ELECTRIC ADVISORS CONSULTING
3 Traylor Drive, West Chester, PA 19382

April 22, 2024

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 comments in response to the Request For Information issued by the New Jersey Board of Public Utilities in the Matter of New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets.

In addition to me, could you please add the following members of the Coalition to the service list in this proceeding:

Joann Worthington Kerinia Cusick Voltus, Inc. Jworthington@voltus.co kcusick@center4ri.org	Katie Rever Lauren Wolf IGS Energy Katie.Rever@igs.com Lauren.Wolfe@igs.com
Leah Meredith Solar Energy Industries Association lmeredith@seia.org	David Skillman Sunnova Energy David.skillman@sunnova.com
Hannah Bent Engie Hannah.bent@engie.com	Katherine Hamilton Gina Jardot Advanced Energy Management Alliance Katherine@aem-alliance.org Gina.jardot@nrg.com
Joanne Zulinski CPower Energy Management Joanne.Zulinski@CPowerEnergy.com	

Thank you for your consideration of these comments.

Sincerely,

Frank Lacey

Frank Lacey
President
frank@eacpower.com
610-793-2809

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

COMMENTS OF THE COALITION ADVOCATING DER REGULATION EFFICIENCY

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

I. Background

On March 7, 2024, the New Jersey Board of Public Utilities ("Board" or "NJBPU") opened this docket by issuing a Request for Information ("RFI")[2] from the Electric Distribution Companies ("EDC") and other stakeholders on the issues identified regarding the participation of distributed energy resources ("DER") in wholesale electricity markets. The Federal Energy Regulatory Commission ("FERC") issued its Order No. 2222[3] in September 2020, which, among other things, required regional transmission operators ("RTO") to remove barriers to DER and DER Aggregations ("DERA") participation 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

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

[2] 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

[3] 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").

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. The DER participation model is scheduled to be fully implemented and functioning on June 1, 2026[4].

The PJM DER participation model includes many rules that have been approved by FERC and a few that are still unresolved in the FERC stakeholder process. FERC has appropriately left some issues unresolved for the various states to consider. These retail matters, or state jurisdictional matters, are the subject of these comments. CADRE appreciates the Board's willingness to hear from stakeholders about the proper resolution of these state jurisdictional matters.

CADRE will present some introductory comments and then address each of the questions addressed to the non-EDC stakeholders in the order in which they are presented in the Board's RFI.

II. Introduction

The introduction of DER and DERA into wholesale electricity market marks a transformational moment in electricity markets. In a presentation to the Michigan PSC demand response stakeholder group, Collaborative Utility Solutions ("CUS") states unequivocally that "Implementation of 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

[4] PJM has recently notified stakeholders orally that it may not be able to allow DERA in the wholesale market by its June 1, 2026 deadline because FERC has not issued orders on some of the remaining contested issues in PJM's implementation docket. PJM made these statements at the March 4, 2024 Distributed Resources Subcommittee meeting. They notified stakeholders that they would make a formal filing with FERC, but to date, PJM has not made this filing.

energy resources called DERs."[5] 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. CUS calls DER "a mammoth opportunity for our industry – not a burden."[6]

Customers are willing and able to provide electricity resources; service providers are willing and able to aggregate and bring these resources to the market; and technologies to reduce emissions and facilitate aggregations are readily available in the market. Federal regulation fully supports the deployment of DER and DERA in wholesale electricity markets. The remaining pieces of the puzzle that could mitigate full deployment of DER and DERA are opposition from stakeholders in the state, reluctance from the utilities, and overly burdensome or inappropriate retail regulations. We urge the Board to be forward-looking, yet prudent when looking at these issues. It will take thoughtful regulatory innovation to capture the full value of DER, but as noted above, the opportunity is mammoth – perhaps the biggest opportunity of our lives. Critically, the Board should not erect barriers to full implementation of DER and DERA.

CADRE is not advocating for a "no regulation" approach. CADRE believes well-designed regulations will facilitate full deployment of DER and DERA. It is important for the Board and stakeholders to take a comprehensive view of the markets and redesign some existing regulations, perhaps add regulations to govern certain aspects of the market and potentially eliminate old or constraining regulations. CADRE will address the issue of a statewide process

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[5] 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 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.

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

below in response to one of the Board's questions, but for the purpose of this introduction, CADRE believes the Board should fully engage stakeholders in a statewide process to develop effective and efficient regulations that will optimize market participation and consumer value.

It is important for the Board to fully understand the opportunity as well as the technical and intimate nature of the relationship between a DER aggregator and the customer providing the resource. We do not believe that either of these can be fully described in comments from one coalition or even from a broad group of docket participants. We believe that dialog, interaction, and perhaps, a more formal process will be extremely valuable to the Board and to all electricity consumers in the state.

We encourage the Board to look to its neighbor, Pennsylvania, in this moment. Pennsylvania has opened a formal rulemaking procedure to address regulation of the retail issues associated with DER participating in wholesale markets.[7] Pennsylvania is still in the formative stage of its process but intends to have a comprehensive suite of regulations in place prior to June 1, 2026, when the PJM market is scheduled to open to DERA participation. Pennsylvania's Advanced Notice of Proposed Rulemaking ("ANOPR") addresses 13 separate issues that are fundamental to the success of the DER market. The Board should investigate in a similarly styled docket these same 13 issues which are discussed below and others that may be presented by stakeholders in this RFI process.

III. Board Questions

In its RFI, the Board seeks responses to 20 specific questions. The Board's first 12 questions are directed at the EDCs. While CADRE will not answer those questions directly

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[7] Advanced Notice of Proposed Rulemaking, *Distributed Energy Resources Participation in Wholesale Markets,* PA PUC Docket No. L-2023-3044115, 54 Pa.B. 1668, March 30, 2024.

because they are directed at the EDCs, we have some concerns that we will address with respect to topics addressed in questions 6 (double compensation), 7 (metering), 9 (cybersecurity), 11 (pilot programs), and 12 (registration review period). We will address these issues in our responses below. These comments will directly address the Board's questions numbered 13 through 20. Some material included in these responses will address the issues in those questions directed to the EDCs.

NJBPU Question 13

Do you have any comments or concerns about the classification of certain resources and their operating profiles as eligible for DERAs? Please state any associated control and/or compensation concerns.

CADRE has concerns about protecting the rights of customers participating in Net Energy Metering ("NEM") programs. While FERC has not issued final rules on all open NEM issues, FERC has ruled that customers should not get paid twice for providing the same service. Order No. 2222 specifically "(1) allow[s] distributed energy resources that participate in one or more retail programs to participate in its wholesale markets; [and] (2) allow[s] distributed energy resources to provide multiple wholesale services." The Order then allows the RTO to "(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."[8] CADRE has no concerns about restricting "double compensation" as FERC has defined it (customers can participate in wholesale and retail programs). CADRE believes that "double compensation" must be defined by the Board in a similar fashion to FERC's definition

[8] Order No. 2222, ¶ 160.

so that the EDCs can properly determine when a customer might potentially be "double compensated."

PJM has taken the position that NEM customers receiving a full retail rate for excess energy production cannot get paid twice, once through the NEM program and then again for participating in energy or capacity markets. PJM has ultimately left the determination of allowing a NEM customer to register in a DERA to the EDC because state and EDC programs are all different[9] with some offering a full retail rate for excess generation and others offering something else. In taking its position, PJM has included in its prohibition all component DER that are located behind the meter at the NEM property, including storage and other potential demand response assets in its resource prohibition.[10]

CADRE believes that there could be state-supported solutions to allowing NEM resources to participate in wholesale markets and allowing component DER behind a NEM meter to participate in DER markets. The Board should strive to allow early adopters of advanced energy technologies such as NEM participants to continue their journey to more advanced energy management. It seems to be flawed energy and environmental policy to stifle the early movers, who have previously committed to a long-term investment in rooftop solar (or potentially other resources), from advancing the energy markets further.

To be clear, NEM resources should not be moved in their entirety to the wholesale market. That would undo a regulatory promise made to those customers who invested in NEM resources. CADRE understands that there will soon be a docket opened in New Jersey that will

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[9] Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C. and Motion for Extended Comment Period, Docket No. ER22-962, p. 40, February 1, 2022.

[10] *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").

be focused on several NEM issues. We urge the Commission to consider options in that docket that will allow for the expansion of NEM customers' rights and abilities to participate in wholesale markets. Doing so would maximize the value these resources can provide to the grid. At the same time, we urge the Board to not disturb the compact with NEM customers currently in place. These customers made investments premised on a regulatory concept implemented by the Board. The Board should not remove any of the attributes of NEM programs for current NEM customers.

PJM's double compensation rules restrict non-NEM DER co-located with NEM DER behind the utility meter from participating in energy and capacity markets. In order for these resources to participate, PJM has suggested (FERC has not yet ruled on this suggestion) that these customers add an additional utility meter at the premise.[11] If a facility with NEM also has a charged battery, a responsive EV, or controllable load in the form of demand response, those resources, which would be quite capable of relieving a constraint, would not be able to participate in the wholesale market under PJM's proposal. PJM's suggestion of separately metered resources is not viable as it would require individual DER to be on a separate circuit from the NEM resource. That would mean the NEM resource could not directly charge the battery or the EV. Similarly, if the Component DER was a load reduction, then the reducing resources (air conditioner, pool pumps, other) would have to be on a separate meter. Of course, it is an incomprehensible outcome for a NEM customer to have air conditioning systems or pool pumps that could not be energized from an on-site NEM resource. Similarly, it does not make sense that a commercial and industrial ("C&I") facility, with significant load participating in demand response, or with large batteries providing backup power, be restricted from

[11] PJM Second Compliance Filing, pp. 18-19.

participating in the market because a small solar system is located on the property. Universities with multiple buildings and meters, and often with local generation, should be allowed to participate, even if one building has solar.

Because the determination of double compensation is left to the EDC, The Board could resolve this issue by requiring the utilities to accept device level metering. Device level metering is available in inverters, storage resources, EVs and can be implemented on other load management resources. The Board has a few options for encouraging PJM or requiring the EDCs to allow device level metering. First, the Board could 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 storage 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 the PJM compliance process, FERC did not order PJM to accept and use device-level metering in DER programs. However, in its compliance orders, FERC has encouraged the stakeholders to continue to develop device-level metering approaches[12]. The Board could exercise leadership on this issue and require the EDCs to process and/or accept device-level meter data from Aggregators. This would alleviate a constraint that keeps some of the most advanced customers, those who have invested in NEM and other DER, from participating in the wholesale energy and capacity markets.

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[12] 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."

Additionally, the Board, via the Organization of PJM States ("OPSI"), could ask PJM to initiate a stakeholder process to define device level metering standards and processes for measurement and verification to allow aggregators to provide the data directly to PJM. PJM defines requirements for meters in Manual 14D.[13] PJM could expand the requirements to include device-level metering. The Board could develop clear rules for both residential customers where all DER are located behind one utility meter, and for C&I applications where multiple resources might be tied to a master meter.

NEM resources are valuable resources for which New Jersey ratepayers have paid substantial sums of money. NEM resources will continue to be funded by ratepayers whether the resources participate in wholesale markets or not. Modernizing the NEM programs to meet the needs of a more modern electricity market will further enable these customers to contribute to the grid, while reducing costs of energy and of the NEM programs which will benefit all customers in the market. In contrast, maintaining the status quo for NEM customers locks those customers in place, providing no incremental system benefit, leaving a valuable resource significantly under-utilized.

NJBPU Question 14

Do you believe that it is technically feasible to implement Order No. 2222 requirements by PJM's originally proposed 2026 implementation deadline? If not, please explain in detail why not. Are there any actions that PJM or NJBPU could take to make the implementation more efficient and timely?

FERC has compelled PJM and the other RTOs to enable wholesale participation models for DER and DERA. If the Board took no action on retail issues, it is likely that Order No. 2222

[13] See: PJM Manual 14, Section 4.2, found at: https://pjm.com/-/media/documents/manuals/m14d.ashx.

would still be technically viable and implemented but at a sub-optimal level. To facilitate full participation from inception, the more relevant questions should be:

- What technological changes should be made to maximize the value of DER, DERA and FERC Order No. 2222? and
- What changes would enable the highest participation in DERA from the greatest number of customers?

CADRE believes that the Board should address many of these technical issues, advancing the New Jersey market and EDCs into the digital, hi-tech, and instant communications age where customers can truly control their energy needs while simultaneously providing reliability, resilience, carbon reductions and cost reductions to the grid. Addressing these issues and implementing these changes would make the implementation more efficient and timelier and would enable the broadest set of customers to participate in these DER markets.

Many regulators have been eagerly anticipating new, game-changing energy products since the beginning of restructuring. The developments prompted by Order No. 2222 will open the door for these products at the wholesale level. As noted above, the opportunity for real change and improvement is “mammoth” and potentially “once in a lifetime.” FERC, through Order No. 2222 has required PJM to update its systems and protocols. Similarly, the Board will need to facilitate change at the EDCs to achieve the maximum benefit from DERA. Changes are required in numerous areas, including billing, metering, interconnection processes, data exchange and EDI rules, and others. We will briefly address each of these issues. However, the technical discussions need to go much deeper than what is presented in these comments and could be understood more readily in a stakeholder process.

Data Exchange, Metering and Billing

The customer/aggregator relationship requires timely, accurate, and clear communication. An Aggregator’s ability to offer into the wholesale markets and settle with PJM will depend on access to customer energy use data. Aggregators will rely upon data from devices and pulse meters that share EDC meter data with the aggregator in real time. Some devices can communicate their state of charge, availability, and current usage in real-time. Aggregators of smaller commercial and residential customers will often rely on meter data coming through the EDC. Without this data, aggregators of certain DER cannot perform measurement and verification and settle with PJM. The Board should ensure that the EDCs are equipped to provide access to meter data to customers and their representatives (e.g., aggregators) in real-time – i.e., Aggregators are receiving data as soon as the EDC receives it – through a centralized, online platform. Housing this data in a readily accessible repository will facilitate enrollment of DERs into aggregations and increase customer revenue streams from wholesale markets. This, in turn, will drive accelerated deployment of other resources such as demand response and storage needed to stabilize the grid. In addition, retrieval of this data should be streamlined to allow aggregators to efficiently pull data for hundreds or more customers, as opposed to current processes that require aggregators to pull data one account at a time.

Device level metering should be incorporated into the EDCs metering and data management programs. Device level metering, to the extent it exists, can be communicated in near real-time to the EDC and to the aggregator. The Board should ensure that EDCs can appropriately account for component DER device-level metering. Alternatively, as discussed above, the Board could approve Aggregators to provide billing and settlement information based on device-level metering.

To be clear, CADRE is not advocating that device-level metering should be a requirement to participate in wholesale markets. It is not necessary, nor is it appropriate for many DER. However, where the technology is available (inverters, battery storage, EVs), its value should be maximized and that starts with having the utilities acknowledge device-level meter data and process it as needed. Device-level data will add material value to the DER market in terms of understanding exactly where and how energy is being delivered, consumed, or injected onto the grid. We encourage the Board to include device-level metering as an issue to be evaluated in a statewide process.

Meter data is a key component in developing an accurate bill. The current billing paradigm in New Jersey is insufficient to support a robust DER market. Under today's standards, a residential customer gets a monthly invoice from the EDC. That invoice typically includes a retail supplier's charges for electricity. That invoice looks the same regardless of the customer and regardless of the customer's day-to-day practices in the energy markets and regardless of the customer's electricity supplier. For example, a demand response customer's bill looks no different and has no more information on it than a non-participant's bill. A customer who actively manages their thermostat (either manually, remotely, or programmatically) sees nothing on the invoice that helps understand the consequences of their actions. Today's electricity bills look much the same as they did 20 years ago and perhaps even 50 years ago. DER aggregators need to own the customer relationship and that includes the billing relationship. DER aggregators need to be able to tell a customer why and when it discharged a battery, or delayed an EV charger or changed the temperature on a thermostat. They need to be able to create products and services that are unique to a customer and then bill that customer accordingly. They need to be able to provide the bill on a website, or on an app, and not on pages of paper that have information that is largely meaningless to a customer. In today's world of e-commerce, a customer sees a bill or an invoice from a supplier and not the transportation company the supplier uses. For example, when buying clothing on-line, the customer will communicate with the clothing vendor, place an order with the clothing vendor and pay the clothing vendor. That payment will include charges for transportation. The clothing vendor will provide an invoice detailing the charges for the clothes, customization, alterations, and delivery. It is virtually inconceivable to think of a situation where the transportation company (e.g., FedEx, UPS, U.S. Postal Service) would or could bill the customer for transportation and include on its invoice the product purchased and the requisite details of that purchase. The billing paradigm must be addressed to facilitate a robust DERA market. We believe a statewide process will be an appropriate forum to address billing issues.

DERA participants, especially early-movers in the DER world are going to be forward-thinking customers. They are going to want a high-tech experience. They will want to interact with the resources at their property and their aggregation provider. They will want to understand what is happening when and why. Transferring this level of information cannot be accomplished under today's data exchange, metering, or billing standards. The Board should push the utilities to develop and implement a modern, technology-capable environment that will enable and empower robust DER participation in wholesale markets. CADRE supports comprehensive changes to the metering, data availability and billing paradigms currently utilized in the New Jersey electricity market. We would welcome a statewide process to facilitate change to these functions.

Interconnection processes

The EDCs have different practices and procedures for evaluating interconnecting resources. CADRE's concerns are related to the varying costs of interconnecting resources, the allocation of interconnection costs and the varying processes and timelines for interconnection. We urge the Board to seek input on alternative interconnection cost allocation methodologies and on the EDCs' processes for interconnection applications.

Today, the utilities evaluate resources individually and assess the engineering needs to interconnect each individual customer using methodologies that are opaque to the interconnecting customers. This results in customers paying wildly different costs for interconnecting and the support for the costs is not transparent. The current approach also has the potential to create significant first mover disadvantages as the first mover might have to pay a six-figure interconnection cost, but then the property next door can interconnect a resource for practically nothing. CADRE is aware of several models which could modify this and likely be fairer to all customers.

First, the EDC could rate base the entire cost of interconnection. This model recognizes that DERs provide a value to the grid generally and that EDCs have a responsibility for upgrading the "poles and wires" to adapt to customer needs and preferences.

Second, there is a fixed fee model, where customers would pay a fee based on the size of the interconnecting resource. It could be a $/kW assessment. That fee could vary for differing resources, and it could vary between EDCs. The key component is that the fee would be tariff based and competitively neutral. Developers and customers could assess their costs of developing DER before expending resources on interconnection studies and refined financial analyses after the assessment is performed. This allocation model would eliminate the vast differences in interconnection costs for similar resources behind the same EDC. This model could become a funding model for distribution upgrades required to support deployment of DER. It would be a direct funding model from DER participants. It will not likely cover every participant's exact cost to interconnect. However, it could be designed to be a fair price, competitively neutral, pre-determined and tariff-based so that customers have some certainty about moving forward with a DER investment.

Another cost model is a batch processing model. Batch processing models have been adopted by several RTOs. In this model, utilities would wait for a pre-determined time to collect interconnection applications. After they are received, the utility would assess the total cost to interconnect those resources and allocate costs among those customers. This approach helps alleviate, but does not necessarily eliminate, the first mover disadvantages.

In either model, some distribution upgrade costs will be socialized among all customers on the grid, each of whom benefits from the increased deployment of DER. These models will avoid charging prohibitive fees to a single customer for upgrades that are, arguably, the responsibility of the EDC and not the interconnecting customer.

A formal statewide process is likely required to reach consensus on a reasonable, fair and certain cost recovery mechanism, where all concerns can be aired and weighed by the Board. Strong leadership from the Board on interconnection issues will facilitate a more robust DER market. The Board should also seek input on the interconnection processes from the EDCs and stakeholders and compel the EDCs to further streamline interconnection processes, review timelines, and response times.

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, at 30 days after date of application). If 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 pay fines to the Board for failing to meet interconnection timeline requirements. These fines could be distributed by the Board to affected customers or to support other need-based customers. Finally, the EDCs should be required to post hosting capacity maps showing where interconnection is readily available without an upgrade; and those maps should be updated daily.

Once an interconnection is approved (either historically or in the future), there should be no incremental testing or analyses from the EDC to evaluate the resource's fitness for participation in an aggregation. Existing EDC interconnection applications and agreements are sufficiently robust as to apply to resources that later join a DER aggregation participating directly in a wholesale market. Interconnection agreements that contain no limitations on system exports signify that the utility has determined that there is sufficient hosting capacity to allow the resource to interconnect with no such restriction. Similarly, if a DER interconnection agreement specifies any export limits, the DER should be required to always adhere to the agreement, whether or not it is participating in an aggregation. DERs should not be required to reapply for interconnection to participate in an aggregation – nor should an aggregation of DERs be reassessed for interconnection as a single resource. Either assessment would be essentially redundant to the review that already occurred when the DER initially interconnected. Aggregations will be dynamic; they will change from year to year. Requiring a supplemental review for aggregated DERs would be unnecessarily burdensome to both DER owners, aggregators, the EDCs and likely, the Board. It would undoubtedly serve as a barrier to wholesale market participation. If the EDCs have concerns about how aggregated DERs might affect grid voltage, smart inverters are capable of autonomously assisting in voltage regulation in a way that can mitigate such issues.

NJBPU Question 15

Do you have any comments or questions about dispute resolution processes between DERAs and utilities?

FERC Order No. 2222 requires the RTO/ISOs to include dispute resolution provisions in their tariffs.[14] However, these provisions are limited to issues that fall within the RTO/ISO's tariff. For example, PJM's tariff and Operating Agreement will include a dispute resolution mechanism to address disputes on the issue of resource enrollment and registration and EDC overrides of PJM's dispatch orders. However, 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." [15] To the extent a tariff dispute arises, for example, about the interconnection of a DER or an override of a dispatch order, a market participant is left with only two solutions under current New Jersey regulations. Market participants can file an informal complaint, for which there is no formal process, guidelines, timelines, or deadlines for resolution. Alternatively, they can file a formal complaint, requiring lawyers, due process for all stakeholders, and other formal procedures, all of which consume valuable time and resources of the EDCs, the affected stakeholder(s), and the Board. The Board should organize a dispute resolution process specifically to address DER/Order No. 2222 issues, especially for disputes concerning application review, interconnection, compensation, and grid reliability issues. We encourage the BPU to offer arbitration and/or mediation as possible modes of resolution.

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

FERC requires the EDCs to review interconnection applications for aggregations within 60 days. FERC requires this timeline because any aggregation is comprised of DER that has 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. PJM will be monitoring 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. The Board should be prepared to take on this function as discussed above.

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.

Through a statewide process, stakeholders could define expected areas of future disputes, criteria for issue resolution and a process for resolving issues that fall outside of the scope of the identified criteria.

NJBPU Question 16

How should DER Aggregator performance be monitored/tracked/reported to the public?

PJM has a robust reporting framework for demand response participation and performance.[16] CADRE does not believe that any need exists for the Board, the EDCs, or the state to capture and analyze DER Aggregator performance. If the Board creates the right framework for measurement and verification of DER performance -- requiring EDCs to furnish real-time access to interval metering data from AMI retail meters for retail customers with DERs

[16] See, for example: https://pjm.com/-/media/markets-ops/dsr/2023-demand-response-activity-report.ashx.

— DER Aggregators will be able to accurately settle with PJM without performance monitoring by the Board. If there is data or information the Board wants to see, PJM is the likely owner of that data. PJM will have ready access to all registrations, bids, offers, clearing prices and performance metrics. They will be able to parse this information by state, by EDC, by Aggregator, by resource type, and more. If the Board requires more incremental information from the DER Aggregators, we encourage the Board to approach information gathering from a "needs" basis. We encourage simple, streamlined reporting requirements. We urge that if reporting is required, that it be made to the Board and not to the EDCs. We also urge that if reporting is required that the reporting requirements be identical for each EDC territory. However, before reporting requirements are implemented, CADRE encourages the Board to work with PJM to ensure that PJM is collecting the information the Board would want to see.

NJBPU Question 17

Should each EDC be required to formally establish pilot programs demonstrating their procedures and performance for DERA integration? Should these pilots be identical/consistent/unique across EDCs?

From the DER Aggregators' perspective, this is an unequivocal and emphatic no. There is no need for the EDCs to run DER and DERA pilot programs. DER technology has been proven to be a reliable resource already. We know that rooftop solar works. We know that behind the meter generation can be injected into the grid. We know that behind the meter generation works when dispatched. We know that battery storage systems and demand response assets can be called on when needed. Demand response is available when PJM dispatches it. Additionally, PJM has a testing procedure for demand response (and other resources) that choose to participate in markets.

These concepts do not need to be piloted. The Board should focus on driving the EDCs to develop the appropriate software and protocols to advance the DER and DERA markets. We understand that the utilities will need to "test" software and "test" communications protocols and others. However, we don't need to design a pilot, run a pilot, evaluate a pilot and then open the market. Pilot programs will yield unnecessary delays, increase costs, and harm consumers.

NJBPU Question 18

As part of NJBPU's efforts to help implement Order No. 2222 how much technical support from the NJBPU, separate from NJBPU's current Grid Modernization Forum working groups, is desired? Would a statewide stakeholder engagement process, working group, technical conference, or public platform for stakeholder engagement be beneficial?

As noted above, we believe a statewide engagement process would be beneficial. That statewide process, as shown in these comments, will require leadership, customer and market stewardship, and decision making from the Board. Embedded in those attributes will be technical guidance and assistance. Earlier in these comments, we addressed data exchange, metering, and billing. We encourage visionary leadership from the Board to push the utilities into the digital age where consumers can act in real time to minimize their own energy costs and costs for all consumers in the market.

DER Aggregators need real time data access, and the ability to use metering devices other than the electric meter sitting on the side of the property to receive real-time data feeds from the premise and premise-level devices. We need to communicate energy market results to our customers in a user-friendly and customer-specific manner. These are technologies that are commonly available, and that the Board can compel the EDCs to adopt. In addition to these technology issues, several policy issues that are likely to be contested will eventually be put before the Board for decisions. As guidance for this section, we have looked to Pennsylvania, which has already undertaken a process similar to this RFI process. Pennsylvania presented several retail-related DER issues in their ANOPR. We believe that the Board will ultimately need to opine on many of the same issues that Pennsylvania is addressing and that a comprehensive statewide process is needed to guide efficient decision-making. We briefly discuss each of these issues below.

Cost Allocation

CADRE believes developing the DER market will reduce energy costs for all customers. We have seen this phenomenon in the demand response market where the PJM Independent Market Monitor has stated numerous times in his annual analysis of PJM's capacity auction that in the absence of demand response participation in the capacity market, capacity prices would be billions of dollars higher than the actual clearing prices.[17] We also know that because of the rules developed in FERC Order No. 745 that if demand response participates in energy markets, it must pass a net benefits test, so by its very existence, demand response must lower energy clearing prices if it is cleared in the energy market[18]. While FERC Order No. 2222 does not have the same net benefits test language, Order No. 745 language will still be binding on Component DER that are demand response resources. More importantly, if a Component DER energy injection clears the PJM market process, it will always be a lower cost option than the resource it displaced. DER and DERA participation in wholesale markets will always benefit consumers, including non-participating consumers.

To interconnect some DER, the EDCs may be required to make distribution investments. CADRE described above a few options to allocate the costs of those investments fairly. As a

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[17] See the Market Monitor's annual analyses of PJMs Base Residual Auction at: https://www.monitoringanalytics.com/reports/Reports/2023.shtml.

[18] FERC Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187, 18 CFR Part 35, Docket No. RM10-17-000, March 15, 2011.

policy matter, the distribution network should be built to accommodate a modern energy economy that includes renewable resources, DER, demand response, bi-directional electricity flow, EVs, mass electrification efforts and an information economy. All Interconnecting DERs will contribute to the cost of upgrades under the models discussed above. No single customer should be compelled to pay for this modernized infrastructure, nor should customers be allowed to interconnect for free. We believe a statewide process could be utilized to determine fair, equitable and transparent charges for interconnection. Similarly, all customers will benefit from an expanded distribution grid, so it might be appropriate to have some upgrade costs placed into base distribution rates.

Distribution Level Benefits

CADRE believes that the Board and the EDCs should look to this DER process as an opportunity to create a distribution platform that can be utilized at the wholesale level by DER aggregators and at the retail level by the EDCs. This platform will include the technical requirements discussed above and the policy requirements discussed throughout these comments. The platform will be used to maximize returns to DER customers, to minimize costs for non-participating customers and to advance the New Jersey electric grid into a model that could be emulated by other states.

The formation of wholesale market DER and DERA could provide tremendous benefits to the EDCs, aiding in reliability and cost reductions for the distribution grid. The same DERA could be used to relieve distribution congestion, alleviate constraints, avoid or delay costly investments in grid infrastructure and potentially for other functions. Parts of New Jersey are extremely constrained electrically. The wholesale market aggregations, formed at no cost to ratepayers, could and should be used by the EDCs to alleviate constraints while simultaneously minimizing costs to EDC consumers. We can point to another neighboring state, New York, for an excellent example of how these programs could work. The New York utilities have each implemented two separate demand response programs. The first, the Commercial System Relief Program ("CSRP"), is a program designed to minimize peak demand. It is triggered when forecast peaks reach certain points. When CSRP is called, resources are dispatched to reduce overall metered demand. This action lowers the system-wide capacity obligation, which keeps prices down for all customers. The other, the Distribution Load Relief Program ("DLRP") is a local emergency relief program. Conditions that trigger a DLRP event include being one contingency away from a "Condition Yellow" or an active voltage reduction by network. These reliability measures can arise locally even when they do not rise to the level of an RTO emergency dispatch. The New Jersey EDCs could implement similar solutions utilizing the previously formed DER and DERA to provide the same or greater level of benefits to the EDC's rate payers. The New Jersey EDCs' customers could benefit greatly from programs to reduce peak loads and alleviate system emergencies without the need for incremental distribution investments. CADRE believes that such programs could be a valuable outcome of a comprehensive statewide process.

Double Compensation

Double compensation is a contentious issue, and we seek strong Board guidance to clarify what is and what is not double compensation. As noted above, FERC has ordered the RTOs to accept registrations from customers participating in one or more retail programs, unless the programs compensate for the same service. There are, for example, some utility demand response programs that are directly tied to the RTO demand programs. These are mostly found in the vertically integrated states that opted out of Aggregator Participation in wholesale demand response markets under FERC Order No. 719. New Jersey does not operate retail demand response programs that are directly tied to PJM's demand response programs. In the prior section, we described the New York demand response programs. Customers operating in the New York utilities' programs frequently also participate in the NYISO demand response market. This practice is embraced by federal and state regulators and does not result in double compensation. The only compensation limitation on a customer participating in each of the three programs is that the customer will only be compensated once for energy if multiple dispatches are called at the same time. Different programs serve different purposes. Just like a doctor who can solve many different medical problems, a DERA can solve many different electricity concerns.

These comments addressed the double compensation issues specifically related to NEM resources above. CADRE believes that addressing double compensation appropriately will yield outcomes that will provide win-win solutions, for participants, non-participants, and the EDCs, but those will not evolve without serious dialog. We believe the double compensation issues will be better understood and can be resolved through a statewide process.

EDC overrides

FERC has given the EDCs a significant amount of authority in its Order No. 2222. Notably, FERC allows the EDCs to override a PJM dispatch of DERs and DERAs[19] in circumstances where such an override is needed to maintain the reliability and safe operation of the distribution system.[20] EDC overrides of a DER dispatch should only be ordered in the case of a reliability emergency that would be caused by the dispatch. In every instance of an override,

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[19] Order No. 2222, ¶ 310.
[20] Order No. 2222, Para 310.

the EDC should communicate directly to PJM, the 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 aggregators, particularly when it comes to the EDC overriding an aggregator dispatch. Importantly, CADRE believes that the EDC should never have direct control over a DER resource.

Order No. 2222 also requires communication between the EDC and the aggregator in cases of outage on the distribution system – either planned or unexpected. As PJM does not regulate the EDCs, they cannot specify information flow. These requirements must come from the Board. CADRE suggests that the Board be prepared to work with the EDCs and Aggregators, 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 stakeholder process would define: 1) clear criteria that define reliable and safe operations and justify an EDC override; 2) procedures for advance notification of an outage to DER aggregators and owners; and 3) after the fact justification review. Additionally, the Board should consider whether a dispute resolution process is required here as well.

EDCs as DER Aggregators

CADRE feels strongly that EDCs should not be allowed to aggregate DER and DERA for the purposes of participating in the wholesale electricity markets. The service of aggregating DER for the purposes of participation in the wholesale market is unquestionably a competitive service.[21] EDCs are regulated monopolies that are primarily motivated to and are allowed to earn

[21] See: NJ Rev Stat § 48:3-55 (2023).

a regulated return on invested capital. Allowing a regulated return on DER participation in wholesale markets, along with all of the other advantages that incumbency has provided the EDCs would give the EDCs an inappropriate anti-competitive advantage in the market. In particular, EDCs could rate base their expenses to subsidize cost with ratepayer funds in a way that third party aggregators cannot. They could also seek cost recovery for losses from errors made while participating in wholesale markets – also a "right" not provided to non-utility aggregators. This disparity in risk exposure will minimize competition in the aggregation market.

A competitive market will put upward pressure on payments to DER owners and put downward pressure on aggregator expenses. Introducing EDCs as aggregators undercuts these market-drive efficiencies. Additionally, EDCs, as noted in the prior section, can override a dispatch of a DER and can reject a registration of a DER from a non-utility aggregator. The business impact of a direct competitor having override authority of a DER provider's dispatch instructions would be untenable. EDCs are free to create competitive affiliates to operate in competitive markets, as the DER market will be. Allowing an EDC with direct competitive conflicts to compete in the same market should not be allowed. The Board should issue strong language to ensure that EDCs cannot develop DER aggregations that would compete with non-utility DER aggregations to participate in wholesale electricity markets.

Customer Protections and Oversight of DERA

We have noted above that CADRE is not seeking a "no regulation" market. However, the Board must be aware of the line between wholesale and retail regulations. Demand response participating in wholesale markets is unequivocally a wholesale service.[22] There is no reason to believe that DER participation in the wholesale electricity market is any different. DER participation will impact wholesale electricity prices in the same manner that demand response affects wholesale rates. CADRE understands that the Board and other stakeholders may be concerned with customer protection and other issues that are seemingly retail in nature but might actually be part of a wholesale (FERC-jurisdictional) transaction.

Willing customer participation is required for successful DER aggregations. As noted above, the customer-aggregator relationship must be very tight. It will not be in an aggregator's interest to take economic advantage of its customers because an unhappy customer can wreak havoc over the DERA participation model. We encourage the Board to exercise patience to determine if consumer protections are necessary before enacting any incremental consumer protection regulations specifically aimed at the DER market. DER, like demand response, is very customer-focused and tends to reduce costs for participating customers and the market. Overly burdensome consumer protections might interfere with the customer-aggregator relationship to the detriment of all customers, including non-participating customers.

Cybersecurity

Cybersecurity and data protection are core issues for any business and are not electricity market specific. In the electricity market, technical standards organizations such as the National Institute of Standards and Technologies ("NIST"), North American Electric Reliability Corporation ("NERC") and the Institute of Electrical and Electronics Engineers ("IEEE") have already developed cybersecurity standards. For example, NIST was mandated by Congress, via

[22] FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760 (2016).

the Energy Independence and Security Act of 2007, to coordinate standards for the development of the smart grid. Some of these standards are embedded now in manufacturing and development processes.[23] Cybersecurity standards have already been addressed by national technical standards organizations and do not need to be reinvented by the NJ Board.

Equity

The Pennsylvania ANOPR raised equity concerns related to cost allocation of DER costs coupled with an inability of low-income customers to participate in DERA because of affordability issues. CADRE understands these equity concerns and believes that the savings from reduced energy costs will more than offset any increases in distribution costs. 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 above, they could result in downward pressure on distribution rates also. By deploying DER and DERA under state retail programs, EDCs will be able to delay and/or avoid distribution upgrades.[24] Additionally, with appropriate regulation, there is no reason that low-income customers would not be able to participate in DERAs. DER do not necessarily require costly investments. A participant can join an aggregation of controllable thermostats, or other home devices. Also, under the appropriate ownership and contracting structures, low-income customers could install storage devices and/or rooftop solar. These equity issues are valid. CADRE believes that DER and DERA are very

[23] See: Cusick, Kerinia, Harry Warren and Versha Rangaswamy, *It's Time for States to Get Smart About Smart Inverters*, Center for Renewable Integration, October 2019, located at https://www.center4ri.org/publications/#smartinverter,.

[24] 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://live-etabiblio.pantheonsite.io/sites/default/files/lbnl_locational_value_der_2021_02_08.pdfCitation?

attainable and beneficial to low-income customers. We believe equity issues should be aired and solutions could be provided through a statewide stakeholder process.

NJBPU Question 19

Are there any specific questions that you have for NJBPU that has not been addressed yet in the FERC Order, PJM's Compliance Filings, or NJBPU's Order No. 2222 outreach efforts?

No.

NJBPU Question 20

Which of the following categories best describes the stakeholder perspective your comments provide?

- ***a. DER Aggregator***
- ***b. Government Agency***
- ***c. Concerned Citizen/Building Owner***
- ***d. Academic Institution***
- ***e. Commercial DER Developer***
- ***f. Energy Asset Investor/Owner***

The market participants that are party to this response fall into the categories of what have traditionally been defined as either competitive generation suppliers, competitive retail suppliers, solar energy providers, or demand response providers. The participants also include industry trade groups from these industries and their members. Collectively, these comments reflect the consensus view of a significant portion of the DER service provider market. The participating entities, or their members, intend to operate in the DER Aggregation market when it is opened.

IV. Conclusion

CADRE appreciates the opportunity to provide our comments on the Board's RFI. We urge the Board to convene a statewide process to engage stakeholders in discussions on the issues discussed above. We look forward to participating in that process.