NEW YORK INDEPENDENT

SYSTEM OPERATOR

REPLY OF THE JOINT UTILITIES TO THE NEW YORK INDEPENDENT SYSTEM OPERATOR PROPOSED DER METERING AND TELEMETRY REQUIREMENTS FOR WHOLESALE MARKET PARTICIPATION

June 1, 2017

Comments of the Joint Utilities on the NYISO's Proposed DER Metering and Telemetry Requirements for Wholesale Market Participation

Central Hudson Gas and Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation ("NYSEG"), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), Orange and Rockland Utilities, Inc. ("O&R"), and Rochester Gas and Electric Corporation ("RG&E") (together, the Joint Utilities) submit these comments after the review of the New York Independent System Operator's ("NYISO") May 2017 proposed DER metering and telemetry requirements for wholesale market participation and after participating in the subsequent stakeholder meeting convened by the NYISO.

The Joint Utilities provide these comments to inform the NYISO as to the current state of system monitoring available on the distribution system. As the NYISO continues to advance towards implementation of its DER Roadmap, the Joint Utilities hope this information will inform the NYISO's meter data study design and ultimately its DER telemetry and metering requirements for participation in the wholesale market. Given an understanding of the differences between utility and NYISO system requirements, the Joint Utilities continue to work on establishing monitoring and control ("M&C") requirements and seek to leverage utility and NYISO needs to optimize design and reduce costs where possible.

While the Joint Utilities focus on situational awareness to operate the distribution system, the NYISO focuses on meeting standards required by the North American Electricity Reliability Council ("NERC") to operate the transmission system and markets, as well as satisfy data requirements for verification and measurement for settlement. Given the fact that each of the utilities is a registered NERC Transmission Operator ("TOP") and has responsibilities to operate in accordance with NERC Standards, the Joint Utilities support the M&C needs of the NYISO associated with securing the system in accordance with NERC Standards.

Although the Joint Utilities believe some of the NYISO's proposed requirements are overreaching, both the Joint Utilities and the NYISO are weighing current and future needs in this evolving marketplace and trying to reduce future retrofits and stranded costs. The level of system monitoring required by the Joint Utilities to operate their systems at this time is equal to or less stringent than what is being proposed by the NYISO as necessary for DER to participate in the wholesale market. The Joint Utilities and the NYISO also understand there is a balance between these proposed requirements and the impacts to markets and operations (e.g., market price divergence, non-optimal dispatch, challenges to operating standards, etc.).

The current level of system monitoring information available varies by utility based on each utility's electrical topology and requirements to operate their respective distribution systems. While advanced metering infrastructure ("AMI") deployment is set to begin in 2017 for some of the utilities, all of the utilities have plans for enhancing their M&C capabilities in their service territories, including added availability of Supervisory Control and Data Acquisition ("SCADA") data and improved communication from customers and DER to the utility control room. The below table outlines some of these current capabilities and future enhancement plans.

Current and Future Utility AMI and SCADA Plans

Central Hudson	• Wholesale deployment of AMI is not planned as the benefit-cost analysis determined that AMI deployment would not be cost effective; a voluntary AMI program will be available • 90% of substations have SCADA; plan for DSCADA and Distribution Management System ("DMS") • 5 minute interval metering for customers larger than 300kW (readings brought back daily)Interconnected DER larger than 1 MW have M&C through RTUs and RTUs on company reclosers
Con Edison	• PSC-approved AMI deployment plan includes full-scale deployment of roughly six million meters between electric and gas customers starting in 2017 and finishing in 2022. • AMI will provide 5-minute data for all commercial customers and 15-minute data for all residential customers • SCADA on all transmission and distribution substations; six-second SCADA data for customers larger than 1 MW • M&C for distributed generation ("DG") larger than 1 MW • Remotely monitor and control vast majority of distribution system
National Grid	• Developed business case for automated meter functionality ("AMF") in the rate case which will provide up to 15-minute data at a four-hour latency in raw collection quality and at 24-hours at bill quality. National Grid will engage stakeholders further with respect to their real-time information access needs. Plan to begin deployment in 2020 and finish by 2024.M&C on a large percentage of feeders and distribution substations. • • M&C in accordance with ESB 756B; generally for generators 1 MW and larger or at the discretion of the utility for smaller capacity • All generators modeled in EMS if installed within the model footprint
NYSEG/ RG&E	• AMI pilot program under development in Energy Smart Community. Companies filed a full AMI deployment plan with the Commission in December 2016. Anticipate beginning AMI deployment in 2018 and finishing in 2021. • Hourly Interval data for customers larger than 300 kW • Currently low deployment of SCADA limited to reclosers
Orange and Rockland	• AMI to be deployed in Rockland County from 2017 to 2019. Awaiting PSC approval for deployment in Orange and Sullivan Counties, which they plan on deploying from 2018 to 2020. Overall deployment expected to be completed by 2020. • AMI will provide 5-minute data for all commercial customers and 15-minute data for all residential customers • Hourly interval metering data for customers larger than 350 kW • Expanding a comprehensive distribution automation / smart grid program that has more than 250 devices deployed and will build out at a rate of nine circuit pairs per year with monitoring and control functionality. Approximately 98% of transmission substations also equipped with SCADA capability. • Communicating with larger scale DG installations via DSCADA on an individual basis • Resources larger than 1 MW require an automatic device at the point of interconnection that will coordinate with current live line work practices

The Joint Utilities are actively exploring ways to standardize and enhance their M&C capabilities to fully integrate DER while maintaining system reliability. For example, the Joint Utilities M&C Working Group and Interconnection Technical Working Group ("ITWG") are coordinating on the development of standards that can enable greater visibility and control of assets. Additionally, these working groups have been working on a benchmarking of costs for various M&C technologies to help identify opportunities to achieve greater control and visibility at a lower cost.

In addition to these efforts, the JU M&C Working Group is also working on a pilot design to drive learning. The pilot design will ultimately help inform the Joint Utilities on the appropriate levels of measurement of DER needed to maintain safety and reliability, the appropriate levels of basic protection control of DER to maintain safety and reliability, and the appropriate levels of aggregation required for different distribution operations related to safety and reliability. Future pilots will allow the Joint Utilities to test emerging technologies, the results of which will guide the development of future M&C standards for the utilities.