NYISO DER Participation Model: Utility Visibility to DER Day-ahead Operating Plan

This document provides background on day-ahead information sharing requirements for the NYISO DER participation model between DER participating in the NYISO wholesale market either individually or through an aggregator and Utility required to ensure safe and reliable operation of the system. This document is limited to the specific issue of DER day-ahead operating plans while operating under the direction of a wholesale DER Aggregator and does not include information on other aspects relevant to operational coordination such as outage notification, real-time market operations, or telemetry.

A. Introduction and context

New York's Climate Leadership and Community Protection Act includes a target of having 70% of electricity consumed in New York produced from renewable generation by 2030 (i.e., "70 by 30 target"). As such the Utilities expect a significant percentage of these renewable resources will be connected to the distribution system, requiring increased situational awareness to maintain distribution system safety and reliability under conditions where DER are directed to operate other than normal full output. The challenge of situational awareness of these DER is increased as DER participate in NYISO wholesale markets. DER participation in wholesale markets may present new challenges to the utility to maintain a safe and reliable system, as those DER will participate in an Aggregation and be dispatched by the NYISO, without visibility into the utility system. It is critical to establish appropriate day-ahead information sharing requirements and processes between the Aggregator, Utility, and NYISO to ensure that ISO dispatch and DER aggregations can be administered in a way that does not threaten the safe and reliable operation of the utility system.

In addition to maintaining safety and reliability, providing day-ahead information sharing will create value for all market participants by allowing the utility to optimize the system. If the utilities do not have day-ahead DER schedules, the utilities will make conservative assumptions in their day ahead load flow analysis to ensure system safety and reliability in all hours. Absent any day-ahead information, utilities will assume that all DERs will be dispatched in the most detrimental manner to the overall reliability and safety of the distribution system, resulting in instances of overrides of dispatch when not necessary. Rather, the utilities request that day-ahead information be made available so that they can perform analysis to identify and resolve system issues to avoid the operator needing to remedy in real-time.

B. The Importance of a DER Day-ahead Operating Plan to Ensure Distribution System Reliability

An Aggregator's requirement to provide the utilities with an hourly day-ahead operating plan is a matter of ensuring system safety and reliability. The utilities have an obligation to ensure a safe and reliable system.

To ensure the safe and reliable transmission level network operation, the NYISO provides each of the Transmission Owners with the cleared hourly day-ahead operating plan, which includes the cleared MW quantities by hour for each of the operational wholesale markets for each individual market actor. The Transmission Owners use this day-ahead operating plan to conduct analysis to ensure that the transmission system can indeed safely accommodate the proposed day-ahead operating plan, considering various congestion points along different portions of the transmission system. Thus, NYISO dispatch information provides sufficient granularity to assess the transmission level congestion, and the utilities apply similar methodologies to conduct load flow analysis and assess the transmission level impact of DER aggregations as a whole via the day-ahead operating plan for their control areas and transmission zones.

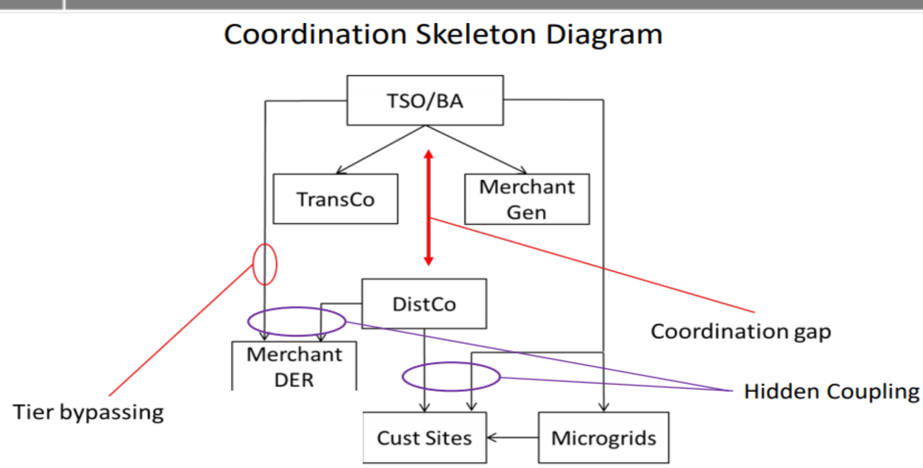
The transmission level impact of every wholesale generator is also studied as part of its interconnection and necessary system upgrades to accommodate such interconnection are implemented. This initial planning study is not a substitute for the daily operational critical analysis of the day-ahead operating plan that is required to ensure system safety and reliability.

However, the transmission nodes (t-nodes) definitions, and accordingly the NYISO cleared dispatch decisions for future DERAs, are uninformed of distribution level system conditions. There are ~100 proposed NYISO t-nodes, whereas there are thousands of distribution-level feeders and substations, each of which may experience unique system conditions. This means that the NYISO-level day-ahead operating plan, which includes information for wholesale generators and aggregators, provides only limited information for a utility to assess the operational impact of DER operating under the dispatch instructions of the NYISO or an aggregator on any part of the distribution system. The utilities need to be able to analyze the transmission and distribution system to ensure system reliability. Absent more granular data it is impossible for the utilities to do so with any accuracy and accordingly the utilities will need to take the most conservative approach to maintain the safety and reliability of the system.

This concern of injection / withdrawal from DER without situational awareness to the utility can result in safety and reliability issues and has been identified since the beginning of wholesale market design for DER integration in New York. Pacific Northwest National Labs (PNNL) Dr. Jeff Taft articulated the difficulties of dispatching resources without adequate situational awareness at the NYS Market Design and Integration Working Group (MDIWG) meeting on February 5, 2021. Dr. Taft discussed the terms Tier Bypassing, and Hidden Coupling as justification, which is relevant in describing issues in the wholesale market design. The following is from Dr. Jeff Taft's' Presentation Electric Industry Architecture Considerations presented at the MDIWG.

Figure 1. Electric Industry Architecture Considerations (Taft)

Tier bypassing	Creation of information flow or instruction/dispatch/control paths that skip around a tier of the power system hierarchy, thus opening the possibility for creating operational problems. To be avoided.
Hidden coupling	Two or more controls with partial views of grid state operating separately according to individual goals and constraints; such as simultaneous, but conflicting signals DER from Customer, DSO and TSO. To be avoided.
Latency cascading	Creation of potentially excessive latencies in information flows due to the cascading of systems and organizations through which the data must flow serially. To be minimized.



There are several factors that may further impact the relative risk associated with a lack of situational awareness. For illustrative purposes we include a few below: [1]

1. **System maintenance/outages.** While interconnection studies provide assurance today that DER may participate wholly, on a normal system, they do not provide assurance for safety and reliability under a system that has undergone reconfiguration due to outages or other operational scenarios. In most instances, DER are curtailed under these circumstances, however dispatch can be optimized with improved information.
2. **Flexible interconnections**. Changes to the interconnection process may include options for DER to choose a lower cost interconnection option via a “flexible” or “curtailable” interconnection. This would allow DER to connect beyond hosting capacity limits under the premise that these DER curtail under certain system conditions. Utilities have ongoing pilots associated with “active resource integration” to explore flexible and curtailable interconnection agreements and most have plans to transition to this method of interconnection in the future. This form of interconnection would likely require improved information requirements regardless of NYISO participation.

C. Data requirements for the DER Day-ahead Operating Plan

The utilities will need visibility to the scheduled (i.e., Day-Ahead) dispatch for each of the individual DERs operating under the NYISO dispatch of the DER aggregation that would be used to meet the aggregations’ cleared NYISO bid requirements, as defined in the Table below. We refer to this schedule as the DER day-ahead operating plan (DDAOP.) The DDAOP will be used by the utilities to perform reliability analysis prior to the actual dispatch. This is analogous to the evaluations performed by the utilities daily based on the day-ahead operating plan issued by NYISO. The analysis will help to secure the system for safety and reliability, adjust proposed DER dispatch, and proactively optimize the system to minimize real time challenges on the system.

Individual utilities have different methods for how they use the DDAOP data to perform distribution reliability analysis, and we anticipate that the level of rigor and automation supporting that analysis will evolve as new technologies and system capabilities evolve such as ADMS and DERMs. It is critical, however, that the DDAOP needs to be made available to utilities beginning on “Day 1” market operations, as absent DDAOP there is no capability for the utilities to perform even the most basic distribution reliability analysis with any accuracy.

Utilities may utilize the DDAOP as input to its ADMS/Load Flow models to evaluate the safety and reliability impacts for the proposed operating schedule for the next 24-hours or the analysis may check to ensure that the proposed DER operation schedule does not conflict with scheduled outages or distribution maintenance that may result in abnormal distribution system operation.

The data requirements for the DDAOP may evolve over time as the wholesale market develops, system tools develop, and situational awareness needs become increasingly important to system safety and reliability. As demonstrated in Figure 2 below, for “Day 1” market operations the DUs envision that the data requirements may vary based on DER type and size.

[1] **Grid architecture variations:** System topologies and operating practices make granular data paramount to maintaining system security and reliability (e.g., long rural feeders, complex system networks, etc.)

Figure 2. Components of NYISO Aggregation Needing Communication of Granular Schedule of Products and Services

		Injecting at POI; All Products and Services	**Load Modifying (Not Injecting)**
Individual DER Nameplate Capacity		>50kW	>500kW
Technology			
	Solar	X	X
	Storage	X	X
	Wind	X	X
	DR		X
	Hybrid	X	X

The utilities are hopeful that these requirements are not particularly difficult to produce. The JU surmise that it is likely that the Aggregators are already producing daily DER-level schedules to establish NYISO bids. In addition, as discussed in Section A above, the communication of granular dispatch to the utilities may allow for a less conservative system dispatch, reducing the need for utilities to issue real time overrides, ultimately resulting in higher value for DER aggregators, DER owners, and all customers.

This process will support emerging wholesale and distribution markets for products and services and will also support the growing numbers of DER Interconnected as a result of state and federal programs and mandates.

1. Means of communicating data:

Each Utility may choose different methods for communication of granular schedules between the Aggregator and the utility. All data exchange options will need to be properly vetted for their cyber security (IT and OT) implications and approved by the utilities to ensure secure data transfer. Each of the utilities will establish their own requirements and protocols for data exchange based on the respective Company's security requirements, and shall make such requirements available to the Aggregator. The data exchange is expected to utilize a common and agreed upon data format.

The utility will initiate communications with the DER or DER Aggregator to resolve any issues that are identified with the utility granular schedule review. Another DDAOP will not be required unless significant operating changes (I.e. multiple DERs on multiple circuits need to be rescheduled/redispatched) are made. Refer to the NYISO Aggregation Manual for details on the communication timeline.

2. Format

Format of data should meet the requirements of the NYISO DAOP, though should include an additional data field to identify the individual DER (i.e., Facility ID) as opposed to the DAOP which is organized based on Gen PTID only (i.e. ID for the aggregation as a whole). For instance, for an aggregation that includes 10 DER, the file would contain unique rows indicating the operating plan for each hour for each of the 10 DER, rather than just a single set of rows for the Gen PTID.

- CSV File
- Containing fields in order and format.

Figure 3. Data format example

Gmt Ltz(Date Hr)	Station Name	Gen Name	SubZone Name	Energy	Minimum Operating Limit	Maximum Operating Limit	Regulation	Min10 Spinning Mw	10Min Non-Spin	30Min Spin	30Min Non-Spin	Feeder Number	T Node	Gen Ptid	Facility ID
08-Oct-2022 00	Station A	GenA	NMPC Central	220				0	0	0	0			12345	11111
08-Oct-2022 01	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11111
08-Oct-2022 02	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11111
08-Oct-2022 03	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11111
08-Oct-2022 04	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11111
08-Oct-2022 05	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11111
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08-Oct-2022 00	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11112
08-Oct-2022 01	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11112
08-Oct-2022 02	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11112
08-Oct-2022 03	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11112
08-Oct-2022 04	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11112
08-Oct-2022 05	Station A	GenA	NMPC Central	220				0	0	0	0			23515	11112

D. Preserving the Safety and Reliability of the Distribution System has its basis in FERC Order 2222

Requiring that the utilities be provided with a DDAOP is a reasonable data exchange expectation, and one that fits within FERC's recognition in Order 2222 that the NYISO and the utilities establish appropriate operations coordination requirements to maintain the safe and reliable of the distribution system.

FERC Order 2222, Paragraph 44 (bolded phrasing added for emphasis):

> *As in Order No. 841, we reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the* ***safety and reliability of the distribution system*** *and that all distributed energy resources must comply with any applicable interconnection and operating requirements.*

FERC Order 2222, Paragraph 279 (bolded phrasing added for emphasis):

> *We agree with commenters that coordination requirements should not create undue barriers to entry for distributed energy resource aggregations. However, we must also consider the substantial role of distribution utilities and state and local regulators in ensuring the* ***safety and reliability of the distribution system****. We believe that the reforms adopted herein appropriately balance those needs.*

FERC Order 2222, Paragraph 310 (bolded phrasing added for emphasis):

> *We agree with commenters that emphasize the importance of real-time coordination to ensure* ***safe and reliable operation of the transmission and distribution systems****. Consequently, to implement § 35.28(g)(12)(ii)(g) of the Commission's regulations, we adopt the NOPR proposal to require each RTO/ISO to revise its tariff to (1) establish a process for ongoing coordination, including operational coordination, that addresses* ***data flows and communication among itself, the distributed energy resource aggregator, and the distribution utility****; and (2) require the distributed energy resource aggregator to report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages. Further, we require each RTO/ISO to revise its tariff to include coordination protocols and processes for the operating day that* ***allow distribution utilities to override RTO/ISO dispatch of a distributed energy resource aggregation*** *in circumstances where such override is needed to maintain the reliable and safe operation of the distribution system. These processes that allow distribution utilities to override RTO/ISO dispatch must be contained in the tariff and must be non-discriminatory and transparent but still address distribution utility reliability and safety concerns. We find these* ***operational coordination requirements will maximize the availability of the distributed energy resource aggregation consistent with the reliable and safe operation of the distribution system.***

FERC Order 2222, Paragraph 311 (bolded phrasing added for emphasis):

> *Commenters disagree over the level of specificity needed in RTO/ISO tariffs and describe different approaches to ongoing coordination.* ***To account for different regional approaches and to provide flexibility, we are not prescribing specific protocols or processes for the RTOs/ISOs to adopt as part of the operational coordination requirements, but rather we will allow each RTO/ISO to develop an approach to ongoing operational coordination in compliance with this final rule.***