DATE: June 14, 2017

TO: Jason Pause, Electric Distribution Systems,
Office of Electric, Gas & Water
Department of Public Service
3 Empire State Plaza, Albany, NY 12223

FROM: Joint Utilities of New York – Interconnection Technical Working Group

RE: 05/10/17 ITWG Meeting Follow-Ups – JU Response to draft EPRI Report Questions

Pursuant to your request, below is the response from the Joint Utilities of New York ("JU") regarding the follow-up items on monitoring and control (M&C) from the May 10th ITWG meeting. The response reflects the position of all of the utilities identified on this letterhead, although it does not necessarily apply to network systems.

Draft Monitoring and Control Requirements for Solar Photovoltaic Projects in NY

Purpose

This document provides the Joint Utilities' requirements for monitoring and control (M&C) for interconnected solar photovoltaic (PV) systems. The M&C requirements in this document are based upon the need for supervisory control and data acquisition (SCADA) connected monitoring and control functions. As the industry matures in equipment offerings, there may be opportunities to leverage recent advances in communicating and configurable "smart" PV inverter technologies, but these functions are presently out of scope for this document.

Background

In the context of this document, monitoring is defined as the ability to observe the performance of various assets, including solar PV, on the distribution system at pre-determined intervals. Control refers to the signaling of distribution assets and solar PV inverters to take actions to satisfy system operational needs in near real-time. The Joint Utilities are currently focused on solar PV; however, monitoring and control requirements may be applicable to other distributed energy resource (DER) technologies. Monitoring and control of solar PV can help to ensure that line sections are appropriately de-energized to ensure worker and crew safety, as well as satisfy system reliability, power quality, and planning/forecasting requirements.

This document is focused solely on planning and operational needs; further requirements will be defined in the near future to address market participation in both the wholesale and retail markets as developed by the NYISO, as well as within the Value of DER and broader REV initiatives.

> *"The DSP distribution grid operator will need to have the ability to monitor and measure key aspects of system operation including…DER status including voltage, current, and generation on a near real-time basis for DERs of a capacity higher than some nominal amount or that are in locations where likely to impact distribution grid performance criteria." – Former PSC Chair Audrey Zibelman*[1]

Monitoring of distribution assets and solar PV on the distribution system is essential for maintaining the reliability of the grid. Monitoring data allows utilities to efficiently implement distribution management systems (DMS), day-ahead forecasting, distribution automation, and operational and planning needs to promote reliable, flexible, and efficient operations. Utility monitoring capabilities increase the situational awareness and performance of solar PV on the utility grid. Monitoring also provides insights to forecasting and planning, which is important to reliability. However, for these goals to be achieved, monitoring will be required for solar PV systems below the current requirement of 1 MW. For example, a DMS will require monitoring of solar PV as low as 50 kW to calculate power flow convergence and to provide functionality such as Volt-VAR Optimization and Fault Location, Isolation, and Service Restoration (FLISR).

In addition to monitoring, control may also be required in cases where the ability to disconnect or curtail solar PV is vital to the reliable, efficient, and safe operation of the distribution grid, in normal and alternate

[1] Audrey Zibelman, "Reving Up The Energy Vision in New York", IEEE power and energy magazine -Volume 14 – May/June 2016 issue – page 23

circuit configuration, and to ensure that anti-islanding protection requirements are met. The specifications of the basic control requirements are elaborated on in the following sections.

General Monitoring and Control Requirements

Monitoring, in the context of this effort, refers to near real-time telemetry as well as the reporting of data values, as listed in the following sections. **This is relaxed from our previous position to require remote monitoring of the disconnect device or inverter status, and opens up the opportunity for lower costs solutions.**

Similarly, basic control, in the context of this document, refers to remotely changing the status of the device (i.e. trip or resetting of a disconnect device). More advanced control may include changing the protective relaying set points. All M&C subsystems for PV installations shall be connected to the DMS/EMS as operationally required.

Two monitoring and control configurations are envisioned and are determined by nameplate specifications of the PV inverter as well as operational needs. When monitoring and/or control ***may*** be required, please refer to the JU's previous submission included in the Appendix of this document. The following M&C requirements apply:

Proposed Monitoring and Control Requirements by Size for Solar PV in New York State			
	< 50 kW	**Aggregated 50 kW to 300 kW**	**300 kW and Greater**
Monitoring	Monitoring ***may*** be required	Monitoring ***shall*** be required	Monitoring ***shall*** be required
Control (PCC Recloser)			PCC Recloser ***shall*** be required
Control (RTU)		Basic control ***may*** be required	

Table 1: Proposed state-wide M&C requirements

Specific levels for the M&C breakpoints are based upon operational needs and benchmarking of other utilities as well as the FERC NOPR of November 2016[2] (FERC NOPR) and the New York State Standardized Interconnection Requirements (SIR). The FERC NOPR makes strong references to monitoring of aggregations of DER at 100 kW and above. This is directly applicable to the large number of multiple PV applications within the JU that are 50 kW and larger and that aggregate to 100 kW and above at the feeder level. Finally, the SIR requires expedited reviewed of systems that are below 50 kW, and provides the option for systems in the range of 50 kW to 300 kW, further supporting these break point levels.

[2] FERC Notice of Proposed Rulemaking, "Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators", November, 2016

Benchmarking examples from utilities in other jurisdictions are as follows:

- Tucson Electric Power (TEP) requires that for PV systems of any size that there be a meter socket within 10' of the existing utility meter to allow the utility to set a second meter to monitor the solar PV output. This meter will have remote communication to SCADA in near-real time for systems above 300 kW, and above 50 kW in some cases[3].
- Toronto Hydro requires that DG facilities greater than 50 kW to have monitoring and control installed and operational prior to connection to the distribution grid[4].
- Salt River Project of Arizona requires monitoring for installations greater than 50 kW[5], and
- San Diego Gas & Electric recently modified their monitoring and control requirement for systems greater than 250 kW at 4kV, and 1 MW and above for 12kV, to requiring solar PV systems above 30 kW across all distribution voltage levels to have direct monitoring and control capabilities.

Monitoring and control equipment and specifications shall follow the individual utility's requirements. Utilities will have discretion to relax these requirements as necessary based on site-specific conditions.

Monitoring Specific Requirements

These values represent the most basic monitoring components that can provide situational awareness at the PCC. Additional monitoring points may be needed per individual utility requirements. Monitoring data shall be accessible remotely by the use of communications technology per the utility's protocols.

The minimum required data values at the point of common coupling (PCC) are as follows:

- Per phase voltage and current,
- Three phase values for real (watts) and reactive (VARs) power, and
- Power factor

As previously described, this is relaxed from our previous position to require remote monitoring of the generator disconnect device or inverter status, and opens the capability for lower costs solutions.

Control Specific Requirements

The control portion is defined as the remote trip and block closing of the interrupting device on the PV supply side, as specified by the utility protection, relay, and control scheme implementation. Any solar PV system requiring control shall also require monitoring. The following are general requirements of the control system:

- The PCC recloser or RTU points list shall be mapped in accordance with DNP3, IEC 61850 or ANSI/C37.2 as specified by the utility.
- The RTU, PCC Recloser, or Energy Control Center data retention shall be capable of capturing sequence of event analysis.

[3] TEP, Distributed Generation Interconnection Requirements, https://www.tep.com/doc/dgir.pdf, Page 24
[4] Toronto Hydro, Distributed Generation Requirements, http://www.torontohydro.com/sites/electricsystem/business/ConditionsofService/Documents/DG%20Requirements%20-%20Rev5%20-%2030-Nov-2015.pdf, Page A4-1
[5] Salt River Project, Technical Requirements for Generating Facilities Interconnecting to The Distribution System, https://www.srpnet.com/electric/pdfx/interconnect_guidelines.pdf, page 5-1

- In addition to meeting the monitoring and remote trip and close capabilities, the RTU or PCC recloser must report the status of the disconnecting device.

Smart Inverters

As the amount of variable solar PV generation connected to the distribution grid increases, the utility industry believes that connecting PV to the grid with more sophisticated technology is needed to maintain stability of the grid. To accomplish this, the industry is moving in the direction of directly connecting "smart" (i.e., advanced, communicating) inverters to the grid. The California Public Utilities Commission (CPUC) Electric Rule 21 (Rule 21) requires that all inverters installed in the CPUC jurisdictional area after September 8th, 2017, be certified for specific autonomous functionality that has been designed to maintain distribution safety and reliability.

Revisions to IEEE 1547, the governing standard for Interconnecting Distributed Resources with Electric Power Systems, is presently being voted on and will be updated by the end of 2017 to include significant smart inverter capabilities. UL 1741 Supplement SA describes test methods for advanced inverter functions and is already been adopted by the industry[6].

The default configuration of the Rule 21-compliant smart inverter, known as "Phase 1 Autonomous Functions", provides for embedded monitoring of voltage, current, as well as real and reactive power levels, largely supplanting traditional external monitoring requirements. Furthermore, the Phase 1 Autonomous Functions provide capabilities that enable greater control of PV output than simple on/off functions, offering greater value to the distribution grid operator. Additionally, there are no minimum size requirements for implementation of Rule 21, thereby providing aggregators/developers as well as the utility granular visibility into PV production at all points in the distribution grid, at a significantly lower cost than traditional M&C solutions.

The JU are evaluating smart inverters as a lower-cost option, but further progress must be made in terms of cyber security, integration, functionality, and standardization before they can be used as a low-cost alternative.

Lower Cost M&C Solutions and Potential Demonstrations

The JU support the requirement of monitoring and control at the system sizes indicated earlier in this document and are open to demonstrating third-party solutions that would further lower the cost of these requirements. Various potential solutions have been established, with further information forthcoming as specifications are finalized around specific projects.

Initial research shows the estimated range for the equipment vendor component of lower cost solutions is $10k to $20k for the 50-300 kW solar PV range for RTU and RTU-like solutions. The JU continues to collect monitoring and control cost data regarding the 50-300 kW range, and will evaluate these options in context of defined demonstrations that document cost of implementation as well as functionality. In addition to equipment vendor costs, the JU are evaluating internal implementation costs for these developing solutions, and feel that costs will drop as economies of scale improve. To implement these

[6] SMA, 8/17/2016 http://www.sma-america.com/newsroom/current-news/news-details/news/15897-sma-is-first-manufacturer-to-achieve-ul-1741-sa-certification-for-smart-solar-inverters.html

solutions, the solar developer will be responsible for wiring of monitoring equipment within 10' of the utility meter.

Highlights of the initial equipment vendor solutions include:

- Power Monitors Inc. (www.powermonitors.com) offers their "Boomerang" product line that is a family of power monitors that interface into SCADA systems. The units have an integrated cell modem and are used extensively in the industry.
- Cleaveland/Price Inc. (https://www.cleavelandprice.com/linescope-power-quality-monitor/) manufacturers the LineScope Power Quality Monitor that can be used in conjunction with various RTUs for transmission of data.
- Schweitzer Engineering Laboratories (https://selinc.com/) offers a number of RTU, RTAC, and other interface solutions that work with a variety of monitoring and control devices to properly format data.
- SolarVu (http://www.solarvu.net/products.php) has deployed a lower-cost solution at Toronto Hydro that may be applicable to JU activities and is under further exploration.

Additional discussions with equipment vendors are being conducted and the list of possible solutions continues to expand as requirements become more definitive.

The JU note that the immediate focus of development of lower cost solutions, is occurring more quickly than what will be available in context of leveraging smart inverter functionality. Once smart inverters are commercially available and tested by UL-1741 SA to meet the updated IEEE 1547 Standard, these inverters will need to be tested for integration with utility distribution management systems (DMS). As these projects mature it is envisioned that a significant number of smart inverters will be installed in NY and as such, more advanced M&C capabilities afforded by smart inverters will need to be leveraged with traditional methods of M&C to compare/contrast costs and benefits of solutions at different PV generation levels.

Conclusion

In conclusion, the JU have provided the following key positions in this document:

- Reiterated the need for M&C and requirements for various levels of solar PV installations.
- Relaxed the requirements for monitoring and control to facilitate lower cost solutions.
- Initiated discussions with vendors in context of identifying lower cost M&C solutions that enable greater operational and situational awareness while supporting the development of M&C requirements that are also sensitive to project economics. The JU will continue these discussions and refine estimates as implementation continues.

Appendix: Previously Submitted to DPS Staff

DATE: April 28, 2017

TO: Jason Pause, Electric Distribution Systems,
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3 Empire State Plaza, Albany, NY 12223

FROM: Joint Utilities of New York – Interconnection Technical Working Group

RE: 03/29/17 ITWG Meeting Follow-Ups – Monitoring and Control Screens

Pursuant to your request, this memo provides the response from the Joint Utilities of New York ("JU") regarding identifying potential methods or options for screens to identify if an interconnection project should require Monitoring and/or Control. This response reflects the position of all of the utilities identified on this letterhead, although it does not necessarily apply to network systems. This information is preliminary for discussion purposes and is not intended to represent a final position on any issues. This response is not intended to replace the previously submitted Planning and Operational drivers for Monitoring and Control requirements.

JU Recommended Screening Criteria

The Joint Utilities have begun developing a list of screening criteria elements to determine when control would be required for solar PV systems larger than 50kW. Other generation technologies are out of the scope of this document. The screening criteria listed below has been developed under the guideline that monitoring is a requirement for all systems 50 kW and above. The Joint Utilities may alter this number depending upon interconnection circuit voltage, total aggregation of distributed energy resources, and available solutions on the circuit. If it is mutually decided to move in the direction of screening criteria, the Joint Utilities expect the final screen for monitoring and control to include an appropriate combination of the screening criteria listed below. Please note that this list was developed within the context of the ITWG, and has been designed to allow for more detailed discussion by the appropriate working groups, i.e. Monitoring and Control and ISO-DSP. Brackets indicate placeholder values to be discussed at a later date or in other forums.

Utility System Voltage – Control may be required for lower proposed solar PV system sizes interconnecting at utility 5kV voltage classes and below.

Hosting Capacity – Control may be required as a means to increase hosting capacity.

Anti-Islanding Requirements – Per the JU's Anti-Islanding requirements, a PCC recloser may be required for monitoring and control.

SIR Screen Borderline Violations – Solar PV systems that only marginally pass or fail a given screen will require monitoring if it is not already a requirement, and may also require control.

ISO Requirements – If the proposed PV system is subject to ISO requirements, monitoring and/or control will be required if it is not already a requirement.

Distribution Automation – Potential monitoring and control screens must consider the aggregate line section generation in multiple circuit configurations. The need for control due to the proposed solar PV system's impact on neighboring line sections is an increasing concern as Distribution Automation continues to be rolled out across utility service territories to ensure customer reliability and efficiency is not sacrificed. The utility may require control if the existing distributed generation exceeds an aggregate capacity of [X] kW on any of the neighboring line sections.

Minimum Daytime Loading – Solar PV output exceeding the local loading raises a number of concerns across voltage, thermal, and protection power system criteria. If the proposed solar PV system exceeds a capacity of [X] % of the minimum daytime loading the utility may require control in addition to monitoring.

Phase Balancing – Aggregate solar PV generation on single phase line sections may create adverse impacts to utility planning and operations. If the proposed PV system on a single phase line section creates a greater than [X] % unbalance at the next upstream 3 phase location but is still allowed to interconnect, the utility may require control in addition to monitoring.

Note: The above criteria shall be evaluated under the assumption that all interconnected and queued DG are operating. The JU will evaluate and implement lower cost solutions to monitoring and control as advances in smart inverter technologies and testing, communication protocols, and applicable standards are made.