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January 31, 2025

Sherri L. Golden
Secretary of the Board
44 South Clinton Ave.
1st Floor
Trenton, NJ 08625-0350

Docket No. EO24020116

Dear Secretary Golden:

On behalf of the Coalition Advocating DER Regulation Efficiency ("CADRE"), I am enclosing the Post Technical Conference Comments of CADRE pursuant to the Board's directive in its Notice of Technical Conference, In the Matter of New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, issued December 13, 2024, and updated January 7, 2025.

Thank you for your consideration of these comments.

Sincerely,

Frank Lacey

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President
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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
DOCKET NO. EO24020116

POST TECHNICAL CONFERENCE COMMENTS OF THE COALITION ADVOCATING DER REGULATION EFFICIENCY

The Coalition Advocating DER Regulation Efficiency ("CADRE")[1] hereby submits these Post Technical Conference comments regarding distributed energy resources ("DER") participation in wholesale electricity markets.

Background

The Federal Energy Regulatory Commission ("FERC") issued its Order No. 2222[2] in September 2020, which, among other things, required regional transmission operators ("RTO") to remove barriers to distributed energy resources ("DER") and DER Aggregations ("DERA") participating in wholesale markets and to specifically create models that would facilitate DER and DERA participation in energy, capacity, and ancillary service markets. PJM Interconnection, LLC ("PJM"), the RTO that operates the wholesale electricity markets in New Jersey and surrounding states has been engaged in lengthy stakeholder process that has resulted in a near-final DER participation model.

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[1] CADRE is an ad hoc coalition of DER service providers including Sunnova Energy, IGS, Engie, and CPower, and also includes the Solar Energy Industries Association ("SEIA"), the Advanced Energy Management Alliance ("AEMA"), and Advanced Energy United ("United"). These comments reflect the opinions of the Coalition and not necessarily the views of any one member.

[2] Federal Energy Regulatory Commission, Order No. 2222, Final Rulemaking, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM18-9-000, 172 FERC ¶ 61,247, 18 CFR Part 35, September 17, 2020 ("Order No. 2222").

On March 7, 2024, the New Jersey Board of Public Utilities ("Board" or "NJBPU") opened this docket by issuing a Request for Information ("RFI")[3] from the Electric Distribution Companies ("EDC") and other stakeholders on the issues identified regarding the participation of DER in wholesale electricity markets. The Board received several responses to its RFI including a response from CADRE.

On December 13, 2024, the Board issued a Notice of Technical Conference seeking self-nominations for stakeholders to participate in one of three panels identified for the Technical Conference.[4] That notice was updated on January 7, 2025 to include a complete agenda, with speakers and times allocated for the different panel discussions. In that notice, the Board invited interested parties to submit comments in response to the Technical Conference by January 31, 2025. On January 17, 2025, the Board convened the Technical Conference. These comments are a follow-up to the Technical Conference.

Introduction

It is the policy of New Jersey to "Ensure that improved energy efficiency and load management practices, implemented via marketplace mechanisms or State-sponsored programs, remain part of this State's strategy to meet the long-term energy needs of New Jersey consumers"[5] DER and DERA fall squarely into this policy mandate as load management practices. As noted in our RFI response, the introduction of DER and DERA into the wholesale electricity market marks a transformational moment in electricity markets. "Implementation of

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[3] New Jersey Board of Public Utilities, Notice, In the Matter of New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, Docket EO24020116, March 7, 2024.
[4] New Jersey Board of Public Utilities, Notice of Technical Conference, In the Matter of New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, Docket No. EO24020116, December 13, 2024.
[5] N.J. Stat. § 48:3-50.

2222 is the single biggest opportunity of our lifetime for meaningful impact across the entire industry to lower cost, improve resiliency and take advantage of these new clean energy resources called DERs."[6] DER and DERA have the potential to reduce emissions, improve reliability, enhance resilience and lower costs to all electricity customers in the market, if they are allowed to flourish as FERC has envisioned. DER has been called "a mammoth opportunity for our industry – not a burden."[7]

This specific docket is about developing policies to support DER participation in regional wholesale electricity markets. In other words, the docket is investigating the implementation of a federal energy market program. Although such a program has state (retail) implications, the policies evolving from this docket should be limited to retail components required for effective implementation of DER products and services into the PJM wholesale electricity market.

CADRE supports the Board taking action to implement retail DER programs as well, but that is a different issue that should be considered in a different docket. These comments will make some recommendations regarding some state issues that logically fall outside of the parameters of this docket. We encourage the Board to issue guidance in this docket that will begin the stakeholder processes on those retail issues. Our goal is to see that FERC Order No. 2222 is implemented in a manner that welcomes more competition and benefits customers to the greatest extent possible.

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[6] See: www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/DR-DER-Aggregation/DR-DER-Aggregation-CUS-Presentation-2-22-24.pdf?rev=e5e9dd35cf99499896021c10b1b5e293&hash=E7F43CFA1D29132C622BC5397FB2C720, p. 6. (Internal quotations omitted.) CUS is a non-profit 501(c)6 organization that was created to advance and support the electric industry by developing, enhancing access to, and enabling data and technology regarding DERs to support a clean energy future.

[7] *Id*., p. 3.

In the evolution of our Coalition, CADRE has developed a set of best practices for states working to implement FERC Order No. 2222. CADRE presented 14 best practices at the Technical Conference. These comments are formatted around those best practices, but also address comments made by some of the panelists and how those comments either support or conflict with these best practices. These comments also address cybersecurity issues, which were raised at the Technical Conference.

Best Practices for DER Regulation

1. Define DER and DERA

DER, DERA, and DER Aggregators are new wholesale market participants, enabled by FERC Order No. 2222. DERs are not Third Party Suppliers ("TPS"), demand response providers, BGS Suppliers, or any other service provider defined in NJ energy regulations. There is currently no avenue for the Board to establish any jurisdiction over DERs and DERAs. Establishing definitions would create a new type of New Jersey jurisdictional entity.

We recommend the following definitions, which are modeled after the definitions implemented by FERC, be incorporated into New Jersey's electricity market regulations:

- **Component Distributed Energy Resource** – any one distributed energy resource that is a part of a Distributed Energy Resource Aggregation.
- **Distributed Energy Resource** -- any electric resource located on the distribution system, any subsystem thereof or behind a customer meter.
- **Distributed Energy Resource Aggregation** -- a group of one or more DER that are joined together for the purpose of participation in the capacity, energy and/or ancillary service markets of the regional transmission organization and/or independent system operator.
- **Distributed Energy Resource Aggregator** – an entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organization and/or independent system operator.

DER and DERA are federally regulated, wholesale electricity market entities and need to interact with the EDCs to facilitate service to customers. The Board should focus on the interactions between the EDCs and the DER aggregators as it develops policies to implement FERC Order No. 2222.

2. Licensing of DER Aggregators

It could be appropriate for the Board to initiate a licensing process for DER aggregators. The threshold for licensing should be technical fitness to engage with and manage data from the EDCs in a manner consistent with standard business practices. DER aggregators will need to interact with the EDCs to provide safe and reliable service to PJM. This includes, at a minimum, communications regarding DER registrations, historic energy usage, dispatch signals and dispatch overrides, and real-time meter data feeds from the EDC. DERA licensing could be the threshold requirement to engage in automated metering and customer-related data transfers and other interactions between the DER aggregators and the EDCs. Ownership of a DER aggregator license could also be a pre-requisite to engage in the Board's dispute resolution process with an EDC.

The Board need not be over-zealous on aggregator licensing requirements. DER aggregators will need to be members of PJM. In order to become a PJM member, they will need to pass certain technical and financial fitness thresholds that are federally regulated and implemented through PJM's tariff and other approved documents. They also carry financial burdens in the form of minimum capitalization requirements, credit requirements and bear default risk of other PJM members. The Board should not impose any financial requirements on DER aggregators beyond the administrative fees required to process the licensing application.

3. Recognize the State/Federal Jurisdictional Boundaries

Recognition of jurisdictional boundaries will be one of the most challenging aspects for the Board during this process. The interactions between the aggregators and the EDCs need to be governed by the Board. As the Board contemplates what it should do to facilitate effective implementation of FERC Order No. 2222, it should be thinking in terms of what it should require of the EDCs that would best facilitate the program. These include tasks like streamlined interconnection processes, economic interconnection processes, real-time meter data access, transparent registration requirements and process and transparent dispatch override criteria. All of these are discussed in more detail below. The onus of effective implementation should be on the EDCs. They are the parties who could stand in the way of efficient implementation of FERC Order No. 2222.

It was stated during the Technical Conference that the Board should regulate DER aggregators similarly to the way Third-Party Suppliers ("TPS") are regulated. For many reasons, that would be inappropriate. First, there are jurisdictional issues. DER aggregators do not have to be a TPS. In fact, other than the EDC interface, there is nothing that makes DER participation in wholesale markets a retail service. It is quite possible that thousands of homes with controllable thermostats are already participating in PJM's wholesale market demand response program without any interaction with the Board. The thermostats could have been purchased at a big box store and an aggregator could be working with the thermostat manufacturer to gather customer data to offer demand response services. These are the types of services that the Board would traditionally regulate if they were provided by a retail energy TPS. That is not the case with DERs participating in federally regulated wholesale energy markets.

In addition to the jurisdictional issues, TPS-like regulation will render the market futile. TPS regulations were designed in an era when electrons moved in one direction, from the power plants, across the wires and into a home or business. The products delivered are kWh and kW. Under FERC Order No. 2222, energy flows will move in both directions across a meter. Aggregators can be creative with evolving technologies like EV charging, storage injections, premise-level energy management, time-varying prices and resilience services.

As discussed at the Technical Conference, the end user, who we normally think of as the customer, is actually the supplier in a DER aggregation. That end user is providing energy (either avoided or injected), capacity and potentially ancillary services to the aggregator, which in turn sells those services to PJM. PJM pays the aggregator who then pays the end users for their services. With all the potential DER technologies and all the potential products, it would not make sense for the Board to attempt to regulate aggregators like TPSs, even if they could.

In the context of this docket, the customer/aggregator interactions and the aggregators' interface and interaction with PJM are wholesale market functions and thus, cannot be regulated by the Board. As discussed later, CADRE encourages the Board to require the EDCs to implement retail focused distribution level aggregations to relieve distribution level constraints. The use of these resources will allow the EDCs to forego or at least delay capital expenditures and will reduce distribution costs for customers. When the Board implements those programs, they would be fully state jurisdictional. In this docket, however, the Board should focus on managing the EDCs.

4. Interconnection

CADRE believes that interconnection costs should either be socialized or a fixed $/kW charge that is embedded in the EDCs' tariffs. Traditional interconnection cost allocation methodologies usually require the interconnecting resource to pay for the system upgrade costs. Similarly, if an interconnecting customer does not require an upgrade, it is not assigned any direct costs. This approach misaligns incentive structures for developers and utilities. Specifically, this provides a first-mover disadvantage for some DER while allowing others to become free-riders, paying little to nothing for their costs on the distribution system. At the same time, this allocation methodology limits the EDCs' ability to plan and deploy investments to increase or maximize utilization of existing hosting capacity.

CADRE believes that either tariff-based charges fixed to a $/kW charge or socialized interconnection across all distribution customers is in line with current statewide energy policy. According to the New Jersey Energy Master Plan, "Allowing for bi-directional flow increases the amount of DERs that can be interconnected at that location when the infrastructure is in place to handle the changing demand and generation profiles. While each electric public utility distribution system is unique, utilities are fully expected to meet these future needs by adopting a potentially standardized and coordinated approach to maximizing distribution level flexibility and replacing grid infrastructure that is not designed for the modern grid. These grid modernization costs should be included in future rate filings."[8]

Including defined tariff costs for interconnections provide many benefits to the market, including:

- **A fair and competitive interconnection process.** This will allow all developers and customers to understand exactly the costs before engaging with a project. In many instances today, developers and customers begin the process of investigating an investment in DER technologies, which includes financial modeling, potentially seeking site permits or engaging in other processes, only to find out, after the interconnection application is processed,

[8] 2019 New Jersey Energy Master Plan, p. 178.

that the utility's interconnection costs are prohibitive. The process today is untenable and will not ever produce a robust DER market.

- **Eliminates first mover advantages and/or disadvantages.** In today's market, it is quite possible that a first mover is saddled with significant interconnection costs, only to learn that their next-door neighbor can interconnect for free because of the upgrades paid for by the first customer. The opposite could also happen where the first mover interconnected at no cost, pushing all of the upgrade costs to the neighbor. This is neither fair nor efficient. A pre-defined fee structure for interconnection costs will allow all customers to be treated the same.
- **Speeds interconnection process.** Because costs are known up front, a developer will know exactly what is required to interconnect to the distribution grid. This should ease the burden on utilities because projects that are uneconomic will not ever need to be reviewed by the EDC. A comprehensive economic evaluation can and will be performed before the project is submitted to the EDC.

CADRE also believes that the interconnection processes should be automated, streamlined and have defined utility response times at every step of the process. The Board should require EDCs to provide automated platforms for interconnection requests that include built-in application error checking, options for e-signatures, options for electronic payment, online scheduling for inspections or remote inspections, online updates on application status, and online notice that the resource owner has permission to operate ("PTO"). The Board should also require that PTO timelines be capped (for example, 30 days after the application date). For residential interconnections, if the EDC fails to respond within the set period, the customer seeking interconnection should be deemed to have PTO.

In addition, EDCs should be required to refund customers or pay fines – not recoverable from ratepayers – to the Board for the EDCs failure to meet interconnection timeline requirements. These fines could be distributed by the Board to affected customers or to support other need-based customers. Colorado has implemented a policy to refund customers up to 100% of the cost of the interconnection application if the utility does not meet stated timelines. The methodology for the refund calculation is a two-step process:

> First, the [utility] shall begin calculating refunds owed to interconnection customers immediately after the total allowed time for processing an interconnection application. The rate for the refunds is four percent of the application fee, adding on a daily basis. Applying this methodology, for Level 1 applications, the Company will owe interconnection customers a 20 percent refund after five business days of delay beyond the total allowed time for the application, leading to a full refund of the entire application fee after 25 business days of interconnection delay beyond the total allowed time for the application. The refund amount is capped at 100 percent of the original application fee of the customer. However, … for administrative efficiency, the Company will not provide any refunds that are for less than $25. [9]
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> The second part of the calculation is to apply interest at the company's authorized weighted average cost of capital. Interest accrues if the company fails to the meet the stated timelines and accrues back to day 1 of the application process.[10]

Finally, interconnection processes should be the same across all EDCs. Costs do not need to be the same across EDCs. However, costs should be pre-determined and tariff-based at each EDC. Interconnection processes should all be the same. Timelines should be the same. Penalties for non-performance should be the same.

5. Distribution Level Benefits

CADRE urges the Board to consider the benefits to the distribution system that DER and DERA can provide. These benefits can be realized from DERA that have been developed for use in the wholesale market or from DERA that the Board authorized the EDCs to develop. Just as DER and DERA can relieve transmission level constraints and mitigate wholesale energy prices, they can provide the same value to the distribution grid. DER and DERA can be used as non-

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[9] Unanimous Comprehensive Settlement Agreement, In the Matter of Advice Letter No. 1921 Electric Filed by Public Service Company of Colorado PUC No. 8-Electric Tariff to Implement Its Interconnection Tariff Effective July 31, 2023, Public Utilities Commission of the State of Colorado, Proceeding No. 23AL-0188E, October 26, 2023, pp. 3-4.

[10] Id. p. 4.

wires alternatives to relieve constraints and avoid, or at least delay, capital spending on the distribution grid, providing savings to all customers. The Board should mandate that the EDCs deploy DER and DER aggregations in retail programs to maximize the benefit of the DER resources already available to the EDCs.

We have argued above that this is not the docket in which the Board should pursue retail issues. What we seek with presenting this best practice in this docket is to make the Board aware that additional value streams exist and request that the Board open a retail DER docket that will compel the EDCs to design and implement retail DER programs.

6. Cost Allocation

Electricity markets are changing in ways not imaginable a decade ago. The distribution grid must grow and evolve to support modern grid needs. Implementation of FERC Order No. 2222 is just one of many transformational developments that will be dependent on an evolving electric grid. In addition, the grid will need to support EV charging, general electrification initiatives, storage injections and withdrawals, intermittent renewable resources, net energy metering resources, distribution level DER aggregations, and other new and perhaps yet unknown technologies. The state realized that these changes were imminent when drafting the 2019 Energy Master plan, which states, "The state should direct the electric public utilities to develop plans that integrate grid modernization and capacity improvements that support demand growth from electrification, demand flexibility, DER penetration, grid resilience, and grid efficiency."[11]

[11] 2019 New Jersey Energy Master Plan p. 176.

Customers will benefit from grid evolution and implementation of these new technologies. Allocating costs to individual customers creates first mover disadvantages, slowing grid evolution. Traditional distribution allocation approaches will continue to provide value to all customers. DERs participating in wholesale markets will reduce energy, capacity and ancillary services costs for all customers, which will offset some of the grid upgrades required to support all of the above-mentioned technologies. DER technologies are some of the few that will exert downward price pressure on energy prices. Given this potential, the Board should require the EDCs to move swiftly in their Order No. 2222 implementation projects.

7. Double Compensation

CADRE supports restrictions on double compensation. However, providing two or more services is fundamentally different from being compensated multiple times for the same service. It is imperative that the Board understands fully what constitutes double compensation and what does not because ultimately, the determination of double compensation falls to the Board.

DER and DERA can provide multiple services at the same time. Compensating a DER or DERA for provision of multiple services provided at the same time does not constitute double compensation. One only has to investigate the wholesale and retail demand response programs in New York to understand what is meant by providing multiple services at the same time. ConEd, the utility for New York City and some of its suburbs offers two demand response programs. The NYISO offers one other. The NYISO program is used to manage the statewide grid and transmission constraints on that grid. The ConEd programs, focused on the New York City area, are called the Distribution Load Relief Program ("DLRP") and the Commercial System Relief Program ("CSRP"). The CSRP program is targeted at minimizing capacity costs for the customers. It is triggered when the projected load reaches certain levels relative to the forecast annual peak. It is essentially a peak load management program. DLRP on the other hand, is an emergency program that can be called on relatively short notice to reduce load on the distribution network. Its intent is to relieve distribution level constraints. It is possible, and in fact, happens with some regularity, that all three of these programs can be called at the same time. When this happens, the participating customers curtail their electricity consumption and provide different values to the CSRP, DLRP and NYISO programs. Under CSRP, the customer is mitigating the peak which will reduce the following year's capacity obligations. Under DLRP, the customer is taking load off the distribution grid to avoid a distribution problem. Under the NYISO program, the customer is providing relief to the transmission grid. Each of these programs obligates the customer contractually to curtail load when called, which provides electricity back to the grid, for which the customer is compensated. If a customer is curtailed under all three programs at the same time, it is compensated under the terms of the respective contracts, however, it is not possible to send three times the energy back to grid during a curtailment event. In this scenario, the customer is compensated only once for energy despite dispatching in multiple programs simultaneously. The Board should develop programs that will capitalize on DER and DER aggregations that will allow the EDCs to manage peak loads and alleviate distribution constraints and compensate those aggregations for the services provided, while still preventing double compensation as described in the New York programs.

Wholesale and retail services provide different benefits to different constituencies. The Board should expressly allow and encourage the provision of multiple services from DERs and DER Aggregations.

8. Metering

The Board should enable, but not require, device level metering on component DER within an aggregation. Device-level metering is required to obtain optimal performance from DER and DER Aggregations, specifically those Component DER resources co-located behind a net energy meter ("NEM"). Under PJM's proposals in its Order No. 2222 compliance docket, all component DER that are located behind the meter at the NEM property, including storage and other potential demand response assets are included in PJM's prohibition against double compensation.[12] In its Order on PJM's compliance filing, FERC accepted PJM's metering requirements, which do not require device-level metering, but in doing so, FERC encouraged PJM to work with stakeholders to develop device-level metering solutions.[13] One of the constraints for device-level metering is the EDCs' inability to process device-level metering data.[14] The Board should compel the EDCs to establish systems that can accept and process device-level metering data in a manner that will provide DERAs and PJM with requisite data to support Component DER located behind NEM meters participation in PJM's electricity markets to the extent possible without violating any restrictions on double compensation.

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[12] *Id*., pp. 29, 39. See also: Second Compliance filing of PJM Interconnection L.L.C., Docket No. ER22-962. September 1, 2023, p. 16 ("PJM Second Compliance Filing").

[13] See: FERC Order on Compliance Filing, PJM Interconnection, L.L.C., Docket No. ER22-962-000, ¶ 250. "We find that PJM has demonstrated that its proposed metering requirements do not pose an unnecessary and undue barrier to distributed energy resources, as Order No. 2222 requires, with the narrow exception discussed further above. However, we encourage PJM to continue to work with its stakeholders to consider additional metering options in the future, including for DER Aggregation Resources to utilize device-level meter data."

[14] See: Comments and Request for Second Compliance Filing of the Indicated PJM Utilities Addressing PJM Order No. 2222 Compliance Filing, *"While the EDCs have proposed use of the retail metering point or Point of Interconnection ("POI") to be the point where wholesale market participation is determined, in cases where DER Aggregation impacts the POI meter data or affects retail billing/submetering at a customer location may be needed so as to participate in the wholesale programs. Significant time and expense will be required to facilitate system changes to settle the market and maintain the retail billing processes."* (pp. 27-28) and "*There must be a deliberate approach to metering requirements, which greatly impact EDC operations."* (page 33), FERC Docket No. ER22-962-000, September 1, 2023.

Device level metering is manufactured into and available in most, if not all, modern inverters, storage resources, and EVs and can also be implemented on other load management resources quite easily. The Board should require the EDCs to receive and process device level metering in addition to their current meter reading functions. If the EDCs processed device-level meter data, PJM could validate a resource's contribution to the grid, outside of the NEM component resource. Alternatively, the Board could define criteria to approve device level meters for revenue-grade and settlement purposes and the aggregators can supply device level data directly to PJM. PJM can process device level data and will accept device level data for certain demand response products. In either scenario, leadership from the Board will be required to enhance current practices.

To be clear, the Board should not require device level metering for all Component DERs. That would be inappropriate as many DERs are singular resources located behind a single meter (e.g., controllable thermostats) and meter data from the EDC's existing meters is adequate to provide accurate measurement and verification of DER dispatch. However, device level metering plays a core role in developing advanced products and services and also allowing participation from DER co-located with NEM resources.

Additionally, CADRE does not believe that device-level metering in any way alleviates the requirement for streamlined, secure access to AMI data as outlined in our section on Data Access below (Best Practice Section 9).

9. EDI Upgrades

Real-time data access is needed as the grid evolves to support modern technologies and energy products, including those envisioned under FERC Order No. 2222. CADRE understands that the Board has begun an investigation into the establishment of AMI meter data access standards.[15] In the context of that proceeding, we urge the Board to consider the needs of the DER aggregators to most efficiently integrate DERs into the wholesale energy market. The data needs are robust and unlike traditional data needs from TPSs and other service providers to understand historic usage, DER integration will require real-time and consistent data feeds to ensure that they are making the most efficient market decisions on an hour-to-hour basis. CADRE urges the Board to complete its investigation in that docket and require the EDCs to fully implement its recommendations before the PJM market opens to DERs and DERAs.

FERC Order 2222 is intended to remove barriers to DER participation in wholesale electricity markets, yet existing utility processes and data access limitations present significant challenges to implementation. The EDCs should be prepared for the number of data transactions to increase exponentially. Unlike the historic usage information needed by TPSs to design products and prices for retail electricity customers, DERA will require real-time data to manage electric load in real-time. As intermittent energy resources expand and DERs become more important to balancing the grid, the timeliness of data will increase in importance. DER aggregators will need near real-time data to ensure compliance with PJM dispatch signals and to optimize DER portfolio value for the consumers.

CADRE believes that ensuring proactive, standardized data access is critical for efficient FERC Order 2222 implementation. Without improvements in data sharing and process automation, many DER aggregators will face significant hurdles in obtaining key information necessary for participation, leading to delays, application errors, and disputes between utilities, aggregators, and PJM.

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[15] In the Matter of a Rulemaking Proceeding to Establish AMI Data Access Standards, Docket No. EX24090717

The Board should require EDCs to integrate key registration parameters within the Green Button Connect ("GBC") framework. GBC is already mandated under New Jersey's proposed AMI regulations for interval usage data access. However, its benefits can extend far beyond basic data sharing. By embedding critical registration parameters – including pNode[16] assignments, interconnection constraints, and dual participation status – directly within GBC, aggregators can pre-screen sites for eligibility before submitting registrations. This will reduce the administrative workload for both utilities and DER providers.

Additionally, digital Letters of Authorization (LOAs) through a standard, authenticated consent process should replace manual review processes to ensure secure, auditable, and automated data exchange between customers, utilities, and aggregators. The current reliance on manual uploads and delayed verification processes creates timing and revenue uncertainty for DER aggregators and can lead to disputes over data accuracy.

When looking at the settlement process, the Board should require EDCs to provide batch AMI data feeds for registered DER sites via their Green Button Connect platforms through an automated process to both the relevant DERA and PJM concurrently. This process should include two data feeds: one for raw AMI data available as soon as feasibly available (typically less than 24 hours) and one for settlement quality data that has been processed by the EDCs' meter data management system (typically available within 72 hours). Automating these data flows, while ensuring raw data is available within 24 hours, would create a single source of truth that reduces settlement disputes and enhances market confidence.

[16] As noted by PJM at the Technical Conference, PJM does not have the capability to link addresses to pNodes. These are determined by the distribution grid and changes to the grid can change the pNode serving a particular address.

To summarize, CADRE urges the Board to mandate specific improvements in four key areas:

1. Automated qualification and registration processes that provide aggregators access to essential data (e.g., pNode, transmission zone, dual participation status) through GBC;
2. Digital LOA validation systems via GBC to replace paper-based authorizations;
3. Consistent and timely settlement data access, ensuring revenue-quality interval data is available within PJM's 24-hour settlement window; and
4. Requiring utilities to provide both raw and settlement quality AMI data to ensure that there is a balance between timeliness (raw data) and accuracy (settlement quality data) while meeting PJM settlement requirements.

These specific measures can be implemented in market ready Green Button Connect platforms. We believe that green button connect should be viewed as a foundational technology platform for enabling FERC Order No. 2222 implementation.

Data access should be a streamlined process, consistent with the digital economy of 2025. This process should be the same across all of the EDCs and the data elements should similarly be the same across all of the EDCs. The data should be readily accessible by customers and/or their agents in a reliable, timely, and consistently useful structure. These changes will significantly reduce administrative burdens, accelerate market participation, and lower costs for all stakeholders while ensuring the smooth implementation of Order 2222 that New Jersey seeks to achieve.

Finally, EDCs should not be permitted to charge a fee to the customer or to the third party with whom the customer wishes to share their AMI data, including DER aggregators, TPSs or any other energy services company. As noted above, this data is required for optimal access to the wholesale electricity market which results in lower energy costs for all ratepayers. Enhanced data access practices are consistent with the needs of an evolving distribution network. As these costs benefit all consumers, they should be included in base rates or AMI riders applicable to all customers.

10. Dispute Resolution

FERC Order No. 2222 requires the RTO/ISOs to include dispute resolution provisions in their tariffs.[17] However, these provisions are limited to issues that fall within the RTO/ISO's tariff. PJM's dispute resolution process will not address issues that PJM determines "solely concern the application of any applicable tariffs, agreements, and operating procedures of the Electric Distribution Company, and/or the rules and regulations of any Relevant Electric Retail Regulatory Authority."[18] To the extent a tariff dispute arises, for example, about the interconnection of a DER, a delay in the registration process or some other "local" matter, the dispute must be resolved at the state level quickly. The Commission should implement a dispute resolution process specifically to address DER/Order No. 2222 issues, especially for disputes concerning application review, interconnection, compensation, and grid reliability issues.

FERC requires the EDCs to review interconnection applications for aggregations within 60 days. FERC requires this timeline because the Component DER in an aggregation have already been through the interconnection process and reviewed by the utilities. The 60-day limit is to review the impact of these assets being aggregated and dispatched. PJM will monitor the applications. However, any complaint by an aggregator, either regarding the timeline or rejection of an application that is perceived to be incorrect, will need to go to the Board for resolution.

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[17] Order No. 2222, ¶ 292.
[18] PJM Compliance filing. 9-1-23, page 54.

PJM is also unable to verify whether an asset is receiving compensation for a wholesale service in a retail tariff, therefore that responsibility remains with the EDC. Similarly, the Board should be prepared to adjudicate over disputes between aggregators and EDCs over tariffs and whether assets are or are not compensated for a service in the retail tariff.

CADRE cannot foretell the full extent of potential disputes between DERAs and the EDCs. We can predict that there will be disputes. When a dispute arises, it should not be left to be a matter of EDC discretion. The market will need meaningful Board oversight on these matters. A streamlined dispute resolution process will provide a useful tool that will enable the Board to respond to and resolve disputes in a timely and efficient manner.

We envision that when disputes arise, they are likely to be a result of an interpretation of rules rather than disputed facts. Accordingly, most disputes will not rise to the level of a "contested proceeding." The streamlined dispute resolution process should disallow, or allow only in limited cases, data requests, interrogatories, testimony, and other tools typically reserved for use in contested litigations. Customers will be investing large sums of money in DER. Customers will be looking for rapid resolution of disputes. Needless delays in getting timely resolution on issues of interpretation are a business deterrent and will stifle investments in DER. A disciplined and streamlined dispute resolution process will enhance the DER market and should be implemented by the Board.

A clear least regrets requirement to minimize disputes will be for EDCs to provide consistent and timely data to both the DERA and PJM through a common, secure, and auditable platform. See Best Practice Section 9, above, for more details on how this could be realized through the AMI rulemaking.

11. EDC Dispatch Overrides

EDC override guidelines must be transparent, and overrides should be communicated to the Board, the Aggregator and PJM. FERC has given the EDCs a significant amount of authority in Order No. 2222. Notably, FERC allows the EDCs to override a PJM dispatch of DERs and DER aggregations[19] in circumstances where such an override is needed to maintain the reliability and safe operation of the distribution system.[20] CADRE accepts this authority but believes that the EDC should not ever be granted direct control over a DER or a DER aggregation participating in wholesale electricity markets. Dispatch overrides should be communicated to the DER aggregator which will, in turn, execute the override. EDC overrides of a DER dispatch should only be ordered in the case of a reliability emergency that would be caused by the dispatch. EDC dispatch overrides will be costly to consumers and DER service providers. PJM provides no monetary relief from non-compliance in the case of an EDC override of a dispatch order. As such, override rules and processes to justify a dispatch override should be well defined and completely transparent to DER aggregators.

In every instance of an override, the EDC should communicate directly to PJM, the DER aggregator, and the Board. We believe the Board should be apprised in real-time of any potential threat to the distribution grid and that is what is required to trigger an EDC override of a PJM dispatch order. Action is required from the Board to ensure data flow occurs between EDCs and DER aggregators, PJM and the Board, particularly when it comes to the EDC overriding a DER dispatch.

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[19] Order No. 2222, ¶ 310.

[20] Order No. 2222, Para 310.

Order No. 2222 also requires communication between the EDC and the DERA in cases of an outage on the distribution system – either planned or unexpected. As PJM does not regulate the EDCs, PJM cannot require or specify information flow from the EDCs to DER Service Providers. These requirements must come from the Board.

CADRE suggests that the Board be prepared to work with the EDCs and DERAs, with representatives from customers hosting the DER, to determine the requirements for information that will be shared and processes to do so. At a minimum, the Board should define: 1) clear criteria that define reliable and safe operations and justify an EDC override; 2) procedures for advance notification of an outage to DERAs and DER owners/operators; and 3) after the fact justification review.

Finally, because PJM does not provide relief to a DER aggregation that is dispatched, but over-ridden by EDC, if an EDC override is found to impose unnecessary costs (the override was not necessary) on DERA, the EDC should be responsible for those costs. Those costs should not be recoverable in distribution rates.

12. EDCs acting as DERAs

In restructured energy markets, EDCs should leverage third-party providers to operate DERAs in competitive wholesale energy markets. In New Jersey, "An electric public utility or a related competitive business segment of an electric public utility shall not offer any competitive service to retail customers within this State without the prior express written approval of the board."[21] DER and DERA participation in the PJM wholesale electricity markets is a competitive service. While CADRE stridently urges the Board to have the EDCs implement

[21] N.J. Stat. § 48:3-55, https://law.justia.com/codes/new-jersey/title-48/section-48-3-55/

retail (state-jurisdictional) DER programs (See Best Practice Section 5 above), we similarly urge caution in allowing EDCs to bring rate regulated aggregations to the competitive wholesale market without leveraging third-party providers as the market intermediary.

It is also the policy of the state to "Ensure that rates for non-competitive public utility services do not subsidize the provision of competitive services by public utilities."[22] While New Jersey has not addressed DER and DERA comprehensively, there is no doubt that DER aggregations participating in wholesale markets are competitive services and are not part of the natural monopoly function of either transmission or distribution.

Finally, an EDC might be in a situation where it would have to override an aggregation dispatch, which could put it in a situation where it had to decide to override the dispatch of its own aggregation or the dispatch of an Aggregator. That conflict puts burdens on a utility that would need to be resolved in a transparent manner, approved by the Board. If the EDC must override their own aggregation dispatch and penalties from PJM are assessed, the EDC would be inclined to seek recovery of those costs from ratepayers.

If the Board is inclined to allow EDCs to be wholesale market participants, it should institute penalties for discriminatory behavior against DERAs. It should also require that all risk of market participation is borne by shareholders, not ratepayers, and it must not allow ratepayers to subsidize their market participation in any way. Otherwise, the disparity in risk exposure could minimize competition in the aggregation market to the detriment of all customers in the

[22] N.J. Stat. § 48:3-50.

market. To the extent that EDCs are allowed to participate in the wholesale energy market, EDCs should leverage third-party providers for their wholesale market operations.

13. Billing

As noted above, the entity that is normally considered the customer is actually a provider or seller of services in DER markets. Customers can provide energy, capacity and ancillary services to the grid. Today, the Board does not have jurisdiction over providers of wholesale demand response services in the state. In the demand response market, the monetary benefit flows from PJM to the aggregator and then to the customer. DER aggregation markets will work the same way.

With this in mind, we urge the Board to evaluate the billing requirements placed on TPSs providing DER services. The Board should consider what types of products and services it has sought from TPS over time and understand what is required to provide an informative bill to the customer. Specifically, mandates that bills be issued in fixed kW and kWh charges and on certain dates with defined charts and tables should be waived when TPSs are providing DER services.

CADRE believes that the Board should allow and encourage billing and product flexibility. It should be mindful that if a DER product cannot be billed appropriately, it cannot be sold to a customer. The breadth of potential product offerings is vast and limited only by regulations – be it billing, or metering or some other constraint.

DER activities are complex with bi-directional flows of electricity. The billing units might be non-standard, for example, a DER customer might be offered a flat rate of $20 per month for EV charging between the hours of 8:00 PM and 5:00 AM but might have disincentive charging rates of $0.20 - $0.30 per kWh in the summer months between the hours of 2:00 PM and 8:00 PM (the hours likely to be used by PJM to determine capacity obligations). Charging in other hours might be at a standard retail "per kWh" rate, or possibly not. (Product innovation is further enabled by device-level metering.) The DER might be able to provide energy to the grid for an hour in the morning at $0.15 cents per kWh and then again in the afternoon for $0.20 per kWh. Load curtailment at the thermostat might result in the provider paying the customer $5.00 per month, but the associated energy and capacity revenues accrue to the DERA. The DER contract might allow for the customer to keep 50% of ancillary service revenues and 100% of energy revenues earned from energy injections across a billing cycle. The iterations are almost unlimited. They do not fit in the format of a standard utility bill, the concepts of which were designed several decades ago.

Shown below is an electric bill rendered to a customer in Texas participating in a DER pilot aggregation program. This invoice is notable in several regards. First, it does have some fixed $/kWh units billed. It also shows variable $/kWh units billed for energy sold back to the market. The variable priced "revenue" units are tied back to a table that is referenced, but not shown on the invoice. It also includes a large negative lump sum of $40.00 for Virtual Power Plant Credits. It includes the charges from the distribution utility and taxes. All of these charges, when netted, sum to a negative $13.14 monthly invoice, with an accrued balance due to the customer of over $700.

TESLA ELECTRIC

Tesla Energy Ventures, LLC REP #10296
13101 Harold Green Dr.
Austin TX, 78725, United States
PUCT Certificate #10296

Invoice Number	[redacted]
Invoice Date	Feb 20, 2024
Bill Period	Jan 16, 2024 - Feb 14, 2024
Payment Due By	Mar 7, 2024

Sold To

[redacted]

Account Number	[redacted]
ESI ID Number	[redacted]
Meter ID	[redacted]
Contract Exp. Date	Month-to-Month

Monthly Statement

Your average cost of electricity: -$0.036 / kWh

Current Charges	Qty	Rate	Amount
Tesla Electric Charges			**$28.16**
Peak	2.715 kWh	$0.124 / kWh	$0.34
Off-Peak	361.332 kWh	$0.077 / kWh	$27.82
Tesla Electric Sellback Credits			**-$25.35**
Real-time Energy Sold	445.009 kWh	Market Price (See Rate Table)	-$25.35
Tesla Virtual Power Plant			**-$40.00**
VPP Credits			-$40.00
TDSP Charges			**$23.96**
Base Charge	1	$4.39	$4.39
Home Energy Delivery Charge	364.047 kWh	$0.0538 / kWh	$19.57
Taxes			**$0.09**
PUCA			$0.09
Total Current Charges			**-$13.14**
Balance Forward			-$691.45
Total Amount Due			**$0.00**
Excess Sellback Credit Rollover			$704.59

With appropriate billing and product flexibility, it is possible that customers receive a negative retail electricity bill. These are products and end results that regulators have been seeking since the advent of restructuring. We encourage the Board to allow billing and product flexibility for all entities providing DER services.

14. Equity

CADRE understands equity concerns and believes that the savings from reduced energy costs will more than offset any increases in distribution costs attributable to DER integration. In fact, if the wholesale aggregations were used by the EDCs in a thoughtful and productive manner, as described in the Distribution Level Benefits section, they could result in downward pressure on distribution rates also. By deploying DER and DER aggregations under state retail programs, EDCs may be able to delay and/or avoid distribution upgrades.[23]

Additionally, there is no reason that lower-income customers would not be able to participate in DER aggregations. DERs do not necessarily require costly investments. A participant can join an aggregation of controllable thermostats, or other home devices. Also, under the appropriate interconnection, ownership, and contracting structures, lower-income customers could install storage devices and/or rooftop solar. CADRE believes that DER and DER aggregations are very attainable and beneficial to low-income customers. To the extent the Board thinks the market is not responding appropriately to that market, it could enable programs, and potentially an EDC sponsored program, to provide greater support to lower-income customers who desire to participate in DER markets, but are not finding market alternatives.

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[23] See, for example: Mims Frick, Natalie, Snuller Price, Lisa Schwartz, Nichole Hanus, and Ben Shapiro, *Locational Value of Distributed Energy Resources,* Lawrence Berkely National Laboratory, February 2021. Found at: https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

DERs will result in lower emissions, lower prices and provide increased reliability to all customers, including non-participants. Equity advocates in New Jersey should fully embrace the proliferation of DERs.

15. Cybersecurity

CADRE did not address cybersecurity in its best practices at the Technical Conference. The topic was raised however, and CADRE is now working on developing a more formal best practice for this topic. Repeating what was said at the Technical Conference, CADRE does not believe the Board needs to implement cybersecurity standards that are specific to DER and DERA participation in the wholesale electricity market. If the Board chooses to implement requirements, those requirements should be based on technological standards or protocols that are common to industry in 2025. The Board should not require implementation of any specific technology or mandate compliance to a certain rule as it is a near certainty that technologies and protocols for cybersecurity will evolve at a rate that is much faster than which a regulatory process can keep pace.

CADRE believes that given a modern data access platform, cybersecurity risk is relatively low for the EDCs and their customers. For instance, we are not aware of any known cybersecurity breaches in states like California or New York, where data access platforms have supported market aggregation and retail programs for many years. Accordingly, EDCs should appropriately size their cybersecurity requirements to the relevant context.

CADRE is aware of potential security guidelines which could be implemented for EDCs and those who access customer data from the EDCs. These include:

- AICPA SOC II and Green Button Alliance certification;
- Utilize OAuth 2.0 and OpenID through RESTful APIs;

- Compliance with U.S. DOE's Data Guard Energy Data Privacy program requirements;
- Data encryption requirements; and/or
- Requirements to access and store data only within the United States (no overseas access)

Regardless of the Boards direction on cybersecurity issues, we urge the Board to require that EDCs provide a transparent and consistent set of terms and conditions for DERAs registering to EDC data access platforms.

The Board can also take solace knowing that there are many laws, regulations and protocols that have already been implemented in New Jersey, in the PJM market, and across the energy industry that will provide security and protections for customer data and other information. These include:

- The New Jersey Data Privacy Law.[24] This law gives New Jersey residents rights over their personal data. It also requires businesses to be transparent about how they collect, process and use customer's personal data.

- The New Jersey Computer Related Offenses Act.[25] This law protects against the theft of data. It also gives individuals the right to take legal action against those who intentionally access, alter, damage, or destroy computer information.

- The New Jersey Data Breach Notification Law.[26] This law requires certain public sector entities and private sector government contractors to report data breaches within 72 hours.

- Federal Trade Commission Act (FTCA). This federal law prohibits deceptive business practices, including those related to data security.[27]

- Computer Fraud and Abuse Act (CFAA). This federal law covers a wide range of cybercrimes, including hacking, stealing data, and cyber extortion.[28]

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[24] https://pub.njleg.state.nj.us/Bills/2022/S0500/332_R6.PDF.
[25] https://law.justia.com/codes/new-jersey/title-2a/section-2a-38a-3/.
[26] https://law.justia.com/codes/new-jersey/title-56/section-56-8-161/, *et seq*.
[27] https://www.ftc.gov/business-guidance/privacy-security/data-security.
[28] https://www.ftc.gov/legal-library/browse/statutes/telemarketing-consumer-fraud-abuse-prevention-act.

- FERC has been granted authority under The Energy Policy Act of 2005 (Energy Policy Act) and the Energy Independence and Security Act of 2007 (EISA) to oversee and coordinate the development of smart grid guidelines and standards. This emanates from a concern that the electric grid could become more vulnerable to cyber attack through all of the information access points associated with smart grid deployment.[29]

- The US Department of Energy ("DOE") is also engaged in a more broad set of cybersecurity issues. DOE has created the Office of Cybersecurity, Energy Security, and Emergency Response ("CESER") who's mission is to "Strengthen the security and resilience of the U.S. energy sector from cyber, physical, and natural hazard risks and disruptions." A review of the CESER website shows that they are working with several organizations across the industry to address cyber threats.[30]

Conclusion

CADRE appreciates the opportunity to provide the Board with its best practices on several matters related to effective regulations related to DER and DERA participation in wholesale electricity markets.

[29] https://www.ferc.gov/industries-data/electric/industry-activities/cyber-and-grid-security.
[30] https://www.energy.gov/ceser/office-cybersecurity-energy-security-and-emergency-response.