER-2019-0335, the Company is in the process of implementing Green Button functionality by the end of this year but as noted, it does not have sufficient data at this time to support the registration process.

E. Regulatory Gaps:

If the Commission modifies its opt-out to permit third-party demand response for C&I customers, what regulatory gaps, if any, exist under MISO and SPP rules governing demand response?

We addressed some of these issues in the Introduction section, above. The regulatory gaps arise from the fact that the none of the six topics – jurisdiction, registration and licensing, data governance, double counting, dispute resolution – have been vetted and resolved in

Missouri, yet all of them apply to DR aggregation just as they do/will to DER aggregation generally pursuant to FERC Order 2222. Ameren Missouri recognizes the likelihood that at the appropriate time FERC will likely eliminate the opt-out for DR aggregation entirely but anticipates that this will occur in the context of broader Order 2222 implementation by RTOs/ISOs. To lift the prohibition now, however, would either leave the above-topics unaddressed, which itself is problematic, or require that they be addressed for DR alone without considering how the ultimate state where both DR and DER aggregations will be taking place will work.

This will likely lead to moving through the adoption/implementation process for aggregations twice – once now for DR and again later for DER. A better alternative is to figure out these issues for both DR and DER together. This would allow all stakeholders and the Commission to implement consistent policy, processes, and system in *one* complete process for both DR and DER. It would also allow for more effective system planning within the context of both DERs and DR instead of having to modify policy, process, and systems now for DR participation and then having to modify them *again* for DER in a few years. This will provide a much more effective DR and DER program in Missouri and allow costs to be much more efficient by incorporating all the required changes to policy and tariffs and subsequent changes to people, processes, and systems at the utilities at one time.

This could also effectively allow Missouri, as noted by the LBNL report and our previous comments, to allow utilities to establish programs to engage customers prior to the MISO 2222 implementation schedule in a phased approach to market participation.

WHEREFORE, Ameren Missouri submits this response in accordance with the Order and looks forward to participating in the July 10, 2023, workshop.

Respectfully Submitted,

/s/ James B. Lowery

James B. Lowery, MO Bar #40503
JBL Law, LLC
9020 S. Barry Road
Columbia, MO 65201
Telephone: (573) 476-0050
lowery@jbllawllc.com

ATTORNEYS FOR UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI