Revisions to ISO-NE Planning & Operating Procedures

Vermont System Planning Committee

July 2024

Overview

- Background
- PP-12: Procedure for Distributed Energy Resource Data Collection
- PP5-6: Affected System Operator (ASO) Study Coordination
- OP-17: Load Power Factor and System Assessment
- Summary

Background

- ISO-NE is a NERC "**Planning Coordinator**", responsible for:
  - Coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems

  → **Planning Procedures (PPs):**
    - Requirements related to regional transmission planning, reliability standards pooled transmission facility cost review, and notice of intent to change facilities

- ISO-NE is a NERC "**Reliability Coordinator**", responsible for:
  - Reliable operation of the bulk electric system
  - Wide area view of the bulk electric system
  - Operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations

  → **Operating procedures (OPs):**
    - Steps the ISO takes to control and manage the high-voltage power system in the six-state New England area

https://www.iso-ne.com/participate/rules-procedures

Detailed Rules, Processes, and Guidance

View the terms, rules, and operating procedures for New England's wholesale electricity markets and power system, as well as for ISO New England's internal operations as the Regional Transmission Organization.

Transmission, Markets, and Services Tariff (ISO Tariff)
The ISO Tariff stipulates the rates, terms, and conditions for transmission, market, and other services provided by ISO New England

Manuals
Procedures for market participant responsibilities related to the region's wholesale electricity markets and power system

ISO Operating Procedures
Procedures that outline steps the ISO takes to control and manage the high-voltage power system in the six-state New England area

System Operating Procedures
Procedures that detail the ISO's day-to-day operation of New England's power system

Master/Local Control Center Procedures
Procedures that establish coordinated operations between the ISO's master control center and local control centers

Generator and Non-Generator VAR Capability
Documents that outline procedures for maintaining desired and/or reliable voltage and reactive capabilities

Planning Procedures
Requirements related to regional transmission planning, including reliability standards, pooled transmission facility cost review, and notice of intent to change facilities

NERC and NPCC Compliance
Guidance for market participants on compliance with reliability standards set by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC)

Background

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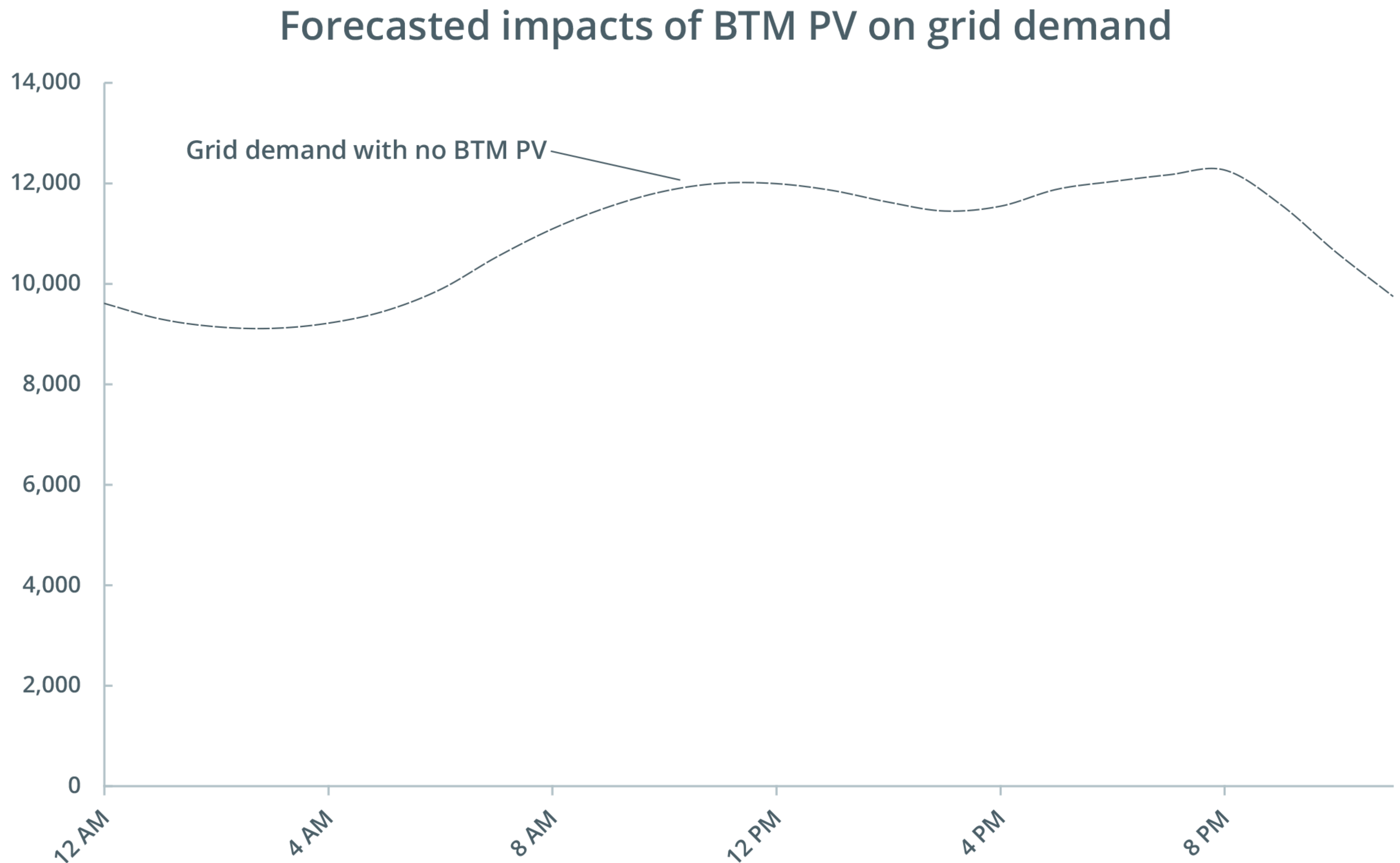

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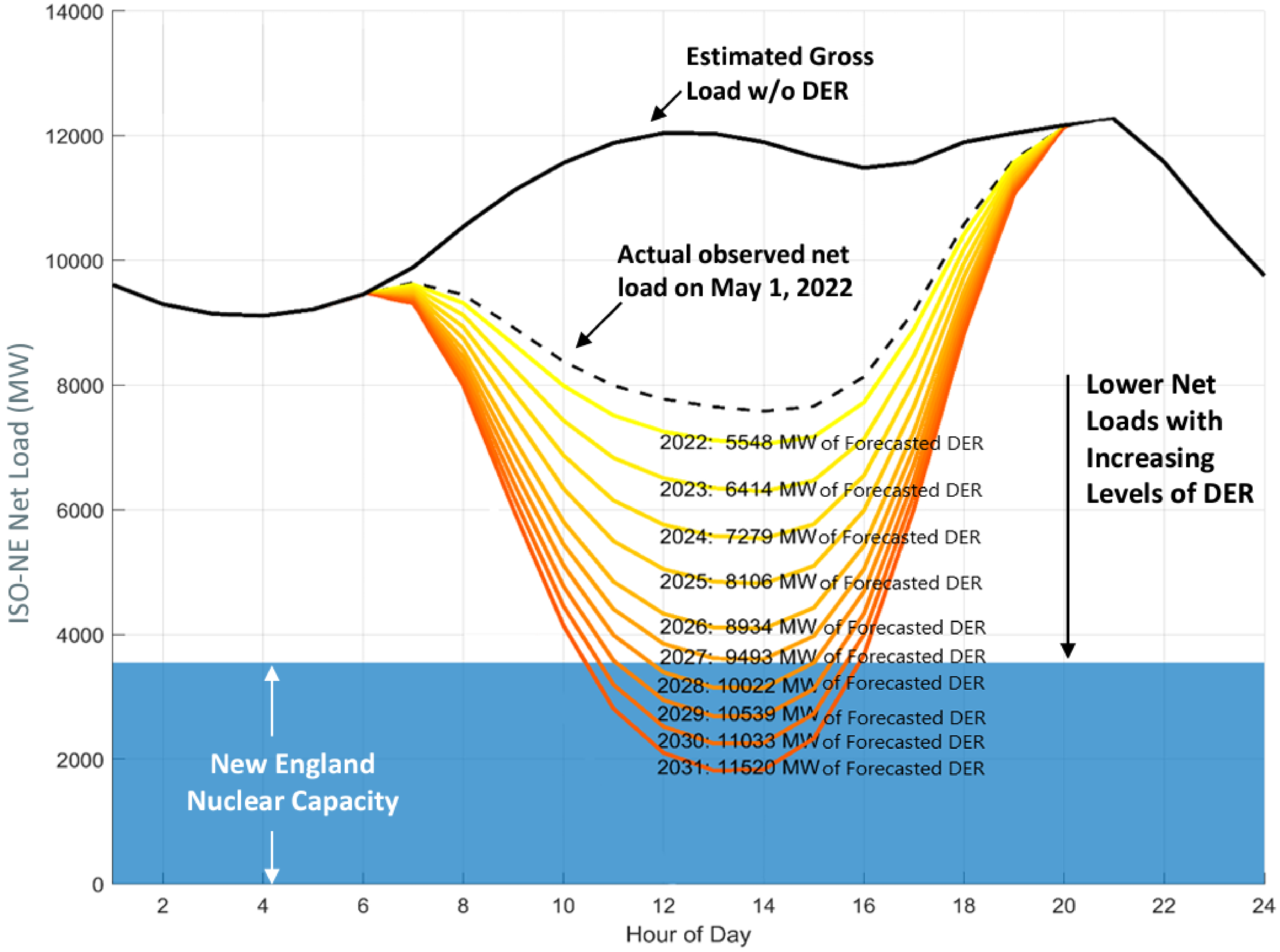

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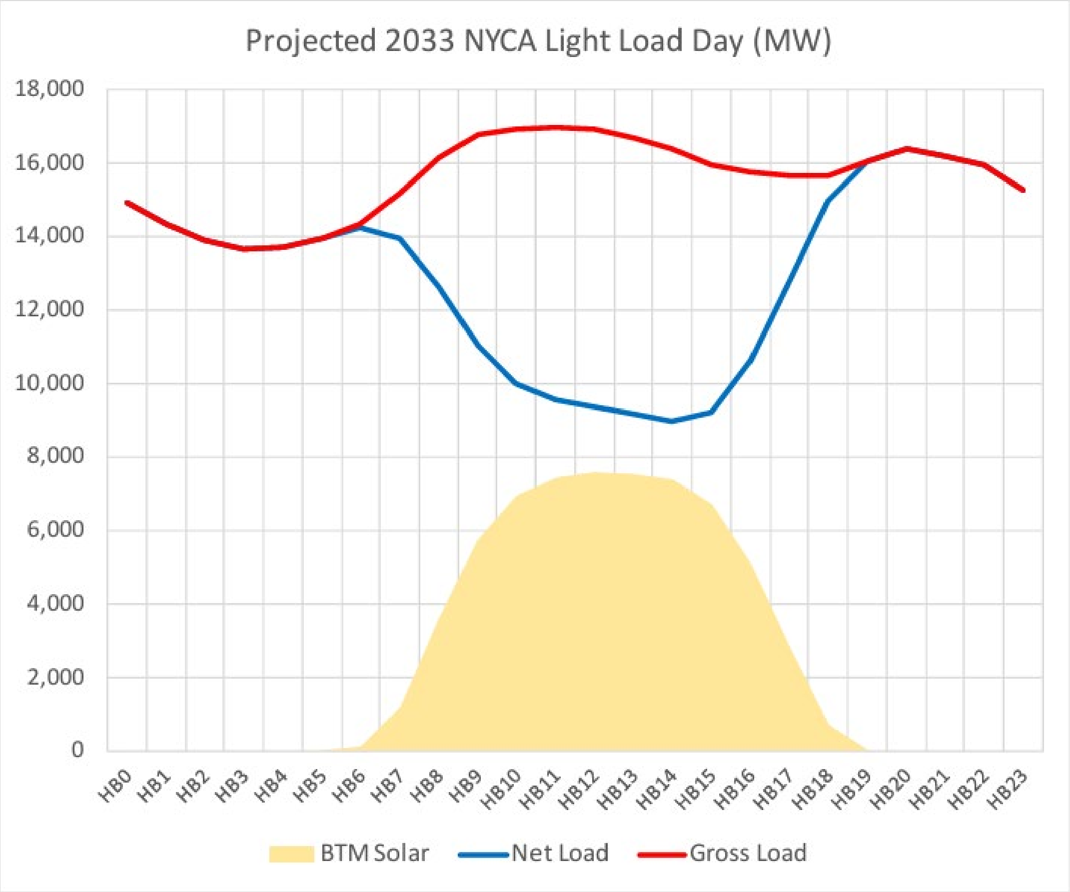
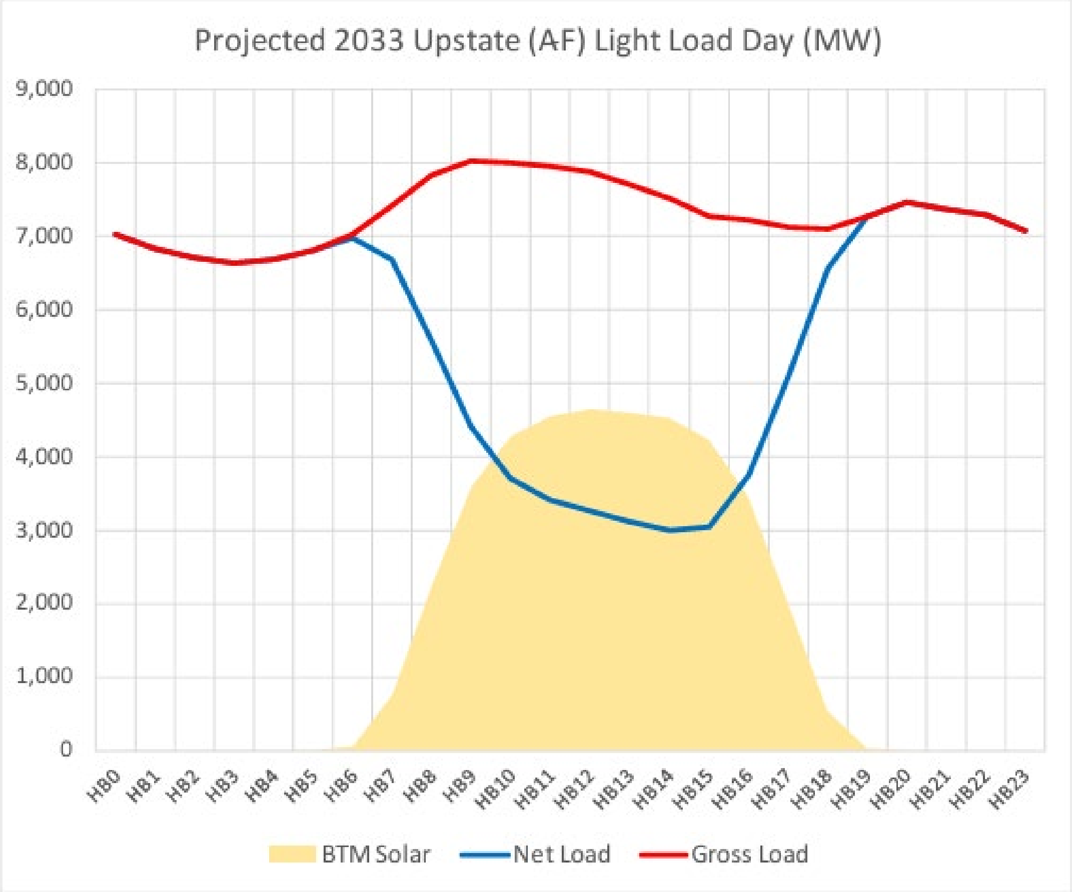




PP-12: Procedure for Distributed Energy Resource Data Collection

- Applicable to all Distribution Utilities
- Transmission Owners shall submit the data in the "Feeder Data Submission Format" worksheet as part of every triannual data submission

For each installation:

Data to be provided by distribution provider

- Size (kW)
- Fuel Type (PV, wind, gas, etc.)
- In-Service Date
- Location (town/city/ZIP code)
- Feeder ID
- Etc.

For each feeder ID:

Data to be provided by transmission owner

- Corresponding PSS/E bus number
- Corresponding ISO-NE EMS substation name
- Corresponding latitude/longitude of beginning of feeder
- Etc.

PP-12: Procedure for Distributed Energy Resource Data Collection

- Applicable to all Distribution Utilities
- Transmission Owners shall submit the data in the "Feeder Data Submission Format" worksheet as part of every triannual data submission

Fields are color-coded based on whether they are required or optional, as follows:
Orange highlight: required for all DER
Yellow highlight: required for all DER interconnected after January 1, 2025; optional for earlier DER
Blue highlight: optional for all DER

Field descriptions:

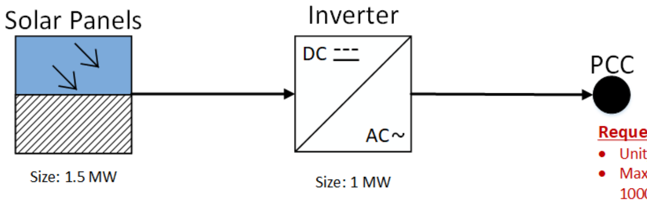
Field Name	Input Type	Input Format	Description
Distribution Provider	Text	N/A	Name of distribution provider.
Unique DER ID	Text	N/A	Unique ID assigned by distribution provider. No two DERs submitted by a single distribution provider should have the same ID, and IDs should remain consistent from one data submission to the next.
Proposed Plan Application ID	Text	N/A	ID number of Proposed Plan Application or Generator Notification Form submitted to ISO-NE. Required for all projects for which a PPA or GNF is required to be submitted. For projects with status "Pending," a PPA identifier is only required once it has been assigned.
ISO-NE Market Asset ID	Numeric	N/A	Asset ID number of DER in ISO Customer and Asset Management System (CAMS) and other market systems, if known.
Revision Date	Date	mm/dd/yyyy	Date on which data was revised (system expanded or retired, for example). Not required for distribution providers who remove data entry and create a new data entry when equipment is modified.
Status	Text	Select from list	DER status. Valid entries are: Online, Pending, Retired, Long-Term Outage, and Canceled. Distribution Providers are not required to keep facilities in their submissions with a status of Canceled if proposed facilities are automatically removed from interconnection queues or tracking systems upon cancellation. Facility retirements or long-term outages should be reported to the extent that the Distribution Provider is notified of these conditions.
In-Service Date	Date	mm/dd/yyyy	Date on which DER was connected to the distribution provider's system. Date on which DER was approved/given permission to interconnect is also acceptable, since exact in-service date is often not known.
Non-Standard Inverter Settings	Text	N/A	If DER is known to have non-standard inverter settings (for example, protection settings that differ from IEEE 1547 due to inclusion in a microgrid), please
State	Text	Select from list	State in which the DER is physically located. (ME, MA, CT, VT, RI, NH)
City/Town	Text	N/A	City or town in which the DER is physically located.
ZIP Code	Text	N/A	ZIP code in which the DER is physically located.
Feeder ID	Text	N/A	Feeder ID to which the DER is interconnected
Unit/Fuel Type	Text	Select from list	Type of DER. Valid entries are: Solar, Wind, Fossil Inverter Based, Fossil Synchronous, Renewable Inverter Based, Renewable Synchronous, Hydroelectric, Storage Only, and Other. For hybrid generation/storage facilities, enter only the generation type.
Other Unit/Fuel Type	Text	N/A	Description of DER unit/fuel type if Unit/Fuel Type entry is "Other." Required if Unit/Fuel Type entry is "Other."
Max AC generation (kW)	Numeric	99999.99	Maximum DER output to the AC network, excluding storage (i.e. nameplate of inverter or maximum power output of synchronous generator).
Max DC generation (kW)	Numeric	99999.99	For solar facilities, panel size in DC kW. Required only for solar facilities, and only for those interconnected on or after January 1, 2025.
Facility includes energy storage?	Y/N	Y or N	Y if facility includes energy storage, N if not.
Voltage/VAR operating mode	Text	N/A	If DER is known to operate in a mode other than constant unity power factor, describe operating mode.
Roof Mounted/Ground Mounted PV	Text	N/A	Optional, for solar facilities only. Valid entries are: Roof Mounted and Ground Mounted
Fixed/Tracking PV	Text	N/A	Optional, for solar facilities only. Valid entries are: Fixed and Tracking
Installed energy capacity (kWh)	Numeric	99999.99	Total energy stored, as determined by storage system nameplate or total capacity. Required only for facilities including energy storage interconnected on or after January 1, 2025.
DC/AC coupled	Text	Select from list	For hybrid generation/storage facilities, indicate whether connection between battery and generation source is a DC connection (generation and storage share an inverter) or an AC connection (generation and storage have separate inverters). Required only for hybrid generation/storage facilities interconnected on or after January 1, 2025. Valid entries are: AC and DC
Can charge from grid?	Y/N	Y or N	For hybrid generation/storage facilities, indicate whether energy storage is allowed to charge with power from the distribution system, or if it is limited to charge only from power produced by on-site generation. Required only for hybrid generation/storage facilities interconnected on or after January 1, 2025.
Storage Injection Capability (kW)	Numeric	99999.99	For Storage Only and hybrid generation/storage facilities, the maximum rate at which energy can be injected to the distribution system from the storage equipment alone. Required only for facilities including storage interconnected on or after January 1, 2025.
Facility Import Limit (kW)	Numeric	99999.99	For Storage Only and hybrid generation/storage facilities, the maximum rate at which energy is permitted to be withdrawn from the distribution system to charge onsite storage (or the facility's maximum withdrawal capability, if this limits the facility). Required only for facilities including storage interconnected
Facility Export Limit (kW)	Numeric	99999.99	For Storage Only and hybrid generation/storage facilities, the maximum rate at which energy is permitted to be injected to the distribution system from the combination of storage and onsite generation (or the facility's maximum injection capability, if this limits the facility). Required only for facilities including storage interconnected on or after January 1, 2025.
Inverter manufacturer	Text	N/A	If known, the manufacturer of the facility's inverters.
Inverter model	Text	N/A	If known, the model number of the facility's inverters.

ISO new england

PP-12: Procedure for Distributed Energy Resource Data Collection

Example 1:

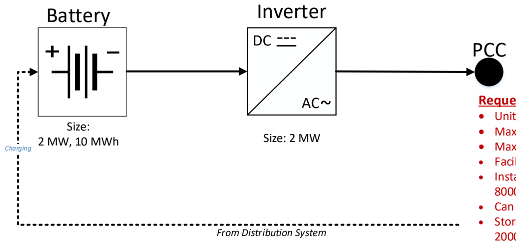
- 1.5 MW solar panel array connected to 1 MW inverter
- No on-site storage



Requested data:
- Unit/Fuel Type: Solar
- Max AC Generation (kW): 1000
- Max DC Generation (kW): 1500

Example 2:

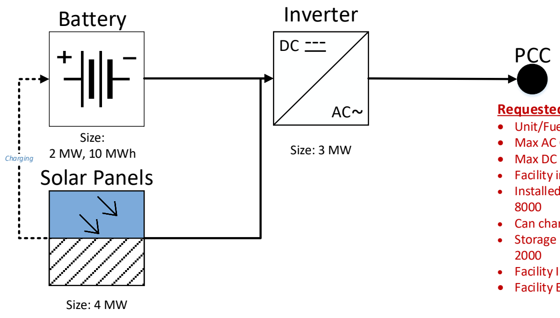
- 2 MW, 8 MWh battery connected to 2 MW inverter
- No other on-site generation – battery charges from distribution system



Requested data:
- Unit/Fuel Type: Storage Only
- Max AC Generation (kW): 0
- Max DC Generation (kW): 0
- Facility includes energy storage?: Y
- Installed energy capacity (kWh): 8000
- Can charge from grid?: Y
- Storage Injection Capability (kW): 2000
- Facility Import Limit (kW): 2000
- Facility Export Limit (kW): 2000

Example 3:

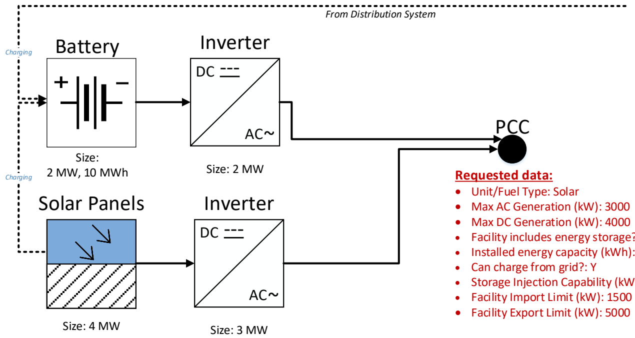
- 4 MW solar panel and 2 MW, 8 MWh battery sharing a 3 MW inverter
- Facility only *injects* power into the distribution system, and batteries are charged only from on-site solar generation



Requested data:
- Unit/Fuel Type: Solar
- Max AC Generation (kW): 3000
- Max DC Generation (kW): 4000
- Facility includes energy storage?: Y
- Installed energy capacity (kWh): 8000
- Can charge from grid?: N
- Storage Injection Capability (kW): 2000
- Facility Import Limit (kW): 0
- Facility Export Limit (kW): 3000

Example 4:

- 4 MW solar panel connected to a 3 MW inverter; co-located with a 2 MW, 8 MWh battery connected to a 2 MW inverter.
- Batteries allowed to charge from either on-site generation or from the distribution system.
- Due to distribution system limitations, facility prohibited from consuming >1.5 MW of power from the distribution system, but can inject its full capability into the distribution system.



Requested data:
- Unit/Fuel Type: Solar
- Max AC Generation (kW): 3000
- Max DC Generation (kW): 4000
- Facility includes energy storage?: Y
- Installed energy capacity (kWh): 8000
- Can charge from grid?: Y
- Storage Injection Capability (kW): 2000
- Facility Import Limit (kW): 1500
- Facility Export Limit (kW): 5000

VELCO

PP-12: Procedure for Distributed Energy Resource Data Collection

Procedure Step	December Data Collection	April Data Collection	August Data Collection
ISO-NE distributes data request to Distribution Providers and Transmission Owners	December 15	April 15	August 15
Submit all DER interconnected and proposed as of:	December 31	April 30	August 31
Distribution Providers and Transmission Owners respond to ISO-NE data request	January 21	May 21	September 21

The first data collection under this procedure will occur in January 2025, and Distribution Providers and Transmission Owners shall submit data by the January 21 due date. As part of that collection, ISO New England shall work with data submitters after this date to identify any data quality and data formatting issues, and these issues may be remedied after the January 21 date.

PP-12: Procedure for Distributed Energy Resource Data Collection

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee April 17, 2024	Initial introduction & background
Reliability Committee May 14, 2024	Present draft procedure
Reliability Committee June 18, 2024	Present updated draft procedure
Reliability Committee **July 16, 2024**	Present updated draft procedure; Vote
Participants Committee **August 1, 2024**	Vote

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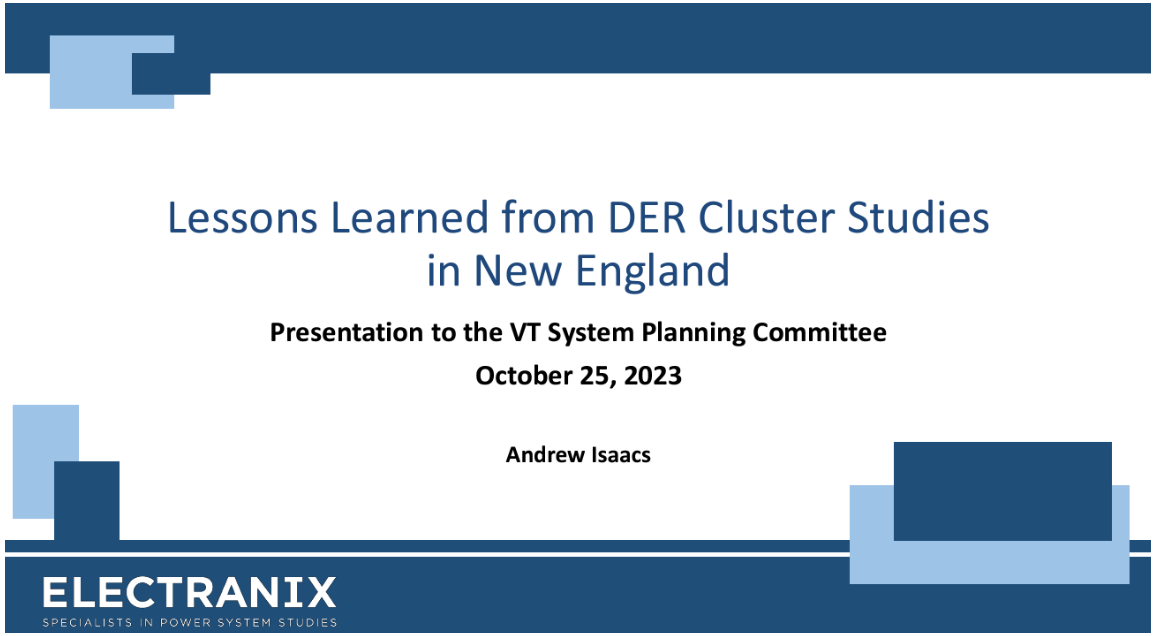
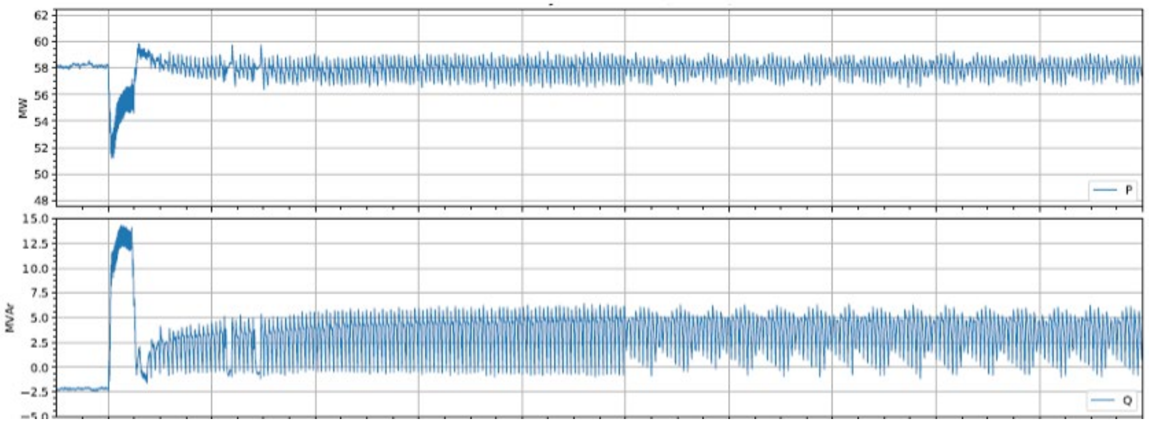
PP5-6: Affected System Operator (ASO) Study Coordination

- For “Lessons Learned” on ASO Studies and PSCAD, please see the VSPC October 2023 Presentation by Electranix

- PP5-6 Revision Takeaway: If the aggregation at the station under review plus the **electrically close** stations is <20MW, and the newly proposed addition of individually <5 MW DERs is >20 MW, then the projects will require **Level III analysis (PSCAD)**

- “ASO studies taking place in a part of the system that are **not relevant** to the ISO Cluster Study will be able to complete their studies without respecting the ISO Cluster Study.”





PP5-6: Affected System Operator (ASO) Study Coordination

- If the ISO continued to process determinations for DER projects on a rolling monthly basis, the following could occur in the months after the ASO coordinated studies are initiated
- Example Substation with no existing DERs in electrical proximity

Months After Closing of Cluster Windows	DER Project Proposed at the Example Substation (MW)	ISO Determination Under the Current Rolling Monthly Process
Month +1	4.9	Level 0
Month +2	4.9	Level 0
Month +3	4.9	Level 0
Month +4	4.9	Level 0
Month +5	4.9	Level III*

*A Level III study of the 4.9 MW proposal in Month +5

PP5-6: Affected System Operator (ASO) Study Coordination

- Revisions to comply with "first ready, first served" requirements of FERC Order 2023

- This may result in **significant delays** and increased interconnection costs

Determination Procedure for New or Increased Generation >1MW and <5 MW (cont'd)

TO Actions:

- TO submits determination request to the ISO with at least the following information for the proposed project:
  - Unique Project Identifier
  - Closest Transmission Substation
  - Distribution Substation
  - Feeder
  - MW Output
  - Fuel Type
  - Technology Type
  - Bus Number

OR:

- TO or MP submits Generator Notification Form/Proposed Plans Application to the Proposed Plans Inbox

PP5-6: Affected System Operator (ASO) Study Coordination

- Revisions to comply with "first ready, first served" requirements of FERC Order 2023

- This may result in **significant delays** and increased interconnection costs

Determination Procedure for New or Increased Generation >1 MW and <5 MW (cont'd)

ISO Actions:

- *Step 0:* Identify project size If project is 5 MW or greater, notify TO that Level III analysis is required before project can be submitted for approval
  - If project is less than 5 MW, move to step 1
- *Step 1:* Identify the transmission/BES/PTF station that the DER(s) normally feed up to (the station that is electrically closest for those with multiple paths)
- *Step 2:* Aggregate all inverter based projects, newly proposed, planned, and interconnected at station identified in step 1, with a PPA submittal date of January 1st, 2019 or later
- *Step 3:* Determine if aggregate quantity of DER from step 2 exceeds threshold
  - If aggregate is 20 MW or greater, notify TO that Level III analysis is required before any new proposals can be submitted for approval
  - If aggregate is less then 20 MW, move to step 4

PP5-6: Affected System Operator (ASO) Study Coordination

- Revisions to comply with "first ready, first served" requirements of FERC Order 2023

- This may result in **significant delays** and increased interconnection costs

Determination Procedure for New or Increased Generation >1MW and <5 MW (cont'd)

- *Step 4:* Run 3-phase fault at station identified in step 1 for six cycles
- *Step 5:* Create list of all transmission/BES/PTF stations that are at .3pu voltage or less
- *Step 6:* Reset simulation
- *Step 7:* Run steps 4 - 6 for each station within the documented list of stations from step 5
- *Step 8:* Aggregate all inverter based projects, newly proposed, planned, and interconnected with a PPA submitted date of January 1st, 2019 or later between all stations documented in step 5

PP5-6: Affected System Operator (ASO) Study Coordination

- Revisions to comply with "first ready, first served" requirements of FERC Order 2023
- This may result in **significant delays** and increased interconnection costs

Determination Procedure for New or Increased Generation >1MW and <5 MW (cont'd)

- *Step 9:* Notify TO of determinations
  - If aggregate in step 6 is 20 MW or greater, then notification will indicate Level III analysis is required before any new proposals can be submitted for approval
  - If aggregate in step 8 is less than 20 MW, but aggregate from step 2 is 5 MW or greater, then notification will indicate that Confirmation of No Adverse Impact is required before any new proposals can be submitted for approval

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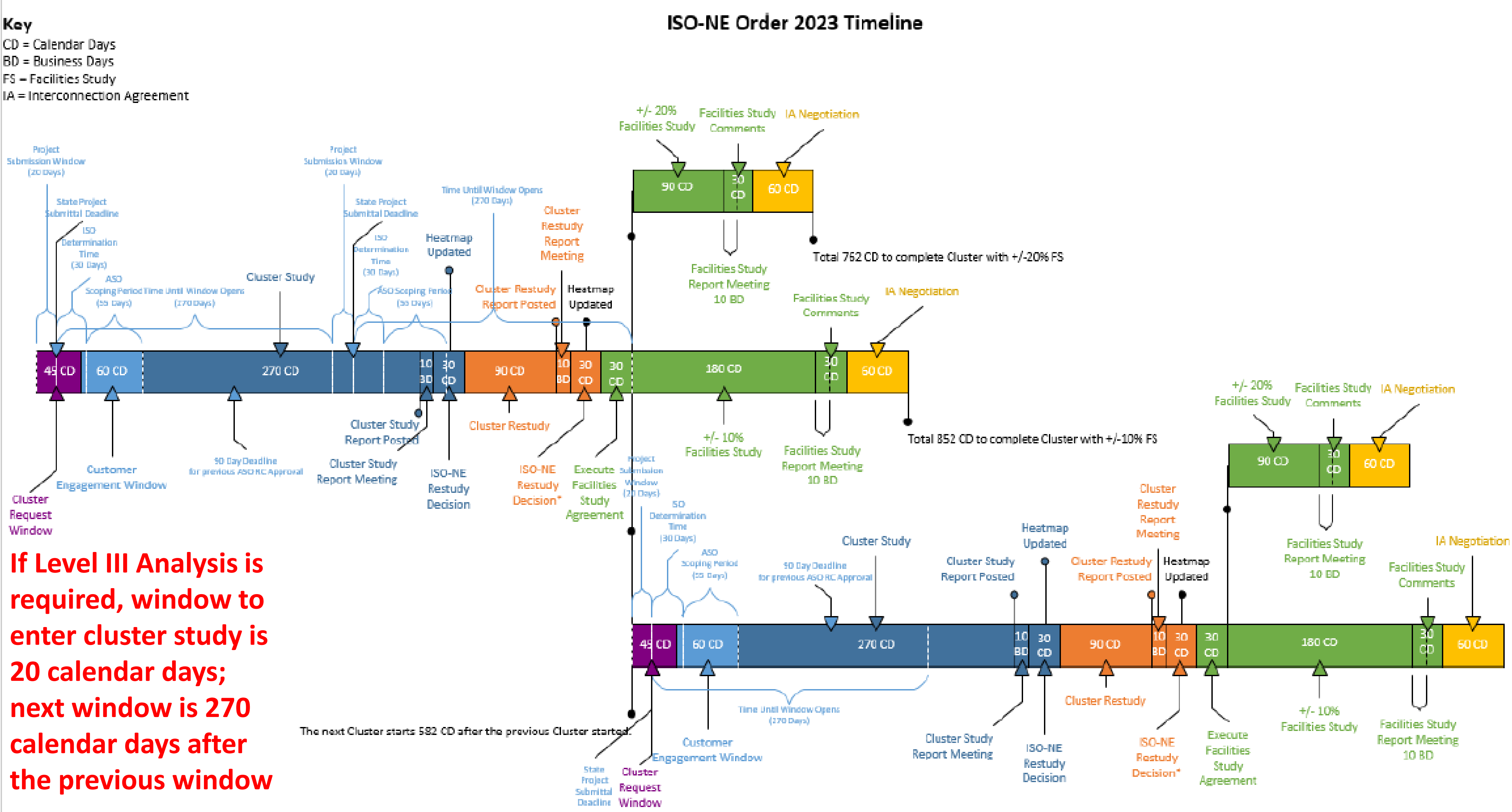
PP5-6: Affected System Operator (ASO) Study Coordination



- **If Level III Analysis is required, window to enter cluster study is 20 calendar days; next window is 270 calendar days after the previous window**

PP5-6: Affected System Operator (ASO) Study Coordination

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee **March 19, 2024**	Initial Presentation
Reliability Committee **June 18th, 2024**	Updated Presentation
Reliability Committee **July 16, 2024**	Review PP5-6 Redlines
Reliability Committee **July 25, 2024**	Additional meeting to continue discussion on PP5-6 redlines from the July 16, 2024 RC and introduce any related amendments. Please contact the RC Secretary (dpatnaude@iso-ne.com) by no later than July 18 to request time to present on the agenda
Reliability Committee **August 13-14, 2024**	Review PP5-6 Redlines and Stakeholder Amendments; Vote
Participants Committee **September 5, 2024**	Vote

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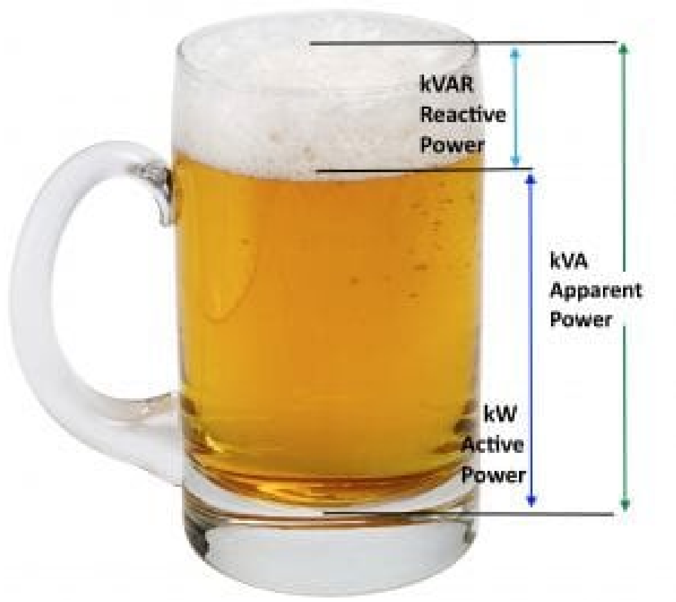
OP-17: Load Power Factor and System Assessment

- Load power factor (LPF) similar to classic beer and foam analogy
- Need to keep balance between amount of beer (real power) and foam (reactive power) to maintain voltage, reduce losses
- The LPF is the ratio of real power demand (MW) to apparent power (MVA)
- LPF is a key study assumption in planning, and a key factor for ISO-NE in operating the power system
- Significant changes in LPF from that assumed in planning studies can lead to out-of-merit Resource commitments ($$$) to prevent unacceptable high or low system voltages, and potential reliability concerns
- New England TOs, through their transmission planners, each provide to the ISO the LPF for their respective load that the system should be planned to for key sets of system conditions, including minimum and maximum load levels



Schneider Electric Blog
Courtesy of PNNL

VELCO

OP-17: Load Power Factor and System Assessment

Scaling capacity, energy, loads, and transmission (**CELT**) Load Power Factor Assumptions

Transmission Owner or Municipal Entity	Nighttime Minimum	Mid-day Minimum	All other load levels (minimum reactive power absorption)	All other load levels (maximum reactive power absorption)
VELCO	0.998 leading	Unity PF	Individual substation load PF limit (9)	Individual substation load lagging PF limit (10)

(9) Net injection of reactive power is not allowed on the high side of transformers that interconnect to voltage levels at or above 69 kV. To calculate the net injection of reactive power, the sum of VAR injections is measured on the high side of the VELCO transformers, assuming generators and capacitors connected to subtransmission/distribution are offline.

(10) Overall LPF for the VELCO system will be 0.99 lagging or better, measured on the high side (69 kV and above) of the VELCO transformers that connect to subtransmission/distribution system, assuming generators connected to subtransmission/distribution are offline. The overall LPF is calculated by summing up the real power flows and reactive power flows across all 69 kV and above transformers in the VELCO system.

Transmission Planning Technical Guide

OP-17: Load Power Factor and System Assessment

Current Version

1. Non-compliance with LPF Standard

For each LPF area that violates its standard(s), a letter will be sent to ***all*** TLC Contacts (s) within the LPF area by the end of the year following the survey year. For example, in 2022, the year 2021 is being surveyed, and by the end of 2022, a letter regarding the 2021 survey results will be sent.

In the letter, TLC(s) within the violating LPF area are encouraged to evaluate their LPF performance, and if they in fact violated the LPF standard, to take mitigating actions to improve LPF performance. However, the TLC is not responsible for providing the analysis or mitigating plan to ISO. Since the LPF survey aggregates the performance of all load serving transformers within an LPF area, it is possible that an individual TLC operated within the LPF standards, yet exists within an LPF area that, as a whole, violated the standard(s).

In the letter, several hours of poor performance will be identified. The poor performance hours do *not* represent the extent of the problem within the violating LPF area; rather, the poor performance hours provide a potential starting point or focus point for the TLCs' investigation. It is possible that the TLC was in fact compliant during the identified poor performance hour and yet not compliant during another hour that was not identified. Ultimately, the responsibility of assessing an individual TLC's LPF performance lies with that TLC. The poor performance hours identified by ISO on the LPF letters will represent 10 unique days of the highest MVAR surplus or deficiency. The hour of the highest MVAR surplus or deficiency of that day will also be identified. Therefore, the hours identified may not be the top 10 hours for highest surplus or deficiency. For example, if one day contains the three highest surplus hours for the year, only the highest surplus hour of that day will be listed on the letter.

Current: No corrective action plan required

Proposed: Corrective action plan required with budget, design, and procurement detail

Proposed Version

2. Non-compliance letters

The ISO shall send non-compliance letters requiring action at the first instance found of a TO / TLC not complying with its provided LPF per this OP. The ISO shall send non-compliance letters by the end of Q2 for each preceding year (for example, for 2024, by 6/30/25).

The timeline and actions applicable when the ISO sends a non-compliance letter are identified below:

a. If there is a need, the ISO shall send a request to the LCC to confirm the TOs / TLC and Transmission Load Customer Contacts (TLC Contacts) as recorded in Appendix C – Instructions for the ISO New England Load Power Factor Survey (OP-17C) in a non-compliant area, within seven (7) Business Days of the event identification. TO contacts are included within the TLC Contact list.

b. The LCC shall confirm / correct the list of TOs / TLCs and TLC Contacts in the non-compliant area within seven (7) Business Days of receipt of the list.

c. Responsible TOs / TLCs shall submit to the ISO an action plan within forty (40) Business Days of receipt of a non-compliance notification. The mitigation plan shall include an expected date of a return-to-compliance based upon completion of the action plan.

d. Responsible TOs / TLCs shall submit evidence of implementing the action plan to return-to-compliance, to ISO within forty (40) Business Days of submitting the action plan, as well as when the action plan is complete.

e. TOs / TLCs that fail to resolve the identified LPF compliance concerns after repeated notifications may see this compliance issue elevated to the proper authority.

ISO will consider the scope of effort needed to correct the LPF in a given area. LPF correction plans are expected to potentially include factors such as budgeting, design, procurement and implementation / construction.

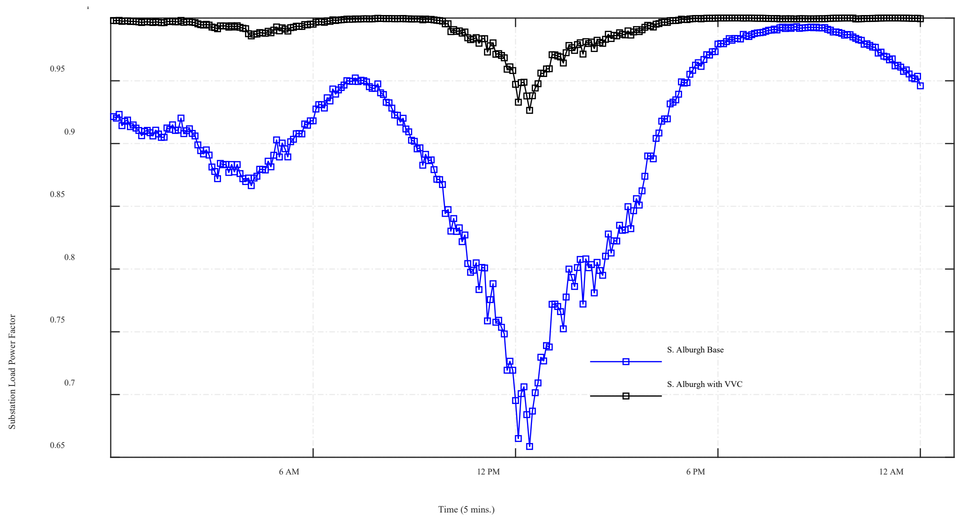
OP-17: Load Power Factor and System Assessment

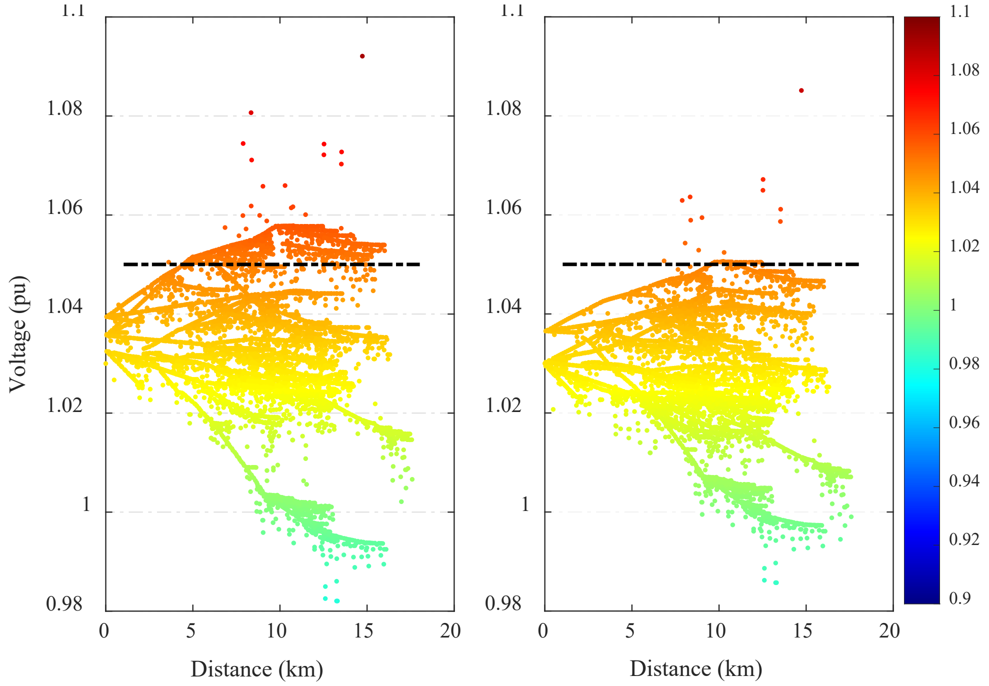
Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee **June 18, 2024**	Initial presentation and questions
Reliability Committee **July 16, 2024**	Revised presentation questions
Reliability Committee **August 13-14, 2024**	Respond to any remaining questions and vote
Participants Committee **September 5, 2024**	Vote

R&D Lessons Learned with VEC, PNNL, and ORNL – Load Power Factor

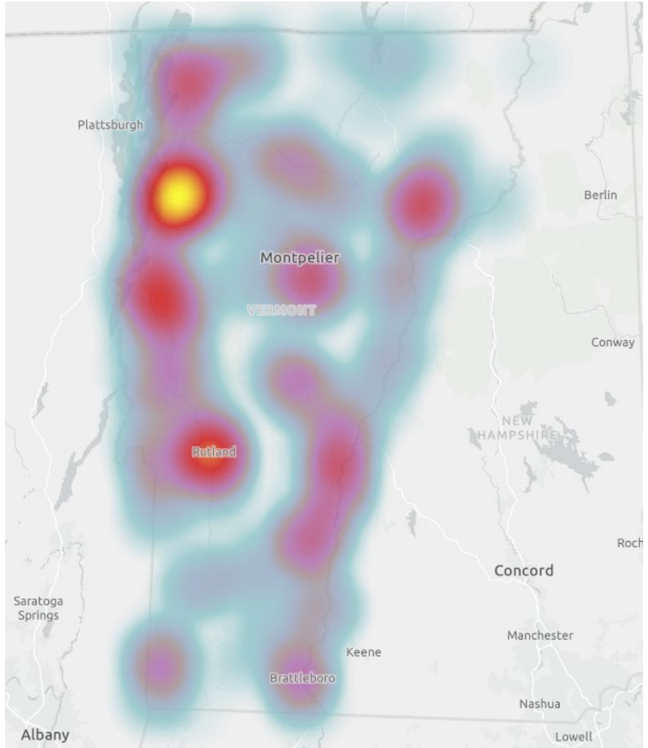
- Load power factor improved with reactive power contribution from inverters
  - Less Q exchanged at the interface

- May represent low cost, high yield solution compared to alternative upgrades





Summary



- ISO-NE Planning and Operating Procedures are catching up to the transforming grid
- Proposed PP-12 would require DER data sharing from all DUs and VELCO
- Proposed revisions to PP5-6 would introduce risk of significant delay and interconnection costs for DER >1 and <5 MW
- Proposed revisions to OP-17 would require corrective action plans and associated investments to improve load power factor

Thank You!

Questions?