PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

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Commissioners Present:

Stephen M. DeFrank, Chairman
Kimberly Barrow, Vice Chair
Kathryn L. Zerfuss
John F. Coleman, Jr.
Ralph V. Yanora

In re: Distributed Energy Resources Participation in Wholesale Markets, Chapter 57 — L-2023-3044115

NOTICE OF PROPOSED RULEMAKING ORDER

BY THE COMMISSION:

The Pennsylvania Public Utility Commission (Commission) adopts this Notice of Proposed Rulemaking (NOPR) Order and seeks comment on the proposed addition of new regulations in Chapter 57 of Title 52, 52 Pa. Code, Chapter 57 (relating to Electric Service), to enable more comprehensive regulation of public utilities that provide electric distribution services within the Commonwealth. Specifically, the Commission proposes to add regulations to include provisions for Distributed Energy Resources (DERs) participating as DER Aggregation Resources on electric distribution company (EDC) distribution facilities, consistent with FERC Order 2222-B.[1] The aggregation of component DERs requires specific technical requirements and review not currently in our regulations. Therefore, we propose creating a separate Subchapter P at Chapter 57 entitled "Distributed Resources" and beginning with Section 57.261 (relating to the purpose) as set forth in the Annex.

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[1] *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

BACKGROUND

Legal Authority and Jurisdiction

Under Section 501(b) of the Public Utility Code (Code), the Commission has the general administrative power and authority to supervise and regulate all public utilities doing business within the Commonwealth and to make such regulations as may be necessary or proper in the exercise of its powers or for the performance of its duties. 66 Pa.C.S. § 501(b) (relating to Administrative authority and regulations). Section 102, in pertinent part, defines a public utility as:

> (1) Any person or corporations now or hereafter owning or operating in this Commonwealth equipment or facilities for:
>
> > (i) Producing, generating, transmitting, distributing or furnishing natural or artificial gas, electricity, or steam for the production of light, heat, or power to or for the public for compensation.

66 Pa.C.S §102, (relating to the definition of public utility (1)(i)). Accordingly, the Commission has jurisdiction over and authority to regulate, *inter alia*, the distribution of electricity in Pennsylvania to the public for compensation. 66 Pa.C.S. §§102, 501(b); s*ee also* 66 Pa.C.S. §504 (relating to reports by public utilities) and 66 Pa.C.S. §506 (relating to inspection of facilities and records).

An EDC's Distributed Energy Resource Plan constitutes "service" as such term is broadly defined under Section 102 of the Code, in relevant part, as follows:

> **"Service."** Used in its broadest and most inclusive sense, includes all acts done, rendered, or performed, and all things furnished or supplied, and any and all facilities used, furnished, or supplied by public utilities. . .in the performance of their duties under this part to their patrons, employees, other public utilities, and the public, as well as the interchange of facilities between two or more of them . . .

66 Pa.C.S. §102 (relating to definitions).

"Service" must be adequate and reasonable pursuant to Section 1501 of the Code, which provides in pertinent part:

> **§ 1501. Character of service and facilities.**
>
> Every public utility shall furnish and maintain adequate, efficient, safe, and reasonable service and facilities, and shall make all such repairs, changes, alterations, substitutions, extensions, and improvements in or to such service and facilities as shall be necessary or proper for the accommodation, convenience, and safety of its patrons, employees, and the public. Such service also shall be reasonably continuous and without unreasonable interruptions or delay. Such service and facilities shall be in conformity with the regulations and orders of the commission . . .

66 Pa.C.S. §1501.

FERC Order 2222

In September 2020, FERC issued Order No. 2222 (Order No. 2222), wherein FERC required regional transmission organizations (RTOs) and independent system operators (ISOs) to amend their tariffs to include DER aggregations as a type of market participant, and to revise market rules that FERC determined were unjust and unreasonable barriers to DER participation in wholesale markets. However, FERC made clear that Order No. 2222 would not impact state regulatory authorities' abilities to prohibit DER aggregators from bidding retail customers' demand response resources into RTO/ISO markets—in other words, to opt-out—per the requirements of Order Nos. 719 and 719-A.[2]

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[2] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), order on reh'g, Order No. 719-A, 128 FERC ¶ 61,059 (2009).

On March 24, 2021, Order No. 2222-A set aside this aspect of Order No. 2222, holding that state regulatory authorities' opt-out abilities would apply only to DER aggregations that contained solely demand response resources (*i.e.*, the aggregation is solely made up of retail customers' resources), but not where the DER aggregation includes a mix of demand response and other DERs. Rather, at that time FERC held that DER aggregations made up of both demand response and other types of resources—termed "heterogenous DER aggregations"—did not fall within the opt-out requirements of Order No. 719 and applying the opt-out to these types of resources would inhibit innovation by preventing DER aggregators from taking advantage of different DER resources' operational attributes and capabilities.

In Order No. 2222-B, FERC set aside its decision in Order No. 2222-A and restored state regulatory authorities' opt-out capability for all demand response resources, including those that participate in "heterogenous" DER aggregations. However, FERC rejected arguments that it was legally required to grant the opt-out, pointing to the Supreme Court's ruling in *FERC v. Elec. Power Supply Ass'n*[3] that FERC's regulation of demand response participation in wholesale markets does not violate the Federal Power Act (FPA) because it directly affects wholesale rates. FERC acknowledged that many states broadly prohibited demand response participation in wholesale markets when implementing the Order No. 719 opt-out, and those states may not have anticipated the Order No. 2222 proceedings calling into question those broad prohibitions. FERC stated that, "Given the importance of these issues, which affect both federal and state regulatory interests, we believe the better course is to provide them full consideration through the Notice of Inquiry issued contemporaneously with Order No. 2222-A."

[3] 577 U.S. 260 (2016).

Order No. 2222-B also clarified that a behind-the-meter resource that is used solely to facilitate demand response, i.e., deployed solely to reduce customer load from expected consumption, will itself be considered a demand response resource for purposes of determining whether the opt-out applies. Finally, Order No. 2222-B clarified under what circumstances behind-the-meter DERs participating as distributed energy resources in DER aggregations may be paid the full locational marginal price. According to Order No. 2222-B, state regulatory authorities will be able to prohibit demand response resources from participating in all wholesale DER aggregations. In Order No. 2222-B, FERC stated, "the participation of demand response in distributed energy resource aggregations is subject to the opt-out and opt-in requirements of Order Nos. 719 and 719-A. Therefore, if the relevant electric retail regulatory authority where a demand response resource is located has either chosen to opt out or has not opted in [pursuant to Order Nos. 719 and 719-A], then the demand response resource may not participate in a distributed energy resource aggregation."

Accordingly, through Orders 2222, 2222-A and 2222-B, FERC is managing PJM's activities that primarily affect the distribution system of Pennsylvania by establishing rules and approving PJM tariffs concerning the participation of Distributed Energy Resources in PJM's market. Even though PJM has not filed a fully compliant compliance filing to date, PJM member States are in various stages of holding stakeholder meetings and adjusting their statutory and regulatory frameworks to support such federal dictates. FERC approved two important PJM timeline proposals including (1) Planned DER Capacity Aggregation Resources participating in the 2026/2027 Delivery Year Base Residual Auction (BRA)[4], and February 2, 2028, is the deadline for PJM's Tariff, Operating Agreement, and RAA revisions effectuating the balance of the proposal including energy and ancillary services markets participation. Thus, although

[4] The 2026/2027 BRA occurred in July 2025. The 2027/2028 BRA was held between December 4 – 10, 2025. Auction results are anticipated to be posted on December 17, 2025. PJM has requested a Third Incremental Auction be held in February 2026. The 2028/2029 BRA is currently targeted for June 2026.

FERC recognized it cannot direct the states in the timing of their actions and responses related to Order No. 2222, it has set an effective date that essentially would require the states to be ready by February 2028.

Recently, on November 5, 2025, the PJM Market Implementation Committee (MIC) endorsed manual revisions that define how DERs will participate in the 2028/29 capacity auction. Specifically, the MIC endorsed conforming changes to Manual 18 regarding DER participation in the 2028/29 BRA as well as the Expanded Load Management availability requirement effective in the 2027/28 Delivery Year. PJM provided an update on the Regulation Market Redesign that went live October 1, 2025. The MIC continues to work on Resource Scheduling Prior to the Day-Ahead Energy Market. Manual 18 changes No. 62 became effective November 20, 2025.[5]

Advanced Notice of Proposed Rulemaking

On November 9, 2023, via a Joint Motion of Chairman Stephen DeFrank and Vice Chair Kimberly Barrow, the Commission opened an Advanced Notice of Proposed Rulemaking proceeding at L-2023-3044115 (Joint Motion re ANOPR). On February 1, 2024, Commission Staff met with EDCs to discuss current law and what might be needed through a rulemaking for DERs to participate in wholesale markets. On January 10, 2024, a Letter was issued announcing adoption of the Joint Motion re ANOPR to be entered and setting stakeholder TEAMS meeting for February 1, 2024; notice published in the *Pennsylvania Bulletin* on January 1, 2024 at 54 Pa.B. 315. On February 1, 2024, a meeting between Commission Staff and DER aggregators was held. On February 6, 2024, a meeting between Commission Staff and ratepayer advocates was held. On February 22, 2024, an Advanced Notice of Proposed Rulemaking (ANOPR) without an annex was entered at the above-captioned docket. On March 30, 2024, the ANOPR was

[5] Revision 62 showing changes to Manual 18 is at the following link. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20251105/20251105-item-01b-1---manual-18-revisions---redline.pdf.

published in the Pennsylvania Bulletin at 54 Pa.B. 1668. The ANOPR was published to the Commission's website on April 10, 2024 for public comment.

The Commission received Comments from the Coalition Advocating DER Regulation Efficiency (CADRE); the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA); Citizens' Electric Company and Wellsboro Electric Company (collectively, Citizens); the City of Philadelphia and Philadelphia Energy Authority (collectively, City Parties); Collaborative Utility Solutions (CUS); the DER Task Force (DER Task Force); Duquesne Light Company (DLC); Elizabeth Hoffman; the Energy Association of Pennsylvania (EAP); Enterwise Global Technologies, LLC d/b/a/ CPower (CPower); FirstEnergy Pennsylvania Electric Company (FirstEnergy); Janet Rich; Mission:data Coalition (Mission:data); the Office of Consumer Advocate (OCA); Paul Fitzpatrick; PECO Energy Company (PECO); Philadelphia Solar Energy Association, et al. (Philadelphia Solar)[6]; Phyllis Blumberg; the PJM Power Providers Group (P3); PPL Electric Utilities Corporation (PPL); ProtoGen, Inc. (ProtoGen); Recurve Analytics (Recurve); Renew Home, LLC (Renew Home); Richard Cole; Solar United Neighbors (Solar United); the Natural Resources Defense Council (NRDC); Thomas Hoffman; and the University of Delaware (University of Delaware).

DISCUSSION

Based on the comments and discussions received to date, the Commission proposes adding Subchapter P. (relating to distributed energy resources) to Chapter 57 (relating to electric service) to Title 52 of the Pa. Code beginning with proposed § 57.261

[6] Philadelphia Solar Energy Association; Solar United Neighbors; Vote Solar; Pennsylvania Solar and Storage Industries Association; Clean Air Action; Third Act Pennsylvania; Blumberg; POWER Interfaith; Working for Justice Ministry, St. Paul's United Methodist Church; Physicians for Social Responsibility Pennsylvania; Mobilify, Southwestern Pennsylvania; Energy Coordinating Agency; Sustainable Business Network of Greater Philadelphia; Keystone Energy Efficiency Alliance; Clean Air Council; Penn Future; Audubon Mid-Atlantic; CASA/CASA in Action.

as set forth in the Annex to this Order. The proposed regulations are broken into Purpose, Definitions, General Provisions, Review of Component DER Applications, Component DER Operations and Disputes. The Commission will address interconnection of Component DERs in another proceeding.

I. Purpose

The Commission proposes stating the purpose of Subchapter P as set forth in the Annex under proposed Section 57.262. Specifically, the Commission proposes that the purpose of Subchapter P is to set forth the requirements that apply to DER operators, DER Aggregators (DERA) and EDCs related to DER Aggregation Resource participation in the energy, capacity, and/or ancillary services markets of PJM through its Intra-PJM Open Access Transmission Tariff, VI. Administration and Study of New Service Requests; R, OATT Attachment K – Appendix Section 1.4B, DER Aggregator Participation Model.

Comments

Comments to the ANOPR expressed that there are benefits to retail customers by the Commission facilitating DER participation in wholesale markets. CADRE anticipates DERA market participation to generally decrease costs for both participating and non-participating customers. CADRE suggests that it is almost certain that on the electricity side of the retail rate, costs will decrease because the two largest components are capacity and electrons. CADRE notes that if component DER energy injection clears the PJM market process, it will always be a lower cost option than the resource it displaced. DERA participation in wholesale market will always result in lower prices that will benefit consumers, including non-participating consumers.

DLC states that while DERA market participation may offer long-term cost benefits through avoided generation investments, the immediate impact on retail rates remains uncertain. The regulatory framework appears to favor direct cost assignment where possible, while acknowledging that some degree of cost socialization may be necessary for costs that cannot be easily attributed to specific aggregations.

The OCA contends that over time, DERA market participation should, with sufficient competition and prevention of double compensation, put downward pressure on retail rates. More competition should reduce the exercise of market power and introduce more efficient resources, thereby putting downward pressure on the wholesale component of retail rates. DERAs should also put downward pressure on transmission and distribution (T&D) rates by avoiding and postponing otherwise needed T&D investments, assuming that transmission owners and EDCs plan their systems appropriately in anticipation and response to the installation of DERs, Component DERs, and DERAs.

The overall impact on retail rates remains uncertain, with PECO highlighting that while compliance and interconnection costs will likely increase distribution rates, there is potential for wholesale market benefits that could offset some or all of these increases. The net effect will depend on the extent of cost recovery from market participants and the magnitude of any wholesale market price reductions.

PPL believes it is too soon to tell whether DER Aggregators' market participation will have any meaningful impact on retail rates because it remains 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, PPL notes that if large volumes of DER Aggregators' generation are bid into the market, this could provide downward pressure on wholesale rates. Retail electric customers would in turn benefit from these lower wholesale generation rates. PPL believes EDC innovation should be encouraged, and the PUC should avoid creating strict prohibitions that could stifle market innovation and prevent EDCs from developing programs that could be used to benefit customers.

Disposition

The Commission agrees with commenters that DERA participation in PJM's wholesale markets are likely to provide benefits to all retail customers. Accordingly, the Commission proposes creating a separate subchapter to Chapter 57 of our regulations establishing standards that EDCs must follow to facilitate the development of DER connecting to their distribution systems. The Commission proposes the purpose of subchapter P as set forth in the Annex at proposed Section 57.261.

II. Definitions

The Commission is proposing definitions relating to the various components of the PJM DER Aggregation Participation Model as set forth in the Annex under proposed Section 57.262. The proposed definitions are either consistent with the definitions used by PJM or other sections of our existing regulations.

III. General Provisions

As set forth in the Annex at proposed Section 57.263, the Commission identifies the EDCs that are required to provide DER Aggregation Resource participation within their service territory and the EDCs that may provide such participation with Commission approval. The proposed section also identifies under what conditions Component DER can participate as a DER Aggregation Resource within an EDC's service territory. Finally, this proposed section requires an EDC that allows DER Aggregation Resource participation within their service territory to file a tariff with the Commission that is consistent with the regulations.

Comments

A. Integration of Component DERs

CADRE does not envision the need for the PUC to address anything specific in its new regulatory model to facilitate the integration of a load resource with an interconnected resource. It notes that PJM has defined rules of participation for homogenous and heterogeneous aggregations that include energy efficiency and demand response resources.

The City Parties suggest that the PUC use this proceeding, in collaboration with PJM, to eliminate inconsistencies between the two regimes and streamline the collective PJM/EDC interconnection process for BTM resources. If interconnection becomes a roadblock, the benefits contemplated by Order 2222 for the grid and for the environment will not be achieved. The City Parties encourage the PUC to use the opportunity created by the ANOPR to reconsider its existing procedures to ensure that they are consistent not only with PJM procedures but also with the goals of Order 2222.

The City Parties submit that customer DERs should be treated like customers. The situation as it exists is neither equitable between customers nor based on any analysis of the benefits to the grid of reducing barriers to entry for retail customers. Moreover, the inequities of the legacy grid have been shown to fall disproportionately on disadvantaged communities.

The City Parties recommend that PUC regulations be revised to reflect an alternative view of the grid structure. While EDCs would remain the default providers, their role is evolving from traditional one-way power delivery to supporting a diverse array of additional power sources for customers, including customers and community direct provision as well as PUC-licensed Electric Generation Suppliers (EGSs). They note that resources acquired by or on behalf of customers will primarily be sized to meet the needs of the specific customer or customers served by the resource, but they will frequently have spare capability or flexible customer needs that allow these resources to contribute through aggregation.

The City Parties present two main arguments regarding interconnection capacity:

1. **Systemwide Support**: They believe that the benefits of local resources justify a greater level of EDC support for interconnection capacity systemwide.
2. **Low-to-Moderate Income (LMI) Customer Focus**: They suggest that the PUC consider whether interconnection for LMI customers should be included in its universal service and energy conservation plans, and additionally require EDCs to pursue efforts to remedy historic inadequacies in underserved areas.

The City Parties note that current DER controls are more sophisticated than existing EDC technologies. For effective grid participation, controls allowing residences to participate in aggregations that respond to hourly or more frequent grid needs must be automated. Manual coordination and communication are considered inadequate for modern grid requirements. For non-export resources, customer meters can demonstrate aggregate performance when all devices operate through a controller, which should be sufficient for aggregators to evaluate bid response capabilities. Current PUC regulations are designed for standalone front-of-the-meter generation and assume that customer buildings with multiple resources will create maximum system risks. The City Parties recommend that interconnection reviews should focus on the adequacy of DER controls rather than assuming their absence.

DLC does not anticipate significant new requirements for energy efficiency and demand response resources because these resources constitute a reduction in load, rather than an injection of energy. However, as the number of these DER resources increase, EDCs will need additional visibility into when load reductions are occurring.

FirstEnergy submits that interconnection requirements for these Component DER types would need to be based on the specific market or program for which they plan to participate in (i.e., Pennsylvania or FERC) to ensure the applicable interconnection requirements are in place and to avoid double counting. Interconnection requirements may include current connection standards, dispatch, over-ride signals, revenue metering and data submittal, telecommunication, energy settlements, and communication processes. FirstEnergy further submits that all DER types and their system impacts must be considered as part of a DER Aggregation evaluation. Both load reductions and energy injections from Component DERs should be coordinated via PJM dispatch and would need to be considered as part of the EDC approval of the DER Aggregation operation.

The OCA submits that existing DERs that are aggregated into a new or existing DERA must comply as part of or along with the same interconnection process for proposed DERAs so that they can be safely and reliably operated. Existing DERs that are aggregated must also comply with any PUC regulations applicable to proposed DERAs and their Component DERs. Further, the DERA interconnecting process should account for the types of Components DERs, such as energy efficiency and demand response, being aggregated by a DERA.

PECO has not yet identified a specific need for a contractual relationship between an EDC and a Component DER customer. However, this position could change as PJM finalizes changes to its OATT and business practice manuals to implement FERC Order No. 2222 and as PECO gains more experience with DERA activities. Component DERs that could potentially export electric power to the grid should still be required to execute an interconnection agreement before being able to export power to the grid or participate in a DER aggregation.

PPL submits that it is essential that the PUC recognize that component DERs injecting onto the grid necessitate an interconnection agreement. PPL notes in its comments that it has created agreements for DER systems that are connected to the distribution system but participate in the wholesale market. These agreements build off of PJM's interconnection agreements with modifications to reflect the interconnection with the distribution system, rather than the transmission system. These types of agreements could be useful in developing interconnection agreements for their resources that inject power onto the grid but are not currently contemplated in the PUC's interconnection agreements.

B. Small Utility Opt-In

In the ANOPR, we sought comment on procedures for small utilities to "opt-in" to Order 2222, and permit their retail customers to participate in DERAs, consistent with Order 2222 and PJM's DAPM, and any specific changes to the PUC's policies and regulations that would facilitate the opt-in process. ANOPR at 42.

CADRE Suggests that the PUC should try to make the opt-in procedure as easy and seamless as possible, and that small utilities should be encouraged to opt-in.

The DER Task Force recommends that small utilities should be allowed to gradually scale up their DER participation instead of facing an all or nothing decision. It suggests the PUC allow smaller utilities to permit DER participation up to a 50 MW threshold before requiring formal opt in procedures.

OCA states that small utilities should be encouraged to opt-in to Order 2222 and calls for transparency if a utility cannot accommodate DERAs stating why they can't and when they will be able to participate if asked.

EAP suggests using existing procedural mechanisms for small EDCs[7] to opt into Order 2222 participation. It proposes that small EDCs petition the PUC under section 5.41 of the PUC's regulations to request participation and explain why and any necessary limitations.

Citizens emphasize that DERAs could have substantial impact on smaller utilities, especially given uncertainty regarding system requirements to accommodate DER operation and market participation. It agrees with EAP's suggestion of filing a petition with the PUC for opting into the program. Citizens states that this approach enables small utilities to assess whether and how they can accommodate DERAs. Their assessment could include potential costs (implementation and ongoing), internal employee resources needed, and the technical and reliability limitations in its territory.

C. Commission Oversight of DERAs

Most stakeholders agree that the PUC has clear authority to regulate the interconnection of DERs to the distribution system. The PUC also has jurisdiction to prevent double counting between retail and wholesale compensation and to regulate the switching process between retail and wholesale market participation.

Several commenters suggest the PUC can establish jurisdiction through existing authorities. If DERAs are implemented through Electric Generation Supplier (EGS) pricing, the PUC will have direct jurisdiction. Additionally, since the collective operation of DERAs can affect distribution system operations, this provides another basis for asserting jurisdiction. However, there are differing views on jurisdictional limits. Some argue that while the PUC has jurisdiction over DER interconnection, it does not

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[7] "Small EDCs" refers to Citizens' Electric Company, Wellsboro Electric Company, UGI Utilities, Inc. – Electric Division, and Pike County Light and Power Company. Pike County is not a member of PJM, but rather NYISO.

have jurisdiction over their participation in DERAs, as FERC Order 2222 establishes FERC's exclusive authority over market participation.

Multiple stakeholders recommend establishing a state-level licensing or registration process for DERAs, similar to that used for electricity generation suppliers and natural gas suppliers. This licensing process should ensure DERAs have appropriate qualifications, cybersecurity protection, necessary insurance and bonding and valid points of contact for EDC communication. They also state that the PUC should establish marketing regulations, including penalties for violations and potential license revocation when warranted. In addition, the PUC should establish a DERA code of conduct similar to its current EGS Code of Conduct. The PUC could begin with the Department of Energy's Aggregator Code of Conduct guidance to develop the code that aggregators must meet. This code could also provide the basis for a public right of action under the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL), 73 P.S. §§ 201-1 – 201-9.2.

CAUSE-PA recommends the PUC institute strong consumer protections, including evaluating the application of UTPCPL to DERAs; adapting existing EGS regulations to address consumer concerns; seeking guidance from the Office of Attorney General for UTPCPL enforcement; and clearly delineating aggregation services as "non-basic service charges" to prevent involuntary service termination. The PUC should ensure consumers understand what data aggregators will use, how their data may be shared, and how aggregation services will be charged. The PUC should create a standardized format for customer authorizations and simplify the process for customers to grant aggregators permission to access their data. The PUC could review and approve any terms and conditions that EDCs wish DER Aggregators to agree to as a condition of receiving customer data. The PUC should require EDCs to conform to the Green Button Connect My Data (GBCMD) standard, with periodic testing and certification by an independent body. The PUC should define the appropriate level of control over DERAs that meets PJM override requirements while maintaining customer and aggregator protections.

D. Double Counting Services Provided by a Component DER

Many commenters expressed that the PUC should ensure DER owners are not compensated twice for providing the same service at the same time in both retail and wholesale markets. While most comments focus on preventing double compensation between retail and wholesale markets, some specifically address the relationship between utility overrides and compensation issues.

CADRE argues that being compensated for energy or capacity at wholesale while also being compensated for those same products for a different retail purpose does not constitute double counting.

CPower clarifies that while a resource should not be compensated twice for providing the same service (such as providing capacity to both an EDC in PA and PJM simultaneously), resources can provide multiple different value streams to both utilities and the wholesale market.

The DER Task Force distinguishes between dual registration and double compensation,[8] noting that a single DER can participate in multiple wholesale programs or both wholesale and retail programs simultaneously. They support "complementary participation," where participation is managed to avoid impermissible double compensation. Accordingly, the DER Task Force recommends that the PUC should narrowly restrict dual enrollment via tariff where retail and wholesale market services would actually conflict, rather than implementing broad restrictions. The DER Task

[8] Dual registration is different from double compensation in that there are certain circumstances when PJM permits a single DER to participate in multiple programs at the same time or in both a wholesale and retail program.

Force supports the GridLab recommendation for retail regulatory authorities to collaborate with utilities, DERs, Aggregators, and RTOs/ISOs to develop transparent dual participation rules that accommodate DER capabilities.

CUS supports providing Component DERs with maximum possible optionality and flexibility to participate in both retail and wholesale programs, without double compensation, noting that the DER Registry serves as the "single source of truth" for DER data to ensure this flexibility while prohibiting double counting.

NRDC notes that PJM rules already address energy double counting for net metering customers, and due to restrictions on net metering DERAs providing energy, they cannot meet PJM's capacity market requirements, eliminating the risk of double counting.

CADRE does not endorse double compensation but urges caution when developing regulations to prevent it. They clarify that double compensation arises from being compensated twice for the same service in the same time period.

EDCs generally advocate for strict separation between retail and wholesale market participation. FirstEnergy states that any compensation received by a DER Component or aggregation for the same service should be prohibited, unless specifically allowed by the PUC's regulations. DLC recommends restricting DERs from offering any services in the wholesale market for which they are already compensated in the retail market, specifically through net metering, and proposes amending interconnection regulations to restrict eligibility for net metering to customers who are not compensated for any service provided by the DER in another market. PECO recommends that individual customers should be prohibited from concurrent participation in wholesale aggregations and retail net metering programs. PECO also recommends regulations to prevent duplicative compensation for the same service and suggests prohibiting individual customers from concurrent participation in wholesale aggregations and retail net metering programs. PECO notes that net-metering programs in Pennsylvania compensate customers for energy, capacity, and ancillary services. PPL supports the PUC adopting regulations that prohibit DERs from participating in both net metering and DER Aggregation, arguing that customer-generators who participate in net metering receive credits at the full retail kilowatt-hour rate, which includes generation, transmission and distribution charges, leaving nothing to sell without double compensation.

However, PECO cautions that with respect to retail demand-side management and energy efficiency programs, the question of whether double counting is occurring requires a nuanced evaluation and may be specific to each retail program. PECO recommends that the PUC provide EDCs with the regulatory flexibility to develop double counting rules for the demand-side management and energy efficiency programs they administer. Similarly, EAP notes that identifying duplicative compensation can be difficult with demand-side management (DSM) programs and asks the PUC to allow consideration of specific circumstances in these situations. CADRE recommends adding a section to the PUC's regulations stating that nothing prevents a net metered resource from participating in wholesale energy market programs, provided resources are not compensated two or more times for providing the same service.

The OCA recommends amending 52 Pa. Code §75.13 to prevent DERs from being simultaneously compensated in wholesale and retail markets for the same service. They propose requiring EDCs to certify that DERs are not double counting and mandating that DERs found to have received double payments must refund such payments and potentially face administrative actions. The OCA specifically opposes allowing net metering customers to participate in DERAs simultaneously if it means receiving both wholesale and retail compensation, as net metering customers receive retail rate compensation that includes PJM wholesale market compensation plus transmission and distribution costs.

CAUSE-PA recommends that the PUC open a "Value of DER" docket to comprehensively evaluate the cost and benefit of DERs to the system before amendments are made to policy and/or regulation. The docket should explore the possibility of DER owners to derive duplicative subsidies for DERs through net metering and aggregation.

The University of Delaware argues that 52 Pa. Code §75.13 should not be adapted to restrict double counting, stating that there can be no instance of double counting if the EDC meters and credits for energy, and the RTO market is compensated for power, response, and time, not including energy. They emphasize that Ancillary Services only and Capacity only can be within net metering premises and still participate in non-energy wholesale markets.

The DER Task Force believes that the PUC has the authority to condition retail program participation upon customers not receiving double compensation through wholesale market participation. However, they emphasize that protections against double compensation should be narrow and can be applied at dispatch, not just registration.

NRDC urges the PUC to issue a finding that allowing participants in Pennsylvania net metering programs to provide ancillary services through DERAs does not result in double counting. They argue that net metering customers do not provide ancillary services as part of their net metering participation since they are not dispatched in real-time to meet system needs.

By contrast, the City Parties note that FERC has determined that net metering customers who receive full retail rate compensation (as is true in Pennsylvania) can appropriately be excluded from participation in DERAs in PJM. They recommend that customers registering for DERA participation should disclose all retail programs in which they participate, and no customer should receive credit for participation in two programs for the same product simultaneously.

Multiple stakeholders recommend limiting the frequency of switching between retail and wholesale market participation. The OCA recommends developing rules limiting the number of switches per year (no more than once per year) and requiring customers to pay study and interconnection costs. PPL suggests customers should only switch once every 12 months and be required to submit a new application to the EDC. PECO recommends a 12-month waiting period before customers can switch back to wholesale market participation after returning to retail net-metering. EAP suggests requiring DER resources to participate in PJM wholesale markets for a minimum of one year before switching to a retail program. Some EDCs propose specific enrollment periods. PPL recommends a two-week open enrollment period concluding prior to June 1st each year to coincide with the beginning of a new PJM Planning Year. DLC proposes setting the enrollment window for the two weeks following May 31st, which is the annual "true up" date for net metering customers. FirstEnergy states that any rules for switching should align with PJM market rules, noting that capacity market registrations apply for the full PJM delivery year (June 1 to May 31), while this is not the case for energy and ancillary service markets.

Disposition

The Commission agrees with the commenters that asserted that DERA participation in the wholesale markets is likely to provide benefits to the grid and is therefore proposing to require the large EDCs[9] to allow DER Aggregation Resource participation within their service territory. The proposed subsection 57.263(a) specifically requires EDCs with 100,000 or more customers to allow DER Aggregation Resource participation within their service territories under two narrow conditions. The

[9] "Large EDCs" refers collectively to FirstEnergy, PPL, PECO, and DLC.

proposed conditions are that (1) customer-generators receiving service under the EDC's net metering tariff are precluded from participating as a DER Aggregator Resource in the PJM capacity and energy markets; and (2) the Component DER was approved by the EDC to participate as part of a DERA in the energy, capacity and/or ancillary services markets. As discussed more fully below, the two conditions are intended to prevent double compensation by a Component DER operator from both a retail program and the wholesale markets for the same service.

Regarding the small EDCs, the Commission agrees with the commenters that the Commission should establish a simple process for the small EDCs to opt-into allowing DER Aggregation Resource participation within their service territory. The proposed subsection 57.263(b) simply requires EDCs with less than 100,000 customers to seek Commission approval to allowing DER Aggregation Resource participation. This would be done through the filing of a Petition that would include a tariff consistent with the regulations. The Commission agrees with the commenters who indicated that the small utilities should be given time to assess any impact Component DERs may have on their distribution systems before they allow DER Aggregation Resource participation. The Commission also agrees with commenters who indicated that the existing Petition process under § 5.41 (relating to petitions) of our regulations is more than adequate and accordingly, declines to preemptively approve small utility participation.

Regarding the issue of dual compensation, the comments reveal a spectrum of approaches from strict prohibition of dual participation to more flexible frameworks that allow for multiple value streams while preventing true double compensation for identical services. To implement section 35.28(g)(12)(ii)(a) of its regulations, FERC in Order No. 2222, allowed RTOs/ISOs to limit the participation of resources in RTO/ISO markets through a distributed energy resource aggregator that are receiving compensation for the same services as part of another program. More specifically, FERC required each RTO/ISO to revise its tariff to: (1) allow distributed energy resources that participate in one or more retail programs to participate in its wholesale markets; (2) allow distributed energy resources to provide multiple wholesale services; and (3) include any appropriate restrictions on the distributed energy resources' participation in RTO/ISO markets through distributed energy resource aggregations, if narrowly designed to avoid counting more than once the services provided by distributed energy resources in RTO/ISO markets.

FERC in Order No. 2222 found that it is appropriate for RTOs/ISOs to place narrowly designed restrictions on the RTO/ISO market participation of distributed energy resources through aggregations, if necessary to prevent double counting of services.[10] Thus, FERC found that it is appropriate for RTOs/ISOs to place restrictions on the RTO/ISO market participation of distributed energy resources through aggregations after determining whether a distributed energy resource that is proposing to participate in a distributed energy resource aggregation is (1) registered to provide the same services either individually or as part of another RTO/ISO market participant;[11] or (2) included in a retail program to reduce a utility's or other load serving entity's obligations to purchase services from the RTO/ISO market FERC provided RTOs/ISOs with regional flexibility with respect to the restrictions that they propose in their tariffs to minimize market impacts caused by the double counting of services provided by distributed energy resources in RTO/ISO markets.[12]

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[10] For instance, FERC explained that if a distributed energy resource is offered into an RTO/ISO market and is not added back to a utility's or other load serving entity's load profile, then that resource will be double counted as both load reduction and a supply resource. Also, FERC stated that, if a distributed energy resource is registered to provide the same service twice in an RTO/ISO market (e.g., as part of multiple distributed energy resource aggregations, as part of a distributed energy resource aggregation and a standalone demand response resource, and/or a standalone distributed energy resource), then that resource would also be double counted and double compensated if it clears the market as part of both market participants.

[11] For example, as part of another distributed energy resource aggregation, a demand response resource, and/or a standalone distributed energy resource. *Id.* P 161 n.414.

[12] *Id.* P 164.

In Order No. 2222-A, FERC clarified that, when it stated that "if a distributed energy resource is offered into an RTO/ISO market and is not added back to a utility's or other load serving entity's load profile, then that resource will be double counted as both load reduction and a supply resource," FERC was indicating that, for planning purposes, double counting of services would occur if the same distributed energy resource reduces the amount of a service that an RTO/ISO procures on a forward-looking basis in a certain time period while also acting as a provider of that same service in that same delivery period.[13] Further, FERC clarified that, to the extent that an RTO/ISO already has restrictions in place to avoid double counting of services, it is not required to propose new restrictions but rather must explain on compliance how these existing restrictions prevent double counting.[14] Such restrictions would only be appropriate "if necessary to prevent double counting of services,"[15] and each RTO/ISO must otherwise "allow distributed energy resources that participate in one or more retail programs to participate in its wholesale markets."[16]

In Order No. 2222-B, FERC clarified that payment of full locational marginal price (LMP) in the energy market to behind-the-meter distributed energy resources participating as demand response resources in distributed energy resource aggregations does not constitute double counting, so long as the requirements of Order No. 745, including the net benefits test, are satisfied.[17]

With respect to net energy metering, PJM's proposed Tariff and Operating Agreement language also provides that Component DER that participate in a net energy metering retail program may only participate with grid injections in the PJM ancillary services markets, and may not participate in the energy and capacity markets unless:

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[13] Order No. 2222-A, 174 FERC ¶ 61,197 at P 63 (quoting Order No. 2222, 172 FERC ¶ 61,247 at P 161).
[14] *Id.* P 64 (citing Order No. 2222, 172 FERC ¶ 61,247 at P 161).
[15] *Id.* (quoting Order No. 2222, 172 FERC ¶ 61,247 at P 161).
[16] *Id.* (quoting Order No. 2222, 172 FERC ¶ 61,247 at P 160).
[17] Order No. 2222-B, 175 FERC ¶ 61,227 at P 43.

(1) the electric distribution company confirms to the Office of Interconnection that participation of the resource will not violate the restrictions on duplicative compensation; and (2) the Office of Interconnection determines that the participation of the resource otherwise meets the requirements for energy or capacity market participation. This provision, as discussed in the record and in this order, is referred to as the "release valve." PJM asserts that under its proposal, it is possible for net energy metering retail programs to be designed in a manner that would allow participation in capacity and energy markets without triggering double compensation concerns.

PJM reiterates that application of the must-offer requirement is an important component of PJM's overall Order No. 2222 implementation, and an important tool in maintaining reliability and competitive markets. To support this assertion, PJM points out that FERC recently found that "exempting resources from the energy market must-offer requirement would significantly impair reliability and provide an opportunity to physically withhold capacity from energy markets, which could result in energy market prices above competitive levels."   PJM explains that the release valve is specifically designed to account for possible future innovation or scenarios where resources may be able to participate in both the energy and capacity markets while simultaneously respecting the must-offer requirement and prohibitions on double counting.

Based on this analysis and the comments received, the Commission proposes to set narrowly tailored conditions on Component DER participation. Specifically, the Commission agrees with the commenters that indicated that customer-generators receiving service under an EDC's net metering tariff shall be excluded from participating in the wholesale capacity and energy markets as a DER Aggregator Resource as they are already being compensated for providing capacity and energy through the EDC's retail net metering tariff. The Commission, however, also agrees with the commenters who indicated that customer-generators can participate in the wholesale ancillary services markets as a DER Aggregator Resource as net metering customers do not provide ancillary services as part of their net metering participation since they are not dispatched in real-time to meet system needs, as would be required if the Component DER was participating in the ancillary services market as part of a DERA Resource. Accordingly, if a customer-generator receiving service under a net metering tariff can be dispatched in real-time to meet system needs they should be able to also receive compensation from the wholesale ancillary service market as well as a DERA Resource.

The second condition in the proposed regulation simply recognizes that the Component DER must meet all the requirements of the PJM tariff and does not adversely impact the safe and reliable operation of the EDC distribution system. As discussed below regarding the proposed section 57.264 (relating to review of component DER applications), PJM's tariff requires EDCs to review and approve Component DER participation as a DERA Resource to ensure that the EDC's distribution system is not adversely impacted by such participation.

Finally, regarding Commission oversight of DERAs, the proposed regulation limits such oversight because DERAs fall under FERC jurisdiction. Specifically, the proposed regulations limit DERA oversight to EDC review and approval of requests from DERAs for EDC approval of Component DER participation, as well as tariff provisions that Component DER must comply with, to ensure the safe and reliable operation of the EDC's distribution system.

In the proposed subsection 57.263(c) the Commission is directing the EDCs that allow DER Aggregation Resource participation within their service territory to file a tariff with the Commission consistent with the proposed chapter. Such tariff should set forth the conditions under which Component DERs and DERAs will operate on the EDCs distribution system. In addition, the tariff will set forth any fees or rates applicable to Component DERs and DERAs.

IV. EDC Review of Component DER Applications

In the proposed section 57.264, the Commission proposes three requirements EDCs must follow in reviewing requests by a DERA, a DER operator or PJM for approval of a Component DER to participate in the PJM wholesale energy, capacity, and/or ancillary services markets as a DER Aggregation Resource. As noted above, the PJM tariff requires that EDCs review and approve such Component DER participation to ensure the safe and reliable operation of the EDC's distribution system. In addition, the Commission is proposing that the EDC may charge a fee for reviewing Component DER applications.

Comments

A. Component DER Approval Process

CADRE does not envision the need for the PUC to address anything specific in its new regulatory model to facilitate the integration of a load resource with an interconnected resource. It notes that PJM has defined rules of participation for homogenous and heterogeneous aggregations that include energy efficiency and demand response resources.

The City Parties suggest that the PUC use this proceeding, in collaboration with PJM, to eliminate inconsistencies between the two regimes and streamline the collective PJM/EDC interconnection process for BTM resources. If interconnection becomes a roadblock, the benefits contemplated by Order 2222 for the grid and for the environment will not be achieved. The City Parties encourage the PUC to use the opportunity created by the ANOPR to reconsider its existing procedures to ensure that they are consistent not only with PJM procedures but also with the goals of Order 2222.

The City Parties recommend that PUC regulations be revised to reflect an alternative view of the grid structure. While EDCs would remain the default providers, their role is evolving from traditional one-way power delivery to supporting a diverse array of additional power sources for customers, including customers and community direct provision as well as PUC-licensed EGSs. They note that resources acquired by or on behalf of customers will primarily be sized to meet the needs of the specific customer or customers served by the resource, but they will frequently have spare capability or flexible customer needs that allow these resources to contribute through aggregation.

FirstEnergy submits that interconnection requirements for these Component DER types would need to be based on the specific market or program for which they plan to participate in (i.e., Pennsylvania or FERC) to ensure the applicable interconnection requirements are in place and to avoid double counting. Interconnection requirements may include current connection standards, dispatch, over-ride signals, revenue metering and data submittal, telecommunication, energy settlements, and communication processes. FirstEnergy further submits that all DER types and their system impacts must be considered as part of a DER Aggregation evaluation. Both load reductions and energy injections from Component DERs should be coordinated via PJM dispatch and would need to be considered as part of the EDC approval of the DER Aggregation operation.

The OCA submits that existing DERs that are aggregated into a new or existing DERA must comply as part of or along with the same interconnection process for proposed DERAs so that they can be safely and reliably operated. Existing DERs that are aggregated must also comply with any PUC regulations applicable to proposed DERAs and their Component DERs. Further, the DERA interconnecting process should account for the types of Components DERs, such as energy efficiency and demand response, being aggregated by a DERA.

PECO has not yet identified a specific need for a contractual relationship between an EDC and such a Component DER customer. However, this position could change as PJM finalizes changes to its OATT and business practice manuals to implement FERC

Order No. 2222 and as PECO gains more experience with DERA activities. Component DERs that could potentially export electric power to the grid should still be required to execute an interconnection agreement before being able to export power to the grid or participate in a DER aggregation.

PPL submits that it is essential that the PUC recognize that component DERs injecting onto the grid necessitate an interconnection agreement. PPL notes in its comments that it has created agreements for DER system that are connected to the distribution system but participate in the wholesale market. These agreements build off of PJM's interconnection agreements with modification to reflect the interconnection with the distribution system, rather than the transmission system. These types of agreements could be useful in developing interconnection agreements for their resources that inject power onto the grid but are not currently contemplated in the PUC's interconnection agreements.

CADRE emphasizes that the use cases for DER and DER aggregations, from the perspective of the rulemaking, are primarily wholesale market use cases. The organization proposes that DER and DER aggregations assembled to provide services to the wholesale market could also provide distribution level services. CADRE takes the position that the aggregation review process should not differ because the use cases are wholesale. The organization believes that the study of different wholesale use cases is outside the bounds of the PUC's jurisdiction. A central tenet of CADRE's position is that an aggregation of DERs should be viewed no differently than a single DER. CADRE argues that if an EDC accepts a resource for interconnection, it must assume that the newly interconnected resource will respond to signals when other resources respond.

CADRE acknowledges the evolving nature of DER aggregations, noting that each DER aggregation will be developed to maximize value for both customers and aggregators. The organization expects that:

- Component DERs comprising capacity aggregations will likely change from year to year.
- Energy and ancillary service aggregations will likely change more frequently, especially as the market continues growing.

This dynamic composition reflects the market-driven optimization of these resources to deliver maximum value to stakeholders.

DLC submits that the DER aggregation review process should vary based on the factors listed. The level of review should be commensurate to the level of impact the aggregation will have. DLC believes the PUC should define a review process that is consistent across the state, while providing EDCs a degree of flexibility to determine what needs to be studied.

FirstEnergy submits that to assist in the review process, Component DERs must inform the EDC of its intended operation in the PJM markets or other sites to determine the review needed. Further, any proposed DER Aggregation will need to be studied to determine the aggregate impacts of the aggregation to allow the EDCs to determine any system reliability impact.

The OCA contends that regardless of the DERA's use case, market composition, DER composition, or grid conditions that the DER aggregation review process needs to ensure that the DERA and Component DERs are planned and operated in a safe and reliable manner. The review process should evolve over time to incorporate technological, regulatory, and business developments, as well as learnings from prior experience.

PECO recommends that EDCs be afforded the ability to customize review procedures due to differences among EDCs and the likely evolution of DER integration in the distribution systems. PECO submits that the PUC should not specify different DER aggregation review processes by regulation but should instead exercise oversight through its review of EDC tariff changes addressing DER aggregation review.

PPL notes that the composition of component DERs is a crucial factor in the review process because factors like technology diversity, size requirements, and physical and operational capabilities must be considered. Additionally, grid location and aggregation-level review must also be considered. FERC Order 2222 mandates that locational requirements must be as "geographically broad" as technically feasible. Beyond individual component reviews, any proposed DER Aggregations will need to be studied to determine the aggregate/coordinated impacts of the aggregation to allow the EDCs to determine any system reliability impact.

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.

B. Automation of Approval Process

DLC anticipates that some processes may initially be completed manually and be gradually transitioned to automated processes as new technology solutions are developed. The ability to accommodate automation may differ between EDCs, and thus the PUC may consider offering guidance, but should avoid one-size-fits-all requirements.

FirstEnergy notes that it is imperative that the EDC DER registration approval process be heavily automated to ensure an efficient review within the 60-day timeline. Insufficient data or lack of information will delay this process resulting in EDCs denying aggregation requests. Communication among DER Aggregation, PJM, and the EDC should be required. Further, relevant electric retail regulatory authority or state regulatory commission should be provided access to PJM's DER hub and registration process to review the status of any DER Aggregations and the communications among the parties involved.

The OCA submits that the decision for whether to implement automatic or manual coordination should be governed by what can be done safely and reliably. The OCA submits that if both processes can be done safely and reliably, then costs should be the determining factor.

Additionally, the OCA suggests that the PJM and EDC DER registration processes should be coordinated as much as possible to avoid duplication of efforts by DER applicants. Information that is needed for both the PJM and EDC DER registration processes should be requested in identical data formats. Moreover, EDCs should coordinate their registration processes as much as possible so that DER applicants are required to submit the same data in the same format across EDCs. Over time, the PJM and EDC DER registration processes will need to be updated and improved to improve their efficiency and eliminate unnecessary and duplicate steps. The PJM and EDC DER registration processes need to protect the privacy, confidentiality, and cybersecurity of the DER applicants' data. A generic rulemaking instead of adjudicated on a case-by-case basis should be used to ensure uniformity among the EDCs and the results codified in the PUC's regulations.

PECO expects automation or manual coordination to be specified in the PJM OATT and in the interconnection agreements. Further, the PJM OATT prescribes a review period and process for EDCs. As such, PECO does not see a need for the PUC to prescribe regulations for communication or registration review. But the PUC should confirm that Component DERs that could potentially export energy onto the distribution grid must coordinate and enter into appropriate interconnection agreements with the applicable EDC.

PPL supports automation and encourages the PUC to recognize the need to construct systems that facilitate automated processes. PPL notes that it does not anticipate being unable to meet the 60-day timeline for reviewing the DER Aggregator's registration. It anticipates that Component DER interconnection approval will constitute the bulk of the review process.

C. Cost Recovery

CAUSE-PA warns DER integration costs shouldn't be passed down to non-participating customers, especially low-income households. It stresses that cost recovery must be equitable, prevent overcompensation, and protect vulnerable consumer groups from harm. CAUSE-PA notes that those who can adopt DER technology - either on their own or with the assistance of a government or non-profit program - must be shielded from confusing, deceptive, and/or misleading marketing, sales, solicitation, billing, and collections practices which could arise through the creation of a DER aggregation market.

The City Parties propose that EDC administrative costs of customer participation in DERAs be paid by all ratepayers, since the costs are meant to provide energy choices and the benefits of increased competition to all customers. They further emphasize that upfront charges assessed with no guarantee of interconnection being possible will be a major barrier to customer adoption.

DER Task Force makes several recommendations for cost allocation of DER. First, it suggests that wholesale market DER aggregations should reduce wholesale power procurements costs in PJM. Second, the distinction between virtual powerplants and non-wires solutions is particularly instructive for cost allocation, including about how EDCs should distinguish between grid modernization, general DER costs, and DERA-specific costs. DER Task Force submits that transmission and distribution deferral value of DERs should be socialized. Third, DER Task Force contends that cost allocation for DER programs does not need to be an all or nothing issue. While a portion of costs can be assigned to the DER owner, some can be socialized in recognition of the benefits that a DER provides to the grid. Finally, DER Task Force submits that DER-related back-office functions, like DERMS, should be socialized, since these are costs that the utility would incur as a function of interconnecting DERs, which is their job as a utility.

EAP focuses on adapting existing regulatory frameworks and establishing clear cost responsibility principles. EAP emphasizes that EDCs should receive appropriate cost recovery for both implementation and ongoing operational expenses related to DER participation in wholesale markets. The association argues that EDCs must receive cost recovery for the expected significant implementation costs, as well as ongoing administrative costs, related to individual component DERs and their participation in the PJM wholesale market via DERAs.

EAP suggests that utilities should have flexibility in proposing cost recovery approaches that align with traditional ratemaking principles. The association recommends that utilities should have leeway to propose approaches to cost recovery, which may include fees or other charges to DERAs and/or their component DERs, that are consistent with cost-of-service principles and historic rate design practices.

FirstEnergy submits that fundamental cost allocation principles such as "beneficiary pays" and "cost causation" should be applied when considering cost allocation issues related to the interconnection of DERs. It contends that these principles dictate that the cost should flow to cost causers who will ultimately benefit. Cost causation principles should be followed with only costs that benefit all customers being socialized. If direct costs caused by the Component DER that participates in PJM's wholesale market can be assigned; they should be assigned to the Component DER owner or aggregator. Costs incurred to implement Order 2222 to manage the grid for the benefit of all customers should be approved for full and timely cost recovery in rates.

PECO submits that EDCs are entitled to full recovery of reasonable and prudently incurred costs associated with implementing Order 2222 and should have flexibility to propose cost recovery mechanisms such as fees, rate riders, or regulatory asset classification in ways that balance cost causation and beneficiary pays principles. PECO recommends component DERs share in fixed costs of constructing, operating, and maintaining the distribution grid.

PPL outlined a comprehensive approach to cost allocation issues for facilities allowing the interconnection of DERs under FERC Order 2222 implementation. PPL identified two main categories of cost allocations that need to be considered in the implementation of FERC Order 2222: Interconnection costs for Component DERs and Backend Infrastructure Costs. The first cost category involves the cost to interconnect Component DERs safely with the distribution system. PPL recommends that existing regulatory frameworks can be adapted for this purpose, specifically stating that Chapter 75 rules requiring interconnection customers being responsible for interconnection costs can largely be adapted to cover Component DERs participating in aggregation. The second cost category encompasses the costs associated with setting up the appropriate backend infrastructure for EDCs to administer and accommodate FERC Order 2222 aggregation. PPL advocates for a clear cost recovery mechanism, recommending that EDCs should be permitted to recover these costs based on established cost of service principles.

D. PJM's Current Rules

PJM has submitted for FERC approval at Section1.4B and its Manuals, a DERA Participation Model. According to that manual, to participate in the energy, capacity, and/or ancillary services markets of PJM through the DERA Participation Model, a DERA shall register each DER Aggregation Resource and DER Capacity Aggregation Resource with the PJM Office of the Interconnection, in accordance with the procedures established under the PJM Manuals. For each Component DER in a DER Aggregation Resource, the DERA shall provide:

i. Identifying information, including the physical address and EDC account number;
ii. Metering information, including meter type (e.g., EDC meter, other meter); and
iii. Capability information, including load reduction and injection capability.

The EDC review portion of the registration process shall commence after: (1) the PJM Office of the Interconnection has an executed DERA Participation Service Agreement on file, to be used for all DER Aggregation Resources associated with the DERA; and (2) the PJM Office of the Interconnection receives a complete registration from the DERA, in a form specified in the PJM Manuals. Upon receipt of a DERA's completed registration, the PJM Office of the Interconnection shall review the registration and data submitted therein for completeness and verify that the DERA meets the eligibility criteria for participation in the DERA Participation Model, as defined under the PJM Tariff and Operating Agreement and Manuals. The DERA shall only submit a registration for Component DER that are under contract for the term of the registration, and only one DERA may operate Component DER at a specific location. The PJM Office of the Interconnection shall notify the appropriate EDC of the DERA's registration through the appropriate PJM system. A single registration shall only be comprised of individual Component DER in the same state, EDC, Transmission Zone, and pricing point unless otherwise noted below.

The EDC review process shall consist of two periods, in sum not to exceed sixty calendar days. The first shall be a single period, not to exceed fifteen calendar days, during which time the EDC and the PJM Office of the Interconnection shall review and verify each Component DER for which a location was created. The second shall be a single period, not to exceed forty-five calendar days, during which the EDC shall perform a reliability review of the DER Aggregation Resource. If the last day of either the fifteen or forty-five calendar day review period falls on a weekend or holiday, the review period shall conclude on the next business day. The first fifteen calendar day review period shall commence upon receipt by the EDC of notification from the PJM Office of the Interconnection.

Following notification, the EDC may review and verify, as applicable, the Component DER for which a location was created and the following information associated therewith:

i. The location and data components that represents each Component DER, as further defined in the relevant PJM Manuals, are accurate;

ii. Participation of the Component DER in an EDC's retail program at the time of registration does not preclude participation of the Component DER in the energy, capacity, and/or ancillary services markets of PJM, and as defined in the PJM Manuals;

a. Component DER that participate in a net energy metering retail program may only participate with grid injections in the PJM ancillary services markets, and may not participate with injections in PJM energy or capacity markets, unless:

1. The EDC confirms to the PJM Office of the Interconnection that participation of the Component DER in a net energy metering retail program or tariff approved by the Relevant Electric Retail Regulatory Authority will not violate the restrictions on duplicative compensation, as described in Tariff, Attachment K-Appendix, section 1.4B(h) and Operating Agreement, Schedule 1, section 1.4B(h); and

2. The PJM Office of the Interconnection determines that the participation of the Component DER otherwise meets the applicable requirements for energy market or capacity market participation.

b. Component DER that participate in a net energy metering retail program that also participate with grid injections in the PJM ancillary services markets shall, based on the information provided by the DERA or the EDC, be excluded from PJM energy market settlements.

iii. The Component DER complies with the rules and regulations of any applicable RERRA;

iv. The RERRA allows the participation of any applicable Component DER that are also end-use customers of an EDC, in accordance with the provisions of Tariff, Attachment.

Disposition

The Commission agrees with the parties that the EDCs should be given some flexibility in conducting review of requests for Component DERs to participate as a DER Aggregation Resource, as long as the requisite and applicable review period meets the timeline set by PJM and is responsive to the request. Accordingly, proposed Section 57.264, as set forth in the Annex, requires the EDC to establish a process for receiving and reviewing requests, whether from a DERA, a DER operator or PJM, for approval of a

Component DER to participate in the PJM energy, capacity, and/or ancillary services markets as a DER Aggregation Resource. The only requirements for such a process being proposed is that the process must allow for electronic submission of requests, that the EDC must complete the review within 60 days of submission and finally that the EDC must describe in detail its reasons for denying a request. This light touch approach to the requirements allows the EDCs the flexibility to begin processing requests as quickly as possible, while allowing the EDCs time to develop more automated processes as they gain experience and as technology advances.

Regarding costs related to the review process and EDC development of Component DER operations on their distribution system, the Commission does not propose establishing a set fee or cost recovery mechanism at this time. The Commission, however, does propose that EDCs may establish a fee to be imposed on applicants to be submitted as part of its tariff to be approved by the Commission.

V. Component DER Operation

In the proposed section 57.265, as set forth in the Annex, the Commission proposes requirements that EDCs provide DERA access to Component DER data upon consent of the DER operator, as well as its DER Component dispatch override procedures and notices. The intent of the proposal is to give EDCs flexibility at this early stage of DER Aggregation to develop policies, practices and procedures relating to DER Component operations on the EDC's distribution system to ensure the safe and reliable operation of distribution system.

Comments

A. Data Access

CADRE acknowledges that PJM has already established communication and telemetry protocols designed to ensure timely communications regarding DER and

DERA performance. CADRE recommends that communication relationships should be limited to being between the DERA, PJM, and the EDC. This establishes a clear three-party communication framework for DER coordination. The PUC should require EDCs to automate certain communications, specifically, planned distribution network outages and override communications. These automated systems should be fully accessible to licensed DERAs.

CADRE recommends that if EDCs feel they need additional data beyond what PJM already requires, they should work directly with PJM to modify their data requirements. This approach would avoid creating unnecessary and wasteful duplication of resources by having different data requirements between PJM and the EDCs. CADRE strongly encourages the PUC not to add to the data burden by creating additional requirements through the rulemaking process, particularly given the nascent nature of the DER market. CADRE suggests that if additional data requirements develop over time, they should be addressed through the PJM tariff or other appropriate avenues rather than through formal regulations.

CUS's primary recommendation is that modifying the PUC's rules to include adoption of the DER Registry would facilitate expeditious and cost-effective implementation of FERC Order No. 2222. The DER Registry will facilitate the inclusion of the full range of DERs allowed under FERC Order No. 2222, avoiding issues such as potential "over-registration," while accommodating a variety of potential implementations. CUS argues that having each EDC forge its own unique implementation path, such as through creating separate DER information databases, would be a highly inefficient and costly way to address the problem of data-sharing among the numerous stakeholders who need a "single source of truth" data set for DER management under FERC Order No. 2222.

CUS recommends that the PUC consider an even broader recommendation for any utility system to utilize CIM data exchange to eliminate all further software interface costs and, instead, have fully implemented data layer exchange through known CIM structures. If a data-centric approach is utilized to define the necessary data elements for each step in this process and these data elements are appropriately "mapped" to CIM data structures, then existing industry systems for CIS, GIS, ADMS, EMS, planning and modeling, etc., will be able to effectively share the data through a secure data API based on the CIM data structures of the existing industry systems, thereby eliminating costly software interfaces.

The OCA submits that DERAs will need to provide all the necessary data to EDCs for EDCs to determine if DERAs are operating safely and reliably, making the necessary distribution system upgrades and costs, and ensure that DERAs comply with all PUC regulations, including not receiving double compensation. DERA data requirements and data formats should be coordinated among and between the EDCs and PJM to streamline the DERAs' data provision. The data collected should be documented based upon standard industry practices that ensure privacy, confidentiality, and cybersecurity. The data should be retained for at least the existence of the DERA, if not longer. Further, the OCA submits that the PUC should have access to this data upon request, subject to confidentiality provisions.

DER service providers assert that for DERAs to be able to operate in the PJM market, they need access to customer data, including historical electricity usage data, peak load contribution and winter peak load values, and curtailment event data. In particular, CPower and CADRE both state that DERAs need timely and reliable data to register its customers with PJM, demonstrate compliance with multiple requirements, settle following events, and to pay customers, but claim that such data is often not easy to obtain, and data access procedures are not scalable to serve large numbers of customers, especially residential and small to medium commercial customers.

CADRE believes that Electronic Data Exchange (EDI) is a potential solution, as it allows aggregators to request data for numerous accounts at once, and suggests that EDI portals should be revamped and standardized across utilities. The DER Task Force takes a more aggressive approach, asserting that Pennsylvania's current EDI is neither scalable nor secure, and has raised concerns over its purported lack of customer protections. The DER Task Force believes that Pennsylvania's current EDI process should be replaced with an open, secure, consent-based common Application Programming Interface (API) platform where customers and third-parties can easily review customer data. The DER Task Force asserts that such a platform would provide transparency and make it easier to avoid dual enrollment. CADRE notes that 66 Pa.C.S. § 2807(f)(3) requires customer consent before customer data is released to a third-party. CADRE suggests that the PUC standardize forms for customer consent across the EDCs and require the utilities to allow "electronic authorization" from customers to provide that consent. In turn, CADRE recommends that aggregators receiving said customer information should be required to agree to proper customer authorization practices, data maintenance, and confidentiality requirements.

EDCs generally see EDI as a good starting point for data exchange protocols relating to DER aggregations. DLC supports the use of EDI to the extent possible to enable efficient, accurate, and automated information exchange. PPL likewise supports the creation of EDI, but would also support other data exchange protocols by the PUC, and believes that consistent statewide guidance will make the implementation of FERC Order 2222 easier and more cost-effective. However, PPL notes that DERAs will have unique requirements that will need to be addressed in specific protocols. PECO does not recommend any modifications to the PUC's data exchange protocols at present, except as necessary to ensure that EDCs have flexibility and to permit EDCs to require that DERAs maintain the confidentiality of data shared with them. However, PECO notes that state-specific requirements for data exchange protocols could render a consistent

PJM-wide approach impossible. EAP encourages the use of EDI and/or other data exchange protocols, but cautions against creating prescriptive requirements or dictating a particular protocol since PJM has not yet provided clarity on what data and the level of information that will need to be exchanged. Both EAP and PECO note that it will be important to allow for the use of common exchange protocols between related EDCs which operate in other states within the PJM footprint. EAP recommends that the Electronic Data Exchange Working Group address this topic once there is sufficient information regarding the data that will be exchanged.

Recurve submits PUC should permit the secure exchange and use of anonymized AMI data of non-participating customers in order to compare customers who participate in demand side programs while using non-participating customers as a baseline in order to more accurately measure the hourly quantity of grid services provided by the participating customers.

The University of Delaware believes that currently very few DER operators and EDCs fully understand how to economically utilize DER resources, and as such state regulation of data exchange protocols among EDCs and DERAs would be premature at this stage. The University of Delaware suggests that the issue of data exchange protocols could be revisited after several years of experience.

B. Dispatch Override Procedures

CADRE believes that EDCs should not have direct control over DERs or DER aggregations participating in wholesale electricity markets. However, CADRE acknowledges that EDCs must retain the ability to override dispatch signals when necessary for system reliability.

CADRE references FERC Order No. 2222, which allows EDCs to override PJM dispatch of DERs and DER aggregations in specific circumstances where such an override is needed to maintain the reliability and safe operation of the distribution system. Importantly, CADRE emphasizes that EDC overrides of a DER dispatch should only be ordered in the case of a reliability emergency that would be caused by the dispatch. CADRE does not support the use of nomenclature to distinguish between "firm" and "non-firm" approval categories. The organization is also concerned about the PUC's use of this distinction to "reduce the need for system upgrades."

CADRE recommends adding new Sections 78.10 through 78.15 to Title 52 of the Pennsylvania Code in a Dispatch Management Subchapter to regulate the EDCs' ability to override dispatch signals from PJM. This comprehensive framework includes:

Key Provisions of the Proposed Sections:

- **§ 73.10 EDC dispatch override responsibilities**: EDCs may only override a DER dispatch signal from PJM when the reliability of the distribution system would be jeopardized by such dispatch.
- **§ 73.11 DER Service Provider Obligation**: DER Aggregators must adhere to an EDC override order.
- **§ 73.12 EDC Override procedures**: EDCs should use best efforts to inform DER Aggregators of a potential override at least one hour before the RTO/ISO day-ahead offer period closes. If system conditions change such that reliability concerns abate, EDCs should notify DER Aggregators before the close of the real-time bidding window.
- **§ 73.13 Override mitigation**: When a PJM dispatch order is overridden, the EDC must communicate the reason for the override to all DER Aggregators and the PUC within one calendar day, develop a mitigation plan within 60 days, and complete any necessary system changes within 180 days.

- **§ 73.14 EDC Error**: EDCs will be liable to DER Aggregators for direct costs assessed by the RTO/ISO if they issue an override order without proper justification or fail to take mitigation action within 180 days. These costs shall not be recoverable from EDC ratepayers.
- **§ 73.15 EDC Communication**: EDCs must communicate planned outages at least 48 hours in advance and unplanned outages immediately to DER Aggregators with customers in affected areas.

CADRE firmly believes that EDCs should not have direct control over DER or DER aggregations participating in wholesale electricity markets. The organization emphasizes that under no circumstance should the EDC have direct control over a DER participating in wholesale electricity markets. EDCs should have to work through DER Aggregators who will then be bound by those instructions enforceable by the PUC. CADRE notes that "monitoring" is a vague term. CADRE believes "monitoring" should mean that EDCs are granted "monitoring" authority over any resource or resource aggregation for compliance purposes. CADRE emphasizes that real-time overrides should be avoided at all costs because an override could be very costly for a DERA.

The City Parties suggest that Distribution Energy Resource Management Systems (DERMS) have an important role in providing grid resilience in a digitally controlled, segmented grid, but micromanaging within customer homes is not appropriate. The City Parties assert that direct EDC control of residential equipment is viewed as problematic, while aggregators should have direct agreements with customers that include protections from arbitrary cut-offs and provisions for customer override.

The City Parties recommend that EDCs and RTOs should look to aggregators, rather than customers, for management of aggregated resources in accordance with distribution system limits. This approach may require aggregators to carry reserves and/or balancing hedges to ensure compliance and reduce risks associated with firm bids to PJM. While automation of customer response prevents unintended failures to respond, the comments emphasize that a customer's ability to override dispatch signals or preselected price responses is critical to customer wellbeing.

In addressing conditions for direct control versus monitoring, DLC submits that only the EDC can monitor and manage the distribution grid. EDCs need the flexibility to define those conditions based on their individual technology and abilities. These conditions may change over time. DLC contends that the PUC must recognize that each EDC's distribution grid is designed and operated differently, and not all EDCs have the same technology capabilities. DLC emphasizes that the need for distribution overrides will often be independent of market bidding windows, in order to maintain safety and reliability after unplanned system events. DLC states that the PUC must ensure that EDCs have the authority to override DERs when the situation dictates, such as under emergency circumstances. However, DLC notes it does not presently have the ability to communicate directly with small DERs, nor does it currently have the technical capability to override a DER.

FirstEnergy contends that monitoring of DERs may be sufficient to provide the needed situational awareness of the impacts of DERs to the grid. However, if there is significant penetration of a DER on the grid and grid stability and/or reliability are at risk, then direct control may be needed to assure that stability/reliability is maintained. Since a DERM is being considered for situational awareness and real-time system contingency analysis, the dispatch device type and size needs to be part of any interconnection standard and interconnection agreement where device control and operating range requirements are necessary to ensure a safe and reliable electric system. Further, direct control may be required pending on the size of the DER Aggregation and distribution system conditions. FirstEnergy opines that the more variable the DER resource mix the more critical it is for the EDC to maintain direct control as opposed to monitoring. FirstEnergy states that EDCs have the responsibility to provide safe and reliable operation of the distribution system for all customers, and EDC overrides are necessary during certain conditions to prevent unsafe or undesirable operating conditions. As such, FirstEnergy proposes that any EDC override communications to the DERA also be required to be communicated to PJM.

The OCA submits that the conditions under which direct control versus monitoring are required should be determined based upon the technical safety and reliability standards for the distribution system. The associated costs should be paid for by the DERA. The OCA comments that the distribution override process should precede the PJM market bidding window whenever possible, and the DERA should be informed as soon as possible. DERA agreements should include all real-time, near real-time, and other update and override requirements to ensure the safety and reliability of the grid, which should be based on technical requirements and industry standards and applied to all DERs in a non-discriminatory and transparent manner. The OCA notes that the economic costs associated with any overrides should be borne by the DERA and not assigned to ratepayers.

PECO does not suggest specifying the conditions where direct control or monitoring will be required because prescriptive conditions will limit an EDC's ability to respond to evolutions in DERs and DER aggregations. PECO submits that EDCs will determine whether to exercise direct control or monitoring based on impact to system safety and reliability. PECO strongly believes that EDCs should have an unencumbered right to override dispatch instructions for Component DERs on their systems to resolve or avoid distribution reliability issues. Accordingly, PECO recommends that the PUC avoid introducing parameters into the distribution override process based on non-operational factors such as market bidding windows.

PPL notes that not all EDCs will be equipped with DERMS when FERC Order 2222 is implemented and, as such, the PUC's regulations should be designed with flexibility, allowing for a variety of EDC override mechanisms to be accommodated. PPL believes the terms “firm” and “non-firm” are ambiguous and require clarification. It identifies two possible interpretations of these terms:

> **Flexible Interconnection Interpretation**: “Non-firm” could reference a “flexible interconnection,” 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.
>
> **Access Guarantee Interpretation**: Alternatively, “firm” and “non-firm” might refer to guaranteed access to the distribution system versus non-guaranteed access, respectively.

PPL believes that for effective management of component DER it will require a combination of direct control and monitoring. PPL notes that 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. PPL anticipates that the interconnection agreement with Component DERs will specify override procedures so that Component DER owners know how and under what situations there may be an override. PPL 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.

The DER Task Force emphasizes the need for a structured approach to developing override frameworks. They recommend preliminary information gathering through workshops or roundtable meetings before the PUC develops specific parameters for overrides and related disputes. The DER Task Force asserts that EDCs must share their current technical capabilities for distribution system forecasting, real-time visibility, and conducting overrides. Utilities should be explicit about what conditions are likely to lead to overrides and explain how they would forecast when they might happen, including how an aggregation dispatch would look different than normal load fluctuations that EDCs manage daily. The DER Task Force also raises the potential to use Non-Wires Solutions to mitigate the need for overrides by strategically deploying them to stabilize the distribution system in certain locations.

EAP states that EDCs must retain discretion to determine when and how to override the physical operation of component DERs or DER aggregation resources on their distribution systems. Moreover, EAP asserts that if an EDC overrides DER aggregation resources to preserve system integrity while those resources are participating in wholesale markets causing aggregators to incur penalties, the EDC should not be required to pay or reimburse the aggregator for such penalties.

The City Parties suggest that EDC ability to override DERs should primarily be addressed to front-of-the-meter DERs and DERs that are substantially oversized for customer expected load. They encourage the PUC to move toward a new grid model where self-supply is an option for any customer.

The University of Delaware proposes that rather than EDCs disconnecting or overriding the entire signal for a given DERA, the DERA could provide the EDC control at a more granular level, such as over individual distribution feeders. They feel that the override agreement is best handled in a contract between EDC and DERA, with the PUC potentially serving as an arbiter in case of disputes.

Disposition

Regarding data exchange between EDCs and DERAs, given the complexity of this issue, and the range perspectives of and proposed solutions concerning data exchange protocols related to DER Aggregation, we will refer this matter and related subtopics to the Electronic Data Exchange Working Group (EDEWG). We believe that the EDEWG process, which allows stakeholders to engage directly with one another to share their respective concerns and recommendations, will facilitate the development of reasonable best practices. We also note that, given the evolving technological and federal regulatory landscape in this area, the EDEWG provides greater flexibility for stakeholders to share developments that may affect data exchange protocols in real-time. We are, however, proposing in subsection 57.265(a), as set forth in the Annex, that EDC's shall provide DERA access to Component DER data upon consent of the DER operator in a format approved by the Commission. As each EDC's systems and capabilities vary, each EDC can propose a data access format for Commission approval in the EDC's tariff filing. This provides data access in the interim until a more standard format is developed based on experience through EDEWG.

Regarding EDC override of DER dispatch, the comments reveal tension between maintaining grid reliability and preserving market participation opportunities for DERs. While utilities emphasize their statutory obligations to maintain safe and reliable service, aggregators and DER advocates express concerns about potential overreach that could undermine the economic viability of DER participation in wholesale markets.

EDC capabilities vary significantly. While some utilities propose advanced monitoring and control systems, others acknowledge limited technical capabilities for communicating with and overriding small DERs. This technological disparity creates challenges for implementing consistent override procedures across different utility territories.

The stakeholder comments demonstrate the complexity of establishing appropriate override frameworks that balance reliability needs with market participation rights, technological capabilities, and regulatory oversight requirements. The diverse perspectives highlight the need for careful consideration of technical standards, procedural requirements, and dispute resolution mechanisms as the PUC develops its regulatory approach to DER overrides.

We agree with OCA and PPL that EDCs should retain the authority to override DER dispatch to maintain safe and reliable electric distribution service. This is consistent with PJM's position that during emergency scenarios, utilities can take actions necessary for safety and reliability, including overriding DER Aggregation Resources or underlying Component DER operating under PJM dispatch. This override is to occur pursuant to applicable tariffs, agreements, operating procedures of the Electric Distribution Company, and/or the rules and regulations of any Relevant Electric Retail Regulatory Authority. NRDC at 11; PJM Compliance filing ER22-962-007, Oct. 2024, DAPM at 45.

Accordingly, we are proposing in subsection 57.265(b), as set forth in the Annex, that each EDC shall establish DER Component dispatch override procedures that include a description of the conditions under which the EDC will override a dispatch request. In addition, each EDC shall describe the notices to be given when a dispatch is to be overridden during (1) preplanned maintenance; (2) emergency conditions; (3) any other conditions established by the EDC; and (4) when the EDC's system returns to normal operations. Finally, each EDC is to describe when the notices will be provided under each condition as well as the method the notice will be provided to PJM, DERA and DER operators.

VI. Dispute Resolution

In the proposed section 57.266, as set forth in the Annex, the Commission proposes mechanisms for EDCs and other parties attempt to resolve disputes regarding DER interconnection and EDC actions related to DER Aggregation Resources. We are also proposing that when attempts to resolve the dispute between the parties fail, parties may seek resolution through the Commission's existing rules relating to complaints and petitions. Finally, we are proposing that pursuit of a dispute resolution shall not impact the applicants position in the EDC’s interconnection queue.

Comments

FirstEnergy emphasizes that agreements facilitating participation in PJM markets under FERC Order 2222 must contain appropriate dispute resolution regulations and requirements. They note that the PUC must accept jurisdiction over DERAs similar to EGSs and demand response curtailment service providers.

The University of Delaware agrees that issues within disputes that PJM determines solely concern EDC tariffs, agreements, and operating procedures should be addressed according to applicable state or local law and not arbitrated by PJM.

NRDC suggests the PUC facilitate efficient registration by requiring EDCs to provide the physical and transmission system electrical location to a customer upon request in a timely manner.

CADRE recommends implementing a specialized dispute resolution process specifically for DER/Order No. 2222 issues, particularly for disputes concerning application review, interconnection, compensation, and grid reliability. They suggest a streamlined process that would disallow or limit traditional litigation tools like data requests and interrogatories to ensure rapid resolution.

PECO believes the PUC does not need to modify its processes specifically for DERA registration because adequate processes already exist under Title 52 of the Pennsylvania Code, including informal and formal proceedings under Chapters 3 and 5 (relating to Special Provision and Formal Proceedings). PECO argues that existing rules are sufficient to satisfy PJM's DERA Participation Model dispute resolution provisions.

PPL similarly believes no meaningful changes to 52 Pa. Code Chapters 1, 3, and 5 are necessary, as existing complaint and dispute procedures can handle diverse subject matters. The OCA recommends adapting the existing application process for net metering customer-generators under 52 Pa. Code Section 75.17 and existing dispute resolution regulations in Chapters 1, 3, and 5 to adjudicate disputes about DERA registration with PJM.

DLC supports the PUC's active engagement in dispute resolution for matters of state jurisdiction and notes that disputes can be minimized by establishing transparent processes for DER review and clear data requirements.

The DER Task Force emphasizes that the most effective approach is to prevent disputes through clear, consistent rules and thresholds across EDCs and states. They recommend that the PUC begin by diagnosing the core problems that will cause the majority of disputes, including common issues such as double compensation/eligibility conflicts during the initial 15-day review period and safety considerations during the 45-day review period. The DER Task Force emphasizes that EDCs must not have a "pocket veto" and should be required to act and provide data to support their claims.

EAP agrees that active PUC involvement, including both formal and informal dispute resolution, will be desirable for addressing DERA-related issues. They support using 52 Pa. Code § 75.17 (relating to Process for obtaining Commission approval of customer-generator status) as a starting point for development of a dispute resolution process but suggest that any state-based process should consider PJM's dispute resolution offerings to avoid duplication and forum shopping.

CUS proposes that adopting a DER Registry would facilitate better dispute resolution between DERAs and utilities by ensuring access to relevant information for all parties. The Registry would allow disputes to be entered by any party, routed to appropriate groups per regulatory requirements, and tracked through the entire resolution process.

Disposition

In subsection 57.266(a) the Commission is proposing to require DERAs and DER operators to attempt to resolve all disputes regarding DER interconnection and EDC actions promptly, equitably and in a good faith manner. We also note that other States in PJM are addressing dispute resolution rules through EDC pilot programs and working groups as they consider rulemakings within their jurisdictions.[18] We are persuaded to employ a balanced approach, adapting our existing processes while monitoring PJM's evolving procedures and the rules developing in other PJM States' jurisdictions for coordination. Effective dispute resolution is crucial for successful DER implementation. The PUC's regulations at Chapters 1, 3 and 5 already provide for informal and formal dispute resolutions. These three Chapters are currently undergoing regulatory review at Docket No. L-2023-3041347.[19]

The PUC's mediation unit is also available; however, it does not provide arbitration services. Nonetheless, there is a settlement judge process available in formal complaint proceedings before the Office of Administrative Law Judge.

We acknowledge that specialized procedures may ultimately be needed as integration of DERs into the electric power system necessitates increased coordination between all actors. FERC Order 2222 requires new interactions between EDCs, DERAs and RTOs. New procedures, tools, and requirements may need to be developed, and existing tools may need to be adapted. In particular, new sets of procedures and

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[18] *Interconnection Workgroup and the Implementation of FERC Order No. 2222 and Retail Grid Services in Maryland,* Case No. 9778, (Order No. 91603 issued April 11, 2025).
[19] *Regulations Governing the Public Utility Commission's General Provisions, 52 Pa. Code Chapters 1,3 and 5 (relating to Rules for Administrative Practice and Procedure; Special Provisions; and Formal Proceedings)* at Docket No. L-2023-3041347.

communications for coordination between DERs, DERAs, EDCs, and RTOs will be required.

However, as the PUC already has various types of existing methods of dispute resolution including but not limited to informal complaints, formal complaint proceedings, mediation, and settlement judge procedures, we initially will employ the existing framework to handle dispute resolution to test whether another procedure is needed as all parties gain experience. Accordingly, in the proposed subsection 57.266(b), as set forth in the Annex, we propose that the applicant may seek resolution of any disputes in accordance with Chapters 1, 3, and 5 of title 52 of the Pennsylvania Code. In addition, in the proposed subsection 57.266(c), as set forth in the Annex, we propose that an interconnection application dispute shall not affect the interconnection applicants position in the EDC's interconnection queue.

With respect to disputes related to ongoing operational coordination, and in particular with respect to overrides, we agree with PJM's proposal that such disputes arising under "any applicable tariffs, agreements, and operating procedures of the [EDC], and/or the rules and regulations of any Relevant Electric Retail Regulatory Authority, shall be addressed in accordance with applicable state or local law."[20] We disagree with parties that suggest that PJM or the IMM should resolve such disputes. The appropriate entity to adjudicate disputes regarding whether an override instruction was reasonable and appropriate to ensure the safety and reliability of the distribution system is the Commission, not PJM or the IMM.

To implement section 35.28(g)(12)(ii)(g) of FERC's regulations, in Order No. 2222, FERC required each RTO/ISO to specify in its tariff, as part of the market rules on coordination between the RTO/ISO, the distributed energy resource aggregator, and the

[20] PJM Tariff, attach. K-app., § 1.4B(f); Operating Agreement, Schedule 1, § 1.4B(f).

distribution utility, how each RTO/ISO will accommodate and incorporate voluntary RERRA involvement in coordinating the participation of aggregated distributed energy resources in RTO/ISO markets. FERC noted that possible roles and responsibilities of RERRAs in coordinating the participation of distributed energy resource aggregations in RTO/ISO markets may include, but are not limited to: developing interconnection agreements and rules; developing local rules to ensure distribution system safety and reliability, data sharing, and/or metering and telemetry requirements; overseeing distribution utility review of distributed energy resource participation in aggregations; establishing rules for multi-use applications; and resolving disputes between distributed energy resource aggregators and distribution utilities over issues such as access to individual distributed energy resource data. The FERC required that any such role for RERRAs in coordinating the participation of distributed energy resource aggregations in RTO/ISO markets be included in the RTO/ISO tariffs and developed in consultation with the RERRAs.

PJM's DER Aggregator Participation Model incorporates significant roles for State Commissions involvement. State Commissions will oversee physical interconnection of Component DER to distribution facilities, and will play a role in overseeing and settling certain disputes between DER Aggregators and EDCs. During the registration process, State Commissions will have the option to directly influence and oversee the operational relationship between the EDC, the DER Aggregator, and the Component DER. Finally, State Commissions will have the option to oversee the conditions under which an EDC may override PJM's dispatch for purposes of preserving distribution system reliability and will have exclusive jurisdiction to adjudicate disputes arising under that oversight.

We agree with PJM that Order No. 2222 identified RTO/ISO market rules as the specific barrier to entry that this exercise of jurisdiction applied to.[21] PJM contends that the legal framework adopted by the FERC in Order No. 2222 acknowledged that the FERC's authority to remediate barriers *within* its jurisdiction must simultaneously coexist with factors *outside* of its jurisdiction that may nonetheless impact participation in PJM's markets—such as distribution system operations, and RERRA rules and regulations. This PUC agrees. The roles and activities reserved for distribution utilities and RERRAs within its Order No. 2222 compliance filing are not legally cognizable "barriers to entry" as contemplated by Part II of the FPA, and they are not "aimed directly at matters in FERC's jurisdiction." We welcome further comment on the jurisdictional boundaries between the PUC and state and local authorities, especially regarding preregistration, registration, dispatch overrides, and dispute resolution.

CONCLUSION

It is imperative that all parties work diligently on developing effective and equitable coordination processes that will guide DER aggregations as PJM implements FERC Order 2222. The PUC welcomes the filing of comments by all interested parties on all aspects of these proposed regulations. To the extent that a party believes any sections of these proposed regulations need revising, we ask that alternative language be suggested. If a party believes that additional definitions are required, specific language should be proposed. A comment period of 60 days has been provided.

Accordingly, under section 501 of the Public Utility Code, 66 Pa. C.S. § 501; sections 201 and 202 of the Act of July 31, 1968, P.L. 769 No. 240, 45 P.S. §§ 1201-1202, and the regulations promulgated thereunder at 1 Pa. Code §§ 7.1, 7.2, and 7.5; section 204(b) of the Commonwealth Attorneys Act, 71 P.S. 732.204(b); section 745.5 of the Regulatory Review Act, 71 P.S. § 745.5; and section 612 of the Administrative Code

[21] Order No. 2222, 172 FERC ¶ 61,247 at P 26.

of 1929, 71 P.S. § 232, and the regulations promulgated thereunder at 4 Pa. Code §§ 7.231-7.234, we are considering adopting the proposed regulations set forth in the Annex, attached hereto; **THEREFORE,**

IT IS ORDERED:

1. That the proposed rulemaking set forth in the Annex be released for comment.

2. That a copy of this Notice of Proposed Rulemaking Order, consisting of a Preamble and an Annex, shall be posted on the Public Utility Commission's website.

3. That the Secretary shall serve this Notice of Proposed Rulemaking Order, consisting of a Preamble and an Annex, upon the Office of Consumer Advocate, the Office of Small Business Advocate, all jurisdictional electric distribution companies and all parties who filed comments in this Docket.

4. That the Law Bureau shall deliver this Notice of Proposed Rulemaking Order, consisting of a Preamble and an Annex, together with the appropriate rulemaking packet, to the Office of Attorney General for review as to form and legality and to the Governor's Budget Office for review of fiscal impact.

5. That, after receiving approvals from the Office of the Attorney General and Governor's Budget Office, the Law Bureau shall deliver this Notice of Proposed Rulemaking Order, consisting of a Preamble and an Annex, together with an appropriate rulemaking packet, for review and comment to the majority and minority chairs of the Senate Committee on Consumer Protection and Professional Licensure and to the majority and minority chairs of the House Consumer Protection, Technology, and Utilities Committee. On the same day, the Law Bureau shall deliver this Notice of Proposed Rulemaking Order, consisting of a Preamble and an Annex, together with an

appropriate rulemaking packet, to the Legislative Reference Bureau to be published in the *Pennsylvania Bulletin*. Also on the same day, the Law Bureau shall deliver this Notice of Proposed Rulemaking Order, consisting of a Preamble and an Annex, together with an appropriate rulemaking packet, to the Independent Regulatory Review Commission with proof of the other deliveries.

6. That interested persons may file written comments to this Notice of Proposed Rulemaking, consisting of a Preamble and Annex, as published in the *Pennsylvania Bulletin*, during the 60-day period following publication in the *Pennsylvania Bulletin*. The 60 days constitute the Public Comment Period. Comments filed during the Public Comment Period will be posted to the Public Utility Commission's website and forwarded by the Public Utility Commission to the majority and minority chairs of the Senate Committee on Consumer Protection and Professional Licensure and the House Consumer Protection, Technology, and Utilities Committee and to the Independent Regulatory Review Commission.

7. That interested persons may file written reply comments to this Notice of Proposed Rulemaking, consisting of a Preamble and Annex, as published in the *Pennsylvania Bulletin*, during the 90-day period following publication in the *Pennsylvania Bulletin*. Reply comments filed during the Public Comment Period will be posted to the Public Utility Commission's website and forwarded by the Public Utility Commission to the majority and minority chairs of the Senate Committee on Consumer Protection and Professional Licensure and the House Consumer Protection, Technology, and Utilities Committee and to the Independent Regulatory Review Commission.

8. That the comments and reply comments regarding this Notice of Proposed Rulemaking Order, consisting of a Preamble and Annex, may be filed electronically

through the Public Utility Commission's efiling system,[22] in which case no paper copy needs to be filed with the Secretary of the Public Utility Commission provided that the filing is less than 250 pages.[23] If you do not efile, then you are required to mail, preferably by overnight delivery, one original filing, signed and dated, with the Secretary at: Pennsylvania Public Utility Commission, Commonwealth Keystone Building 2nd Floor, 400 North Street, Harrisburg, PA 17120. Comments must reference Docket No. L-2023-3044115. All pages of filed comments and reply comments, with the exception of a cover letter, must be numbered.

9. That comments filed prior to publication of the *Notice of Proposed Rulemaking* in the *Pennsylvania Bulletin* will be considered untimely filed and may be rejected by the Pennsylvania Public Utility Commission.

10. That the contact persons for this proceeding are Joseph P. Cardinale, Jr., Esq., Law Bureau, 717-787-5558, jcardinale@pa.gov; Tiffany L. Tran, Esq., Law Bureau, 717-783-5413, tiftran@pa.gov; and Karen Thorn, Regulatory Review Assistant, Law Bureau, kathorne@pa.gov.

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[22] https://www.puc.pa.gov/efiling/default.aspx

[23] Any persons submitting a filing of 250 pages or more must mail one copy to the Secretary of the Commission.

11. That an electronic copy, in WORD® or WORD®-compatible format, of all filed submissions, comments for filings at the docket must be emailed to the contact persons and to ra-pcprgreview@pa.gov.

BY THE COMMISSION

Matthew L. Homsher
Secretary

(SEAL)

ORDER ADOPTED: December 18, 2025

ORDER ENTERED: December 18, 2025

ANNEX

TITLE 52. PUBLIC UTILITIES
*** * * * ***
CHAPTER 57. ELECTRIC SERVICE
*** * * * ***
Subchapter P. DISTRIBUTED ENERGY RESOURCES
*** * * * ***

§ 57.261. Purpose.

This subchapter sets forth the requirements that apply to DER operators, DERAs and EDCs related to DER Aggregation Resource participation in the energy, capacity, and/or ancillary services markets of PJM through its Intra-PJM Open Access Transmission Tariff, VI. Administration and Study of New Service Requests; R, OATT Attachment K – Appendix Section 1.4B, DER Aggregator Participation Model.

§ 57.262. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

Commission—The Public Utility Commission of the Commonwealth.

Component DER—Any resource that is located on an EDC distribution system, any subsystem thereof, or behind a customer meter, and is used in a DER Aggregation Resource by a DERA to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A Component DER may not exceed 5 MW.

Customer-generator—A nonutility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations, except for customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure, such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities, provided that technical rules for operating generators interconnected with facilities of an EDC, electric cooperative or municipal electric system have been promulgated by the institute of electrical and electronic engineers and the Commission.

Customer-generator facility—The equipment used by a customer-generator to generate, manage, monitor and deliver electricity to the EDC.

DER Aggregation Resource – Comprised of one or more Component DER. A DER Aggregation Resource is used by a DERA to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A DER Aggregation Resource is capable of satisfying a minimum energy and/or ancillary services market offer of 100 kW. The market participation eligibility of a DER Aggregation Resource shall be determined in accordance with the physical and operational characteristics of the underlying Component DER that comprise the DER Aggregation Resource.

DER Aggregator Participation Model—The participation model described in PJM Tariff, Attachment K-Appendix, section 1.4B.

DER Capacity Aggregation Resource—One or more DER Aggregation Resources that participates in the PJM Reliability Pricing Model, capable of satisfying a minimum capacity market offer of 100 kW, or is otherwise treated as capacity in PJM's markets, such as through a Fixed Resource Requirement Capacity Plan.

DER—Distributed energy resource— Energy resources interconnected at the distribution level. The term refers to generation resources, load sources, and energy storage resources.

DER operator – Any entity operating a DER or seeking to interconnect a DER in Pennsylvania.
DERA—Distributed energy resource aggregator—An entity that is a PJM Market Participant that:
(i) uses one or more DER Aggregation Resources to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregation Participation Model; and
(ii) has a fully-executed DER Aggregator Participation Service Agreement. A DERA must be a PJM member.

Electric distribution system—

(i) The facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from interchanges with higher voltage transmission networks that transport bulk power over longer distances. The voltage levels at which electric distribution systems operate differ among areas but generally carry less than 69 kilovolts of electricity.

(ii) Electric distribution system has the same meaning as the term Area electric power system, as defined in 3.1 of IEEE Standard 1547-2018.

EDC—Electric distribution company—A public utility providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners/operators that manage an internal distribution system which serves a building or facility and which supplies electric power and other related electric power services to occupants of that building or facility.

EGS—Electric generation supplier—

(i) A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to December 16, 2006, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission and distribution facilities of an EDC or that purchases, brokers, arranges or markets electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an EDC.

(ii) The term excludes building or facility owner/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related power services to occupants of the building or facility.

(iii) The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Chapter 74 (relating to generation choice for customers of electric cooperatives).

FERC—The Federal Energy Regulatory Commission.

MW—Megawatt—A unit of power representing 1,000,000 watts. An MW equals 1,000 kWs.

Net metering—The means of measuring the difference between the electricity supplied by an electric utility or EGS and the electricity generated by a customer-generator when any portion of the electricity generated by the alternative energy generating system is used to offset part or all of the customer-generator's requirements for electricity.

PJM – PJM Interconnection, L.L.C.—An RTO serving thirteen states, including the Commonwealth of Pennsylvania and the District of Columbia.

Retail electric customer or customer—A direct user of electric power as defined by 66 Pa.C.S. § 2803 (relating to definitions).

RPM Auction – Reliability Pricing Model Auction—the Base Residual Auction or any Incremental Auction held by PJM.

RTO—Regional transmission organization—An entity approved by the FERC that is created to operate and manage the electrical transmission grids of the member electric transmission utilities as required under FERC Order 2000, Docket No. RM99-2-000, FERC Chapter 31.089 (1999) or any successor organization approved by the FERC.

§ 57.263. General provisions.

(a) EDCs with 100,000 or more customers shall allow DER Aggregation Resource participation within their service territories under the following conditions:

(1) Customer-generators receiving service under the EDC's net metering tariff are precluded from participating as a DER Aggregator Resource in the PJM capacity and energy markets.

(2) The Component DER was approved by the EDC as part of a DER Aggregation Resource of a DERA to participate in the energy, capacity, and/or ancillary services markets of PJM through the PJM DER Aggregator Participation Model.

(b) EDCs with less than 100,000 customers, may allow DER Aggregation Resource participation within their service territories upon Commission approval.

(c) An EDC allowing DER Aggregation Resource participation within their service territory shall file a tariff with the Commission that provides for DER Aggregation Resource participation consistent with this chapter.

§ 57.264. Review of Component DER Applications.

(a) EDCs shall establish a process for receiving and reviewing requests from a DERA, DER operator or PJM for approval of a Component DER to participate in the PJM energy, capacity, and/or ancillary services markets as a DER Aggregation Resource in the PJM DER Aggregator Participation Model with the following conditions:

(1) The process must allow for electronic submission of requests.

(2) The EDC shall complete review of the request within 60 days of submission.

(3) The EDC shall describe in detail the reasons for any denial of a request.

(b) The EDC may establish a fee approved by the Commission for processing a request.

§ 57.265. Component DER Operations.

(a) EDCs shall provide DERA access to Component DER data upon consent of the DER operator in a format approved by the Commission.

(b) EDCs shall establish DER Component dispatch override procedures that include the following:

(1) A description of the conditions under which the EDC will override a dispatch request.

(2) A description of the notices to be given when a dispatch is to be overridden under the following conditions:

(i) Pre-planned maintenance.

(ii) Emergency conditions.

(iii) Other conditions established by the EDC.

(iv) Return to normal system operations.

(3) A description of when the notices will be provided under each condition as well as the method the notice will be provided to PJM, DERA and DER operator.

§ 57.266. Disputes.

(a) A party shall attempt to resolve all disputes regarding DER interconnection and EDC actions as provided in this chapter promptly, equitably and in a good faith manner.

(b) When a dispute arises, a party may seek immediate resolution through complaint and petition procedures available through the Commission.

(c) Pursuit of dispute resolution shall not affect a DER interconnection applicant with regard to consideration of an interconnection request or an interconnection applicant's position in the EDC's interconnection queue.