

August 25, 2016

VIA ELECTRONIC MAIL

Michael Worden
Deputy Director - Electric
New York State Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

**RE: Review of Wellsville Solar PV Project Application of Monolith Solar
with Niagara Mohawk Power Corporation d/b/a National Grid**

Dear Deputy Director Worden:

This letter provides the response of Niagara Mohawk Power Corporation d/b/a National Grid (“National Grid” or the “Company”) to your August 18, 2016 letter communicating the results of the New York State Department of Public Service Staff (“DPS Staff”) review of the analysis and recommendation of Pterra Consulting (“Pterra”) in regard to the subject application (the “Wellsville Project”) and provides the Company’s plan of action with respect to the Wellsville Project.

National Grid completed the initial Preliminary Review of the Wellsville Project on May 17, 2016. The Preliminary Review determined that a Coordinated Electric System Interconnection Review (“CESIR”) would be needed for the Wellsville Project to further analyze an unintentional islanding risk at a mid-line recloser on the interconnection circuit. On July 8, 2016, the Company revisited the islanding screen analysis at the applicant’s request, recognizing the applicant’s desire to avoid the need for a CESIR. In so doing National Grid expended the extra effort beyond that required by the New York State Standardized Interconnection Requirements (“SIR”) at the Preliminary Review stage to address an issue that would typically not have been analyzed until the CESIR stage. In that review, the Company noted that further analysis in the CESIR stage is required to determine the need for Distribution Upgrades relative to anti-islanding protection.

Upon further review, National Grid, as it concerns the Wellsville Project, agrees to proceed with an expedited process under the SIR provided that the applicant submits satisfactory supporting documentation to the Company to demonstrate that the proposed SolarEdge inverters are equipped with firmware version 2.0 or greater that implements a positive feedback anti-islanding protection method. As with other expedited applications, the applicant will be required to undertake the customary efforts to obtain a new electric

service at the applicant's cost. Further, the applicant will be required to assume the costs of a three-phase transformer secondary service installed in conformance with National Grid's Electric System Bulletin ("ESB") No. 750 – Specifications for Electrical Installations ("ESB 750") and the Company's Electricity Tariff, P.S.C. No. 220.

National Grid looks forward to a discussion on Pterra's methods and findings at an upcoming Interconnection Technical Working Group ("ITWG") meeting with the goal of establishing a uniform method to be employed by all of the utilities when assessing the risks of islanding for all types of distributed generation. To the extent DPS Staff can facilitate the inclusion of this subject on the agenda for an upcoming ITWG meeting as soon as possible, it would be much appreciated.

National Grid remains committed to following the SIR process and using good utility practice to ensure the safety and reliability of the electric power system for the benefit of all customers. The Company has made considerable efforts to improve its risk-of-islanding analysis practices for interconnecting distributed generation, as captured in the attached paper, *Rationale for Requiring Anti-islanding System Upgrades to Integrate Distributed Generation* (Version R1 dated May 17, 2016), and continues to explore cutting edge and lower cost solutions to mitigating islanding risks.

Sincerely,

/s/ Chris Kelly

Chris Kelly
SVP of Electric Process and
Engineering (Acting)

Enc.

cc: Tammy Mitchell, DPS Staff, w/enclosure (via electronic mail)
Jason Pause, DPS Staff, w/enclosure (via electronic mail)
John Gavin, w/enclosure (via electronic mail)
James Cross, w/enclosure (via electronic mail)
Carol Sedewitz, w/enclosure (via electronic mail)
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Allen Chieco, w/enclosure (via electronic mail)
Neil LaBrake, w/enclosure (via electronic mail)
Kevin Kelly, w/enclosure (via electronic mail)
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Rationale for Requiring Anti-islanding System Upgrades to Integrate Distributed Generation

The addition of generation sources, such as distributed generators (“DG”), to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, the substation transformer. Anti-islanding protection equipment may be required by the utility to ensure that unintentional islanding is not sustained on a feeder or line section or substation bus by disconnecting one or more generation sources from the rest of the Area Electric Power System (“EPS”). This becomes part of system modifications attributed to the impact of a generator connection on the distribution system.

National Grid’s considerations for the evaluation of a DG integrated with a radial distribution system begins with a technical screening process using established criteria and; at times, further engineering analysis to ensure that the distribution EPS is safely and reliably protected from an unintentional islanding situation. The IEEE 1547 states that anti-islanding protection is required for parallel generation on the EPS where *“an unintentional island in which the distributed resource (“DR”) energizes a portion of the Area EPS through the point of common coupling (“PCC”), the DR Interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.”* Good utility practice has been that the use of direct transfer trip (“DTT”) is a definitive protection means for anti-islanding protection. Industry standardization of islanding detection methods is needed to help reduce the volume of DTT installations in the utility EPS. The DG customer may propose various methods of anti-islanding protection of their own generation facility. It is the DG customer’s responsibility to demonstrate comprehensively the validity of such methods and the Company reserves the right to make the final determination as to which anti-islanding protection method is suitable.

Technical Screening

National Grid’s “screening tests” to determine if anti-islanding protection requires a DTT scheme on the feeder or line section of the feeder (the “Local EPS”) based upon feeder loading dynamics and the generation type first requires customer documentation of the proposed generator electrical nameplate and characteristics as specified in the state jurisdictional interconnection requirements for DG. For inverter-based DG facilities, National Grid may also request the DG customer provide documentation from the inverter manufacturer for the islanding detection method that is used by the inverter(s). The documentation shall be sufficient to determine whether the islanding detection method is active (perturbing the utility system and looking for a response), or passive (monitoring grid parameters without perturbing the utility system), and describe how the islanding detection method functions, including what parameters (*i.e.*, phase, frequency, VARs,) are perturbed and monitored. The documentation must also be sufficient to determine whether the inverter uses bi-directional perturbation (if applicable), and whether the inverter employs positive feedback on one or more grid parameters. The inverter manufacturer’s documentation shall be in the form of a certified letter and provide a single contact name and/or department that National Grid can communicate about the information provided, if needed.

National Grid’s present experience has determined that a number of inverter types cannot be screened using the technical screening method set out in SAND2012-1365, “Suggested Guidelines for

Assessment of DG Unintentional Islanding Risk” (the “Sandia Report”)¹, because they are outside the specific requirements listed in this report and that the results of detailed risk of islanding studies performed for some cases have concluded that a risk of an undetected island exists.

The Sandia Report screens are valid only for those inverters that have been confirmed, in writing from the manufacturer, to meet the definition of the Sandia Frequency Shift (“SFS”), or Sandia Voltage Shift (“SVS”) as positive feedback based methods according to the report or for inverters using impedance detection with positive feedback. SFS and SVS both rely on *positive feedback* to work. In these methods, the inverter employs positive feedback on voltage or frequency. If the inverter detects a change in one of these parameters, it attempts to “push” on that parameter *in the same direction*, trying to drive it out of limits. If it can, then the inverter trips. There are three key parameters:

- 1) Active islanding detection – perturbing (‘pushing’) on the grid.
- 2) Positive feedback – detecting a deviation in grid parameters and acting to try to make that deviation from nominal worse. Where acting to try to make that deviation worse, the perturbations must push harder as the deviations from nominal increase.
- 3) The push/perturbation is in the same direction as the deviation from nominal. The algorithm must be able to push bi-directionally in order to be considered for this screen. A single directional perturbation cannot be screened using the Sandia report. For example, if the frequency is >60Hz, the inverter should be capable of pushing the frequency upward, and if the frequency is <60Hz, the inverter should be capable of pushing the frequency downward to meet the bidirectional requirement.

Inverters that do not meet the detection criteria listed in the Sandia Report will be subject to the basic load match screening criteria that are consistent with good utility practice.

For the screening of minimum EPS Load versus generation (“minimum load-to-generation match”), National Grid evaluates aggregate generation, including the DG customer’s generation on the Area EPS. Islanding is a concern if:

- the aggregate generation is greater than 33%² of the EPS light load for rotating machines and where there is a mix of rotating machines and inverters or type 4 wind turbine installations that do not use the 88% undervoltage trip point with a time delay no greater than 2 seconds; or
- the aggregate generation is greater than 67%³ of the EPS light load for all inverter-based generators. This inverter-based criterion is considered to be a conservative good utility practice, since maximum output for solar PV systems does not occur in the same period as minimum EPS daytime load⁴; and, typical distribution systems will have multiple inverters supplied by a range of manufacturers with different anti-islanding algorithms, thereby resulting in anti-islanding operation conflicts between them. Until inverter manufacturers develop a universally accepted short circuit model that can be applied using commercially available short circuit software programs (*e.g.*, ASPEN, CAPE, and CYME),

¹ See <http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf>, M. Ropp, *et al.*, *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk*, SAND2012-1365, SANDIA NATIONAL LABORATORIES (2012) (the “Sandia Report”), recognized by National Grid and other utilities for risk of islanding evaluation.

² See IEEE 1547.

³ See Sandia Report (assuming the DG facility uses the 88% undervoltage trip setting).

⁴ *Daytime light load and the absolute light load are determined by National Grid, which daytime is defined between 8AM and 8PM.*

the islanding detection and protection schemes along with the current review process is the best utility practice for detecting a risk of islanding on the Local EPS.

Where the minimum load-to-generation match is exceeded in the technical screen and/or the DG facility is proposed to be integrated with a feeder having an automatic transfer scheme enabled to an alternate feeder in the distribution system, DTT is required.

Detailed Analysis

For those DG applications where the application of the Sandia Report criteria in the screening tests determines further analysis is needed, National Grid will initiate a Risk of Islanding (“RoI”) study to assess certain complex situations. A RoI study is performed on a case-by-case basis but will not apply to all DG projects. When National Grid performs a RoI study, it is at the DG customer’s cost. The results of the RoI study may or may not change the requirement for DTT. If the RoI study results indicate islanding scenarios greater than 2.0 seconds on the Local EPS, then DTT is required.

During an impact study, National Grid also evaluates if the DG facility can or cannot detect faults on the utility source. If the DG facility cannot detect such faults, modifications to the EPS zone of protection or the DG facility’s design, or both, may be required; otherwise DTT is required.

The DG customer may propose alternative methods of anti-islanding protection for their DG facility and National Grid’s Local EPS. It is the DG customer’s responsibility to comprehensively demonstrate the validity of alternatives for National Grid’s final determination as to which anti-islanding protection method is suitable. To be valid, the DG customer’s protective device coordination study must demonstrate to National Grid that the generation voltage and/or frequency protection will trip within 2.0 seconds upon the loss of the utility source (*e.g.*, feeder breaker trip) including any transient overvoltage protection that may be required upon detection of an island while meeting NERC reliability criteria. These devices are designated as Local EPS protective control devices and if, at any time, they trip due to a fault or are intentionally opened (*i.e.*, for maintenance or emergency purposes) and analysis shows that the DG facility is able to island the Local EPS, then the DTT is required. Some key points to be considered by the DG customer proposing anti-islanding protection alternatives are:

- When National Grid performs feeder switching for any reason and the normal feeder breaker is open for the interconnection of the DG facility, the DG facility could synchronize to the EPS without the protection necessary for the alternate feeder breaker source.
- If National Grid’s station feeder breaker or upstream interrupting device such as a line recloser does not have voltage sensing, then such sensing would need to be added for alternative islanding prevention schemes to ensure protection of the breaker or line recloser from reclosing on a live line where the DG facility’s scheme fails and the generator is still in parallel.

These two situations above would require a SCADA remote terminal unit (“RTU”) for status/supervisory control at the DG facility or PCC recloser.

When a DG customer proposes alternative protective device systems not utilizing DTT, there are operating concerns to National Grid’s EPS. National Grid continues to monitor and pilot technological advances and industry practices that could address this issue. Note when a DG customer proposes to use a generating facility as a stand-by or emergency generator, their DG facility will require an interlocking scheme or transfer switch to prevent the energization of a de-energized Local EPS in compliance with the requirements of ESB 750, Section 11.

Installation

When a DTT system is required by either the DG customer or by National Grid, the DG facility shall use equipment generally accepted for use by National Grid and shall, at the option of National Grid, use dual channels.

- Where DG interconnection projects have NERC reliability requirements, a dual channel DTT scheme is required between the National Grid Local EPS protective device(s) and the DG facility. The two channels shall use diverse communications media from each other such as digital microwave for one and leased telephone line for the other.
- For distribution system interconnected projects where NERC reliability does not apply to the DG customer, single channel telecommunication requirements for the DTT application normally consist of a leased telephone circuit, or other National Grid-approved communication circuit (*e.g.*, radio path, power line carrier). Regardless of which communications scheme is adopted, the DG customer shall provide and maintain a means to mount equipment and associated wiring to the DTT communications media and National Grid shall have access rights to operate and inspect this equipment.
- For the reliability of the DTT scheme using audio tone, the DG customer shall have controls in place to trip the DG facility upon loss of communication signal(s). National Grid's Protection and Telecommunication Engineering department will determine dependability and security requirements associated with the DTT scheme to be implemented and advise the DG customer of such requirements.
- National Grid will outline the requirements for equipment, installation, and communications media in the interconnection study. The DG customer shall bear the responsibility for cost and securing equipment on their property and contribute to the associated costs for National Grid's equipment in accordance with National Grid's tariff provisions.
 - National Grid will be responsible for procuring the DTT transmit equipment for installation at the Company's facilities.
 - The DTT receive equipment will be specified by National Grid and shall be provided by the DG customer after National Grid's acceptance review of the DG customer's proposed vendor equipment design.
 - National Grid's telecommunications requirements for the DTT equipment and associated devices using telephone circuits are that the DG customer shall be the entity responsible for initiating contact with the local telephone company for all required work. (See ESB 756A, Exhibit 1.)

National Grid implements standard utility grade equipment and installation methods for anti-islanding protection in its EPS as good utility practice. If site-specific restrictions are encountered to installing DTT telecommunications equipment as one example; other alternative means as available are considered. Constructability is assessed in the decision-making process included in National Grid's DG impact study results.

versionR1 **May 17, 2016**