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E-File

May 29, 2024

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17120-3265

Re: Distributed Energy Resources Participation in Wholesale Markets
Docket No. L-2023-3044115

Dear Secretary Chiavetta:

Enclosed for filing on behalf of PPL Electric Utilities Corporation ("PPL Electric") are PPL Electric's Comments in the above-captioned proceeding. These Comments are being filed pursuant to the February 22, 2024 Advance Notice of Proposed Rulemaking Order which was published in the March 30, 2024 *Pennsylvania Bulletin.*

Pursuant to 52 Pa. Code § 1.11, the enclosed document is to be deemed filed on May 29, 2024, which is the date it was filed electronically using the Commission's E-filing system.

If you have any questions, please do not hesitate to contact me.

Respectfully submitted,

Michael J. Shafer

Enclosure

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Distributed Energy Resources	:	
Participation in Wholesale Markets	:	Docket No. L-2023-3044115

COMMENTS OF
PPL ELECTRIC UTILITIES CORPORATION ON
THE ADVANCE NOTICE OF PROPOSED RULEMAKING ORDER

I. INTRODUCTION

On February 22, 2024, the Pennsylvania Public Utility Commission ("Commission" or "PUC") issued an Advance Notice of Proposed Rulemaking Order ("ANOPR") seeking comments from interested parties on the topics set forth in the ANOPR, which is designed "to investigate the PUC's role in the implementation of FERC Order 2222 and to determine whether any amendments or additions are needed to align existing Commission regulations or policy statements with the Federal Energy Regulatory Commission's ("FERC") Order 2222." (ANOPR at 1) (footnotes omitted). The ANOPR directed Comments to be filed within 60 days of the ANOPR's publication in *The Pennsylvania Bulletin*. Because the ANOPR was published on March 30, 2024, Comments by interested parties are due by May 29, 2024.

PPL Electric Utilities Corporation ("PPL Electric" or the "Company") appreciates the opportunity to provide input on the questions raised in the Commission's ANOPR. The Company supports the Commission's effort to investigate its role in implementing FERC Order 2222[1] and determine the revisions and changes that will be required to align the Commission's existing

[1] *See Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, 172 FERC ¶ 61,247 (2020) ("FERC Order 2222"), *order on reh'g*, 174 FERC ¶ 61,197 (2020) ("FERC Order 2222-A"), *order on reh'g*, 175 FERC ¶ 61,227 (2021) ("FERC Order 2222-B").

regulations and policy statements with FERC Order 2222. As outlined in FERC Order 2222 and reiterated in the ANOPR, state regulators will play a vital role in implementing FERC Order 2222, and coordination will be required among all stakeholders, particularly distribution utilities, state regulators, and the Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"). The Company believes this ANOPR is a good start in preparing the Commonwealth for participation of Distributed Energy Resource ("DER") aggregations ("DER Aggregations") in wholesale energy, capacity, and ancillary markets. However, it will take a significant and collaborative effort to implement the changes necessary to support and facilitate the participation of DER Aggregations in the wholesale markets in a safe, reliable, and reasonable way.

PPL Electric believes it is well-positioned to provide insight to the Commission on the topics set forth in the ANOPR. The Company has been engaged with PJM Interconnection LLC ("PJM") since the passage of FERC Order 2222. The Company also has been actively collaborating with peer electric distribution companies ("EDCs") in Pennsylvania and in the PJM footprint to discuss FERC Order 2222's implementation. Further, as noted in the ANOPR, the Company participated in the Commission's stakeholder meetings to discuss FERC Order 2222, proposed topics for the ANOPR, and potential concerns.

As the ANOPR rightly points out, PJM is still waiting for FERC's ruling on its FERC Order 2222 compliance filing. PJM cannot proceed with development of its Manual provisions until all components of its compliance filing have been approved by FERC. As highlighted below, the eventual implementation of FERC Order 2222 at the distribution level will be informed by that ruling and the resulting PJM revisions. Thus, there remains uncertainty around how FERC Order 2222 will be implemented by PJM, which expectedly will inform the Commission's implementation as well. Notwithstanding, PPL Electric supports the Commission's efforts to begin the process now through its ANOPR, as the implementation will likely require a significant amount of time, coordination, and fact-gathering to be successful.

Before addressing the topics set forth in the Commission's ANOPR in detail, PPL Electric would like to offer the following overall observations concerning FERC Order 2222:

A. EDCs MUST RETAIN THE ABILITY TO MAINTAIN A SAFE AND RELIABLE ELECTRIC GRID

EDCs have a statutory duty to provide safe, reliable, adequate, and reasonable service to all of their customers. *See* 66 Pa. C.S. § 1501. Accordingly, with implementation of FERC Order 2222, it is paramount that EDCs retain the ability to maintain a safe and reliable electric distribution system and continue providing safe, reliable, adequate, and reasonable service. Such ability includes but is not limited to: (1) discretion over technical interconnection requirements and standards; and (2) override authority when necessary.

With FERC Order 2222, FERC required "each RTO/ISO to revise its tariff to include coordination protocols and processes for the operating day that allow distribution utilities to override RTO/ISO dispatch of a distributed energy resource aggregation in circumstances where such override is needed to maintain the reliable and safe operation of the distribution system." FERC Order 2222 at P310. FERC explained that "[t]hese processes that allow distribution utilities to override RTO/ISO dispatch must be contained in the tariff and must be non-discriminatory and transparent but still address distribution utility reliability and safety concerns." *Id.* Moreover, FERC found that "these operational coordination requirements will maximize the availability of the distributed energy resource aggregation consistent with the reliable and safe operation of the distribution system." *Id.*

As a result, the Commission should reaffirm that EDCs can determine when and how to override the dispatch of DER Aggregations because such override capability is necessary for EDCs to fulfill their duties, under the Commission's jurisdiction, to provide safe and reliable electric distribution service to customers. Indeed, situations under which an EDC may have to initiate an override include, but are not limited to, when:

1. DER is auto-transferred or non-planned manually transferred to a different feeder that cannot handle it at its current level;
2. DER is operating outside the terms of its interconnection agreement;
3. DER is operating on a de-energized line;
4. Safety disconnection (fire, crew work, etc.); or
5. DER is causing or contributing to unexpected equipment overload and/or violation condition.

To be clear, EDCs should not be limited to overriding the dispatch of DER Aggregations under these circumstances only. Rather, EDCs should be given discretion, as the operator of the distribution system, to override for any reasons necessary to provide safe and reliable electric distribution service.

B. NEW INTERCONNECTION AGREEMENTS MUST BE CREATED

To implement FERC Order 2222, EDCs will need to develop new standard interconnection agreements with language that outline EDCs' override authority. Such language should state that EDCs can override resources that participate in a DER Aggregation including a Component DER and/or DER Aggregation Resource and make clear that EDCs have the authority and discretion to determine when and how to override these resources.

Further, under FERC Order 2222, certain types of resources, including demand response and energy efficiency, will now be able to interact with the grid through participation in an aggregation. *See* FERC Order 2222 at P1 n.1 (defining "distributed energy resource"). The Commission's existing standard interconnection agreements were designed for net metered inverter-based, behind-the-meter generation. Therefore, a new standard agreement between the EDC and these other resources must be developed. The agreement should, at a minimum, outline and facilitate the data sharing process for resources that do not inject energy to the grid. The Commission could refer to this new agreement as a "component aggregation contract" or a "load management contract." Resources with injection potential, such as electric vehicles and energy storage, will need a more comprehensive agreement similar to the existing standard interconnection agreements.

EDCs and DER Aggregators also will need a new standard agreement that will govern the sharing of information between both parties. At the very least, this information sharing will be needed for billing and market settlement purposes. This agreement should be incorporated into a larger DER Aggregation review process through which the EDC would evaluate whether the Component DER has the necessary metering infrastructure in place in order to participate in a DER Aggregation. Also during this review, it should be confirmed that the DERA has an agreement in place with an EDC. This should be required before any of its Component DER can participate in an aggregation.

C. THE INTERCONNECTION APPLICATION AND COMMISSION'S REGULATIONS SHOULD BE UPDATED

The Commission's interconnection application should also be updated to reflect the information that is necessary to accommodate DER Aggregation. PPL Electric proposes that

Component DER will need to choose whether to be net metered or aggregated. This choice will dictate the application and review path the customer goes through. The current application is also incomplete and excludes relevant information, such as whether the applicant has any existing DER, electric vehicle ("EV") chargers, and/or batteries. The interconnection application also is missing information pertinent to the application and subsequent feasibility study, such as the DER system's grid coordinate location at the point of interconnection.

Also, the Commission should update its regulations to reflect the time required for EDCs to complete system studies based on the current interconnection application processing conditions. Advancements, including processing automation, have the potential to dramatically reduce application processing time. As such, an evaluation of the application process is warranted to determine more realistic time requirements that should be incorporated into the Commission's regulations.

II. COMMENTS ON TOPICS FOR ANOPR

In the following sections, PPL Electric responds to the various topics set forth in the Commission's ANOPR for interested stakeholders to address in their Comments. Although PPL Electric responds to most of those topics, the Company's failure to address a topic specifically should not be considered as PPL Electric's agreement with any particular approach. Moreover, the Company reserves the right to provide further comment on these subjects in subsequent stages of this rulemaking proceeding as it progresses and in response to other parties' Comments.

A. CHANGES TO DISTRIBUTION DER INTERCONNECTION RULES

In its ANOPR, the Commission sought "comment on whether its existing interconnection regulations for customer-generators, 52 Pa. Code §§ 75.31—40, can be adapted to address interconnection of a Component DER participating in a DER Aggregation Resource with EDC distribution facilities, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's interconnection regulations that would facilitate this adaption." (ANOPR at 21.) Also, the Commission requested comment on the following "sub-topics": (1) "[h]ow will Component DERs previously not subjected to interconnection (energy efficiency and demand response resources) be integrated into an aggregation?"; (2) "[i]n consideration of future technology advancement through distributed energy resource management systems (DERMS) and other technologies that may allow for utility direct control and overrides, should approval of interconnection requests extend to consideration of an option for firm and non-firm approval categories to reduce the need for system upgrades?"; (3) "[u]nder what conditions will direct control vs. monitoring be required?"; (4) "[h]ow should the DER aggregation review process differ for different use cases, market services, DER compositions or grid conditions?"; (5) "[h]ow should load assumptions be adjusted to accommodate the use of load-modifying resources?"; (6) "[w]hat data will DERAs need to provide to EDCs and to what extent can this leverage existing PJM registration data requirements," and "[h]ow should these data be documented?"; (7) "[w]here should automation versus. manual coordination and communication between EDCs, the DERA and PJM be required," and "[h]ow should the PUC ensure that the EDC DER registration approval process is efficient to consistently meet PJM's 60-day timeline and avoid potential 'over-registration'?"; and (8) "[h]ow should the PUC clarify and harmonize the relationship between DER interconnection under PUC regulations with DER interconnection under to PJM's small generator interconnection rules, if needed?" (ANOPR at 21-22.)

As to the main topic, PPL Electric believes it would be more appropriate to create a separate subchapter within Chapter 75 to address the interconnection standards for DERs seeking to participate in DER Aggregation. Currently, Subchapter C of Chapter 75 of the Commission's regulations only pertains to "the interconnection standards that apply to EDCs which have customer-generators intending to pursue net metering opportunities in accordance with the act." 52 Pa. Code § 75.21. However, customers who participate in DER Aggregation are participating in the wholesale market. Given this clear distinction, Subchapter C would either have to be overhauled to include DERs, such as energy efficiency, demand response, and electric vehicles, which can participate in DER Aggregation, or, as suggested by PPL Electric, the Commission could create a separate subchapter to address those other types of interconnections.

Moreover, the Company recommends that the Commission's regulations mandate that DERs make a decision—either they can either participate in a DER Aggregation Resource as a Component DER or participate in net metering. However, the DERs cannot do both. This decision could potentially be revisited by the DER owner on an annual basis.

In addition, even beyond the changes needed to incorporate DER Aggregations, the Commission should update Chapter 75 of the Commission's regulations, the standard interconnection agreements, and the current interconnection application review process. In particular, the regulations should be updated to revise the fee structures in a manner that more accurately reflects EDCs' cost to process applications. PPL Electric supports a dollar per kW structure of the fee, but the amount of the fee needs to cover the cost to process the interconnection application. This cost will vary for different utilities given their different systems and processes; as such, PPL Electric recommends that the Commission conduct a formal analysis of the cost for the EDC to process an application and prepare an Interconnection Request Review ("IRR").

Furthermore, it is critical that metering and data requirements be established to accommodate DER setups that did not exist when the Commission's current regulations and standard interconnection agreements were adopted. Indeed, those regulations and agreements contemplate inverter-based, behind-the-meter generation, not resources such as electric vehicles, energy efficiency, and demand response. *See, e.g.*, 52 Pa. Code §§ 75.37-40 (setting forth the Level 1, Level 2, Level 3, and Level 4 interconnection review procedures for small generator facilities). Therefore, the Commission must update the interconnection agreements with metering and data requirements that properly reflect these new DER setups and the distinct markets in which they may choose to participate under FERC Order 2222.

As for the "sub-topics" raised in Section III.A of the ANOPR, PPL Electric responds to them as follows:

1. How Will Component DERs Previously Not Subjected to Interconnection (Energy Efficiency and Demand Response Resources) Be Integrated Into an Aggregation?

Existing interconnected DERs, as well as DERs not previously subject to the Commission's interconnection requirements, could become Component DERs by entering into DER Aggregation-related agreements. It is essential to recognize that Component DERs injecting onto the grid necessitate an interconnection agreement. Currently, some of these resources (e.g., storage and vehicle-to-grid ("V2G")) lack interconnection agreements. Other resources that do not inject electricity onto the grid, such as energy efficiency and demand response, similarly lack interconnection agreements. Therefore, the Commission should develop aggregation agreements that would govern those resources' participation in a DER Aggregation.

In addition, the Company has created agreements for DER systems that are connected to the distribution system but participate in the wholesale market. These agreements build off PJM's interconnection agreements with modifications to reflect the interconnection with the distribution system, rather than the transmission system. Such agreements could prove useful in developing interconnection agreements for other resources that inject power onto the grid but are not currently contemplated by the Commission's interconnection agreements.

2. In Consideration of Future Technology Advancement Through Distributed Energy Resource Management Systems (DERMS) And Other Technologies That May Allow for Utility Direct Control and Overrides, Should Approval of Interconnection Requests Extend to Consideration of An Option for Firm And Non-Firm Approval Categories To Reduce The Need For System Upgrades?

PPL Electric implemented a Distributed Energy Resource Management System ("DERMS") in July 2019 and currently uses its DERMS and Advanced Distribution Management System ("ADMS") to monitor and manage DERs on its distribution system under its Commission-approved First DER Management Plan.[2] Based on that experience, a DERMS has significant potential for EDCs to manage overrides efficiently. However, not all utilities will be equipped with DERMS when FERC Order 2222 is implemented. Therefore, the Commission's regulations should be designed with flexibility, allowing for a variety of EDC override mechanisms to be accommodated.

Furthermore, PPL Electric believes the terms "firm" and "non-firm" are ambiguous. One interpretation is that "non-firm" references a "flexible interconnection,"[3] whereby the customer agrees that the generating facility's real power output can be reduced, when necessary, in exchange for the interconnection not requiring a distribution system upgrade. Alternatively, it is possible that "firm" and "non-firm" refer to guaranteed access to the distribution system versus non-

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[2] *See Petition of PPL Electric Utilities Corp. for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, Docket No. P-2019-3010128 (Order entered Dec. 17, 2020).

[3] *See Understanding Flexible Interconnection*, September 2018, Electric Power Research Institute, https://www.epri.com/research/products/000000003002014475. The Electric Power Research Institute (EPRI) describes "Flexible Interconnection" as the number of options that are available for DER interconnection, and in particular to options that involve real-power. Unlike conventional interconnections, which assume that DERs operate in a free-running unconstrained manner, Flexible Interconnection involves management of DER operation to increase grid utilization and support more average energy transfer and larger DER sizes in more locations.

guaranteed access, respectively. Notwithstanding, while DERMS may allow for flexible interconnections to reduce interconnection upgrade costs, EDCs must nevertheless retain full discretion, authority, and override capability to protect the integrity of the distribution system.

3. Under What Conditions Will Direct Control Vs. Monitoring Be Required?

Effectively managing Component DER will require a combination of direct control and monitoring. EDCs will need to monitor the status of the distribution system and Component DER activity to assess the safety and reliability of the grid. If a problem is identified, direct control may be necessary to override the operation of a Component DER in addition to the traditional EDC equipment operations in order to protect the distribution system, and the safety of the public and EDC employees.

4. How Should the DER Aggregation Review Process Differ for Different Use Cases, Market Services, DER Compositions or Grid Conditions?

PPL Electric anticipates that the bulk of the review will occur when the individual Component DER applies to interconnect. Each Component DER submitted to register as part of a DER Aggregation Resource is reviewed by the EDC, and once approved will be permitted to broadly participate in DER Aggregation. The Company anticipates the DER Aggregation review process to focus on the details of specific DER Aggregation to facilitate necessary data sharing, metering, and settlement activities.

When considering the review process for the DER Aggregation, several key factors come into play. First, the composition of the Component DERs is crucial. Per FERC Order 2222, there can be no limitation on the types of technologies eligible to participate as Component DERs, and heterogeneous aggregations must be allowed.[4] PJM is focused on identifying the physical and operational capabilities of a DER Aggregator to ensure participation in the appropriate markets. The location of Component DERs on the grid is another significant factor. FERC Order 2222 mandates that locational requirements must be as "geographically broad" as technically feasible.

The process for reviewing changes in Component DERs within a DER Aggregation Resource is pending before FERC. Proposed updates to the inventory of Component DER within a DER Aggregation Resource or additional markets a DER Aggregation Resource wants to participate in are reported to PJM's Office of Interconnection. The EDC will receive notification and all applicable information/data and will have a 15-or-45-day review process to recommend approval/denial to PJM.

Finally, it is important to note the size limitations for DER Aggregation Resources. The minimum size threshold for inclusion is 100 kW, and the maximum capacity for a Component DER participating in a DER Aggregation Resource is 5 MW. Larger resources must participate in markets individually or under a different PJM model.

5. How Should Load Assumptions Be Adjusted to Accommodate the Use of Load-Modifying Resources?

Load modifying resources that affect load growth should be included as part of the forecast development process. Currently, PPL Electric has found that battery storage has no material impact to load projections, but the Company continues to monitor trends if installations pick up. Demand response is already considered in historical load values, and if there is a significant increase in the number of customers willing to respond to demand response events, the Company would factor that into load projections.

[4] *See* FERC Order 2222 at Par. 141-143.

6. What Data Will DERAs Need to Provide to EDCs and to What Extent Can This Leverage Existing PJM Registration Data Requirements? How Should These Data Be Documented?

PJM has not received final approval from FERC on what information is required for the registration process. However, PPL Electric supports efforts to avoid duplication of registration data. The Company anticipates that, at a minimum, the EDC will need to know the identity, type of technology, size, and location of each Component DER making up a DER Aggregation Resource. Depending on whether the EDC is responsible for any billing of the DER Aggregator, additional information will be required.

7. Where Should Automation Versus Manual Coordination and Communication Between EDCs, The DERA And PJM Be Required? How Should the PUC Ensure That the EDC DER Registration Approval Process Is Efficient to Consistently Meet PJM's 60-Day Timeline and Avoid Potential "Over-Registration"?

PPL Electric supports automation and encourages the Commission to recognize the need to construct systems that facilitate an automated process. The registration process first requires that the Component DER receive interconnection approval. The Company anticipates that this step will constitute the bulk of the review process. The DER Aggregator's registration is reviewed after the Component DER(s) have obtained interconnection approval. Provided that the individual Component DERs have requisite approvals, PPL Electric does not anticipate being unable to meet the 60-day timeline for reviewing the DER Aggregator's registration. Finally, the Company does not know what the Commission means by "over-registration" and respectfully requests clarification.

8. How Should the PUC Clarify and Harmonize the Relationship Between DER Interconnection Under PUC Regulations With DER Interconnection Under PJM's Small Generator Interconnection Rules, If Needed?

PPL Electric believes that the creation of standardized and workable interconnection rules for Component DER will effectively harmonize the relationship between PUC regulations and PJM small generator interconnection rules. It is important to note that these Component DERs are not required to comply with PJM's small generator interconnection rules.[5] As discussed previously, if Component DERs have an approved interconnection, the Company anticipates being able to meet the requirements of PJM's small generator interconnection rules.

B. CHANGES TO METERING REQUIREMENTS

The Commission's ANOPR also sought "comment on whether its existing metering regulations for customer-generators, 52 Pa. Code § 75.14 (relating to meters and metering), can be adapted to facilitate provision of metering and telemetry data by DERAs to public utilities, consistent with Order 2222 and PJM's DAPM, and if so, whether and what specific changes to the PUC's interconnection regulations that facilitate this adaption." (ANOPR at 24.) Further, the Commission asked for stakeholders to address the following "sub-topics": (1) "[h]ow should interconnection regulations evolve to ensure alignment between EDC and PJM telemetry and metering to facilitate consistency and avoid extensive telemetry differences between DERA requirements and retail DERs?"; and (2) "[s]hould the PUC facilitate device-level metering and if so, how?" (ANOPR at 25.)

Section 75.14 of the Commission's regulations is housed within Subchapter B of Chapter 75 of the Commission's regulations. Subchapter B "sets forth net metering requirements that apply to EGSs and EDCs which have customer-generators intending to pursue net metering opportunities in accordance with the act." 52 Pa. Code § 75.11. Therefore, PPL Electric believes it would be

[5] *See* FERC Order 2222 at Par. 90.

better to create a new subchapter within Chapter 75 that applies specifically to non-net metered DERs. Such a dedicated subchapter would avoid confusion and be easier to craft. For example, Section 75.14(a) of the Commission's regulations only allows for one bidirectional meter at a customer location. Under DER Aggregation, however, a customer may have several DER installations at one location. Each of the DER may have different rates for load and may be compensated at different rates, thereby requiring each DER to have its own meter. As opposed to revising Section 75.14 (and other provisions in Chapter 75) substantially, the Commission would be better served to create a new subchapter in Chapter 75 to address DER Aggregations.

As for the sub-topics on the metering requirements, PPL Electric addresses them in the following sections.

1. How Should Interconnection Regulations Evolve to Ensure Alignment Between EDC And PJM Telemetry and Metering to Facilitate Consistency and Avoid Extensive Telemetry Differences Between DERA Requirements and Retail DERs?

For accurate settlement of Component DERs participating in DER Aggregations, metering and/or load data in some form must be available any time energy would be charged or compensated at a different rate than other energy at a single premises. This will be a requirement for any future rate structure that could exist for participating in a wholesale or retail program.

PPL Electric envisions two possible avenues to address this need. First, the Commission could require that each individual asset be sub-metered, so that the load from each asset is distinguishable. This would likely be costly for customers who would need to purchase and pay for installation for a meter for each asset. It could also potentially be impractical depending on how many assets are involved. Further, the matter of sub-metering is likely to be impacted by FERC's forthcoming ruling on PJM's September 2023 compliance filing.

Alternatively, data from resources such as Home Area Network ("HAN") devices, electric vehicles, and/or electric vehicle chargers could be utilized by the EDC to identify load and injection from different assets from the overall load and injection at any given site. In this scenario, the meter data from a single meter would be received by the EDC in addition to asset-specific information from another device or resource, such as those noted above, that distinguishes the load and injection by each individual asset. The Commission should consider the acceptability of data from devices, such as HAN devices or electric vehicle chargers, for billing and markets settlement purposes. Of note, PJM metering accuracy standards will need to be met for any Component DERs metered separately.

For DERs seeking to participate in an aggregation as Component DERs, the EDC must review to confirm that the DER has the necessary metering requirements to qualify as Component DER. This means that load data is available for all DER devices capable of injecting to the grid. The EDC's review must be completed for all new DERs (not previously interconnected) seeking to participate in an aggregation as well as DERs that are currently interconnected to the system, not participating in an aggregation, and now seeking to participate in a DER Aggregation.

2. Should The PUC Facilitate Device-Level Metering and If So, How?

To successfully implement DER aggregation, the Commission should create standards for what level of accuracy is needed for device-level metering. The Commission should allow for flexibility in communication and technology standards, software and hardware standards, and telemetry communication type (Radio Frequency ("RF") Mesh, cellular, radio, etc.). This will accommodate different EDC approaches to metering and be able to adjust for changes in technology. For consistency, the Commission should identify and standardize accuracy requirements while allowing for different technical solutions. Such requirements should account for PJM's existing metering standards. Moreover, this topic is likely to be impacted by FERC's forthcoming ruling on PJM's September 2023 compliance filing.

C. COST ALLOCATION ISSUES FOR FACILITIES ALLOWING THE INTERCONNECTION OF DERS

The Commission asked for "comment on whether its existing interconnection cost allocation regulations for customer-generators, 52 Pa. Code § 75.36(8), 75.38(e) and 75.39(e)(4) (relating to additional general requirements, level 2 interconnection review, level 3 interconnection review), can be adapted to address interconnection cost allocation among Component DERs, DERAs and EDCs, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's interconnection regulations that would facilitate this adaption." (ANOPR at 26.) The Commission further requested comment on the following "sub-topics" related to cost allocation: (1) "[h]ow will DERA market participation impact retail rates?"; (2) "[w]hat cost recovery guidance, if any, is needed by EDCs for investments that may support both transmission and distribution?"; (3) "[h]ow should EDCs distinguish cost allocation between grid modernization, general DER costs, and DERA-specific costs?"; (4) "[w]hat cost recovery mechanisms should be used (upfront charges, usage charges, rates)?"; and (5) "[w]hat is the interplay between the direct procurements aspects of EDCs' default service plans and an EDC's costs to administer DERA participation in wholesale markets, if any?" (ANOPR at 26-27.)

On the overall question, there are two categories of cost allocations that need to be considered in the implementation of FERC Order 2222. The first cost category is the cost to interconnect Component DERs safely with the distribution system. Chapter 75 rules requiring interconnection customers being responsible for interconnection costs can largely be adapted to cover Component DERs participating in aggregation. This is an equitable result because

Component DERs and net metered DERs that need to interconnect with the distribution system are functionally the same and should follow similar interconnection rules. FERC Order 2222 also allows the relevant electric retail regulatory authority ("RERRA") to impose its interconnection standards on Component DERs. The second cost category is the costs associated with setting up the appropriate backend infrastructure for EDCs to administer and accommodate FERC Order 2222 aggregation.

EDCs will likely need to build out their internal infrastructure to support aggregations. This includes billing systems, data sharing systems, operational systems, and related processes. Updates to these systems and processes will be required to facilitate the participation of aggregations, meaning these costs will be incurred by utilities before aggregation occurs.

EDCs should be permitted to recover these costs based on established cost of service principles. Specifically, EDCs should recover the costs of implementing changes required to facilitate aggregations because: (1) the EDCs must comply with FERC Order 2222; and (2) there are societal benefits to be realized from implementation of FERC Order 2222. As outlined in FERC Order 2222, DER participation in wholesale markets "will help the RTOs/ISOs account for the impacts of these resources on installed capacity requirements and day-ahead energy demand, thereby reducing uncertainty in load forecasts and reducing the risk of over procurement of resources and the associated costs." FERC Order 2222 at P4. Further, DER aggregation can "potentially [help] to alleviate congestion and congestion costs during peak load conditions and to reduce costs related to transmitting energy into persistently high-priced load pockets." *Id.* Given DERs "relatively short development lead time," they can also "respond rapidly to near-term generation or transmission reliability-related requirements, further improving their ability to enhance reliability and reduce system costs." *Id.* Beyond those benefits outlined in FERC Order

2222, increasing the number of DERs interconnected with the grid will also support clean energy policy goals at both the state and federal level.

As a result, the costs incurred to implement and comply with FERC Order 2222 should be recoverable in rates. Such costs do not include individual customers' costs to interconnect with the grid and participate in DER Aggregation. Customers interconnecting with the grid should still be responsible for costs related to any system upgrades needed to facilitate interconnection, even if the customer is participating as part of a DER Aggregation, as provided in EDC's respective tariffs.

As for the sub-topics on cost allocation, PPL Electric responds to the Commission's questions as follows:

1. How Will DERA Market Participation Impact Retail Rates?

It is too soon to tell whether DER Aggregators' market participation will have any meaningful impact on retail rates. This is largely because it is unclear whether there will be significant amounts of DER Aggregators' generation bid into the PJM market at rates to be determined in the future. However, if there are large volumes of DER Aggregators' generation bid into the market, that could provide downward pressure on wholesale rates. Retail electric customers would in turn benefit from lower wholesale generation rates.

At this early stage, it is also unclear what viable business models will be available for DER Aggregators. For this reason, PPL Electric encourages the Commission to avoid setting strict limits on who can be a DER Aggregator and recommends that, at minimum, EDCs not be prohibited from this ability because of this proceeding. As an example, if an EDC were an aggregator, the EDC could design rates and use aggregation to avoid or limit capital expenditures. This would in turn have the potential to lower customers' distribution rates. Further, EDCs' participation in the market as DER Aggregators is also allowed under FERC Order 2222. Given that aggregation is a new market resource, EDC innovation should be encouraged, and the Commission should avoid creating strict prohibitions that could stifle market innovation and prevent EDCs from developing programs that could be used to benefit customers.

2. What Cost Recovery Guidance, If Any, Is Needed by EDCs For Investments That May Support Both Transmission and Distribution?

PPL Electric does not believe that new guidance needs to be created. Costs can be assigned to transmission or distribution (or allocated between them) using existing cost of service principles.

3. How Should EDCs Distinguish Cost Allocation Between Grid Modernization, General DER Costs, And DERA-Specific Costs?

As mentioned earlier, interconnection costs should be the responsibility of Component DERs at the time of interconnection. Further, the Company would look to distinguish the costs that only benefit the Component DER or DER Aggregator and the costs that provide broader grid benefits. These costs would then be allocated accordingly.

4. What Cost Recovery Mechanisms Should Be Used (Upfront Charges, Usage Charges, Rates)?

Existing cost recovery mechanisms can be utilized to accommodate DER Aggregation. Upfront charges for the interconnection of Component DERs are appropriate, while having rates to recover the costs associated with the broader implementation of DER Aggregation is also needed. As the market matures, opportunities for usage charges may become apparent. However, PPL Electric is concerned that relying on usage charges to support investment needed to implement backend systems to support DER Aggregation at this early stage without knowing whether there will be users of the aggregations systems creates the risk of having stranded costs.

5. What Is the Interplay Between the Direct Procurements Aspects of EDCs' Default Service Plans and An EDC's Costs to Administer DERA Participation in Wholesale Markets, If Any?

PPL Electric does not currently see a direct interplay between DER Aggregators' participation in wholesale markets and direct procurements in default service plans. Unlike net metering, there is no requirement that EDCs take the output of DER Aggregators. Rather, DER Aggregators need to bid into the PJM markets. That being said, DER Aggregators could bid in an EDC's default service auction like any other generator.

D. ADJUDICATION OF DISPUTES REGARDING THE REGISTRATION OF DERS

The Commission also sought comment on "whether its existing application process for net metering customer-generators, 52 Pa. Code § 75.17, or its existing dispute resolution regulations, 52 Pa. Code Chapters 1 (relating to rules of administrative practice and procedure), 3 (relating to special provisions) and 5 (relating to formal proceedings), or both, can or should be adapted to facilitate adjudication of disputes about DERA registration of its Component DERs with PJM, consistent with Order 2222 and PJM's DAPM, and if so, the specific changes to the PUC's regulations that would facilitate this adaption." (ANOPR at 29.)

PPL Electric does not think that any meaningful changes to 52 Pa. Code Chapters 1, 3, and 5 are necessary to accommodate the handling of DERA related disputes. The PUC's existing complaint and dispute procedures can handle a wide variety of cases with diverse subject matters. Assuming the PUC asserts jurisdiction over DERs as described below, there is no reason to believe that existing procedures cannot accommodate DERA disputes. Additionally, creating subject matter specific procedures introduces the risk of creating confusion in the proceeding as to which rule applies.

E. MANAGEMENT OF DISTRIBUTION UTILITY OVERRIDES OF DERS TO MAINTAIN RELIABILITY, AND DISPUTES ARISING THEREFROM

In the ANOPR, the Commission requested "comment on whether and how its regulations can or should be augmented to address EDC overrides of DER Aggregation Resource or Component DER operation, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's regulations that would address overrides." (ANOPR at 31.) Also, the Commission asked for stakeholders to address these "sub-topics": (1) "[h]ow should the distribution override process align with market bidding windows?"; and (2) "[w]hat EDC 'real-time' update and override requirements should be addressed in DERA agreements to ensure the reliability and safety of the grid?" (ANOPR at 31.)

PPL Electric anticipates that the interconnection agreement with Component DER will specify override procedures so that Component DER owners know how and under what situations there may be an override. To mitigate intra-day EDC overrides of a Component DER within a DER Aggregation, the EDC would need to be an active participant in formulating the day ahead schedules developed by PJM and DER Aggregators. This coordination would follow PJM's current and proposed practices for day-ahead market processes and bidding timeframes.

PPL Electric supports the EDC's ability to mitigate system overload and voltage violations throughout varying normal and emergency conditions that are encountered on a daily basis. These mitigation actions would include both traditional PPL Electric system equipment operations and customer Component DER operation schedules overrides. Furthermore, it is expected that through this process, Component DER operational overrides would not solely be a de-energization of the customer's equipment, but would only involve a partial reduction in the system's output until PPL

Electric can return the system to a configuration that allows for the DER Aggregators expected operation schedule

F. PROTECTION OF DER OWNERS FROM UNFAIR TRADE PRACTICES OR EXCESSIVE RISK IN THE WHOLESALE MARKETS

The Commission's ANOPR also sought "comment on whether the [Unfair Trade Practices and Consumer Protection Law ('UTPCPL')] applies to the DERA-Component DER relationship and whether and how the PUC's EGS regulations can or should be adapted to address consumer protection in the DERA-Component DER relationship, consistent with Order 2222 and PJM's DAPM, and if so, what specific changes to the PUC's regulations would address these matters."

PPL Electric does not have a position on whether the UTPCPL applies to the "DERA-Component DER relationship." The Company questions whether DERAs meet the definition of an EGS and are subject to applicable EGS rules and regulations. However, PPL Electric believes that this is an area where customer protection is needed. It is PPL Electric's position that successful implementation of FERC Order 2222 in Pennsylvania will require the Commission to have jurisdiction over DER Aggregators. In particular, the Commission will need jurisdiction over DER Aggregators to address disputes, implement standards, regulate their activities, and oversee the interaction between aggregators and public utilities. As part of their jurisdiction oversight, the Commission should also license DER Aggregators to operate in EDCs' service territories. The authority to operate should not be governed or managed by EDCs' contracts with DER Aggregators.

G. PREVENTION OF DOUBLE COMPENSATION OR DOUBLE COUNTING BETWEEN RETAIL AND WHOLESALE MARKET PARTICIPATION, INCLUDING RULES GOVERNING DER OWNERS' ABILITY TO SWITCH BETWEEN RETAIL AND WHOLESALE MARKET PARTICIPATION

In its ANOPR, the Commission further requested "comment on whether its existing regulations on compensation for net metering customer-generators, 52 Pa. Code § 75.13, could or should be adapted to incorporate appropriate restrictions on double counting of services provided by a Component DER in wholesale and retail markets, on duplicative compensation for the same service, consistent with Order 2222 and PJM's DAPM, or on both, and, if so, what specific changes to the PUC's regulations would or should facilitate this adaption." (ANOPR at 38.) Additionally, the Commission asked stakeholders to address the following "sub-topics": (1) "[d]oes the PUC have authority to decide whether to permit net metering customers to participate in DERAs, noting FERC's statement that 'under a [RERRA]'s jurisdiction over its retail programs, such a [RERRA] is able to condition a distributed energy resource's participation in a retail distributed energy resource program on that resource not also participating in the RTO/ISO markets'?"; (2) "[a]ssuming the PUC does have requisite authority, should the PUC permit net metering customers to also participate in DERAs at the same time?"; and (3) "[a]ssuming the PUC does have requisite authority, should the PUC develop rules for when and how often a retail customer may switch between met [sic] metering and DERA participation?"

PPL Electric supports the Commission adopting regulations that prohibit DERs from participating in both net metering and DER Aggregation. In Pennsylvania, customer-generators who participate in net metering receive credits for their generation at the full retail kilowatt-hour rate. *See* 52 Pa. Code § 75.13(d). Such rate "include[s] generation, transmission and distribution charges." *Id.* In other words, there is nothing left for customer-generators to sell without being double compensated. Thus, PPL Electric recommends that the Commission prohibit dual participation by requiring that a DER be declared as net metered or wholesale when the interconnection application is submitted to the EDC.

1. Does The PUC Have Authority to Decide Whether to Permit Net Metering Customers To Participate In DERAs, Noting FERC's Statement That "Under A [RERRA]'S Jurisdiction Over Its Retail Programs, Such A [RERRA] Is Able To Condition A Distributed Energy Resource's Participation In A Retail Distributed Energy Resource Program On That Resource Not Also Participating In The RTO/ISO Markets"?

Yes, the Commission has authority to enact regulations governing Pennsylvania's net metering program. As the Commission noted on page 4 of its ANOPR, FERC stated that "under a [RERRA's] jurisdiction over its retail programs, such a [RERRA] is able to condition a [DER]'s participation in a retail distributed energy resource program on that resource not also participating in [PJM] markets." FERC Order 2222 at P61. As explained above, net metering compensates customer-generators at the full retail kilowatt-hour rate. Any additional compensation for net metered facilities would necessarily involve some level of double compensation.

2. Assuming The PUC Does Have Requisite Authority, Should the PUC Permit Net Metering Customers to Also Participate in DERAs at the Same Time?

No, as explained above, this would result in double compensation.

3. Assuming The PUC Does Have Requisite Authority, Should the PUC Develop Rules for When and How Often a Retail Customer May Switch Between Net Metering and DERA Participation?

PPL Electric suggests that customers should only be permitted to switch from participating in net metering or in the wholesale markets once every 12 months and should be required to submit a new application to the EDC to do so. Allowing for more frequent changes will be administratively difficult and tax limited resources. Changing from DER Aggregation to net metering or vice versa would require EDC review to make sure the requirements of participation are met. If allowed on a rolling basis this change review could interfere with initial DER applications. Additionally, frequent changes would make billing and settlement much more difficult and costly. The additional costs and resources needed to manage the ability of customers to switch between DER Aggregation and net metering cannot be justified by any perceived benefit the customer may have by being able to switch at any time.

Interconnection agreements, or any agreements developed subsequently for use between the EDC and DER Aggregator, should include this limitation. Further, to streamline this process, the Commission should consider establishing an "open enrollment period," during which DERs would be permitted to change their status. PPL Electric recommends that the Commission consider a two-week open enrollment period concluding prior to June 1st of each year to coincide with the beginning of a new PJM Planning Year.

For DERs that are already interconnected with the distribution system, are operational, and seek to change their status to participate in DER Aggregation, a full interconnection study would not be needed. A smaller scale review process would be acceptable. In such a review process, the EDC would ensure that the DER meets the metering requirements to participate in DER Aggregation and enter into a new agreement with the DER specific to DER participating in DER Aggregation.

H. ANY NECESSARY ELECTRONIC DATA EXCHANGE REVISIONS

The Commission's ANOPR asked for "comment on whether it should encourage or impose EDI and/or other data exchange protocols between and among EDCs, EGSs, DERAs and Component DERs to facilitate implementation of Order 2222, and, if so, what, if any, specific changes to the PUC's policies and regulations would or should facilitate this adaption." (ANOPR at 40.) Moreover, the Commission requested comment on three "sub-topics": (1) "[w]hat DERA cybersecurity items require further evaluation?"; (2) "[w]hat role will advanced metering infrastructure (AMI) data play in operational coordination?"; and (3) "[h]ow should the PUC ensure that processes are in place for efficient data exchange among and between Component DERs, DERAs and EDCs for customer authorizations?" (ANOPR at 41.)

PPL Electric supports the creation of Electronic Data Interchange ("EDI") or other data exchange protocols by the Commission. Consistent statewide guidance will make the implementation of FERC Order 2222 easier and more cost-effective. The EDI protocols for EGSs are a good starting point; however, DER Aggregators will have unique requirements that will need to be addressed in specific protocols. As discussed earlier, the Commission should provide guidance on standards that allow for the device level metering. Also, EDCs will need to recover the costs for building an EDI platform to accommodate the implementation of FERC Order 2222.

In addition, PPL Electric addresses the sub-topics on this subject as follows:

1. What DERA Cybersecurity Items Require Further Evaluation?

At a minimum, customer information needs to be protected. Likewise, any critical system information that is made available to DER Aggregators needs to be secured. The Commission should develop regulations to place cybersecurity restrictions and requirements on DER Aggregators, so that customer and utility information is protected from unwarranted public disclosure.

2. What Role Will Advanced Metering Infrastructure (AMI) Data Play in Operational Coordination?

AMI data will allow for the exchange of some usage data through EDI. However, depending on the setup at the DER site, additional metering points may be necessary. As an example, if a customer's service address has solar participating in net metering and a battery, smart thermostat, and electric vehicle participating in DER Aggregation, the individual components at the service address will need to have distinct data streams. This cannot be accomplished with a single AMI meter, but AMI can support this setup. A complex setup like this would need additional meters or device level telemetry to bill and settle the customer's usage and generation.

3. How Should the PUC Ensure That Processes Are in Place for Efficient Data Exchange Among and Between Component DERs, DERAs And EDCs For Customer Authorizations?

The Commission should support working groups, so that data exchange standards can be agreed upon by all stakeholders. Having standardization will allow for automation which promotes efficiency. EDCs also will need rate recovery to build robust data exchange platforms that are efficient and accurate.

I. SMALL UTILITY OPT-IN PROCEDURES

Because PPL Electric is not a "small utility" as defined in Order 2222, the Company does not have a position on small utility opt-in procedures.

J. POTENTIAL PUC OVERSIGHT OF DERAS

The Commission also asked for "comment on whether the PUC may assert jurisdiction to regulate DERAs, and, if so, what requirements should the PUC impose on DERAs, consistent with Order 2222 and PJM's DAPM, and what specific changes to the PUC's policies and regulations would facilitate the PUC's exercise of authority over DERAs." (ANOPR at 43.)

It is unclear if the Commission currently has jurisdiction over DER Aggregators. DER Aggregators would not be public utilities and it is questionable whether they fit under the definition of EGSs. That being said, it is imperative for the PUC to have jurisdiction over DER Aggregators to effectively implement FERC Order 2222. FERC made it clear in FERC Order 2222 that there is an important and active role for RERRAs to play in the implementation of FERC Order 2222. At a minimum, the Commission will need to create regulations governing metering, data sharing, billing, customer protection, override protocols, cybersecurity protections, and interconnection standards for DER Aggregators. This will be difficult, if not impossible, to do if the Commission does not have jurisdiction over DER Aggregators.

Lastly, PPL Electric believes that DER Aggregators should receive an annual assessment from the Commission due to the considerable time and attention anticipated to be dedicated to develop, monitor, and adjudicate issues in this area.

K. CYBERSECURITY CONSIDERATIONS

In the ANOPR, the Commission also requested "comments on whether it should impose cybersecurity standards or requirements on Component DERs, DERAs or EDCs, consistent with Order 2222 and PJM's DAPM, and any specific changes to the PUC's policies and regulations that would facilitate appropriate levels of cybersecurity in the implementation of Order 2222."

See comments in Section II.H, *supra*.

L. DISTRIBUTION LEVEL BENEFITS

The Commission further asked for stakeholders to "comment on whether and how it should account for the distribution level benefits of DERAs." (ANOPR at 44.)

DER Aggregator models should remain flexible including allowing accommodating an EDC to being a DER Aggregator. EDC participation as a DER Aggregator may lead to distribution level benefits that can be accounted for in the EDC's rates. Thus, any such distribution level benefits would flow back to customers.

M. EDCs ACTING AS DERAs

In its ANOPR, the Commission sought "comment on whether and how it should mitigate conflicts of interest that may arise from an EDCs participating in wholesale markets as a DERA, consistent with Order 2222 and PJM's DAPM, and whether and what specific changes to the PUC's policies and regulations could facilitate such mitigation." (ANOPR at 44.)

PPL Electric believes that the competitive market will primarily provide DER Aggregator services and products. However, there may be instances where an EDC can provide benefits that a third-party DER Aggregator cannot or where an EDC can serve markets that are being underserved by DER Aggregators. For example, if the low-income community is being underserved, there may be an EDC program that can provide aggregation services where appropriate. No conflicts of interest would arise if an EDC were the only aggregator that can or is willing provide those services. There is no reason an EDCs acting as a DER aggregator would preclude its ability or willingness to facilitate interconnections and enable DER aggregations by non-EDC DER Aggregators on its system. Furthermore, EDCs should not be precluded from acting as DER Aggregators because the market is so new. As such, PPL Electric respectfully requests that the Commission not prohibit EDCs from participating as DER Aggregators.

N. BILLING ISSUES

The Commission also requested "comment on whether and how it could make the billing relationships between EDC customers, DERAs and EDCs transparent to the customer, consistent with Order 2222 and PJM's DAPM, and whether and what specific changes to the PUC's policies and regulations could facilitate such transparency." (ANOPR at 45.)

The success of the billing relationships will depend on the outcome of previously discussed topics. Specifically, billing will require the accurate and efficient exchange of data, which will rely on whatever EDI platform and metering protocols that are implemented. This will facilitate customer billing and market settlement at PJM. The EDC, DER Aggregator, and customer relationship depends on the PUC having jurisdiction over DER Aggregators to provide for technical regulations, customer protections and dispute resolution capabilities. The specifics of whether DERA charges should be on EDC bills should be further considered by the Commission.

As this market is new, and it remains unclear what products and services will be offered by DER Aggregators, it is difficult to predict what billing guidelines will be required.

O. EQUITY CONCERNS

Lastly, the Commission asked for "comment on how to identify and address potential equity concerns associated with the expected proliferations of DERAs in Pennsylvania in the coming years." (ANOPR at 45.)

The Commission should develop policies so that DER Aggregators support disadvantaged communities. As mentioned earlier, there may be a role for EDCs to act as a DER Aggregator if low-income communities are being underserved by DER Aggregators.

III. CONCLUSION

PPL Electric appreciates the opportunity to provide these Comments on the changes required to implement FERC Order 2222 and respectfully requests that the Commission take these Comments into consideration in developing its next steps. PPL Electric also looks forward to continuing to be an active participant in subsequent stages of this proceeding.

Respectfully submitted,

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