April 28, 2017

Solar Industry Comments on and Recommendations for the EPRI Report *"Harmonizing Distributed Generation Interconnection Practices in NY State: Technical Review Processes"*

Section 1 – General Comments and Points of Agreement

1. **Inclusion of aggregate DG in Screen E:** (p. 15-16) We support the continued inclusion of aggregate and queued DG as part of the screen and recommend only that it be clarified to make explicit that only DG ahead of the project in the queue be included.

2. **Removal of voltage flicker and harmonic injection screens from supplemental review and CESIR:** (p. 18 and 29) We strongly support this recommendation and feel that in combination with our comment 1.3 below that this is a more appropriate way to address any potential concerns from these issues. Such a change for flicker would be compatible with the current versions of IEEE 519 and IEEE 1453, which have removed the borderline of visibility and irritation curves and replaced them with the use of a flickermeter and limits on the short and long-term flicker intensity parameters. The adoption of limits based on this methodology are also likely to be included in the power quality section of IEEE P1547. The use of the flickermeter post-facto if complaints or other issues arise along with the requirements for addressing violations spelled out in the interconnection contract as noted in our comment 1.3 on retroactive incompatibility would serve, in our view, to ensure the safety and reliability of the electric system. The removal of flicker as an a priori element of study will greatly simplify the screening and study process as the requirements for accurate time domain analysis are complex and time consuming as noted by EPRI.

3. **Retroactive incompatibility:** (p. 10-11) We agree that this is a concern with the current interconnection documents as they do not include mechanisms to address post-interconnection issues explicitly. We would propose providing strong support from the members of the ITWG for the IPWG to take this issue up in combination with other pending changes being discussed for the interconnection contracts such as the issues of insurance and indemnification raised during the supplemental anti-islanding discussion.

   On this point, we would recommend that there would need to be some clearly defined process in the new contract language establishing a process by which the root cause of any problems be determined as other changes on the distribution circuit may be to blame for a problem with power quality and not the DG facility. We recognize that troubleshooting power quality problems can be very challenging and that it is often hard to determine whether something is the cause of the problem or a reaction to the problem. As an example starting point for such discussions, we would recommend the Massachusetts: Eversource Exhibit G - Interconnection Service Agreement section 6 which we have included as an annex to this response.

4. **Modification of Screen C:** (p. 14-15) We generally agree with our understanding of the EPRI recommendation to simplify this screen to look at only the transformer and secondary conductor rating as is done in California's Rule 21 (Screen D).

   We share the concern noted by EPRI on the impact of load on modifications to the thermal limits and note that the inclusion of this effect could make automation of the screens complicated. EPRI notes that the 15% of peak load screen addresses the issue of aggregation of multiple DG facilities and this point is supported by the absence of a screen like this in the current Massachusetts Standards for Interconnection of Distributed Generation. Thus, while we would support their proposed simplification to consider only the single facility, we do note that the California screen applies to "the maximum aggregated Gross Ratings for all the Generating Facilities connected to a secondary distribution transformer" and so we would not oppose the retention of aggregate DG in this screen if strongly preferred by the JU or DPS Staff.

Section 2 – Recommended Modifications

1. **Reporting results of preliminary review:** (p. 35) For the reporting of the quantitative preliminary screening results, knowing by how much a system failed would be of great value in determining whether or not to move forward to a CESIR as there is a substantive difference to knowing that a system was at 30% percent of peak load versus 300% for example.

2. **Modifications to Screen F: Simplified Voltage Fluctuation** (p. 16-17)
   a. It is unclear to us why a new 3% voltage rise or fraction of feeder rating screen is necessary as part of the initial technical review. This screen is not a part of the initial technical review in California, Massachusetts, or Hawaii which have all successfully relied on the 15% of peak load screen to address concerns over voltage impacts from DG in the preliminary review. In addition, it is unclear the technical basis for the selection of either 3% voltage rise or 10% or 15% of feeder rating as a new preliminary screen.

   b. The screen in the original SIR appears to have been intended as a translation of IEEE 1547 section 4.1.3 on synchronization "[t]he DR unit shall parallel with the Area EPS without causing a voltage fluctuation at the PCC greater than ±5% of the prevailing voltage level of the Area EPS at the PCC, and meet the flicker requirements of 4.3.2." This section of IEEE 1547 does not reference aggregate generation and also pre-dates advanced inverter ramp rate control and reconnection by "soft-start".

   c. As such we recommend eliminating the proposed changes to Screen F and suggest instead that it be modified to be more readily and clearly identify it as a screen that is intended going forward to address only voltage sag upon the startup of spinning generators. Specifically, we recommend that Screen F be renamed the "Starting Voltage Drop Test" and that it should adopt the same tests currently in use in California Rule 21 (Screen C) and in the Massachusetts Standards for Interconnection of Distributed Generation (Screen 7 and Note 4). These rules both use the following standards:

i. This Screen only applies to Facilities that start by motoring the generating unit(s) or the act of connecting synchronous generators.

ii. The Distribution Provider has two options in determining whether Starting Voltage Drop is acceptable. The option to be used is at Distribution Provider's discretion.

Option 1: Distribution Provider may determine that the Generating Facility's starting In-rush Current is equal to or less than the continuous ampere rating of the Customer's service equipment.

Option 2: Distribution Provider may determine the impedances of the service distribution transformer (if present) and the secondary conductors to Customer's service equipment and perform a voltage drop calculation. Alternatively, Distribution Provider may use tables or nomographs to determine the voltage drop. Voltage drops caused by starting a Generator must be less than 2.5% for primary Interconnections and 5% for secondary Interconnections.

3. **Requiring supplemental review:** (p. 9) While we understand the motivation to consider making a revised supplemental review mandatory, we feel strongly that making the review optional is critical. There are likely substantive numbers of mostly larger systems that due to the circuits they would be on will be clearly identifiable as requiring a full CESIR following the preliminary review. Requiring such systems to pay the added expense of a supplemental review and the added time delay for the developer and added workload for the Utilities would not seem efficient or equitable.

   We recognized that this will affect the standardization of the CESIR results as projects that forgo supplemental review will still require things like supplemental anti-islanding protection screening, but we feel that such differences in CESIRs are reasonable trade-offs against the benefits or retaining supplemental review as optional rather than required.

4. **Replacing Screen G with supplemental anti-islanding protection screen:** (p. 18) The supplemental anti-islanding protection methodology is not a pass/fail screen as only an optional ROI and/or the addition of reclose blocking or DTT are outcomes. The timeline for a supplemental review would have to include provisions for the effect of the optional ROI study. We would recommend that developers get all results from the supplemental screens before being required to choose whether to pursue an ROI and that they have the option to pursue an ROI study simultaneously with choosing to proceed to a CESIR if they wish so that both can proceed in tandem.

   a. In addition, we note that replacing Screen G and eliminating Screen I (p. 18-19) would not appear to currently address the potential for feeder backflow into the substation and the possible need for upgrades to LTC or the potential for substation reverse power flow and the possible need for transmission system ground-fault over-voltage protection. We saw the report's note that "[i]ssues such as fuse coordination, breaker ratings, fault current coordination for relays and 3V0 protection (where applicable) should be covered in the supplemental protection screen" (p. 19) but saw no specific proposal for the language of such a screen.

5. **Voltage fluctuation supplemental screen:** (p. 19) While we note that it is more common in California and Hawaii to run a power flow simulation as part of the supplemental review to confirm ANSI limits are not exceeded, we would support the adoption of a 5% voltage rise screen as part of supplemental review with the following key improvements.
   a. We feel that the use of the worst-case resistance is overly conservative and should be changed to either the average resistance or the resistance from the applicant's PCC to the nearest upstream voltage regulation device (if any). In addition, the existing and queued DG included in this calculation should not include systems in upstream voltage regulation zones. Finally, the default resistance values per foot used by the utilities should be made available publicly in a transparent way and should be kept up to date as system configurations and manufacturers change.

   b. As this screen appears to be intended to solely examine the potential for steady-state voltage issues, we would recommend that its name be changed to "Simplified Voltage Rise Test" to avoid confusion with other voltage variations not accounted for in this screen.

6. **Standardized content in CESIRs:** We strongly support the goal of standardizing both the CESIR reporting formats and (where possible) the methodologies used to determine system upgrades across Utility service territories.

   a. We would recommend that the CESIR results include a construction timeframe/scope. While we recognize the uncertainties inherent at this stage and would not see this as a construction schedule, but a good faith estimate of the timeframe would be of significant value to developers.

   b. With respect to the ambiguity as to whether the steady-state voltage limit for this analysis should be 5% as in ANSI C84.1 or 3% as in Hawaii when onsite generation is present in significant quantities please see comment 3.2 below.

   c. For both thermal and voltage modeling where temporal concerns exist, we propose the use of long-term dynamics modules that represent the impact of an intermittent DG varying its output with realistic levels of ramping and can take appropriate account of geographic diversity of systems rather than simply relying solely on the full-on to full-off transition as proposed by EPRI (p. 24-25).

   d. It's important that voltage regulating line equipment be modeled in these time series analyses. The report notes that "[r]egulators and capacitor banks may not be directly modeled, however, the expected status of these devices should be reflected in the substation voltage and feeder reactive power requirements" (p. 24). We interpret this to refer to substation regulators and capacitors, but this should be clarified so that equipment on the distribution lines is included in the model.

e. In the presentation of CESIR results that are quantitative in nature we would recommend that the "make clear Rationale and Concerns" (p. 38) requirement suggested by EPRI include the expectation that the quantitative values be included. For example, rather than reporting only that a steady-state overvoltage exists, it would be helpful to developers to know how much over the ANSI limits the system was and what the voltages were before the DG facility was interconnected.

Section 3 – Questions and Requests for Clarification

1. EPRI states that fault current rise and reduction of breaker reach are not expected to be an issue with inverter-based DERs. (p. 27) It was not clear if the report was recommending that these elements not be studied for inverter based DG or whether they were simply expressing the view that they would be studied but simply not likely to identify concerns for inverter based DG. We would request clarification on this point.

2. It is unclear if EPRI is recommending a 103% maximum or a 105% maximum for steady-state voltage rise. If they're using Hawaii as an example to recommend a 103% maximum, it's important in our view to recognize that Hawaii is dominated by residential rooftop interconnected on low voltage secondaries. For example, in their most recent queue (accessed on April 24, 2017) the Hawaiian electric utilities had just 24 total projects out of 9,507 that were at or over 1 MW in size while nearly 94% of the systems by number were under 50 kW.[1] We also note that Hawaii is implementing line drop compensation (LDC) at their high penetration substations. Without LDC, implementing a 103% maximum could immediately disqualify a significant portion of each distribution feeder.

[1] https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue
https://www.mauielectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue
https://www.hawaiielectriclight.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue

Annex A – Language from an Interconnection Agreement from Massachusetts Addressing Retroactive Incompatibility

Eversource: Exhibit G - Interconnection Service Agreement

6. Operating Requirements.

General Operating Requirements.

Interconnecting Customer shall operate and maintain the Facility in accordance with the applicable manufacturer's recommended maintenance schedule, in compliance with all aspects of the Company's Interconnection Tariff. The Interconnecting Customer will continue to comply with all applicable laws and requirements after interconnection has occurred. In the event the Company has reason to believe that the Interconnecting Customer's installation may be the source of problems on the Company EPS, the Company has the right to install monitoring equipment at a mutually agreed upon location to determine the source of the problems. If the Facility is determined to be the source of the problems, the Company may require disconnection as outlined in Section 7.0 of this Interconnection Tariff. The cost of this testing will be borne by the Company unless the Company demonstrates that the problem or problems are caused by the Facility or if the test was performed at the request of the Interconnecting Customer.

No Adverse Effects; Non-interference.

Company shall notify Interconnecting Customer if there is evidence that the operation of the Facility could cause disruption or deterioration of service to other Customers served from the same Company EPS or if operation of the Facility could cause damage to Company EPS or Affected Systems. The deterioration of service could be, but is not limited to, harmonic injection in excess of IEEE Standard 1547-2003, as well as voltage fluctuations caused by large step changes in loading at the Facility. Each Party will notify the other of any emergency or hazardous condition or occurrence with its equipment or facilities which could affect safe operation of the other Party's equipment or facilities. Each Party shall use reasonable efforts to provide the other Party with advance notice of such conditions.

The Company will operate the EPS in such a manner so as to not unreasonably interfere with the operation of the Facility. The Interconnecting Customer will protect itself from normal disturbances propagating through the Company EPS, and such normal disturbances shall not constitute unreasonable interference unless the Company has deviated from Good Utility Practice. Examples of such disturbances could be, but are not limited to, single-phasing events, voltage sags from remote faults on the Company EPS, and outages on the Company EPS. If the Interconnecting Customer demonstrates that the Company EPS is adversely affecting the operation of the Facility and if the adverse effect is a result of a Company deviation from Good Utility Practice, the Company shall take appropriate action to eliminate the adverse effect.