March 12, 2018

Kathleen H. Burgess
Secretary
State of New York
Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case 18-E-0018 – In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators.

NYSEIA Comments on 11/27/17 Department of Public Service Proposed Redline of the *"New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems"*

Dear Secretary Burgess:

NYSEIA respectfully wishes to submit the following comments on the proposed changes to the New York SIR on behalf of its member companies. The attached comments are in addition to those we have submitted with the Joint Utilities under a separate cover.

These comments are focused on the technical Appendix G of the SIR, and are included as highlighted, tracked changes to the DPS Staff redline from November

27th. The comments include suggested revisions of the language in screens B, C, D, E, F, G, H, and I on topics including:

1. effective grounding,
2. the application of the stiffness factor screen for inverter based DER like solar PV,
3. the use of minimum daytime load for solar PV in the supplemental penetration screen,
4. the application of the IEEE 1453 standard for visible flicker and in particular the setting of the emissions limit
5. the need to test for violations of ANSI C84.1 voltage limits as part of supplemental review
6. the application of a screen for the impact on voltage regulation devices from variations in output from intermittent renewables, and
7. modifications to the screens on system protection and operating limits.

Rigorously supported up-to-date technical screens are essential to the successful interconnection of DG facilities to New York's distribution grid so that projects with minimal impacts on the distribution system are not unnecessarily driven to the time and expense of a full study, and because the standards referenced in these screens also drive the upgrades required and costs when a full study is required. While some of the proposed changes are intended to clarify the language in the SIR, others are more technically substantive.

In support of the later, we are also including the solar industry responses to a series of questions posed by the leadership of the Interconnection Technical Working Group on February 1, 2018 concerning our recommended changes to screens F and H. In addition to this supporting material, NYSEIA notes that our recommendation to change the emission limit (Epst) for visible flicker referenced in screen H is consistent with changes to the draft IEEE 1547 standard that have occurred since the discussions surrounding the September 2017 workshop at which Pterra presented the shape factor methodology for addressing visible flicker that is otherwise employed in this screen. At that workshop Pterra presented a methodology that included a calculation of the emission limit that was consistent with that included in IEC 61000-3-7. At the time, however, there was discussion that the ongoing revisions to IEEE 1547 might include a single limit for Epst at 0.35 and it was this value that was included in the proposed screen H. However, in response to comments from stakeholders in the IEEE process, it now appears likely that the final revision of IEEE 1547 may adopt the emission limits as calculated by the methodology in IEC 61000-3-7 which have 0.35 as the minimum allowed Epst and not the maximum (as currently employed in the proposed screen H). In order to maintain consistency with the latest IEEE standards and to avoid needlessly sending systems to detailed study when their impact on the distribution system does not warrant it as mentioned above, NYSEIA is recommending a change in the language to screen H that references the emission limit “based on IEC 61000-3-7 and included in IEEE 1547”.

NYSEIA thanks you for your leadership on these important issues and looks forward to moving forward with these improved interconnection standards.

Sincerely,

Valessa Souter-Kline

Valessa Souter-Kline
Policy Coordinator,
New York Solar Energy Industries Association (NYSEIA)

New York State
Standardized Interconnection Requirements and Application Process
For New Distributed Generators and Energy Storage Systems 5 MW or Less
Connected in Parallel with Utility Distribution Systems

New York State
Public Service Commission

~~**August 2017**~~

APPENDIX G

PRELIMINARY SCREENING ANALYSIS

Screen A: Is the PCC on a Networked Secondary System?

Does the proposed system connect to a secondary network system?

• If yes (fail),

• If no (pass), continue to Screen B.

Screen B: Is Certified Equipment Used?

Does the Interconnection Customer ~~Interconnection Request~~ propose to use equipment that has been listed to meet safety standards such as UL 1741 and its supplement SA (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) ~~and~~ by a nationally recognized testing laboratory?

• If yes (pass), continue to Screen C.

• If no (fails preliminary screening)

Screen C: Is the Electric Power System (EPS) Rating Exceeded?

Does the maximum aggregated generation connected to an EPS ~~or loading capacity connected to an EPS~~ (existing and ~~,~~ approved ~~and being considered~~prior to application) or incremental loading capacity at the PCC exceed any EPS ratings (modified per established utility practice)? ~~Do the maximum aggregated Gross Ratings for all the Generating Facilities connected to an EPS exceed any EPS rating, modified per established Distribution Provider practice, absent any Generating Facilities?~~

• If yes (fails preliminary screening),

• If no (pass), continue to Screen D.

Screen D: Is the Line Configuration Compatible with the Interconnection Type?

1. Identify primary distribution line configuration that will serve the distributed generation or energy storage. Based on the DER interconnection and using the table below, determine compatibility with the electric power service, including voltage rating, phase balance, line and grounding configuration

Primary distribution line configuration	**Type of DER connection to primary**	**Result/Criteria**
Three-phase, three-wire	Any type	Pass Screen
Three-phase, four-wire	Single-phase line-to-neutral or effectively-grounded 3 Phase	Pass Screen
Three-phase, four-wire (For any line that has sections or mixed three-wire and four-wire)	All others	To pass, aggregate DER nameplate rating or maximum export must be less than or equal to 10% of line-section peak load

2. Based on aggregate DER on the feeder, is phase balancing maintained within utility limits?

- ~~Line Configuration Screen: Identify primary distribution line configuration that will serve the Generating Facility. Based on the type of Interconnection to be used for the Generating Facility, determine from the table below if the proposed Generating Facility passes the Screen.~~

- If yes to both questions (pass), continue to Screen E.
- If no (fail)

~~Primary Distribution Line Type~~	~~Type of Interconnection to Primary Distribution Line~~	~~Result / Criteria~~
~~Three-phase, three wire, > 5 kV~~	~~3-phase~~	~~Pass~~
~~Three-phase, four wire, >5 kV~~	~~Effectively grounded 3 phase~~	~~Pass~~
~~All~~	~~Single phase, phase-phase, or ineffectively grounded sources or transformers~~	~~Fail~~

Screen E: Simplified Penetration Test

If the aggregate DER generation capacity on any medium voltage line section (existing and approved prior to application) is less than 15% of the annual peak load for all line sections bounded by automatic sectionalizing devices upstream of the DER? If no, consider if feeder data are available that shows aggregate DER will not exceed a minimum load. Note that calculation of minimum, or peak, load should consider both generation and charging modes of DER..~~Is the aggregate Generating facility capacity on the Line Section less than 15% of the annual peak load for all Line Sections bounded by automatic sectionalizing devices?~~

• If yes (pass), continue to Screen F.
• If no (fail), Supplemental Review is required, continue to Screen F.
•

Screen F: ~~Simplified Voltage Fluctuation Test~~Is Feeder Capacity Adequate for Individual and Aggregate DG?

For inverter based solar PV DER, is the feeder available short circuit capacity at the medium voltage PCC divided by the rating of the individual DER multiplied by the ratio of Z/R greater than 50? For all other DER, is the feeder available short circuit capacity at the medium voltage PCC divided by the rating of the individual DER greater than 25?

Is the feeder available short circuit capacity at the substation divided by the capacity all aggregate DER on the feeder greater than 25?

• Yes to both feeder and substation levels (pass screen)

No to either (fail screen)"~~Is the feeder available short circuit capacity at the medium voltage PCC, divided by the rating of the individual DG, greater than 25? Is the feeder available short circuit capacity at the substation divided by the capacity all aggregate DG on the feeder, greater than 25? In aggregate with existing generation on the Line Section~~

~~a. Can the Generating Facility parallel with the Distribution Provider's Distribution System without causing a voltage fluctuation at the PCC greater than 5% of the prevailing voltage level of the Distribution System at the PCC?~~

~~• If yes (pass), Preliminary Screening Analysis is complete.~~
- ~~If no (fail), Supplemental Review is required~~

Commented [BS4]: See "Solar Industry Responses to ITWG Questions from 2/1/18" (March 2, 2018) for supporting details

SUPPLEMENTAL SCREENING ANALYSIS

Screen G: Supplemental Penetration Test

- Where 12 months of line section minimum load data are available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate DER capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the DER? (Note: The minimum load considered for solar PV should be the minimum day-time load while that for all other DER should be the overall minimum load.) Is the DER within the thermal limitations of utility equipment?

~~Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?~~

- If yes to both questions (pass) Continue to Screen H.~~, continue to Screen H.~~
- If no (fail), a quick review of the failure may determine the requirements to address the failure; otherwise the Interconnecting Customer may be required go on to the Coordinated Electric System Interconnection Review (CESIR) process. Continue to Screen H.

Screen H: Power Quality and Voltage Tests

1. Can it be determined that the voltage fluctuation is within acceptable limits as defined by IEEE 1453?

Voltage flicker emission generated by each fluctuating installation (Pst) should be limited to its emission limit (Epst). It fails the screen if Pst is higher than the emission limits based on IEC 61000-3-7 and included in IEEE 1547.

Calculate Pst using the following formula:

$$P_{st} = d \times \frac{F}{d_{pst=1}} = \frac{\Delta S}{S_{SC}} \times \frac{0.2}{2.56\%}$$

- *$d \sim \left(\frac{\Delta S}{S_{SC}}\right)$ is the relative voltage change caused by the project*
- *ΔS is the power variation from the project*
- *S_{SC} is the available short-circuit capacity of area EPS at the PCC*
- *F is the shape factor related to the shape of expected voltage fluctuation (F can be considered equal to 0.2 if detailed information is not available)*
- *$d_{pst=1}$ is the relative voltage change that yield P_{st} value of unity assuming rectangular voltage fluctuation (2.56% assuming 1 dip per second)*

2. Can it be determined that the aggregate DER on a feeder does not cause voltage excursions outside of the ANSI C84.1 limits?

3. Can it be determined that fluctuating DER output, such as PV plants experiencing transient cloud cover, do not change the voltage at any primary regulating device more than 1/2 the regulator bandwidth and more than 3 times per hour?

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- If answers to questions 1, 2 and 3 are all yes (pass screen)
- If answer to any question is no (fail screen)

~~In aggregate with existing generation on the Line Section,~~

~~a. Can it be determined within the Supplemental Review that the voltage regulation on the line section can be maintained in compliance with current voltage regulation requirements under all system conditions?~~

~~b. Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE1453?~~

~~c. Can it be determined within the Supplemental Review that the harmonic levels meet IEEE519 limits at the Point of Common Coupling (PCC)?~~

- ~~If yes to all of the above (pass), continue to Screen I.~~
- ~~If no to any of the above (fail), a quick review of the failure may determine the requirements to address the failure; otherwise the Interconnecting Customer may be required go on to the Coordinated Electric System Interconnection Review (CESIR) process. Continue to Screen I.~~

Screen I: Operating Limits, Protection Adequacy and Coordination Evaluation~~Safety and Reliability Tests~~

1. Review anti-islanding protection requirements based on the most recent version of the JU Unintentional Islanding Protection Practice and identify utility and DER system upgrades, if required.
2. Review DER system configuration to determine if design and operation meets utility's effective grounding and ground source contribution requirements.
3. Identify equipment where fault current exceeds 90% of its short circuit current interrupting capability.
4. Identify any additional concerns related to utility and DER protection adequacy and protection, including but not limited to: protective device coordination and coverage, load rejection overvoltage, and 3V0 protection (where applicable).

~~Review the installation based on the JU Unintentional Islanding Protection Practice, Version 1.2 2/9/2017. Identify islanding related protection concerns and requirements by application of the JU flow charts. Consider operation mode options (such as energy storage back feed relay, changing limit or reactive power control options). Also, evaluate protection coordination and coverage, breaker ratings, fault current coordination for relays and 3V0 protection (where applicable). Determine if there are any required changes in protection setting or additions. If yes (fails supplemental screening), a quick review of the failure may determine the requirements to address the reason for failure; otherwise the Interconnecting Customer will be provided with information on the specific points of failure in the supplemental review results and may elect to go to the Coordinated Electric System Interconnection Review (CESIR) process. Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create specific impacts to safety or reliability that cannot be adequately addressed without a detailed study?~~

- ~~If yes (fail), a quick review of the failure may determine the requirements to address the failure; otherwise the Interconnecting Customer will be provided with information on the specific points of failure in the supplemental review results and may go to the Coordinated Electric System Interconnection Review (CESIR) process.~~
- ~~If no (pass), Supplemental Review is complete.~~

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March 2, 2018

Solar Industry Responses to ITWG Questions from 2/1/18

Comments on Revised Screen F – Stiffness Factor

While some members of the solar industry continue to have questions concerning the specific threshold level for the stiffness factor screen to be applied at the level of the preliminary screening analysis and about the impact of the proposed screen on smaller systems that would otherwise pass the existing preliminary review process, the solar industry has no objections to its inclusion in the modified form discussed below.

Specifically, given the nature of the impact of inverter based PV generation on the distribution system and acknowledging the concerns raised by the JU regarding the application of the modified screen at the substation level, we would recommend that the screen be applied in two different ways at the two different levels.

First, at the level of the substation, the solar industry proposes maintaining the current language of the screen concerning the impact of aggregate DER. Second, at the level of individual DER facilities, however, we continue to strongly support the modification discussed at the most recent ITWG meeting where the stiffness factor for inverter based solar PV is modified by the Z/R ratio in recognition of the actual impacts of solar PV on the feeder's voltage profile. As such we would propose the following language for the new screen F.

> "For inverter based solar PV DER, is the feeder available short circuit capacity at the medium voltage PCC divided by the rating of the individual DER multiplied by the ratio of Z/R greater than 50? For all other DER, is the feeder available short circuit capacity at the medium voltage PCC divided by the rating of the individual DER greater than 25?
>
> Is the feeder available short circuit capacity at the substation divided by the capacity all aggregate DER on the feeder greater than 25?
> - Yes to both feeder and substation levels (pass screen)
> - No to either (fail screen)"

As discussed at the ITWG meeting, the goal of the current modification to the SIR is to develop a set of technically robust screens that more accurately reflect the reality of which systems require additional study and which have such minimal impacts that they can proceed to interconnection without detailed analysis. In our view, the above modification to the proposed stiffness factor screen (i.e. the inclusion of the Z/R correction) makes the technical basis of this screen more robust and more accurately reflects the impact solar PV will have on the voltage profile of the distribution grid. In addition, having both the short-circuit current ratio and the information about Z/R at the PCC would be of significant value to developers of larger systems that do not pass the preliminary screening analysis. Along with information about peak load, these two additional pieces of information on the feeder's stiffness can help companies decided on which sites to pursue full CESIR analyses with far greater accuracy than is currently possible. As such the modification of this proposed screen we support would provide significant benefits to both the developers and the utilities by avoiding the time, cost, and effort of pursing detailed technical analyses on systems that will be likely to face unacceptably high interconnection costs due to voltage issues.

Finally, in light of the nearly unique application of this type of stiffness factor screen at the level of preliminary analysis compared to other major solar markets, the solar industry would request that the efficacy and impacts of the stiffness factor screen (particularly on developers of smaller scale systems) be evaluated six months to a year after it is implemented to determine if any modifications should be considered.

Comments on Voltage Limits / Regulator Tap Changes

The solar industry does not support a return to the earlier proposed version of the Voltage Change/Limits screen. The inclusion of the rapid voltage change limits of 3% for an individual facility and 5% for the aggregate of all facilities is likely to be far too conservative and is not representative of realistic impacts to be expected from inverter based DER. As such, we continue to believe that this element of the proposed screen would run counter to the intent of the SIR update, as it will act to unnecessarily drive more systems - not fewer - to detailed study.

As discussed at previous ITWG meetings and in their written comments on the EPRI report, the Joint Utilities have indicated that the running of power flow models during supplemental review is an important element in determining the impact of DER on the system. Specifically, they have noted the need to ensure that the voltage profile of the system stays within the ANSI C84.1 limits regardless of whether or not the rapid voltage change limits of 3% for an individual facility and 5% for the aggregate of all facilities are applied. This is significant as the primary purpose of the 3% / 5% limits on voltage variation as stated by EPRI in their earlier report was to test if voltage changes caused by the DER on a feeder are likely to violate ANSI limits.

Thus, with the more accurate information available from a power flow model testing directly for compliance with ANSI C84.1 limits and the visible flicker and voltage variation screens testing for the impact of intermittency caused by transient cloud cover all coupled with the unique features of inverter based DER such as the ability to incorporate ramp rates and soft-start capabilities after a trip, the solar industry sees no technical justification for applying the more limited rapid voltage change limits as proposed in the earlier Voltage Change/Limits screen. As such, the solar industry would instead propose to include the following two additional tests to the new Screen H with its existing test for visible flicker as number one:

"2. Can it be determined that the aggregate DER on a feeder does not cause voltage excursions outside of the ANSI C84.1 limits?

3. Can it be determined that fluctuating DER output, such as PV plants experiencing transient cloud cover, does not change the voltage at any primary regulating device more than 1/2 the regulator bandwidth and more than 3 times/hour.

- Yes to all three tests (pass screen)
- No to any of the three tests (fail screen)"

Finally, as clear from our proposed language, the solar industry continues to support the application of a new third test in the modified Screen H. In conducting such a screen, however, it is critically important to take into account a realistic change in irradiance so as to avoid needlessly driving systems to detailed study. This is particularly true given the significant time and effort required to conduct a detailed time series analysis within the CESIR to more accurately evaluate the impact of the fluctuating DER on regulator tap changes.[1] Given the concern being addressed by this screen is the possibility of increased wear and tear on voltage regulation devices, the solar industry advocates for a statistically based approach that selects a ramp rate that occurs rarely enough that excursions outside of this range are infrequent enough to cause only acceptable levels of additional wear on the devices.

With such a statistical view in mind, and in order to retain a level of conservativeness that is consistent with the needs of a supplemental review, the solar industry continues to support the use of a 0% to 75% change in system output. This recommendation is consistent with the application of a similar screen in Minnesota and with our analysis of solar irradiance data. Specifically, as noted in our July 2017 presentation, we analyzed nine years of data from a single NREL irradiance sensor at Oak Ridge (2008-2017) and found that the 99% fluctuation level at 1 minute intervals was just 38%. In fact, more than 99.98% of all fluctuations over these nine years were less than 75%. In addition, the EPRI data from single irradiance measurements in New York show that ramps of greater than 75% occurred on less than 2% of the days in that year and that more than 99.9% of the fluctuations in irradiance were again less than 75%. Thus, the existing data supports the conclusion that the use of a 0% to 75% change in system output is likely to be highly conservative and represent a minimal impact on the maintenance requirements for voltage regulation devices when coupled with the screen's

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[1] As noted in our June 2017 comments, the need for such detailed analyses if the simple screen is failed is consistent with the findings of the 2013 report from Sandia National Laboratory which concluded that

"QSTS [Quasi-Static Time Series] analysis is necessary to accurately quantify the effects of PV on voltage regulation device operations. The analysis should be an estimate of the long term, e.g. annual, difference in operations that can be expected due to PV. It is necessary to run both the base case and the PV case for comparison in order to quantify the impact due to PV."

Robert J. Broderick, Jimmy E. Quiroz, Matthew J. Reno, Abraham Ellis, Jeff Smith, and Roger Dugan, "Time Series Power Flow Analysis for Distribution Connected PV Generation", Sandia National Laboratories, January 2013 (SAND2013-0537) p. 18

requirement that voltage excursions do not exceed half the bandwidth of the regulation device.

Of particular note in supporting this recommendation is the fact that both the NREL and EPRI irradiance data represent single point measurements. As we have discussed at length at recent ITWG meetings, the impact of geographic smoothing which occurs over the spatial scale of solar facilities likely to pursue supplemental review will act to substantively reduce the actual fluctuations in system output as compared to that implied from measurements by single devices.[2] As a result, using the NREL and EPRI data as a guide and selecting a ramp that will occur only very rarely even for a single point measurement layers two conservative assumptions for this screen that, in our view, provide adequate protection for voltage regulation devices.

Comments on Flicker Screening / Detailed Analysis:

The solar industry strongly supports the detailed flicker analysis methodology proposed by Pterra at the flicker workshop and detailed at the most recent ITWG meeting. We agree that such analyses, when needed, will most likely require being done outside of the CESIR timeline and at some additional cost. We view such analyses as analogous to detailed risk of islanding studies that can be requested by developers if the simpler screening analyses fail.

Given the time, effort, and cost of such studies, the solar industry feels very strongly that the appropriate screening analysis to conduct at the level of the CESIR would be to apply the Pst limits based on the shape factor approach with the same assumptions about ramp rate and repetition rate as those used in the first step of the proposed Screen H, but with the actual $d = \Delta V/V$ calculated from a power flow model. In IEEE 1453-2015 section 7, the shape factor methodology is laid out in detail. In sub-section 7.1 where the specific use of the shape factors is described, the standard is clear and explicit that the intent of the screen is to test

$$P_{st} = \left(\frac{d}{d_{Pst=1}}\right) \times F$$

where $d = \Delta V/V$. The remainder of the sub-section goes on to describe methods of estimating $\Delta V/V$ when it's value is not available. These simplified approximations for $\Delta V/V$ are the basis for the visible flicker test in the proposed screen H, but the clear intent of the Pst limit under the shape factor methodology in IEEE 1453 is that it is testing the relative voltage fluctuation. This can be seen elsewhere in the standard as well. For example, in Table 4 where the $d_{Pst=1}$ limits are found, it also makes

[2] For example, we noted in our July 2017 presentation that in a 2012 Sandia study of a large-scale PV plant, the standard deviation of ramp rate distributions was reduced by a factor of three between a single inverter as compared to that for all 96 inverters in the entire system at the level of one second and by a factor of two at the level of thirty seconds.

Shedd, S., Hodge, B., Florita, A., Orwig, K., 2012. A Statistical Characterization of Solar Photovoltaic Power Variability at Small Timescales. 2nd Annula International Workshop on Inegration of Solar Power into Power Systems Conference, Lisbon, Portugal.

clear that these “[r]elative voltage changes for unit flicker severity for 120 V lamps” are for “ΔV/V (%)”.

Thus, at the level of a detailed CESIR analysis, the use of the actual ΔV/V from a power flow model in the shape factor methodology from section 7 of IEEE 1453-2015 would appear most fully consistent with the language and intent of the standard.

Finally, as we have noted on multiple earlier occasions, the solar industry believes, based on our analyses of irradiance fluctuations and extensive experience with such systems in the real-world, that visible flicker is very unlikely to be a concern for solar PV. The fact that the shape factor limit on ΔV/V, even with the extremely conservative assumptions of a 1 second ramp from 0% to 100% in plant output and that such changes re-occur every minute for an extended period of time, comes out to 4.49% is further evidence for this conclusion. Specifically, it is very likely that other voltage issues (such as violations of the ANSI C84.1 limits or impacts on voltage regulation devices which are studied at the CESIR level) will become important well before a system would trigger the need for a more detailed visible flicker screen based on this limit. Given this, we strongly recommend the use of the more accurate actual ΔV/V value in the CESIR screen for visible flicker based on the shape factor methodology with the same set of assumptions as those used in the simplified screen H test and only when that screen is failed should the option be offered for a detailed study using the Pterra approach.