Connecticut Distributed Generated Interconnection Working Group Meeting Summary

State of Connecticut Public Utilities Regulatory Authority
Office of Education, Outreach & Enforcement

May 14, 2024

May 14, 2024 IX WG Meeting Goals

Meeting Goal	Relevant due date(s) & material(s)
1. Understand and discuss EDC's approaches and strategies they plan to include in their meter relocation plans, as described in Order No. 16 in PURA's November 8th, 2023 Decision in Docket No. 23-08-03 (*RRES – Year 3*).	Meter relocation solutions compliance filing due **June 1, 2024.** Link to PURA Decision
2. Learn about the Massachusetts Technical Standards Review Group's (TSRG's) experience, accomplishments, and ongoing work addressing interconnection-related issues in Massachusetts.	Link to MA TSRG webpage
3. Explore and discuss energy storage interconnection practices in accordance with Order No. 28 in PURA's November 29, 2023 Decision in Docket No. 23-08-05 (*ESS – Year 3*), through the following means: **a.** Learn about how the TSRG is working to address energy storage interconnection challenges; **b.** Hear which jurisdictions the EDCs are looking to for examples of energy storage interconnection approaches that ensure distribution system reliability while minimizing upgrade costs;	Summary of energy storage findings due **August 1, 2024.** Link to PURA Decision

c. Hear from participants which additional jurisdictions—if any—the EDCs should look to as they prepare for their compliance filing.

Meeting Summary

Topic 1: Understand and discuss EDC's approaches and strategies they plan to include in their meter relocation plans

1. Eversource worked with CONNSSA to come a resolution/draft proposal
    a. Primary issue associated with meter relocation: Relocating IT-rated meters
        i. Extended length from 50ft to 100 feet for 1800A or less
        ii. Extended length from 50ft to 150ft for greater than 2000A
    b. Could extend beyond these lengths on a case-by-case basis, but all existing requirements listed in Eversource I&R book must be met
2. UI's guidelines will remain the same. UI can meet onsite at individual projects to identify specific solutions
3. UI and Eversource will file a joint summary outlining their approaches

CONNSSA

1. Guidelines provide developers with a lot of clarification
2. Appreciate flexibility for extenuating circumstances
3. Nothing else to add, good back/forth

Topic 2: Learn about the Massachusetts Technical Standards Review Group's (TSRG's) experience, accomplishments, and ongoing work addressing interconnection-related issues in Massachusetts

Topic 3a: Learn about how the TSRG is working to address energy storage interconnection challenges

Because of the significant overlap between these two topics, they were discussed together and are summarized together accordingly.

Presentation from Mike Porcaro (National Grid and Chair of the Massachusetts Technical Standards Review Group), with facilitated discussion and Q&A

TSRG Overview

1. Mike Porcaro is Director of Innovative Grid Solutions for National Grid, Chair of the Massachusetts Technical standards Review Group (TSRG), and the MA Interconnection Ombudsperson
2. Safety moment: Arc flash safety
    a. Always perform safety brief, understand what is/is not energized, do not expose any potentially live wires or operate any equipment unnecessarily, dress in

appropriate fire resistant clothing, and thoroughly explain new technology/controls

3. MA TSRG meets quarterly, meetings open to public
    a. 6 members + one ex-officio DPU member
    b. TSRG membership, by-laws, meeting notes, etc. listed on their website
    c. Subgroups work through topics more granularly, with expectation that they come to the next quarterly meeting demonstrating progress
    d. TSRG members choose topics
        i. Topics to discuss do not come through DPU (but the topics often overlap with what DPU would be likely to direct the group to discuss)
4. Worked through many topics including (not limited to) the following, which are memorialized in MA's Common Technical Standards Manual—not a governing document, just a reference document

Anti-islanding & DTT requirements	Utility grade relaying
DER Capacity – Feeder Limits	Substation reverse power
Remote monitoring and control	Simplified spot network & area network connections
PCC protective device requirements	Flicker
Witness test protocols	Detailed Studies
Power factor requirements	Energy Storage
GSU transformer configurations	Significant vs Moderate Changes

5. Current/upcoming TSRG topics:
    a. Inverter swap-out: How to handle inverters coming to end of life, being swapped out?
        i. Considering "light system impact study" approach
    b. Bi-directional Eversource charging station UL certification
        i. Substations being challenged with getting SB certification
    c. Transmission underfrequency setting requirement for distribution system-connected DG
    d. Impact study efficiencies
        i. MA's grid is quite saturated, with high volume of projects seeking to interconnect. System upgrades/improvements require time-consuming and costly studies
    e. Flexible Connections constructs
6. Additional MA interconnection review groups:
    a. Energy storage interconnection review group (ESIRG)
    b. Interconnection implementation review group (IIRG)—more process-related, less technical

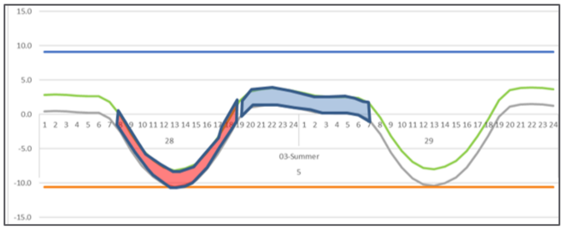
TSRG's energy storage discussions

1. So far working to address the big questions related to battery deployment: Should batteries be considered full nameplate in both directions? Could there be set curtailment/capacity limit schedules to avoid needing to consider full nameplate 24/7/365?

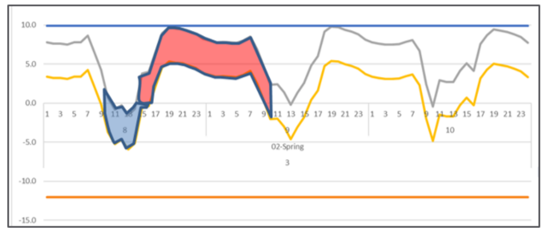
a. Ultimately, until the system is fully automated with DERMS and can constantly say what is/is not happening at all times, there is a need to be conservative.

2. Energy storage systems can act as generation (discharge scenario) or load (charge scenario). System planning requires being prepared for discharge at full capacity, at any point in the day, even if that isn't the most realistic "constant state."

ESS as Generation (Discharge Scenario)



ESS as Load (Charge Scenario)



   a. On the generation curve, red indicates electricity being pushed backwards towards the grid (i.e., worst case scenario). Blue is electricity that is beneficial to the system.
      i. Same would happen (in reverse) in a charging scenario
      ii. Key problem: Cannot reliably count on the blue areas, and there is a need to plan around the "red" worst case scenarios
   b. Infrastructure buildout necessary to plan for the worst is very expensive
   c. In impact studies, MA looks at worst case scenario, at all times, even though that is not what will most realistically be happening.

3. National Grid uses a 24-hr standardized energy storage discharge schedule, designed to generally align with the duck curve, with the goal of tempering peaks from the system limits—the schedule is not adjustable or tailored to any specific sites

National Grid Charge/Discharge Windows

	Charge Window	Discharge Window
Spring	11PM-5PM	5PM-11PM
Summer	11PM-3PM	3PM-11PM
Fall	11PM-4PM	4PM-11PM
Winter	11PM-3PM	3PM-11PM

   a. Certain state incentive programs (e.g., Clean Heat Standard) identify specific hours of charge/discharge
   b. Onsite equipment ensures that projects can keep below the threshold—allows projects to be more economical
   c. Pros: More mangeable integration, more efficient use of available capacity, slower to large infrastructure upgrades
   d. Cons: Reduced opportunity for ROI from various markets, ISA ability to adjust schedules in the future
   e. Note: Doesn't work in all areas, including areas with high DG penetration or high spot load customers.
      i. Individualized schedules for these sorts of sites could be a potential solution that avoids site-specific issues, but this can be very difficult to

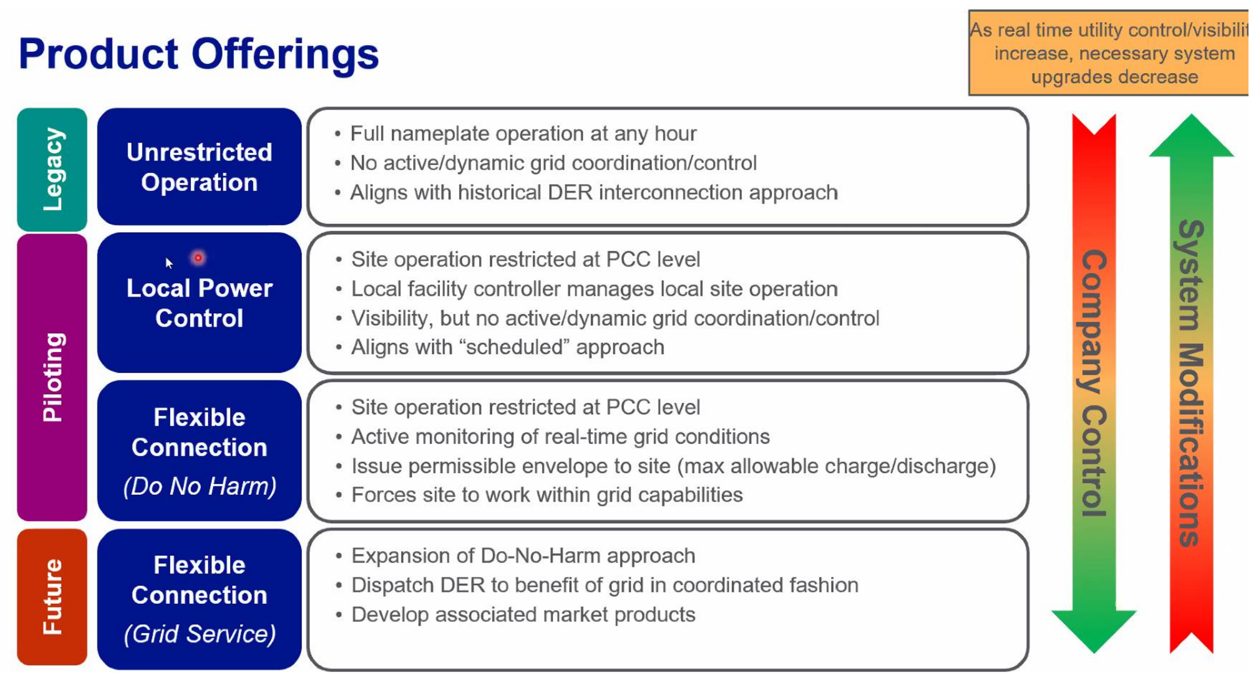
predict/plan around in aggregate (would require live reconfiguration from control operators)

4. Switching difficultly at control center:
    a. Near term control center difficulties: Day to day switching and operational flexibility can be limited
    b. Long term planning difficulties: Available feeder and substation capacity reduced, leading more quickly to need for infra investment
        i. Affects DG customers directly through cost obligation from impact studies
        ii. Affects all customers through long-term planning
5. Site predictability becomes very important
    a. An approach in which there's an agreement to take specific facilities off when they're not needed is not necessarily practical because there's a need to look for multiple customers, multiple load types, etc.
6. Equipment requirements for 24hr standardized schedule:
    a. National Grid owns a Real Time Automation Controller (RTAC), set with a static schedule
        i. 651R required at recloser to allow this—this is where schedule is set and curtailments are established
        ii. Not a DERMS setup because it's localized, but provides some control
    b. No active communication between National Grid and customer equipment
    c. Customer-owned site controls to maintain operation below scheduled limits
7. *Question:* If there's a change to the schedule, is National Grid able to make the RTAC schedule update remotely, or does re-setting the schedule require a site visit?
    a. *Answer:* This can be done remotely, but a site visit is still required just to ensure that all things are in order and operating correctly

National Grid's Flexible Interconnection Strategy (Flex IX)

1. Flex IX strategy objectives driven by customer and employee needs, and are in alignment with state and federal objectives.
    a. Near-term initiatives (by CY2025):
        i. Interconnection efficiency: New customer offerings to reduce DER interconnection time and cost
        ii. Monitor & control: Establish and standardize Monitoring & Controlling (M&C) capabilities to integrate DER on to the system
        iii. Reliability & resiliency: Maintain/ improve the reliability and resiliency of the system as DER increases
    b. Long-term initiatives (CY2025-2029)
        i. Compliance with FERC 2222 (late CY2026)
        ii. Compliance with state targets, including state electrification and flexible load goals
        iii. Grid services: Leverage customer DER to support system needs
        iv. Provide accurate forecast for load and generation to enable real-time system management—what will the grid need, and how can utility control/respond in a coordinated way.

2. Need to ensure that Flex IX does not disadvantage utility staff in operations, field, regulatory, etc.
3. *Question:* How does a Flex IX strategy impact projects' ability to build accurate financial models—seems like it could reduce interconnection costs, but also add a layer of complexity that may make it more difficult to predict generation revenue over time.
    a. *Answer:* Yes, it makes it more difficult, because developers have to figure out how the utility controlling as needed may impact their financial model. By going through a Flex IX approach, the customers most excited are those that are avoiding multi-year system costs, allowing them to get online sooner/faster. Currently working to include a "worst-case scenario curtailment" value for models.
    b. *Question*: What has the interest been for this in MA (for standalone storage and solar)?
        i. *Answer:* National Grid had a pilot open since last August, and >500MW of projects expressed interest. Many of those projects choose not to move forward once they become aware of the site obligations. So far seven sites totaling ~30MW have moved forward, and these remain in the study stage. Five standalone storage projects, one solar + storage project, and one standalone solar projects. A number of other projects are undergoing their final evaluation.
4. Summary of Flex IX trajectory:



    a. "Do not harm"—because of grid constraints, don't go above X
    b. In the future, want to move towards an optimization approach, that provides a grid service, managed by DERMS and Flex IX systems
        i. Future DERMS approach enables interconnections with more energy, due to this flexibility

5. Increased economic viability:
    a. Firm capacity paradigm: no system upgrades required
    b. Flex IX paradigm: will have some upgrade costs, but is economic to curtail
    c. Upgrade paradigm: large sites find less value in curtailment

Discussion and Q&A regarding National Grid's Flexible IX pilot

1. *Question:* Would this help increase capacity that comes out of Capital Investment Projects (CIPs)?
    a. *Answer:* Flex IX does not increase firm capacity but allows more interconnection for the same "amount" of capacity that the grid can accommodate. It helps interconnecting customers better fit into the capacity that currently exists.
    b. *Question:* Are there plans to pilot the DERMs grid services model?
    c. *Answer:* By end of 2025, plan to have some piloted company-owned site, working to ID grid needs/conditions to determine where the site is most economical
2. *Question:* Regarding pilot details: Is National Grid piloting this in specific areas with a lot of grid constraints? Or throughout MA service territory? Or in MA's case, is pretty much everywhere in N Grid service territory constrained enough for this to make sense all over?
    a. *Answer:* Program is open to entire service territory, since there are lots of constraints. Eligibility criteria are listed on National Grid's website.
3. *Question:* What goes into this as a pilot, and what are the intended outcomes of the pilot? Will you submit results to DPU, provide a plan for understanding DERMS, etc.?
    a. Answer: That is to be determined—currently need to install the necessary devices and review for a year to better understand what is needed from a control/coordination standpoint before more widespread deployment.
4. *Question:* Through the pilot, National Grid is looking to figure out a lot of technical aspects related to forecasting, grid needs, coordination needs/capabilities, etc. Is the pilot also looking to identify potential administrative/support needs (e.g., staff capacity) for this becoming more widespread throughout National Grid's MA service territory?
    a. *Answer:* Yes, that's part of the evaluation that will come out of the pilot program. Equipment, services, overall scaling needs including personnel, departments, etc. Might need a new distribution system operations type of department, but not yet entirely sure.
5. *Question:* How do the contracts address potential changes to constraints on time windows and charge/discharge limitations, and what is the term/length of these contracts?
    a. *Answer:* If under a Flex IX contract, there would be no schedule/time window. The study would look at historical load forecast, then give predictions for Flex IX. Operationally, it ends up being real-time, but there is a need to identify some sort of worst-case-scenario financially. Contract ties in directly to the customer's current interconnection agreement so if a site is seeking a new interconnection agreement, it would void the Flex IX contract.

Topics 3b/3c: Identify jurisdictions with energy storage interconnection approaches that ensure distribution system reliability while minimizing upgrade costs, for the EDCs to explore in accordance with Order No. 28 in PURA's November 29, 2023 Decision in Docket No. 23-08-05

1. Eversource updated IX guidelines late last year. Updated included some energy storage items. Eversource coordinates well with MA, presented similar schedules to those in the previous presentation. Working with Joe at UI on this.
    a. Eversource looking at CT, MA, NH, NY, ME, CA. For benchmarking, using IREC model as reference. Open to suggestions from others if there are other benchmarks they'd suggest using.
    b. IREC model: https://irecusa.org/programs/batries-storage-interconnection/
2. Participants had no additional suggestions beyond these states