May 28, 2024

Via Electronic Filing
Secretary Rosemary Chiavetta
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

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

Dear Secretary Chiavetta,

Attached for electronic filing please find the University of Delaware Electric Vehicle Research and Development Group comments on the above-referenced proceeding.

Respectfully submitted,

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John Metz (Electricity Policy Analyst)
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Comment by University of Delaware

Docket No. L-2023-3044115

Distributed Energy Resource Participation in Wholesale Markets

Comment submitted 28 May 2024

Qualifications as Commentator

Authors have developed Federal and state policy recommendations for V2G, and are working with utilities, RTOs, and automakers to implement interconnection and market operation of V2G resources. Kempton created the concept of V2G (4 patents awarded) and has published extensively on it. The authors have significantly affected FERC rulings on distributed storage, state law and regulations allowing battery discharge from behind the meter, and with UD colleagues have guided changes to both European and US RTO rules allowing behind-the-meter (BTM) storage to participate in RTO markets.

Background

Vehicle-to-Grid power (V2G) aggregates distributed EVs to create a large energy storage system, capable of integrating variable generation from renewables, increasing stability and reliability, and lowering the cost of electric supply. The University of Delaware (UD) EV research and development group originated the idea of V2G 25 years ago[1]. Our lab at UD has been operating as a PJM wholesale market participant with EVs and distributed batteries for the last 12 years. The UD team has worked with automakers and designed EV charging systems capable of bidirectional charging and worked with FERC, PJM, ISO-NE, CAL-ISO, and state governments to design policies that allow for the interconnection of V2G resources and allow them to participate in power markets.

[1] W. Kempton and Stephen Letendre, 1997, "Electric vehicles as a new power source for electric utilities." Transportation Research. Part D, Transport and Environment. 2 (3): 157-175. doi:10.1016/S1361-9209(97)00001-1.

To be V2G capable, vehicles must have bidirectional charging, that is, they must allow power to flow from grid to battery and from battery to grid. That capability must be code-compliant and must be able to be controlled for the benefit of the grid. As we will itemize, V2G metering for retail services can require little more than an Electric Distribution Company (EDC) time of day (TOD) meter, whereas V2G for RTO services typically requires only EDC net metering, with a DERA device meter and telemetry provided by the DERA. The EDC meter often does not even need to be a smart meter. V2G substantially lowers the cost of storage and preserves resources by utilizing already existing battery systems in the grid i.e. EVs.

V2G is projected to have the capacity to be an extremely large resource for the grid. US light vehicles are stationary 96% of the time[2], where they can be used to perform grid services. US DRIVE[3] projects by 2035, the US light-duty fleet will be 25% of the US fleet, with 25 M vehicles on the road (see Table 1). As a quick calculation, assuming 10 kW charging/discharging, a 50 kWh battery, and 80% of battery available for grid services, 25M vehicles is 250 GW of fleet power and available stored energy of 1 TWh. In 2050, corresponding quantities for the US are 82.5 million EVs, power available of 420 GW and 1,680 GWh of storage connected.

A more comprehensive model of the size of the V2G resource was done by Xu et al. Globally, they estimated that the use of V2G technology could yield 18-30 TWh of storage by 2050. Xu et al.[4] compared four scenarios of future grid 4-hour storage need, with self-described “conservative” assumptions, finding that in all of 2030, 2040, and 2050, V2G from that year’s EVs was sufficient to meet the storage needs of that year’s grid without any added storage built only for grid purposes. We ultimately believe the new FERC DER model for grid operations can overcome today’s major impediments to

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[2] W. Kempton and Jasna +Tomić, 2005 "Vehicle to Grid Fundamentals: Calculating Capacity and Net Revenue" J. Power Sources Volume 144(1): 268-279. doi:10.1016/j.jpowsour.2004.12.025.

[3] U.S. DRIVE. Grid Integration Technical Team and Integrated Systems Analysis Technical Team (2019) Summary Report on EVs at Scale and the U.S. Electric Power System. United States Department of Energy. Retrieved from: https://www.energy.gov/eere/vehicles/articles/summary-report-evs-scale-and-us-electric-power-system-2019

[4] Xu, C.; Behrens, P.; Gasper, P.; *et al.* Electric vehicle batteries alone could satisfy short-term grid storage demand by as early as 2030. *Nat Commun* 2023, 14, 119. https://doi.org/10.1038/s41467-022-35393-0

implementation of V2G and other DER resources, but only if state law, utilities, and RTOs implement this consistently with the Order and with now-proven best practice.

Our comments are divided by the questions raised in separate sections of the PUC docket. We comment only on questions for which we have expertise and experience. Our responses are in bullet points following the question being asked. Many of our comments apply to any behind-the-meter (BTM) storage, including V2G. When we refer to “BTM storage” that also signifies V2G unless explicitly stated otherwise. If BTM storage is used as a distributed energy resource (DER), we will refer to it as DER Storage.

For background on a neighboring state, we describe several provisions of the Delaware law on V2G. Delaware has code specific to V2G for grid storage. Such DERs qualify for NEM (Title 26 Section 10 §1014 (e)(1)). Delaware code explicitly allows grid-integrated EVs to participate as NEM-metered DER storage resources for PJM markets (Title 26 Section 10 §1014 (h)). In addition, Delaware authorizes interconnection with injection based on compliance with UL or IEEE standards, as well as with standards of the Society of Automotive Engineers (Title 26 Section 10 §1014 (e)(5)). Lastly, the Delaware code includes a section that allows the PSC to create different rate structures for grid-integrated vehicles but only if they do not hinder the development of grid-integrated electric vehicles (Title 26 Section 10 §1014 (i)).

Topics Requested by this ANOPR, with Our Responses

Section B:

Changes To Metering Requirements

The PUC seeks comment on whether its existing metering regulations for customer-generators, 52 Pa. Code § 75.14 (relating to meters and metering), can be adapted to facilitate the provision of metering and telemetry data by DERAs to public utilities, consistent with Order 2222 and PJM's DERA Participation Model (DAPM) and if so, whether and what specific changes to the PUC's interconnection regulations that facilitate this adaption.

- As general guidance, if BTM storage is transacting energy, the storage operator typically can use an EDC meter on the premises (at the POI). (The meter would need to be bidirectional and would require TOD recording, or the value to EDC cannot be logged.) Suppose the BTM storage is transacting ancillary services (A/S), capacity, or other RTO markets. In that case, RTO service metering is more cost-effective and more precisely recorded and transmitted via a device-level meter (submeter) on the controlled DER. For RTO services, the EDC meter need only be capable of net metering; to understand the additional parallel value to the ECC it could be bidirectional TOD recording. (This is addressed further below)
- The above general guidance greatly affects metering and telemetry. With some exceptions, for EDC energy at TOD from BTM storage, existing EDC premise energy metering is required at 1-hour or 15-minute resolution, with existing utility methods for reading those meters. For RTO markets, device submetering of power (kW) and time at 1-second resolution is needed, with real-time telemetry directly to the RTO or an aggregator (DERA). For RTO services, existing EDC energy metering (kWh) of premises may not require a change in either the EDC meter or telemetry.

- We agree with the suggestions that meters should be bidirectional, and record both directions (consumption & production) at the same rate, and if a new EDC meter is required, EDCs should pay for the meters or upgrades.
- For a device (DER) meter, the DERA will determine the time resolution of the meter based on the market requirements. This may require very high time resolution (2 seconds today, possibly 500 ms in the future). We see no reason for the PUC to regulate DER or DERA meters providing RTO services. The purpose of the EDC premise meter with BTM storage typically will be to capture the value of shifting energy to off-peak, injecting energy on-peak, reducing load on distribution lines, reactive power, and injecting during power shortage emergencies. PUC regulation may be appropriate to ensure alignment with the intent to capture value to the EDC. Some of these distribution services may require 5 minute or less response time, for other services. hourly would be sufficient.
- Device level metering should be pursued as a connection type for RTO services, despite PJM's apparent confusion today about requiring higher-cost premise meters for Reserves and Capacity markets.
- Regarding code changes, the PUC may want to add "DER Storage" defined as "Behind the meter, electricity storage providing grid services." In *75.1 Definitions*, DER Storage could either be an additional type (ix) within Tier I, or it could be defined as a separate Tier III. The advantage of defining a separate name and/or Tier III for storage is that storage cannot produce new energy, thus many provisions within Chapter 75 do not apply. Since storage cannot produce energy, there are no RECs and no net energy over time. The reason for adding "providing grid services" is to clearly eliminate BTM storage that is used only for emergency lighting, home backup, etc and which never injects power nor has any public purpose. The customer could demonstrate "providing grid services", for example, by filing a copy of a contract for grid services, or by providing installation records showing that such control equipment has been installed.
- Regarding 52 Pa. Code § 75.14(a) to explicitly add that DER Storage also qualifies for net metering.

- Within 52 Pa. Code § 75.13 (a) add "DER Storage" or "Tier III" after "... Tier I or Tier II alternative energy sources". In § 75.13(d) add "DER Storage" or "Tier III".
- For DER Storage, PSC might consider dropping or modifying the requirement "§ 75.13 (2) The owner or operator of the alternative energy system may not be a utility." This is because electric utility fleets are potential early adopters and because there is no net injected energy nor any RECs involved.
- We note that § 75.13 sections (d) through (i) are not relevant because no net energy is produced over time. We don't have any opinion as to whether this should be reflected in the code.
- We see no other changes needed to these code sections.

The PUC seeks comment on whether they should facilitate device-level metering and if so, how? At the DERA stakeholder meeting, it was noted that: "The PUC should permit device-level metering". "Device-level metering is a contested issue at FERC right now at PJM. PJM has said it will not require or allow device-level metering. FERC urges PJM to work with stakeholders to accept device-level metering. PJM says it puts an unreasonable burden on the EDCs because they generally use standard meters located on the side of the house"

- The quoted statement by PJM is incorrect. Device-level metering is currently used by PJM for A/S regulation; co-author Gilman is currently managing such a resource in Newark, with 2-second resolution, device-level power metering, and telemetry to PJM.
- As of May 2024, PJM is resisting FERC's and DERA's requests for device-level metering for other A/S. We have submitted comments to FERC and discussed at PJM Stakeholder meetings that premises-level metering requirements for DERs are unnecessary and superfluous, and will significantly raise costs to ratepayers and/or to DER operators. If the DERA must absorb this cost, it becomes a market barrier to DERAs, favoring incumbent generators in the A/S and Capacity markets. If premise metering costs are added to the rate base, it becomes an unnecessary ratepayer cost. Either is undesirable and inconsistent with FERC Order 2222.

- We suggest that PUCs should permit and facilitate device-level metering. The technology to automatically report and compile individual device meters does exist, we are using it in a utility and with PJM currently, and it presents no burden to either utility or to RTO systems. DERAs meter devices and combine those devices into aggregations also called virtual power plants. DERAs are now required to keep an audit trail on individual devices as well as the total aggregation being bid. That combining also makes it possible to consolidate individual premise devices into a distributed aggregation to meet market participation thresholds (PJM is 100 kW). All these device-level metering costs, including telemetry to PJM, logically and reasonably are the responsibility of the DERA.
- The quotation attributed to PJM above, that submeters on the device “puts an unreasonable burden on the EDCs because they generally use standard meters located on the side of the house” represents substantial confusion by the speaker. There are two cases: 1) If BTM storage is serving EDC markets (e.g. charge EV off-peak and discharge on-peak) then the utility needs a net premise meter, possibly upgraded to a dual-rate TOD meter measuring kWh. The utility will read this premise meter and bill according to their tariff, as they do now. If there is a system benefit, say peak load reduction or valley filling, then there is a reasonable argument that this EDC meter upgrade should be rate-based. PJM is not involved and has no jurisdiction here. If the DERA has a device-level meter that is only for device management, that is the DERA’s cost and responsibility and the utility has no need to monitor or maintain the device meter. 2) A different case is if the DER is providing “A/S only” on the PJM market. In that case, the utility would still have a net kWh meter in the usual premise location in order to read and bill for energy (kWh) as they usually do. Still, the DERA would require a submeter on their DERs, recording power (kW), and time at a much higher resolution. The DERA is responsible for installing, meter certification, maintaining, reading, telemetry to PJM, and any required auditing for PJM. The utility in neither case has any need to read the submeter, although the DERA and utility could optionally enter an agreement to exchange data. PJM might have an

interest in premise meter data, and in our experience, some at PJM and in PJM stakeholder groups incorrectly believe this is needed, but the utility meter does not record power at sufficient time resolution to be useful even for auditing.

- Note for the two cases above: the utility installs, maintains, and reads the same type of premise meter that they do today. And likely the DERA installs the same device-level meter and telemetry for device management in either case. The first case is state jurisdiction only. PJM requires data from the device-level meter only in case 2. Note also that with these clear distinctions, switching between EDC and PJM markets only involves whether the DERA needs to send power (kW) and time readings to PJM. This is simple, cost-effective, and accurate metering for all parties in both types of markets.

<u>Section E:</u>

Management Of Distribution Utility Overrides Of DERs To Maintain Reliability, And Disputes Arising Therefrom

The PUC seeks comment on whether and how its regulations can or should be augmented to address EDC overrides of DER Aggregation Resource or Component DER operation, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's regulations that would address overrides.

- A DERA controlling BTM storage will typically be able to make storage charge or discharge with a very fast response. When an EDC experiences an unexpectedly large load or loss of supplying generation or transmission, it would be preferable to have storage discharge to prevent system failure or rolling backouts. The converse problem, when some EDC circuits are over-voltage, DERA control could increase the battery charging rate or provide reactive power on those circuits. Proposed PJM rules would give the EDC the ability to "turn off" the DERA, putting any controlled storage in a neutral state (neither charging nor discharging and power factor of 1.0). It would be far more valuable to the EDC to be given EDC-level and substation-level (or even circuit-level) control, that is, the ability to request that the DERA charge or discharge at a certain rate.

- In other words, rather than disconnecting or overriding the entire signal for a given DERA, which may be spread out over the service area of an EDC, the DERA could provide the EDC control at whatever resolution the DERA can. For example, the DERA could give the EDC control over individual distribution feeders. This would provide diverse solutions for multiple types of reliability, out-of-specification, or fault events in the EDC. Finer control, when the affected DERs are less than the entire EDC, would incidentally also be less taxing to the DERA resources. Example protocol semantics follow. PJM can “allow” this by administratively requiring DERA market participants to offer this to EDCs, not by literally processing such signals. Our impression is that it would be computationally and administratively cumbersome to have such signals go through the RTO. Rather, the RTO could simply confirm by document inspection that the EDC and DERA have an agreement to convey such information.
- No new policies need to be made between PJM and DERAs to improve the override of PJM signals to DERAs. The only agreement that would need to be made is between the DERA and EDC to create a contract providing that the EDC can control DER resources, within limits.
- EIA reports (2018) that the average utility customer had 1.3 power interruptions with a total outage time of 4 hours per year[5]. Additionally, sometimes the load is so high that reliability thresholds are exceeded or expensive peaking generators must be dispatched. We have been told by utilities that such times are in the range of 70 hours/year but don’t have a good reference at hand for yearly frequencies.
- If the DERA sets dispatch control according to EDC needs, that could prevent some blackouts and improve power quality at other times. On the other hand, when the DERA cedes control, it cannot earn on either RTO or EDC markets by providing a grid service.
- For example, a contract could have terms such as the following:

[5] Average Frequency and Duration of Electric Distribution Outages Vary by States. U.S. Energy Information Administration (EIA). 2018. https://www.eia.gov/todayinenergy/detail.php?id=35652.

- The EDC is given control up to 80 hours per year. 80 hours would have only a small effect on DERA A/S revenue and performance for the RTO, given the potential of operating 8760 hours/year.
- The EDC would have discretion as to when they consider an emergency justifying taking control but potentially could be charged a fee over the maximum yearly hours.
- PJM or a PSC could enforce this requirement simply by filing paperwork, for example, a signed statement or contract between a DERA and the EDC would be shown to PJM.

- The question about override is stated in response to the FERC Order. However, override or EDC control would also be of value If the DERA is providing grid services only for the EDC.
- The PUC can facilitate this override process to support a more reliable service for PJM, DERAs, and DERs. ("facilitate" first, by the PUC just allowing it, or more actively the PUC could suggest that the DERA receive an incentive to accept a targeted EDC signal rather than just a shutdown signal.)
- Below is an example of how EDC could request control (rather than just cutoff). This illustrative example in our comment does not imply that we suggest requiring automated control by EDCs. Indeed, it may be easier for initial implementations to have the EDC system operator simply call the DERA operator on the telephone to request a charge or discharge per EDC request.

Operation Coordination could use signals like the following:

EDC Request	DERA Response
Request EDC control start	Acknowledge
Query capacity available for Feeder #_____	Up ___ kW, Down ___ kW
Query capacity available for Substation #_____	Up ___ kW, Down ___ kW
Dispatch Feeder #_____ at ±_____ kW	Confirm dispatch.
Dispatch Substation #_____ at ±_____ kW	Confirm dispatch.
Query capacity for entire EDC service area	Up ____ MW. Down ____ MW.
Dispatch entire EDC area at ± ______ MW.	Confirm dispatch.
End EDC control	Acknowledge

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- In summary, we feel that the override agreement is best handled in a contract between EDC and DERA. The PSC might simply recognize that such contracts could exist. Or the PSC could suggest some overall parameters for such contracts and/or serve as an arbiter in case of disputes.

Section G.

Prevention Of Double Compensation Or Double Counting Between Retail And Wholesale Market Participation, Including Rules Governing DER Owners' Ability To Switch Between Retail And Wholesale Market Participation

The PUC seeks comment on whether its existing regulations on compensation for net metering customer-generators, 52 Pa. Code § 75.13, could or should be adapted to incorporate appropriate restrictions on double counting of services provided by a Component DER in wholesale and retail markets, on duplicative compensation for the same service, consistent with Order 2222 and PJM's DAPM, or on both, and, if so, what specific changes to the PUC's regulations would or should facilitate this adaption.

- No, 52 Pa. Code §75.13 should not be adapted to restrict double counting.
- See below, NEM is not double counting with PJM markets "A/S only" nor "capacity only" etc. NEM resources need not be defined differently in this section § 75.13, rather, the EDC need only report to the RTO which DERs are within NEM premises, per below.

The DAPM provides "A DERA may participate in the PJM energy, capacity, and/or ancillary services markets… using DER Aggregation Resources containing one or more Component DER that also participate in one or more retail programs. PJM shall only credit a DERA for the sale of a product in the PJM energy, capacity, and/or ancillary services markets if that same product is not also credited as part of a retail program, including but not limited to a Component DER participating in a retail net energy metering program."

- We agree with the above statement. However, it should be clarified explicitly due to the confusion regarding this topic. There can be no instance of double counting if the EDC meters and credits for energy, and the RTO market is a market compensated for power, response, and time, not including energy (as elaborated further elsewhere in this comment).

“The DAPM also provides that any “issues within disputes” that PJM determines solely concern the application of EDC tariffs, agreements, and operating procedures and/or PUC regulations shall be addressed in accordance with applicable state or local law and shall not be arbitrated or in any way resolved by PJM .”

- We agree with this statement.

“Does the PUC have authority to decide whether to permit net metering customers to participate in DERAs, noting FERC’s statement that “under a [RERRA]’s jurisdiction over its retail programs, such a [RERRA] is able to condition a distributed energy resource’s participation in a retail distributed energy resource program on that resource not also participating in the RTO/ISO markets”? Assuming the PUC does have requisite authority, should the PUC permit net metering customers to also participate in DERAs at the same time?”

- PUC has the ability to determine that NEM is allowed based on state law and tariff independent of RTO activities. We recommend that BTM storage, including V2G if used for grid services, should qualify for net energy metering. We believe that the PSC need only address whether or not the EDC is accurately reporting to the RTO that net metering is being used for premises with DERs. Even if RERRAs (the PUC) should have the authority to condition DER admission to NEM on wholesale activity, they should not do so.
- We do not see the need for the PUC or an EDC to make a judgment regarding net energy metering’s impact on qualification for RTO markets. As long as the RTO is informed about which DERs are located within premises that are net metered, the RTO can determine which RTO markets those DERs can participate in. (PJM’s current compliance filing with FERC implies NEM resources would

qualify for all non-energy markets, such as PJM's new "A/S only"; we recommend also allowing a market for "Capacity only"). The "only" means that PJM pays for timely response in kW, and PJM pays nothing for energy (kWh). Thus net metering by EDC cannot be double counting with RTO "only" markets. If the NEM resource DERA applied for a PJM energy market, PJM, not the PUC, would be responsible for declining entry to that wholesale market.

- Arbitrarily barring NEM DERs from non-energy markets such as "A/S only" would create barriers to entry for storage DERs, undermine the implementation of FERC Order 2222, and via requiring duplicate storage equipment would raise rates to consumers.
- Overall it is reasonable to guard against duplicate compensation. However, there should be a stated emphasis in PUC's guidelines agreeing with Order 2222 that Ancillary Services only and Capacity only can be within NEM premises and still participate in non-energy wholesale markets.

Section H:
Any Necessary Electronic Data Exchange Revisions

The PUC seeks comment on whether it should encourage or impose EDI and/or other data exchange protocols between and among EDCs, EGSs, DERAs and Component DERs to facilitate implementation of Order 2222, and, if so, what, if any, specific changes to the PUC's policies and regulations would or should facilitate this adaption.

- We don't recommend state regulation of data exchange protocols among EDCs, DERAs, etc at this early stage. Frankly, very few DER operators and to our knowledge essentially no EDCs fully understand how to economically utilize V2G resources, so the industry is several steps away from accepted protocols for such interactions. Thus PUC guidance or encouragement would be a negative now. This could be revisited after several years of experience.

The PUC seeks comment on whether the PUC may assert jurisdiction to regulate DERAs, and, if so, what requirements should the PUC impose on DERAs, consistent with Order 2222 and PJM's DAPM, and what specific changes to the PUC's policies and regulations would facilitate the PUC's exercise of authority over DERAs.

- We suggest the PUC should assert jurisdiction over DERAs participating in only a retail EDC energy market as per the PUC's already existing retail market monitoring standards. In the case of a wholesale transaction, it makes sense that PJM market rules should govern DERA participating in those markets; the state jurisdiction clearly applies to transactions on the utility's premise meter.
- Regardless of the market, we suggest that the PUC provide guidelines for EDC approval of interconnection. PJM compliance filing for 2222 also suggests that EDCs approve interconnection to their grids (which is of course under PUC jurisdiction). V2G has some unique characteristics because the inverter may be in the vehicle and because it drives around, may do grid services from different areas of jurisdiction. Specifically, injection from EVs with AC charging should be permitted by using compliance with SAE J3072, or SAE3068, or UL17441-SC, which are designed for EVs. These SAE standards draw from existing interconnection standards developed for solar, such as UL1741, and they require IEEE 1547 performance by reference.
- Because recent versions of UL1741 require much more complex controls in the inverter, and these are not needed for safety, we recommend that inverters in cars not require more than IEEE1547-2003, which covers all the safety requirements and is much simpler for automotive OEMs to implement.
- In the case of interconnection, FERC Order 2222 envisions the utility making interconnection decisions, including approval of injection. Apart from using the appropriate standards per above, this would be done by the utility in the same way that they now approve solar installations to maintain safety and power quality.

We are glad to provide further information on any of these points or provide data to support our recommendations.

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