Comments on Operational Coordination in PJM's second compliance filing with FERC order 2222

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Rationale for comment

- The UD Electric Vehicle R&D Group develops and demonstrates grid integration of Electric Vehicles with V2G technology. The goal is to provide EDC or RTO grid services during time parked, and receive payment for services rendered.
- We comment on specific policies in PJM's compliance and/or FERC comments that directly impact the cost and effectiveness of this nascent technology. Most also are relevant to stationary storage behind a retail meter.
- Each topic is organized by quoting a section of the FERC response to PJM's compliance filing for Order 2222, followed by our proposed solution.
- This comment concerns Operation Coordination, specifically, controlled override of PJM market signals.

Section 335 on page 142

“the Commission required each RTO/ISO to revise its tariff to include coordination protocols and processes for the operating day that allow distribution utilities to override RTO/ISO dispatch of a distributed energy resource aggregation in circumstances where such override is needed to maintain the reliable and safe operation of the distribution System. To account for different regional approaches and to provide flexibility, the Commission did not prescribe specific protocols or processes for the RTOs/ISOs to adopt as part of the operational coordination requirements but rather allowed each RTO/ISO to develop an approach to ongoing operational coordination.”

UD Comment on Section 335 on page 142

<u>Problem:</u> The phrasing “allow the distribution utility to override RTO/ISO dispatch of a DER aggregation” is not representative of the spectrum of cases that can occur in the power system. Currently, the proposal by PJM to FERC for Order 2222 compliance only offers the choice to either disconnecting the PJM signal from the DERA or replacing a single PJM signal with a single EDC signal. By their nature DERAs have visibility down to the service drop meaning dispatch can be finely controlled (e.g. by substation or distribution feeder). It is not required for EDCs to disrupt or disconnect PJM’s entire market signal to a DERA when the grid experiences issues. Order 2222 only requires that the EDCs be allowed to dispatch the DERA, it does not require that PJM provide, receive, or process that signal, nor that PJM negotiates how the DERA should be compensated for doing so.

<u>UD Solution:</u> 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 is able to. 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 per section 335, by administratively requiring DERA market participants to offer this to EDCs, not by literally processing such signals.

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

Section 348 on page 146

“Regarding real-time operations, specifically commenters’ concerns with the ability of the distribution utility to initiate an override, PJM states that compliance with a distribution utility’s operating procedures is outside its purview because it is a requirement of Order No. 2222, and one that the DER Aggregator must attest compliance with prior to participation in PJM’s markets. PJM states that the purpose of its proposed tariff language regarding real-time operations is to simply acknowledge that RERRAs and distribution utilities may formulate different non-jurisdictional rules regarding the physical operation of Component DER and/or DER Aggregation Resources, and that DER Aggregators will be required to comply with those rules whether they relate to physical dispatch or otherwise.”

UD Comment on Section 348 on page 146

Problem: DERAs are seen as offering very limited override resolution. An EDC overriding signals for the entire service territory is an imprecise control for many type of distribution problems. Also total system override will likely degrade RTO market capability or performance measures. This problem would be worse if the only possible signal were only for the EDC to interrupt the RTO signal, or only to replace the RTO signal for the entire EDC's service territory.

Solution: 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 the EDC can control DER resources, within limits. EIA reports (2018) that the average utility customer had 1.3 power interruptions with total outage time of 4 hours per year (see: https://www.eia.gov/todayinenergy/detail.php?id=35652). Thus, for example, a contract could allow the EDC to control up to 80 hours per year. 80 hours would be more than typically needed for EDC reliability resolution, yet 80 hours would have only a small effect on DERA A/S performance for the RTO, likely to be operating closer to 8760 hours/year. PJM could enforce this requirement simply by paperwork, for example, a signed statement from the EDC, or requesting a copy of the contract.

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