

## **Day Two DER Forum:**

**October 15, 2020 8:30 a.m. – 2:00 p.m. EDT**

### **12.0 Distributed Energy Resources (DER) Forum Topics**

- 12.1 DER, Approach to Regional Guidance and DER Impact Reporting
- 12.2 Presentations by NYISO on DER Aggregation, Roadmap and Interconnection Requirements (8:40-9:30 AM)
- 12.3 New York State Reliability Council (NYSRC) High Renewables Capacity Study Presentation by Mayer Sasson and Howard Kosel (9:30 AM)
- 12.4 Test and Analysis of the Dynamic and Transient Behavior of Inverters used in Solar Residential Projects presented by Hache Jean-Francois from Hydro Quebec (10 AM)
- 12.5 Presentation by ISO-NE DER Interconnection and Aggregation
- 12.6 Effective Grounding of DER Presentation by Devin Van Zandt and Tom Key from EPRI (11 AM)
- 12.7 Presentation by Song Ji from National Grid on Substation Protection issues associated with DER
- 12.8 FERC Order 2222 relating to Participation DER Aggregation in Markets in ISOs and RTOs presentation by David Kathan from FERC

## **Northeast Power Coordinating Council, Inc. (NPCC)**

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- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
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RSC and DER Forum Meetings, WebEx, and Conference calls:

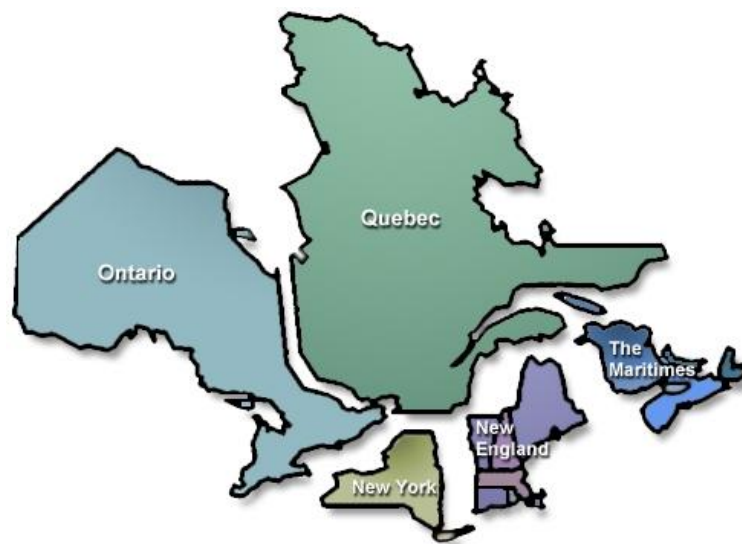
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**DRAFT**

# **NPCC DER Guidance Document, Distributed Energy Resources (DER) Considerations to Optimize and Enhance System Resilience and Reliability**



|                                         |
|-----------------------------------------|
| NPCC Regional Standards Committee (RSC) |
| Version 2 Approved 12/XX/2020           |



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NPCC also thanks the Regional Standards Committee and the state and provincial regulatory authorities who provided guidance and information during the development of this document.

### Revision History

| <b>Version</b> | <b>Date</b>    | <b>Action</b>                                   | <b>Change Tracking<br/>(New, Errata or<br/>Revisions)</b>                                             |
|----------------|----------------|-------------------------------------------------|-------------------------------------------------------------------------------------------------------|
| <b>1</b>       | <b>8/19/19</b> | <b>Effective Date</b>                           | <b>New</b>                                                                                            |
| <b>2</b>       | <b>X/XX/XX</b> | <b>RSC and Subgroup<br/>developed revisions</b> | <b>Revisions, add<br/>AGIR and various<br/>enhancements<br/>and clarifications<br/>and Appendices</b> |
|                |                |                                                 |                                                                                                       |

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## Executive Summary

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the International, interconnected Bulk Power System in Northeastern North America.

Development of this document was initiated by the NPCC Board of Directors to provide Regional guidance and information for voluntary use by NPCC Members and stakeholders. The guidance provided herein identifies potential reliability risks<sup>1</sup> to the BPS, recommendations to mitigate them, and also identifies opportunities to leverage the operational characteristics of DER to enhance reliability and resilience of the NPCC Bulk Power System (BPS). Helpful links to other resources are provided throughout the document.

As Distributed Energy Resources (DER) installed on the distribution system, continue to replace traditional industry generation resources the resource fuel mix and operational characteristics of the system will change. DER will necessitate changes to how the system is planned and operated. The North American Electric Reliability Corporation (NERC) Reliability Standards are not applicable to equipment on the distribution systems unless such equipment has a direct impact on the “reliable operation”<sup>2</sup> of the BPS, such as Automatic Underfrequency Load Shedding (UFLS). However, as penetration of DER increases, planning and operating assessments used to assure reliable operation of the BPS will need to accurately represent how DER interacts with the BPS.

NPCC recognizes that national efforts are underway at the NERC level to define DER and address some aspects related to planning and modeling. [Appendix C](#) outlines some specific reliability activities related to DER which are either developed, or in the process of being developed, by the NERC System Planning Impacts Working Group (SPIDER), along with links to some of their documents. NPCC and its members have been engaged in efforts at the national level and are leading efforts to address outstanding issues within the scope of those groups and provide expertise. With the understanding of what efforts are underway nationally, NPCC can coordinate and fill a vital role in identifying additional areas where the Region may provide information and services to promote reliable deployment of DER. Specifically, in the area of coordination with State and Provincial Government Regulatory Authorities, and distribution utilities. Also, opportunities exist in the areas of obtaining data, models, testing and verification, observability, protection systems and other operational characteristics of DER and their effect on the distribution systems.

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<sup>1</sup> An example of a reliability risk not addressed is remote dispatch of DER. A significant challenge that has been found by some NPCC members is that DER Operators can be anywhere in the world and that as a result, communications can be significantly delayed, leading to reliability risks. This includes time zone challenges and language challenges,

<sup>2</sup> “reliable operation” is defined in 16 U.S. Code § 824o and means “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

NPCC has also been conducting DER Forums, the purpose of which is to promulgate DER related information, educate, and inform. NPCC's Regional Standards Committee (RSC) and Reliability Coordinating Committee (RCC) have also developed a joint process and a form to report DER related impacts, analyze and determine a way to address any issues. The Form and process may be found in [Appendix A](#) and on the NPCC website.

NPCC, is not creating new Criteria or Standards through this guidance document. The intent is purely informational and as NERC's SPIDER, and other groups develop their respective guidance documents it will be revised to achieve continued alignment and avoid duplication.

This guidance document contains **DER Recommendations**, and information provided by NPCC's Members, NERC, the industry, the US National Labs, the Electric Power Research Institute and information from NPCC Staff. Also, it is important to note that specific distribution utility requirements within NPCC at the local level will supersede any suggested approaches in this document.

## Introduction and Objective

A consistent defined term for what type generating resources are included in DER is not broadly accepted by the industry. Also, DER is not currently a term that is defined by NERC.

For the purpose of this NPCC guidance, DER refers to:

Any non-BPS connected real or reactive power resources (generating units, multiple generating units at a single location, distributed generation installations, battery storage, systems etc.) located within the boundary of any distribution utility's service territory, irrespective of capacity, allowing individual small DER to be captured if they are not aggregated. Some DER technologies are more intermittent in their production characteristics than resources which operate based on a controllable fuel input.

Initially, in the first version of this guidance document, NPCC specified a threshold for inclusion of DER in any Regional Guidance would not include individual rooftop solar or wind turbines or other localized DER net metering installations, however the aggregate effect of these types of DER can have a significant change in the power system and if not properly understood can impact the reliable operation of the BPS, as we have seen in California subsequent to their Rule 21<sup>3</sup>. NPCC is now observing aggregation of DER beginning to enter capacity wholesale markets within the NPCC Region. This document will continually be modified as emerging issues related to DER's deployment, interconnection, planning and operations are identified and technology improves.

This document identifies opportunities for DER related process improvement and address potential reliability risks, promote good utility interconnection practices necessary for reliability, and promulgate

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<sup>3</sup> <https://www.cpuc.ca.gov/Rule21/> Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. The tariff provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.

information on how DER can enhance reliable operation of the Transmission Distribution interface by providing essential reliability services. In addition, during the development of this document, a review of existing DER related documents was performed and NPCC is working with the NY Interconnection Technical Working Group as well as the Joint Utilities group of NY to align processes where possible.

National standards are established to address DER impact on system reliability. IEEE Std 1547-2018 brings significant potential benefits to the BPS by requiring that DER provide essential reliability services to ensure stability, reliability, and security. State and Provincial requirements for DER interconnection should also require compliance with IEEE 1547 through inclusion in those interconnection agreements.

As DER continues to penetrate the electric system at the “grid edge” or distribution system, and replace conventional transmission grid connected resources, there is an increasing reliability related need to understand and influence the effect of these DER resources on the BPS. It is important to understand how DER is interconnected, planned, operated and how they interact with the transmission system.

Reliably and securely integrating DER into the electric system requires a comprehensive multi-pronged approach utilizing perspectives from different areas. DER design, modeling, planning, and relay coordination require consideration of jurisdictional issues. The importance of Members working with their respective national, state, and provincial regulatory authorities to help them understand the consequences of and formulation of effective DER interconnection requirements is critical. While there may be some broad universal guidelines, the details of effective DER interconnection requirements should be reconciled with the nature of the system within which the interconnection is taking place.

[Appendix B](#) of this document provides a comparison of NPCC’s Area requirements, at the time of the Version 1 writing, to help identify opportunities for guidance.

Many, if not most, of the contemporary DER is theoretically capable of bringing several enhancements to reliability, provided that there are sufficient design specifications and interconnection requirements to implement the enhancements. Inverter based DER may use fast, programmable response to provide benefits to reliability if properly configured with coordination with the host utility. Coordination must consider effects both on the distribution system and the BPS. The sections below address DER impact on the BPS including aspects of:

- Interconnection guidance
- Voltage response
- Frequency support
- Reconnecting to the utility following faults
- Under frequency load shedding

While DER presents opportunities to enhance reliability, they also introduce challenges at the transmission/distribution interface if not deployed correctly. Interoperability with the transmission system is not solely determined at the point of interconnection. Visibility and a level of controllability of DER is essential for transmission operators to maintain situational awareness for reliable operation of the BPS, and for short-term forecasting. Additionally, characteristics of DER such as capacity,

intermittent production, location, protection settings, and other parameters must be known for long-term operational performance forecasting and system planning to ensure BPS reliability is maintained.

Presently there are limited study tools in general use to perform fully integrated studies of transmission and distribution which would allow both systems to be modeled and studied (in steady state and dynamically) together, although work is underway in this regard. EPRI has an open sourced co-simulation tool under test. In the shorter term, visibility of the variability of DER capacity could dramatically affect the quality of state estimator information and methods of improving data and forecasting need to be explored.

In recognition of both the benefits and challenges associated with DER, the approach taken with this second version of the NPCC DER guidance document is to collect interconnection related information within the NPCC Region as well as in other areas of the NERC Electric Reliability Organization (ERO) Enterprise. There are some specific situations where opportunity exists to ensure better coordination across the NPCC Region. The intent of this document is to identify any emerging reliability issues and opportunities for further work, and provide general guidance and information where possible, offer consistent guidance with North America wide technical direction to promote reliable interconnection and operation of DER. It is recognized that DER may not be placed optimally and in areas where deliverability to load may not be ideal. In this respect any specific information in this document must be considered in conjunction with the requirements of the interconnecting distribution utility.

## NPCC DER Impact Reporting

In order to ensure the reliability and Resilience of the interconnected BPS in Northeastern North America as DER, both aggregated and single installations, continue to proliferate throughout the distribution systems within the NPCC Region, it is important to have a Regional DER impact reporting mechanism. The NPCC Regional Standard Committee (RSC) created an impact reporting form and process that allows entities to report DER impacts and to seek guidance regarding emerging issues and reliability risks that affect or could affect the reliable performance of the BPS see [Appendix A](#). The Word version of form also is available on the NPCC website at:

[BES Impact Reporting Form](#)

Impact reporting and its associated process provide an orderly mechanism for NPCC to review reliability impacts submitted. A Report will initiate a collaborative review by the Reliability Coordinating Committee and the Regional Standards Committee.

## DER BPS Impact Considerations

NPCC's Regional Standards Committee (RSC) and Task Forces (i.e. Task Force on System Studies) reviews of DER as it pertains to the NPCC Region's BPS performance have identified several areas which, going forward, may warrant further and continual monitoring and analysis. NPCC has identified the following items that should be carefully considered as DER levels (total MWs) increase.

- DER performance with respect to voltage and frequency ride through

- DER ability to provide regulation and reserves
- DER availability and quality of forecasting.
- Observability and situational awareness of DER and importance of implementing Advanced Metering Infrastructure (AMI) if telemetry is not deployed
- DER impacts on Underfrequency Load Shed programs.
- Impacts of DER on the System Restoration and Black Start Plans.

Although DER markets, both wholesale and dual participation models, are not the focus of this document, due consideration should be given to their structure. Market rules that allow aggregation also vary across the NPCC Region. Some Areas allow injection of the aggregation across their market area while others require specific aggregations to be injected nearest to a transmission node. DER are capable of providing ancillary services that are necessary to support reliability, if there are appropriate market mechanisms and incentives that allow and encourage them to do so. Wide-area aggregation and injection may create challenges for the system planners and operators as well as raise deliverability and operations concerns.

## NPCC Interconnection Guidance

This document and any detailed specifications which follow, are intended to provide examples of general information regarding DER interconnection. The examples do not constitute a Regional Criteria (which can only be implemented through NPCC Directories and approval of NPCC's Full Members). There are numerous efforts underway in many forums and regulatory bodies that are expected to create new, more specific guidance<sup>4</sup>. The level of detail and specificity provided is intended to be used as information and guidance for any NPCC Member Area which may not have yet seen the need to establish detailed operating parameters. This document shares the practices of some Members of NPCC which have already established detailed DER requirements, even in advance of upcoming applicable industry standards due to the rate of penetration of DER in their Area. NPCC Members considering improving or adding to their respective DER guidance are encouraged to reach out directly to other members which may have already addressed DER related reliability risk issues.

NERC and NPCC have criteria for resource and transmission planning. For transmission, criteria require transmission planners to simulate different transmission system events and ensure the transmission system remains reliable by meeting performance characteristics for these events. If the transmission system does not remain reliable, the planners are required to identify remediation, including upgrades or expansions of the transmission system. One aspect of the simulation is to account for the loss of generation resources. If a significant amount of DER trips for the simulated transmission event, the transmission system could become unreliable for that event and require remediation. This can occur in several scenarios such a peak load day with maximum output from DER like solar PV or a light load spring day where PV solar and small hydro make up a significant percentage of the generation. IEEE Std.

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<sup>4</sup> At the time of this guidance document development, these include but are not limited to: NERC (e.g. SPIDER WG, IRPTF, Events Analysis, Modelling and Standards process), Inverter- Based Resources Task Force), IEEE (IEEE Std 1547-2018, P2800), and various state initiatives such as the New York ITWG, Other Regional, Provincial and State initiatives.

1547-2018 “Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces” addresses this issue by setting the default DER trip settings for Category II at a level that coordinate with NERC standard PRC-24-02. This is the standard that defines ride-through capability for generators connected to the transmission system. Requiring DER to ride-through disturbances, similarly to large generators, would be a significant step towards ensuring a reliable transmission system at the lowest possible cost.

IEEE 1547-2018 was approved in 2019 and also unanimously adopted by the National Association of Regulatory Utility Commissioners (NARUC). The standard outlines the technical specifications and performance requirements which are universally needed for interconnection and interoperability of DER and will be sufficient for most installations. Implementation guidance for IEEE 1547-2018 may be found here: [Guideline IEEE 1547-2018](#). The applicability of certain specifications and requirements are dependent on specific application considerations. For these, the requirements are provided in terms of a limited number of technology-neutral performance categories, for which it is the responsibility of the authority governing interconnection requirements (AGIR) to consider. Within New England, interconnection requirements vary by state, and further, by Distribution Provider. In New York a common set of DER interconnection requirements exists and there is a Coordinated Electric System Interconnection Request (CESIR) which outlines and initiates the process. Several other the State and Provincial AGIR have developed local interconnection requirements which are listed in [Appendix E](#) of this document along with links which will be helpful to access specific interconnection information. These requirements are then supplemented by individual Distribution Provider interconnection agreements and standards.

The DER owner must follow interconnection agreements and any AGIR requirements for fault ride through. Utilities and other AGIR entities should ensure that their requirements describe necessary DER performance with ride-through capabilities for frequency and voltage events. Interconnection agreements and standards generally have requirements to provide documentation upon request.

In terms of resource adequacy and resource management there is also the possibility of over generation, as has been demonstrated in the state of California when the system operator runs out of load to absorb the available generation. Operating procedures for selecting which generation to curtail should be in place requiring System Operator visibility of DER either individually or in aggregate. In lieu of operating procedures, some areas of the country are planning to use market mechanisms to address this issue. Interconnection agreements or other state or local standards may require DER installations to provide communication channels so that generation can be coordinated with a central dispatch authority.

The DER owner’s protection and control equipment also must be capable of automatically disconnecting the generation from the system to which it is directly connected upon detection of frequency or voltage conditions outside of the applicable ride-through requirements. Note that those interconnection agreements and standards should account for both distribution protection and reliability of the BPS. For three-phase installations, the over and under voltage function should be included for each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface should disconnect for appropriate voltage or frequency trip conditions sensed by the protective devices. Voltage protection should be wired phase to ground for single phase installations

and for applications using wye grounded-wye grounded service transformers. Automatic disconnect devices must be sized to meet all applicable local, state, and federal codes.

The specified size of the generation facility or energy storage system should be based on electrical generator or inverter AC nameplate ratings. The specific design of the protection, control, and grounding schemes will depend on the size and characteristics of the DER owner's generation, as well as the DER owner's expected load level. Dynamic protection systems may be needed based on the characteristics of the particular portion of the utility's system where the DER owner is interconnecting.

The settings referenced herein are generally intended for single-phase and three-phase applications using wye grounded- wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review should be performed by the utility and the revised settings identified in the DER Application Process<sup>5</sup>.

The guidance set forth in this document is intended to be consistent with those specifications contained in the most current version of IEEE Std. 1547-2018. It is recommended that the requirements in IEEE 1547-2018 be referenced in the interconnecting utility requirements as well as any further state interconnection requirements as appropriate.

## Voltage Response

Within IEEE-1547 and in NY State Public Service Commission Interconnection Requirements, the operating range for the generators is generally intended to be from 0.88 to 1.10 per unit of nominal voltage magnitude. In addition, the generator should not cause the system voltage, at the Point of Common Coupling (PCC), to deviate from a range of 0.95 to 1.05 per unit of the utility system voltage. For excursions outside these limits with a duration longer than the applicable fault ride-through requirements, the protective device generally automatically initiates a disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547-2018. Planning Coordinators and Transmission Planners should also be aware that DER installed with older interconnection agreements may reference prior versions of 1547 and may not meet current ride through requirements. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functions may be permitted or required as agreed upon by the utility and DER owner. The industry is now in the process of promoting ride-through via several different standards initiatives which NPCC is tracking through its DER Forum

As described above, ensuring that DER can respond appropriately for various voltage conditions is critical for system reliability, as well as avoiding equipment damage and protecting personnel safety. Continuous operation over a wide band of voltage levels will ensure that DER do not prematurely trip and further deteriorate system conditions. IEEE Std. 1547-2018 includes ranges of trip settings. For inverter-based DER, the "shall trip under" voltage setting should be chosen to meet the requirements of NERC PRC-024-2, as described in Annex B of IEEE Std.1547-2018.

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<sup>5</sup> At this time there has not been an assessment of potential change in sensitivity (increase or decrease) to the effects of GMD from the presence of high DER penetration. This is a potential reliability risk to be evaluated in the future.

## Quebec Interconnection

Ride through during system disturbances is of primary importance for resources connected to the grid, with the objective of maintaining system reliability<sup>6</sup>. IEEE-1547-2018 addresses the topic, however, for voltage and frequency, what is required in the IEEE standard does not match the requirements in Quebec.

DER should have voltage related operational capability and protection settings set as prescribed by the area Electric Power System (EPS) operator and in accordance with IEEE Std. 1547-2018.

This subject area is a matter of facility installation and personnel policy of the asset owner, balancing both reliability and safety. This information should be communicated to the interconnecting utility for proper protection system coordination.

In the Quebec interconnection voltage ranges and regulation requirements vary from the Eastern Interconnection. The requirements of the AGIR having jurisdiction should be followed (typically the Régie de l'énergie and Hydro-Québec). Details for Quebec's process may be found in [Appendix E](#).

## Frequency Support

Frequency support is provided through the combined interactions of synchronous inertia and frequency response. Working in a coordinated way, these characteristics and services arrest the decline in frequency after a disturbance and eventually return the frequency to the desired level. As increased levels of DER are introduced to the system, synchronous inertia will be displaced, which may have an impact on the frequency response performance of the system. With increased penetration of DER it is becoming desirable for DER to remain connected even outside the prescribed frequency range if there is no risk to the DER equipment. The ride-through curves are "shall not trip within the acceptable range," not "must trip immediately outside of the acceptable range."

Interconnection agreements should require DER distribution resources to have a frequency and voltage operating range that is equivalent to BPS connected resources consistent with the most limiting of PRC-006-NPCC, PRC-024 and the latest version of IEEE 1547. The sequence for a protective device to automatically initiate a disconnect sequence from the utility system is also detailed in the most current version of IEEE 1547-2018. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the point of common coupling (PCC) and includes detection and intentional time delay. Other static or dynamic frequency functionality may be permitted or required as agreed upon by the utility and DER owner. There is a need to establish a mechanism to ensure distribution provider transmit information to planners and operators as to which DER facilities are connected to distribution feeder that have UFLS protection systems.

## Quebec Interconnection

Note that in the Quebec Interconnection the frequency operating range is wider than in the Eastern Interconnection. In Quebec, the acceptable steady-state frequency range is from 59.4 Hz to 60.6 Hz, and DER must be capable of riding through frequency as low as 55.5 Hz (for a short time period). Therefore

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<sup>6</sup> NERC report on Loss of Wind Turbines During System Disturbances : [NERC Report-Loss of Wind Turbines](#)

in Quebec, UFLS systems must operate outside this operating range in accordance with the Quebec variance to the PRC-006-NPCC UFLS-1 regional standard table 4.

## Reconnection to the Utility System

If the generation facility is disconnected as a result of the operation of a protective device, the DER owner's equipment must remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits for an acceptable amount of time. Interconnection agreements or local standards should address times for reconnection to the utility system. Per IEEE 1547-2018 Clause 4.10.3, the allowable range of settings is 0-600 seconds with a default setting of 300 seconds. IEEE 1547-2003 in clause 4.2.6 allows an adjustable delay or a fixed delay of 5 minutes. The time specified by the interconnection agreement should be coordinated to support BPS reliability as well as distribution requirements.

Systems greater than 25 kW that do not utilize inverter-based interface equipment should not have automatic recloser capability unless otherwise approved by the utility. If the interconnecting utility determines that a facility must receive permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

Utilities in other parts of the Eastern Interconnection who have experienced increased levels of DER have determined that during system restoration, DER should not be allowed to return to service until the system has been reestablished and is in a stable operating state. Interconnection agreements and standards should address necessary communications and SCADA requirements. As traditional resources on the BPS are retired and the grid becomes increasingly reliant on grid edge DER on the distribution, Black Start and System Restoration plans will have to be adjusted accordingly.

## Inverters

A power inverter, or inverter, is a power electronic device or circuitry that changes direct current (DC) to alternating current (AC). The inverter itself does not produce any power. The power is provided by the DC source. Inverter design and/or configuration should be capable of ride-through for specified utility system events and are grouped into three separate performance Categories.

- Category I is based on minimal BPS reliability needs and is reasonably attainable by all DER technologies that are in common usage today.
- Category II covers minimum BPS reliability needs, and coordinates with NERC Reliability Standard PRC-024-2, which was developed to avoid adverse tripping of BPS generators during system disturbances.
- Category III provides the longest duration and widest bands for voltage ride-through capabilities that are attainable by inverter-based systems where there very high levels of DER penetration are expected or where momentary cessation requirements are seen as a desirable solution for coordinating with distribution system protection and safety. This category is intended to address DER integration issues like power quality and system overloads caused by DER tripping in the local Area EPS and to provide increased BPS reliability by further reducing the potential loss of DER during bulk system events.

Inverters intended to provide local grid support during system events that result in voltage and/or frequency excursions as described in this document and should be provided with the required onboard functionality to allow for the equipment to remain online for the duration of the event.

It is recommended that all applicable inverter-based applications should:

- be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter
- have the voltage and frequency trip settings as specified by the interconnecting utility
- have the abnormal performance capabilities (ride-through)
- provide interactive inverter functions status

In New York State it is recommended that equipment be selected from the Department of Public Service “Certified Interconnection Equipment list” maintained on the NY Public Service Commission’s website. Interconnected DG systems utilizing equipment not found in such list should meet all functional requirements of the current version of IEEE Std. 1547-2018 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test in New York State must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section. Individual New England State interconnection standards and agreements also typically refer to IEEE Std. 1547-2018 functional requirements and include protection setting review requirements.

ISO-NE also has developed a technical bulletin, contained in [Appendix F](#), which outlines required settings for inverters in New England.

### Certification per UL 1741 SA as grid support utility interactive inverters

Because Inverters certified for IEEE 1547-2003 do not currently provide adequate grid support functionality, in the interim period while IEEE P1547.1-2018 is not yet revised and published, certification of all inverter-based applications is needed. For example, in one NPCC Area the following approach was taken to assure having inverters installed with a standardized set of grid support functionality to ensure the reliability of the BPS (e.g. maintaining acceptable system frequency and voltage).:

- Should be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std. 1547-2018 (2nd ed.)<sup>1</sup> that can be certified per the type test requirements of UL 1741 SA (September 2016).
- May be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawaiian Rule 14H as the Source Requirement Document (SRD). Such inverters are deemed capable of meeting the requirements of this document.
- Applications should have the voltage and frequency trip points and abnormal performance capabilities consistent with IEEE 1547-2018, PRC-024-2 and PRC-006-NPCC.
- Abnormal performance capability (ride-through) requirements for inverter-based applications should have the ride-through capability per abnormal performance Category II of IEEE Std. 1547-2018 (2nd ed.) as quoted in Tables III and IV. Additionally, an effort is underway at IEEE to

amend 1547-2018 to expand the range of under-voltage trip settings in Category III. If the amendment is approved, Category III inverters should be recommended for use.

## Minimum Protective Functions

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

- Type and size of the distributed generation facility
- Voltage level of the interconnection
- Location of the distributed generation facility on the circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the distributed generation facility under isolated conditions
- Amount of existing distributed generation on the local distribution system.

Local interconnection agreements and standards should require that synchronous, induction and inverter based DER include protection functions for Under/Over Voltage (27/59), Over/Under Frequency (81O/81U), Overcurrent (50P/50G/51P/51G) and Anti-Islanding Protection. Reverse power protection should also be considered as appropriate for BPS support. Interconnection agreements and standards should require that inverter based DER should be certified according to UL 1741SA as grid supportive. DER protection equipment should utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points. Interconnection agreements and standards should require that DER protective devices utilize their own current transformers and potential transformers for protection and not share electrical equipment associated with utility revenue metering.

The need for additional protective functions will be determined by the utility on a case- by-case basis. If the utility determines a need for additional functions, it will notify the DER owner of the requirements. The notice should include a description of the specific aspects of the utility system that necessitate the addition, and ideally, explicit justification for the necessity of the enhanced capability. The connecting utility will specify and provide settings for those functions that the utility designates as being required to satisfy their individual protection practices. Any protective equipment or setting specified by the utility is not to be changed or modified at any time by the DER owner without consent from the utility.

The DER owner is responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of the generating equipment.

All interface protection and control equipment should operate as specified by state and local interconnection agreements and standards.

In New England, for monitoring and control of new DG projects, [Appendix E](#) lists current interconnection documentation and standards for DER by State. The DER communications hardware, protocols, and data models must comply with these state and local interconnection utility standards.

In New York, for monitoring and control of new DG projects, the most current version of the Monitoring and Control Criteria should be employed by the utilities to evaluate the need for such equipment in New York. The New York Monitoring and Control Criteria document was developed and agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG)<sup>7</sup>. The communications hardware, protocols, and data models must comply with local interconnection utility standards.

Also, and fundamentally, existing over-current protections in distribution system are typically designed to clear line and ground faults occurring downstream from their location, as the only source feeding the fault is the transformer station. Connecting a DER provides another source supplying the fault, and the fault contribution from the facility might cause protection to operate non-selectively for reverse faults, out of the protected zone. If the maximum reverse fault current through a non-directional fault-interrupting device exceeds the setting of the device, the fault-interrupting device should be considered with a directional feature to prevent tripping for reverse fault current flow. For instance, phase protection could be replaced with an impedance relay (function 21) if required.

## Metering

### Advantages and Opportunities of Implementing Advanced Metering Infrastructure (AMI):

IEEE 1547-2018 interoperability requirements specify that the DER have communication capabilities and shall measure specific quantities and have this information available at the communications interface. Most utilities, however, do not have and are not requiring DER owners to provide the communications needed to connect all DER to a grid SCADA system. Such requirements tend to be placed only on large DER. Most utilities do not have the information infrastructure necessary to interoperate with large numbers of small DER; however, implementation of AMI will help in this regard.

Depending on the level of analytics utilized by an Electric Distribution Company (EDC), AMI can provide varying levels of intelligence and operability about the electric distribution system. Even if no analytics are implemented, value can be gained by reviewing and having access to the data provided by AMI. If a full-fledged data analytics package is implemented, then significant benefits can be realized.

Without an analytics package, engineers or analysts can still review basic voltage information provided from AMI. Using SAS, Excel or other simple tools, the voltage data provided, on a daily basis, can be quickly filtered down to exhibit meters that have high or low voltages exceeding the limits set by local Regulatory bodies. With minimal research, it can be determined if high voltage is caused by the presence of DER, either for the meter affected or a nearby neighbor on the same secondary transformer. The transformer can be evaluated by engineering to determine if new, larger equipment is needed.

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<sup>7</sup> This document can be found on the Department of Public Service website ([www.dps.ny.gov](http://www.dps.ny.gov)) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information.

With reports of abnormal voltage, Distribution Planning can evaluate the data and determine if voltage regulators need to be added towards the end of a circuit, if switching needs to occur to change circuit topology, or if other actions are needed. If the low voltage only occurs at certain times of the day, then perhaps load tap changers at the substation may be used to address the issue.

If implementing a data analytics package, whether off-the-shelf or home grown, more details on system operating conditions can be found. For instance, by evaluating the sum of meter usage for a specific transformer, secondary transformers can be determined to be over or under loaded. If voltage interval data is available, the GIS model of the system can be evaluated to identify meters that are incorrectly assigned to transformers; the model can be corrected to properly assign meters to transformers.

With data analytics and near real-time data transfer from the head-end system then volt-var optimization can occur. As LTCs, capacitor banks or voltage regulators are adjusted, live feedback from the system can be evaluated to ensure the expected responses are occurring. If something unexpected is happening, then operators receive evidence of this quickly and can take remedial actions.

The specific benefits of AMI are still evolving, and as more analytical tools are made available, and as meters become more advanced, the data will be leveraged to provide more insights into the operation of the distribution network.

Metering requirements for SCADA purposes are usually determined by the local connecting utility and based on the configuration of the DER system prior to energization. Whether SCADA metering can be integrated with revenue metering is a matter for the local connecting utility and connecting DER facility to decide. New metering or modifications to existing metering should be reviewed on a case-by-case basis and be consistent with metering requirements specified by the local connecting utility and any overarching requirements adopted by the local regulatory authority that has jurisdiction (e.g. state commission for example for revenue metering). Net Energy Metering should be required when a DER has the capability or potential to provide generation back into the utility distribution system, however, the eligibility of a DER provider to receive net metering will be subject to the rules of the interconnecting utility and the local regulatory authority that has jurisdiction.

IEEE-1547-2018 requires DER to be capable of providing monitoring of connection status, real power output, reactive power output, and voltage either at the point of connection or some agreed upon point if multiple DER facilities are involved. Going forward, member utilities should consider developing IT Infrastructure plans to aggregate and report critical DER Status to BPS Operators, i.e. aggregate DER output within a given area. This information should be available to the system operator as required by the connecting utility. The monitoring equipment should be installed at the time of interconnection and meet the technical requirements of the connecting utility. The DER metering and monitoring communications will allow interoperability and the capability to provide system operators with situational awareness necessary for reliable operation of the interconnecting utility facilities. As more DER is employed and base load generation is replaced with DER resources, it will be important for the Distribution Provider (DP) or interconnecting utility to be able to monitor the availability and production of electricity (power output and energy delivered) from the DER resources.

## Power Quality

The requirements for acceptable flicker levels should be in accordance with the latest version of IEEE Std. 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems. Short and long-term perception of flicker should be within the planning and compatibility levels delineated in any applicable requirements or standards.

## Power Factor

If the output power factor, as measured at terminals of the generator, does not meet the connecting utility's power factor requirements, the method of power factor correction necessitated by the installation of the generator can be negotiated with the utility as a commercial item. If the average power factor of the DER over time is proven to be outside 0.9 (leading or lagging) by the customer and accepted by the utility, that power factor range may be used for any further utility facility design calculations and requirements.

Induction power generators may be provided with a VAR capacity from the utility system. The installation of VAR correction equipment by the generator- owner on the DER owner's side of the PCC is to be reviewed and approved by the interconnecting utility prior to installation.

## Islanding

The guidance provided in this document is designed and intended to avoid islanding and may be superseded by local requirements. Additional protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

The need for zero sequence voltage and direct transfer trip protection schemes should be evaluated based on minimum loads on the associated feeder and substation bus, including the impact of fault conditions resulting from DER installation to protect facilities for an islanded condition.

Transfer trip is needed in some instances (e.g. on DER connections to non-radial transmission or sub-transmission circuits) in order to protect the utility systems and DER facility from damage during faults and/or reclosing operations into faults. The decision as to the applicability of direct transfer trip and specific technology to be used for direct transfer trip communications rests with the connecting utility.

## Automatic Underfrequency Load Shedding (UFLS) Programs

UFLS is implemented to restore power system frequency stability if system frequency drops below the UFLS operational set point. Significant deviations in system frequency typically occur during major disturbances such as a loss of generation or events in excess of design contingencies used for planning purposes. UFLS is considered the "safety net" for the BPS and a last resort automatic control operation designed to stabilize BPS islands for a generation deficiency. Various fractions of load are shed through this process, typically 25%. UFLS is primarily installed on distribution feeders, where DER is increasingly being deployed.

NERC has a set of requirements in the PRC-006 standard and NPCC has more stringent requirements in NPCC's Regional Standard, PRC-006-NPCC which outline expected UFLS performance. Approved and effective versions of these standards may both be found on the NERC website.

SS-38 is the NPCC working group responsible for inter-Area dynamic analysis. The SS-38 Working Group regularly studies the UFLS performance within the Region and has recently completed sensitivity analysis showing that a moderate increase of DER penetration anticipated in the short term will not result in any significant degradation in the UFLS program performance based on the conditions and assumptions used in the analysis.

In the future, adopting a more flexible approach to UFLS may be necessary as DER penetrations reach higher levels. There are utilities that are reviewing the feasibility of “Adaptive UFLS” which uses real time monitoring of distribution feeder loads and their DER to determine how much additional load may need to be tripped when DER has increased output. Some utilities, such as Duke Energy avoid choosing those distribution feeders for the UFLS program that have DER interconnected to them.

### Effective Grounding for DER

With the onset of high penetrations of DER, such as photovoltaic (PV) generation, utilities should consider interconnection of PV plants similarly to how they would interconnect synchronous generators.

Conventional generators are considered voltage sources as the magnetic flux within the generator tends to provide a constant voltage source during faults. In contrast, inverter-based DER plants are considered voltage-controlled current sources during faults. Inverter-based plants generally provide less short-circuit current than similarly sized synchronous unit.

Solidly grounding a transformer neutral for a DER plant eliminates a possible phase overvoltage stemming from a single-line-to-ground fault. A potential problem with the solid grounding in the distribution line is that large fault currents can flow through the transformer neutral, which can desensitize the overcurrent protection coordination. In order to mitigate this issue, impedance grounding can limit the fault current and potential equipment damage, while allowing overvoltage to some limited magnitude. Some utilities protect their distribution from overvoltage by using overvoltage protection so Effective Grounding isn’t a concern. Further investigation on the how specific installations are grounded is warranted and being pursued by the Interconnection Technical Working Group (ITWG) in New York.

### Resource Adequacy

Forecasting resource adequacy is an import system reliability function. The reporting of generation capability and data is integral to this activity. Specific modelling information of intermittent DER resources is critical to planning and understanding system performance. Information related to DER in-service dates, capacity value, availability, emergency assistance, scheduling, and deliverability should be available to the planners. Modeling, data, and other necessary information should be defined and made available to those needing it, such as planners and system operators. Any requirements associated with this information should be in Interconnection Agreements or Tariffs prior to any commissioning of the DER. There are currently no mechanisms within NERC Standards or NPCC Criteria to require DER entities to provide this information. It currently needs to be covered under other contractual agreements such as local utility Interconnection Agreements or Tariffs.

## Energy Storage Systems for DER

Battery storage technology is undergoing a rapid evolution from Lead Acetate to Absorbent Glass Mat to Li-Ion due to the expanding application of batteries to transportation and other sectors. Li-Ion batteries have been and continue to be deployed in a wide range of electric energy-storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services. The Energy Storage Association (ESA) anticipates at least 35 GW of new energy storage will be deployed in the United States by 2025.

NPCC is also observing marked increases in Hybrid Resources which are combinations of multiple technologies that are physically and electronically controlled by the Hybrid Owner/Operator behind the point of interconnection (“POI”) and offered to the grid as a single resource at that POI. This arrangement usually involves energy storage at a photo-voltaic or wind turbine site. It optimizes the use of DER and enables normally clipped energy (energy beyond the rating of an inverter or unneeded by the BPS) to be stored on-site and released in the future. It also allows low outputs of DER which may be outside the operational range of an inverter to be harvested for charging on-site storage allowing better utilization of the total resource. In the figure below the red curve represents the capability of an inverter and the blue is the capability of the DER. Areas between the curves may be used to charge or “harvested.” This leads to a more efficient utilization of the DER and supports grid reliability and state of charge of the energy storage. As shown below, the capability of an inverter can be exceeded by the capability of the DER behind it. This is designed with due consideration of the degradation of DER, such as a solar panel over time.

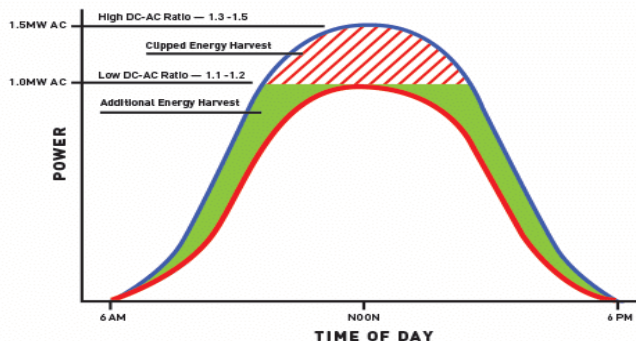


Figure 1- Storage showing Clipped and Unused Energy

The ESA has an online report to manage any risks associated with Energy Storage. Their report may be found here, [Energy Storage, Operational Risk Management](#). Care should be used in placement of batteries and should avoid physical proximity (due to the risk of fire or explosion) and electrical proximity (due to harmonics and other power electronic interaction concerns) to other facilities that may be critical to the reliable operation of the BPS.

## System Control and Data Acquisition (SCADA) and Communications

As DER penetration increases all DER above a certain MW level, as determined by the interconnecting utility or System Operators, should be required to provide SCADA telemetry data to a control center to monitor their output. It might be beneficial to have DER data be communicated to a Distribution System Operator, distribution system platform or similar, to provide analysis and aggregation of data for a concise summary to the transmission system operator. IEEE-1547-2018 has a communication port requirement. This ensures that the output remains visible to the system operator. It allows the system operator to observe DER status when working on a feeder in emergent or planned outage situations. Some NPCC Members have encountered difficulty with obtaining information and data from the DER. DER owners should be encouraged to keep their end of any SCADA equipment functional and reconnect their telemetry devices when they have been disabled and this can be done through interconnection requirements. The operator should be alerted by the DER when telemetry is interrupted. Scan rates equivalent to the scan rates used by the system operator are preferred (typically in the 6 second range). Although IEEE 1547-2018 defines and requires a communication port, the path that a utility may use for data from that communication port may pose a cyber-security risk. It is suggested that full consideration be given to cyber security risks when transferring data until such time as the IEEE 1547 has been amended to require cyber security protections.

## DER Recommendations

As DER continues to penetrate the NPCC Region we suggest the following initial activities:

### Participation in National DER Forums

- 1) Participate in national efforts to fully understand the issues and best practices associated with DER.
- 2) Engage NPCC and its members at the national level leading efforts to address the issues and provide expertise.
- 3) As the understanding at the national level of the issues and best practices matures then NPCC will be well positioned to understand the regional differences that need to be considered.

### Process and Risk Management Recommendations

- 1) Continue with sensitivity analysis at the Transmission level for various levels of penetration of DER on the distribution facilities to determine effects of increased penetration levels of DER on BPS performance.
- 2) Pursue further opportunities to coordinate distribution and transmission requirements for DER generating resources, share Member best practices, and promote consistency regarding DER installations where possible within the NPCC region.
- 3) Continue to review and identify approaches to coordinate NPCC AGIR and utility interconnection requirements relative to DER to identify dissimilarities between Areas which may negatively impact reliability.

- 4) Identify opportunities to share information regarding DER related reliability risk problems and problem solutions and promote sharing.
- 5) Encourage consideration of developing IT Infrastructure plans to aggregate and report critical DER Status to BPS Operators.
- 6) Continue to solicit and address observable reliability related issues of DER using NPCC's DER Impact Reporting Forms and its associated process.
- 7) Continue to discuss any changes required for System Restoration and Blackstart Plans, as a result of increased DER.
- 8) Continue to follow DER related ESA ESS safety issues and associated recommendations and share the results with NPCC stakeholder.
- 9) Avoid placement of UFLS on distribution feeders with DER unless sufficient telemetry exists to ensure proper functionality of the UFLS program as a whole.

#### Planning Related Recommendations Due to Changing Resource Mix

- 1) Identify and consider new methods to obtain and facilitate collection of DER modeling and performance data to enable Long-Term Resource, Long-Term Transmission and Operational Planning of the BPS<sup>8</sup>
- 2) Clearly identify DER in the NPCC Region's Area interconnection queues or forecasts where DER is being proposed for installation, including the magnitude and location relative to the existing resource base and load projections.
- 3) Address masking of load by DER at the distribution level to ascertain its impact on the behavior of load, as well as the assumptions that underpin UFLS programs.
- 4) Determine the appropriate entities responsible for providing DER data to the Planning Coordinator for the purposes of model building and maintenance and ensure that this data is provided.

#### Analytics and simulation recommendations to deal with increase system complexity

- 10) Support interconnection wide inertia loss study efforts, to determine potential reliability impacts, as DER replaces conventional synchronous generation resources.
- 11) Obtain DER modelling data to be able to model, predict and examine system behavior and assess the interactions between the new resources and the existing reliability preserving systems and programs. Examples include:
  - a. Dynamic behavior of the transmission system
  - b. Sudden loss of large amounts of DER due to transmission system events
  - c. Under Frequency Load Shedding,
  - d. Under Voltage Load Shedding,
  - e. Frequency response sharing mechanisms (BAL standards).
  - f. Analysis of system protection systems (both T and D) so that the parameters to set protection systems and other control systems are known to permit the most reliability benefits to be garnered from the new resources.

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<sup>8</sup> Questions exist regarding which entities should be responsible for providing DER data to the Planning Coordinator for the purposes of model building. NERC is working on this issue.

## Appendix A, NPCC DER Impact Reporting Form and Process



NORTHEAST POWER COORDINATING COUNCIL, INC.  
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

Please Complete and email this form to; [npccstandard@npcc.org](mailto:npccstandard@npcc.org)

### Distributed Energy Resource (DER), BES Impact Reporting Form

|                                       |  |                                              |  |
|---------------------------------------|--|----------------------------------------------|--|
| <b>Name</b>                           |  | <b>Date</b>                                  |  |
| <b>Email</b>                          |  | <b>Company</b>                               |  |
| <b>Impact on Bulk Electric System</b> |  | <b>Area (NY, NE, State or Province etc.)</b> |  |

#### Equipment Impacted

| Equipment | Location<br>(substation name, etc.) | Impact (Positive reliability impact? Negative reliability impact-Protection System failure, Misoperation, load affected or lost?, power quality issue?, etc) | Duration of Impact,<br>(start and stop times, length of impact, ongoing? etc.) |
|-----------|-------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------|
|           |                                     |                                                                                                                                                              |                                                                                |
|           |                                     |                                                                                                                                                              |                                                                                |
|           |                                     |                                                                                                                                                              |                                                                                |

#### Description of Impact on BES- What Happened or was observed?

Please describe below the details of all the impacts of the DER as it pertains to this report, such as load loss, loss of life, equipment failure or potential reliability improvement. A sequence of events showing the impact is helpful. Attach supporting information to this form if necessary.

|  |
|--|
|  |
|--|

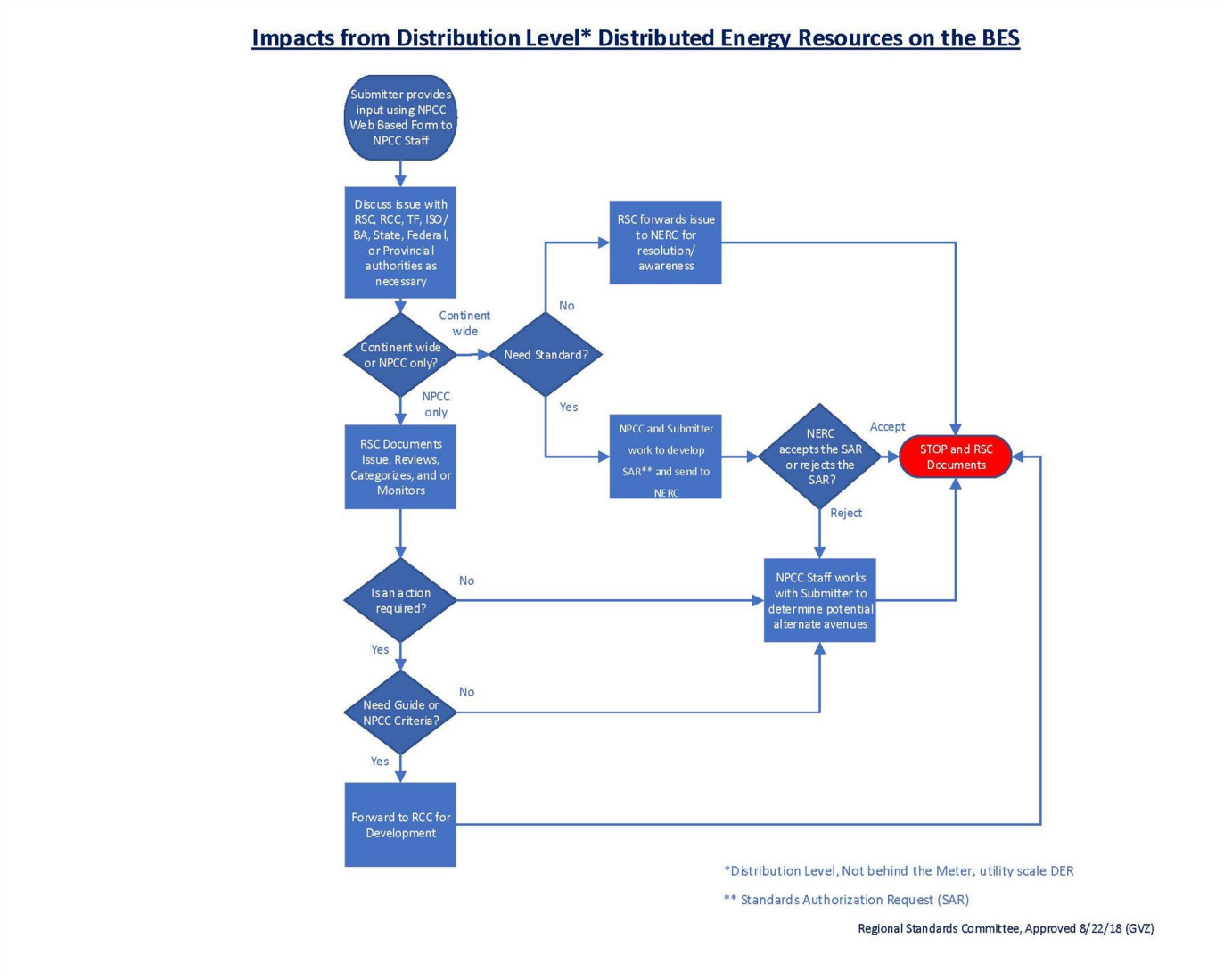
Root Cause or additional Analysis

Please describe below the details of any investigation your company may have already done to identify causes or contributing factors to the incident. This will help NPCC route the issue properly to address it.

NPCC Review of Issue and Recommendations (i.e. refer to NERC, develop a Criteria, Guideline, Already Addressed or Identified, etc.)

NPCC Date of Resolution of Issue \_\_\_\_\_

# Evaluation Process



## Appendix B, NPCC Areas-Comparisons

### Key Inverter based specification extracts

| ISO-NE Inverter Requirements | NG ESB 756 B, C, D | NY SIR <sup>9</sup> | IESO F2 Technical Requirements |
|------------------------------|--------------------|---------------------|--------------------------------|
|------------------------------|--------------------|---------------------|--------------------------------|

<sup>9</sup> NY SIR is the [New York Standardized Interconnection Requirement](#).

|                                                                                             |                   |     |     |     |
|---------------------------------------------------------------------------------------------|-------------------|-----|-----|-----|
| Inverter Certification                                                                      | yes               | yes | yes | yes |
| Voltage and frequency trip settings for inverter-based applications                         | yes               | yes | yes | yes |
| Voltage Response                                                                            | yes <sup>10</sup> | yes | yes | yes |
| Frequency Response                                                                          | yes <sup>11</sup> |     | yes | yes |
| Abnormal performance capability (ride-through) requirements for inverter-based applications | yes               | yes |     |     |
| Other grid support utility interactive inverter functions statuses                          | yes               |     |     |     |
| Minimum protection functions                                                                |                   | yes | yes |     |
| Monitoring and Control                                                                      |                   | yes | yes | yes |
| Reconnection to the System                                                                  |                   | yes | yes |     |
| Distribution Protection Coordination                                                        |                   | yes |     | yes |
| Inverter Certification                                                                      |                   | yes | yes |     |
| Power Quality                                                                               |                   |     | yes |     |

## Appendix C – SPIDER Working Group Reliability Guidelines & Activities

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was formed to focus on the impacts that aggregate amounts of DER can have on transmission planning and BPS reliability. This SPIDERWG is seeking to provide high-level, technical recommended practices for ensuring BPS reliability in the face of growing penetrations of DER across North America. The recommended practices and guidance provided by SPIDERWG, in many cases, will need to be adapted to

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<sup>10</sup> The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

<sup>11</sup> The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

specific utility and Regional planning and operating practices. The following DER-related topics are covered, as described in NERC Staff’s “Summary of Activities: BPS-Connected Inverter-Based Resources and Distributed Energy Resources”<sup>12</sup>:

**Modeling:** Representing aggregate DER in BPS reliability studies, advancing industry capabilities and expertise with representing DER in these reliability studies, developing robust and reasonable data sets for power flow and dynamic simulations

**Verification:** Ensuring that the models used in studies provide a reasonable and suitable representation of the actual aggregate performance of these resources, benchmarking software platforms to ensure uniformity in tools, recommending analysis techniques for accounting for aggregate DER during large BPS disturbances

**Studies:** Improving study techniques and methods to ensure the most stressed operating conditions are chosen for BPS reliability studies, identifying key operating conditions and sensitivities to perform, improving software tools and study capabilities

**Coordination:** Supporting coordination between transmission and distribution entities for improved data exchange and coordinating with IEEE to support the application of IEEE Std. 1547- 2018 across North America

A list of SPIDERWG Reliability Guidelines and other activities is provided in Table 1 and Table 2, respectively.

**Table 1. SPIDER Working Group Reliability Guidelines**

| Subgroup | Title                            | Description                                                                                                                                       | Status                                                        |
|----------|----------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------|
| Modeling | DER Data Collection for Modeling | Guideline providing recommended practices for collecting DER data for the purpose of developing aggregate DER models for BPS reliability studies. | In Review – Draft Posted for Comment ( <a href="#">here</a> ) |
|          | DER_A Model Parameterization     | Guideline providing recommendations for using state-of-the-art aggregate DER dynamic models in BPS reliability studies.                           | Published ( <a href="#">here</a> )                            |

<sup>12</sup> Available here: [https://www.nerc.com/comm/PC/Documents/Summary\\_of\\_Activities\\_BPS-Connected\\_IBR\\_and\\_DER.pdf](https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf)

|              |                                                                                                                                      |                                                                                                                                                                                                                                                            |                                    |
|--------------|--------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------|
| Verification | DER Performance and Model Verification                                                                                               | Guideline providing recommended practices for performing model verification for aggregate DER dynamic models including placement of measurement devices, execution of verification simulations, and how to use the data collected through these practices. | In Development                     |
|              | DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies                                                   | Guideline providing how forecasting practices are linked to DER modeling for reliability studies, specifically on how DER are accounted for in future reliability assessments.                                                                             | In Development                     |
| Studies      | Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources                                              | Guideline providing recommended practices for performing planning studies considering the impacts of aggregate DER behavior.                                                                                                                               | In Development                     |
|              | Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration                          | Guideline regarding how to study UFLS programs and ensure their effectiveness with increasing penetration of DER.                                                                                                                                          | Under Consideration                |
| Coordination | BPS Reliability Perspectives on the Adoption of IEEE 1547-2018                                                                       | Guideline providing industry recommendations and BPS reliability perspectives on the implementation and adoption of IEEE 1547-2018.                                                                                                                        | Published ( <a href="#">here</a> ) |
|              | Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources | Guideline recommending strategies to encourage coordination between Transmission and Distribution entities on issues related to DER such as information sharing, performance requirements, DER settings, etc.                                              | In Development                     |

**Table 2. SPIDER Working Group Other Activities**

| Subgroup | Title                                                            | Description                                                                                                                                                                         | Status                          |
|----------|------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------|
| Modeling | Modeling Notification: Dispatching DER off Pmax in Case Creation | Notification of accounting for DER in powerflow and dynamics cases, particularly regarding accounting for power output levels with DER utilizing advanced grid-supportive features. | Posted ( <a href="#">here</a> ) |
|          | DER Modeling Survey                                              | Survey of SPIDERWG member organizations regarding the use of DER models in BPS planning studies.                                                                                    | Compiling Results               |

|              |                                                                    |                                                                                                                                                                                                                                                 |                |
|--------------|--------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------|
| Studies      | White Paper: Review of TPL-001-5 for Incorporation of DER          | White paper discussing technical review of NERC TPL-001-5 in the context of increasing DER and their impacts to the BPS. Possible SAR development following completion of white paper, as needed.                                               | In Review      |
|              | White Paper: Recommended Simulation Improvements and Techniques    | White Paper recommending simulation software improvements to enhance the ability to accurately account for and model DER.                                                                                                                       | In Development |
|              | White Paper: DER Impacts to Undervoltage Load Shedding             | White Paper briefly discussing how DER may impact UVLS program development.                                                                                                                                                                     | In Development |
|              | White Paper: Beyond Positive Sequence RMS Simulations for High DER | White Paper highlighting the use of tools that provide additional technical detail to DER studies beyond just positive sequence RMS simulation tools.                                                                                           | In Development |
| Coordination | Coordination of DER Terminology                                    | Development and ongoing review of definitions and terminology pertaining to DER and related topics.                                                                                                                                             | In Development |
|              | NERC Reliability Standards Review                                  | White Paper reviewing NERC Reliability Standards and the impacts that increasing penetrations DER may have on BPS reliability and standards compliance/implementation. Possible SAR development following completion of white paper, as needed. | In Development |
|              | Tracking and Reporting DER Growth                                  | Coordinated review of information regarding DER growth, including types of DER, size of DER, etc. Consideration for useful tracking techniques for modeling and reliability studies.                                                            | In Development |
|              |                                                                    |                                                                                                                                                                                                                                                 |                |

## Appendix D, NPCC Reliability Principles

Using its membership structure and governance authority to create and apply Regional Criteria<sup>13</sup>, NPCC Member adherence to Regional criteria contributes to a more robust level of reliability beyond NERC ERO reliability “results-based” standards / requirements. For example, NPCC Criteria mandate specific design requirements for NPCC Member facilities. NPCC’s approach to reliability and Resilience can be summarized in Principles that guide NPCC Members in their effort to meet or exceed NERC requirements. NPCC’s core Reliability Principles<sup>14</sup> and activities support the NERC Bulk Electric System and NPCC’s Bulk Power System reliability.

<sup>13</sup> See NERC Rule of Procedure #313 on page 15 of the [NERC Rules of Procedure 3-9-2018](#).

<sup>14</sup> The Reliability Principles were summarized in the NPCC 2018 Strategic Review Report.

The NPCC Reliability Principles include:

1. **Focus on the most important system components:** In order to focus resources to those portions of the power delivery system most important (critical) to overall reliability, NPCC Members employ mechanism(s) for identifying those facilities that are most critical to the reliable planning and operation of the power delivery assets in the NPCC region<sup>15</sup>. These critical facilities collectively are identified as the NPCC Bulk Power System<sup>16,17</sup>.
2. **Application of Criteria beyond NERC requirements to identified critical facilities:** Where, in the opinion of NPCC's Membership, the NERC standards do not adequately specify a necessary performance or design outcome in a given technical, operation or planning area, NPCC Criteria govern the design of their respective portions of the NPCC Bulk Power System planning and operation<sup>18</sup> activities.
3. **NPCC Members support the Criteria:** NPCC's Full Members in accordance with the NPCC Bylaws are committed to designing and operating their systems to meet the NPCC Criteria under peer review of the NPCC Full Members.
4. **No conflict with NERC Requirements:** The NPCC Criteria supplement, improve upon where necessary, benefit, and do not conflict with or duplicate the results-based performance requirements of NERC standards where they apply to the NPCC Bulk Power System. NPCC adjusts its regional Criteria to retire or adapt to any new NERC requirements as they come into effect as necessary.
5. **Include design specifications where needed:** The NPCC Criteria and related guidelines and procedures provide design criteria and practices to assure implementation. NPCC Directories go into greater detail regarding how to accomplish a given reliability result, where NERC standards may simply require a "reliability result."

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<sup>15</sup> The method of identifying critical facilities is currently embodied in the [NPCC A-10 Classification of bulk power system Elements](#) document, currently under review by the CP-11 Working Group with a due date of October 31, 2018.

<sup>16</sup> The NPCC bulk power system is identified by a specific list of facilities in the NPCC region deemed critical by the NPCC A-10 classification process. This list is not determined based on the definition of the ERO bulk power system, which is defined in the US 2005 EPACT as:

"(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

"(B) electric energy from generation facilities needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy.

<sup>17</sup> There are other documents which supplement the Directories, for instance the NPCC Compliance Guidance Statements. These documents usually refer to NERC standards applicability and can be found here: [NPCC CGS](#)

<sup>18</sup> NERC [Rule of Procedure](#) #313 (page 15) permits the following: "Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. "

6. **Resilience has always been an element of NPCC Criteria:** Based on experience, resilience<sup>19 20</sup> is a necessary constituent component of reliability and it is important both to electricity consumers and regulatory authorities in NPCC's Region. NPCC Criteria provide substantial resilience benefits to the NPCC Bulk Power System by providing:
- Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
  - Resourcefulness – The ability to detect and manage a crisis as it unfolds.
  - Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
  - Adaptability – The ability to absorb new lessons from events

## NERC, Model of Resilience

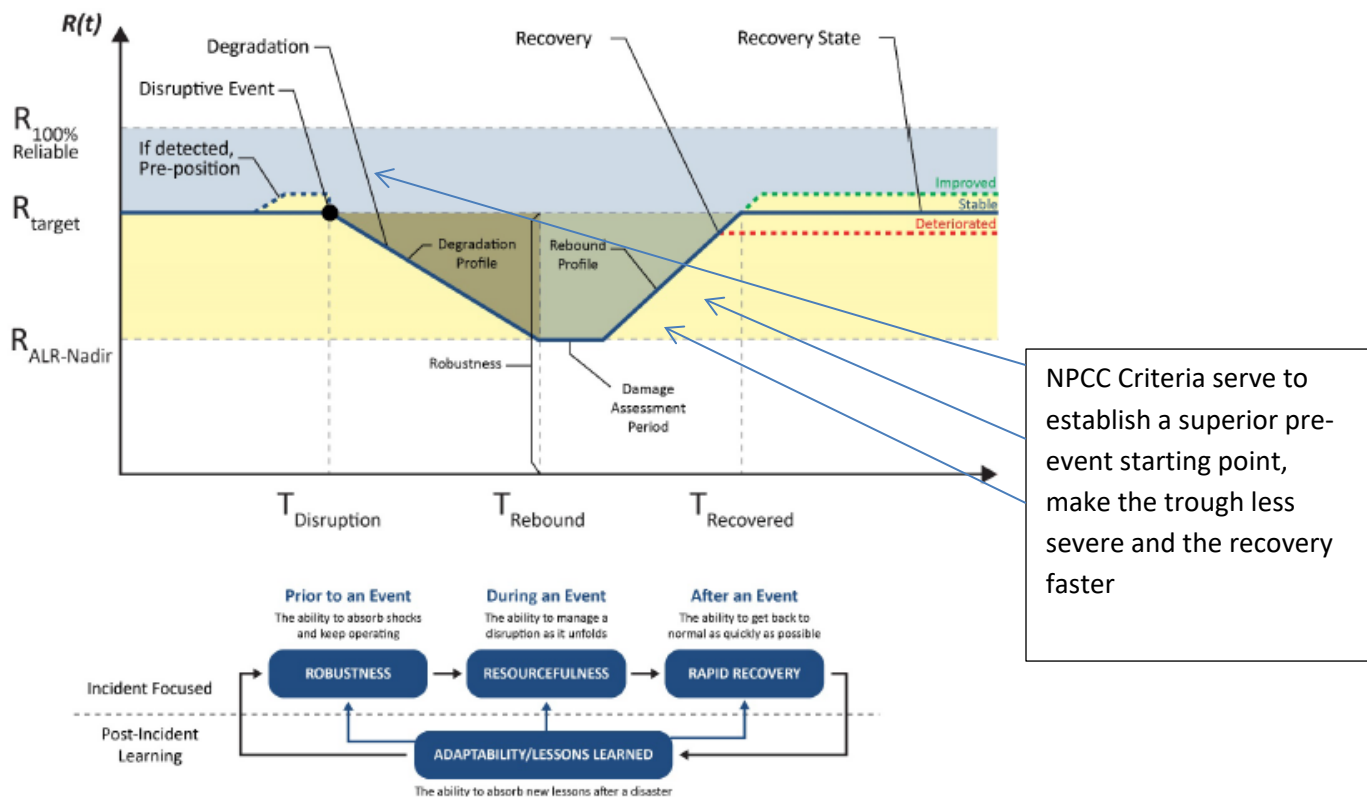


Figure 2.1

Figure 2.1 depicts a typical disruptive event and maps how the systems responds in a qualitative fashion. The y-axis above is meant to represent a relative level of reliability and system response is plotted

<sup>19</sup> Reference NERC's recent [filing](#) with FERC regarding Resilience for a more complete discussion of the relationship between resilience, the NERC standards and the NAICS Resilience Framework. FERC is expected to define resilience in the course of its current examination of electric system resilience concepts.

<sup>20</sup>In the US, [Presidential Policy Directive – 21](#) defines resilience as “The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents”.

temporally. DER will increasingly fill a critical role with respect to reliability and Resilience of the Bulk Electric System. Specifically, DER can contribute to the overall robustness of the system and provide increased resource support within islands during system separations. As DER continues to penetrate the system, changes to NPCC's Underfrequency Load Shedding program may be required.

## Appendix E, State and Provincial AGIR Information

### New York State

Statewide Interconnection Technical Documents may be found at:

[Interconnection Technical Working Group Webpage](#)

### New England, by State

Inverter Source Requirement Document of ISO New England (ISO-NE)

#### Connecticut –

Department of Energy and Environmental Protection, Public Utilities Regulatory Authority (PURA)

Eversource Energy – Connecticut Interconnection Standard

<https://www.eversource.com/content/general/about/about-us/doing-business-with-us/builders-contractors/interconnections/connecticut-application-to-connect>

Summary of Facility Connection Requirements for Generation, Transmission and End Users Connecting to UI Transmission Facilities, Revision 4.0, December 7, 2015:

<https://www.uinet.com/wps/wcm/connect/89138d72-c4a0-403b-9871-937a00f91c42/NERC%2BFAC-001%2BInterconnect%2Bsummary%2BDocument%2BRevision%2B4.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-89138d72-c4a0-403b-9871-937a00f91c42-mkr0qCb>

Eversource/United Illuminating Guidelines for Generator Interconnection, Fast Track and Study Processes, April 5, 2019:

[https://www.uinet.com/wps/wcm/connect/bd802aec-1e83-4051-8a6e-58f0cb98d1fd/Guideline\\_for\\_Generator\\_Interconnection\\_Fast\\_Track\\_and\\_Study\\_Process\\_5-12-10\\_doc\\_1577.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-bd802aec-1e83-4051-8a6e-58f0cb98d1fd-miUZQ4n](https://www.uinet.com/wps/wcm/connect/bd802aec-1e83-4051-8a6e-58f0cb98d1fd/Guideline_for_Generator_Interconnection_Fast_Track_and_Study_Process_5-12-10_doc_1577.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-bd802aec-1e83-4051-8a6e-58f0cb98d1fd-miUZQ4n)

#### Maine –

Maine Public Utilities Commission

Chapter 324 Small Generator Interconnection Procedures

Central Maine Power Transmission and Distribution Interconnection Requirements for Generation, December 15, 2018:

<https://www.cmpco.com/wps/wcm/connect/dee5fbf1-7af0-40ec-b06c-af3ec015e0be/SchB-TransmissionDistributionInterconnectionRequirementsforGeneration.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-dee5fbf1-7af0-40ec-b06c-af3ec015e0be-mwfmMCK>

Emera Maine Interconnection Agreement:

<https://www.emeramaine.com/energy-solutions/connecting-renewable-resources/small-generator-interconnection-process/>

## **Massachusetts –**

MA Department of Public Utilities (MADPU) interim guidance (DPU 19-55)

MADPU Massachusetts Department of Energy Resources

MADPU Interconnecting Renewable Energy webpages with links to: resources, past and present proceedings before the DPU, each electric distribution companies' tariff, and the Ombudsperson dispute resolution process: <https://www.mass.gov/interconnecting-renewable-energy-facilities>

MADPU is currently conducting a large-scale investigation into the rules and procedures by which distributed generation is interconnected in Massachusetts in docket D.P.U. 19-55. This investigation includes implementation of IEEE 1547-2018. Documents and information can be found in our online file room: <https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber> (enter "19-55")

Massachusetts Technical Standards Review Group:  
<https://sites.google.com/site/massdgic/home/interconnection/technical-standards-review-group>

Renewable energy generally: <https://www.mass.gov/topics/renewable-energy>

MADPU Net Metering Information: <https://www.mass.gov/net-metering>

MADOER SMART Program Information: <https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program>

Who to contact in MA for your renewable energy question: <https://www.mass.gov/info-details/who-to-contact-about-my-renewable-energy-question-or-concern>

Massachusetts Utilities

National Grid / Supplement to Specifications for Electrical Installations / ESB 756-2019 ver. 5.0 (Section 7.8 includes voltage and frequency ride through and control requirements);

[https://www9.nationalgridus.com/non\\_html/shared\\_constr\\_esb756.pdf](https://www9.nationalgridus.com/non_html/shared_constr_esb756.pdf)

NSTAR ELECTRIC COMPANY d/b/a EVERSOURCE ENERGY STANDARDS FOR INTERCONNECTION OF DISTRIBUTED GENERATION, M.D.P.U. No. 55, Effective: February 1, 2018:

[https://author.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/55-tariff-ma.pdf?sfvrsn=8582c462\\_6](https://author.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/55-tariff-ma.pdf?sfvrsn=8582c462_6)

Unitil Energy Systems, Inc. Interconnection Standards for Inverters Sized up To 100 kVA:

[https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009\\_08\\_21\\_1.pdf](https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009_08_21_1.pdf)

Individual Massachusetts Municipal Electric Utility Entity Interconnection Requirements:

<https://www.mass.gov/guides/net-metering-guide>

## **New Hampshire –**

New Hampshire Public Utilities Commission

Liberty Utilities Electricity Delivery Service Tariff – NHPUC No. 20:

[https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-183/INITIAL%20FILING%20-%20PETITION/18-183\\_2018-12-10\\_GSEC\\_TARIFF.PDF](https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-183/INITIAL%20FILING%20-%20PETITION/18-183_2018-12-10_GSEC_TARIFF.PDF)

New Hampshire Electric Co-op Net Metering Requirements:

<https://www.nhec.com/wp-content/uploads/2017/02/2017-Interconnection-Application-Package.pdf>

Public Service Company of New Hampshire Interconnection Standards for Inverters Sized Up to 100 KVA, August 2009:

[https://www.eversource.com/content/docs/default-source/builders-contractors/eversource's-interconnection-standards-for-inverters.pdf?sfvrsn=2dd9cf62\\_0](https://www.eversource.com/content/docs/default-source/builders-contractors/eversource's-interconnection-standards-for-inverters.pdf?sfvrsn=2dd9cf62_0)

Unitil Energy Systems, Inc. Interconnection Standards for Inverters Sized up To 100 kVA:

[https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009\\_08\\_21\\_1.pdf](https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009_08_21_1.pdf)

## **Rhode Island –**

State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers

Block Island Power Company Net Metering Application:

<https://blockislandpowercompany.com/net-metering-application-2/>

The Narragansett Electric Company Standards for Connecting Distributed Generation, Effective September 6, 2018:

[https://www9.nationalgridus.com/non\\_html/RI\\_DG\\_Interconnection\\_Tariff.pdf](https://www9.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf)

Pascoag Utility District – Electric Net Metering Policy, Requested Effective Date: June 1, 2010:

<https://www.pud-ri.org/wp-content9999/uploads/2015/07/Net-Metering-Policy.pdf>

## Vermont –

### Vermont Public Utility Commission

The Vermont Public Utility Commission issued an interconnection rule in 2006 that was largely modeled on the FERC Small Generator Interconnection Procedures at that time. The rule has not been updated since 2006.

Links to the current rule as well as an application form and application instructions:

PUC Rule 5.500 – Interconnection Rule

[https://puc.vermont.gov/sites/psbnew/files/doc\\_library/5500-electric-generation-interconnection-procedures\\_0.pdf](https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-electric-generation-interconnection-procedures_0.pdf)

PUC Rule 5.500 – Application Form

[https://puc.vermont.gov/sites/psbnew/files/doc\\_library/5500-revised-application\\_0.pdf](https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application_0.pdf)

PUC Rule 5.500 – Application Instructions

[https://puc.vermont.gov/sites/psbnew/files/doc\\_library/5500-revised-application-instructions\\_0.pdf](https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application-instructions_0.pdf)

In addition, the Department petitioned the PUC to initiate a rulemaking to make adjustments to the interconnection rule in 2016. As of the date of this DER Guidance document there were some filings and a workshop, but the process recently ended without resolution. The PUC has indicated that they are likely to take up the process again in the near future however has not provided NPCC with a date. Information regarding this process can be found here: <https://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5500>

## Province of Quebec (some references are only available in French)

Section 112 of the [Act respecting the Régie de l'énergie](#) (chapter R-6.01) (the Act) reads as follows:

### **112. THE GOVERNMENT MAY MAKE REGULATIONS DETERMINING**

[...]

(2.1) *for a particular source of electric power supply, the corresponding energy block and maximum price established for the purpose of fixing the cost of electric power referred to in section 52.2 or for the purposes of the supply plan provided for in section 72, or for the purposes of a tender solicitation by the electric power distributor under section 74.1;*

(2.2) *the timeframe applicable to a public tender solicitation by the electric power distributor under section 74.1;*

(2.3) *the maximum production capacity referred to in section 74.3, which may vary with the source of renewable energy or the class of customers or producers specified;*

[...]

*In cases where energy needs are to be supplied out of an energy block, a regulation may provide that only certain classes of suppliers may be invited to tender by the electric power distributor and that the quantity of electric power required under each supply contract may be limited.*

Consequently, the Government has taken the following regulations, regarding Distributed Energy Resources (or DER), between 2003 and 2013:

- [CONCERNANT le Règlement sur l'énergie produite par cogénération](#) (Décret 1319-2003, 10 décembre 2003);
- [CONCERNANT le Règlement sur l'énergie éolienne et sur l'énergie produite avec de la biomasse](#) (Décret 352-2003, 5 mars 2003);
- [CONCERNANT le Règlement modifiant le Règlement sur l'énergie produite par cogénération](#) (Décret 298-2004, 29 mars 2004);
- [CONCERNANT le Règlement sur le second bloc d'énergie éolienne](#) (Décret 926-2005, 12 octobre 2005);
- [CONCERNANT le Règlement sur l'énergie produite par cogénération à la biomasse](#) (Décret 916-2008, 24 septembre 2008);
- [CONCERNANT le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 1043-2008, 29 octobre 2009);
- [CONCERNANT le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 1045-2008, 29 octobre 2008);
- [CONCERNANT le Règlement modifiant le Règlement sur l'énergie produite par cogénération à la biomasse](#) (Décret 9-2009, 7 janvier 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 179-2009, 4 mars 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 180-2009, 4 mars 2009);
- [CONCERNANT le Règlement sur la capacité maximale de production visée dans un programme d'achat d'électricité pour des petites centrales hydroélectriques](#) (Décret 336-2009, 25 mars 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 520-2009, 29 avril 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 521-2009, 29 avril 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 468-2010, 2 juin 2010);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 469-2010, 2 juin 2010);
- [CONCERNANT le Règlement sur la capacité maximale de production visée dans un programme d'achat d'électricité produite par cogénération à base de biomasse forestière résiduelle](#) (Décret 1085-2011, 26 octobre 2011);
- [CONCERNANT le Règlement sur un bloc de 450 mégawatts d'énergie éolienne](#) (Décret 1149-2013, 6 novembre 2013).

The following regulations, or modified regulations, (marked in yellow in the section above) have led to four tender solicitations, targeting precise quantities, or energy blocks, of wind Energy:

- [CONCERNANT le Règlement sur l'énergie éolienne et sur l'énergie produite avec de la biomasse](#) (Décret 352-2003, 5 mars 2003);

- [CONCERNANT le Règlement sur le second bloc d'énergie éolienne](#) (Décret 926-2005, 12 octobre 2005);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 468-2010, 2 juin 2010);
- [CONCERNANT le Règlement sur un bloc de 450 mégawatts d'énergie éolienne](#) (Décret 1149-2013, 6 novembre 2013).

The Régie considers the results of these tenders when examining Hydro-Québec's supply plan, as per section 72 of the Act:

**72.** *With the exception of private electric power systems, a holder of exclusive electric power or natural gas distribution rights shall prepare and submit to the Régie for approval, according to the form, tenor and intervals fixed by regulation of the Régie, a supply plan describing the characteristics of the contracts the holder intends to enter into in order to meet the needs of Québec markets following the implementation of the energy efficiency measures. The supply plan shall be prepared having regard to*

- (1) the risks inherent in the sources of supply chosen by the holder;*
- (2) as concerns any particular source of electric power, the energy block established by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112; and*

*[...]*

*When examining a supply plan for approval, the Régie shall consider such economic, social and environmental concerns as have been identified by order by the Government.*

Sections 74.1 and 74.2 of the Act provide that the Régie oversees the process of such tender solicitations:

**74.1.** *To ensure that suppliers responding to a tender solicitation are treated with fairness and impartiality, the electric power distributor shall establish and submit for approval to the Régie, which shall make its decision within 90 days, a tender solicitation and contract awarding procedure and a tender solicitation code of ethics applicable to the electric power supply contracts required to meet the needs of Québec markets in excess of the heritage pool, or the needs to be supplied out of an energy block determined by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112.*

*The tender solicitation and contract awarding procedure shall, in particular,*

- (1) allow all interested suppliers to tender by requiring the tender solicitation to be issued in due time;*
- (2) grant equal treatment to all sources of supply and energy efficiency projects unless the tender specifications provide that all or part of the needs met by a particular source of supply must be supplied out of an energy block determined by regulation of the Government;*
- (3) favour the awarding of supply contracts based on the lowest tendered price for the required quantity of electric power and in keeping with the required conditions, taking into account the applicable transmission cost and, where the tender specifications provide that all or part of the needs met by a particular source of supply must be supplied out of an energy block, taking into account the maximum price established by regulation of the Government; and*
- (4) provide that, following a tender solicitation, contracts may be awarded to two or more suppliers, in which case a supplier offering the required quantity of electric power may be invited to reduce the quantity offered without modifying the tendered unit price.*

*An energy efficiency project to which a tender solicitation applies under subparagraph 2 of the second paragraph must meet the stability, sustainability and reliability requirements that apply to conventional sources of supply.*

*The Régie may dispense the electric power distributor from soliciting tenders for short-term contracts or where urgent needs must be met.*

*For the purposes of this section, the promoter of an energy efficiency project is deemed to be an electric power supplier.*

**74.2.** *The Régie shall monitor the implementation of the tender solicitation and contract awarding procedure and code of ethics provided for in section 74.1 and ascertain whether they are complied with. To that end, the Régie may require any document or information it considers useful. The Régie shall report its findings to the electric power distributor and to the supplier chosen.*

*The electric power distributor may not enter into an electric power supply contract unless it has obtained the approval of the Régie, under the conditions and in the cases determined by regulation by the Régie.*

The Régie's Website lists every docket related to this jurisdiction over Québec's electricity distributor (in French only): [Approval of supply contracts](#).

The Régie also considers DER when adopting specific reliability standards. Sections 85.2 and 85.7 of the Act read as follows:

**85.2.** *The Régie shall ensure that electric power transmission in Québec is carried out according to the reliability standards it adopts.*

**85.7.** *The Régie may request the reliability coordinator to modify a standard filed or submit a new one, on the conditions it sets. It shall adopt reliability standards and set the date of their coming into force.*

*The reliability standards may*

- (1) subject to section 85.10, provide for a schedule of sanctions, including financial penalties, that apply if standards are not complied with; and*
- (2) refer to reliability standards set by a standardization agency that has entered into an agreement.*

Docket [R-4070-2018](#) (in French only) relates to a request by the reliability coordinator (HQCME) and is still under examination by the Régie. It aims the adoption of reliability standards associated with Special Protection System (Remedial Action Scheme) and Dispersed Power Producing Resources.

We know you also contacted Hydro-Québec in this matter, but just in case, the following sections of Québec' electricity distributor and transmitter's web site might be useful, since they list the applicable technical codes, standards and requirements:

- [http://www.hydroquebec.com/transenergie/fr/commerce/raccordement\\_distribution.html](http://www.hydroquebec.com/transenergie/fr/commerce/raccordement_distribution.html) ;
- [http://www.hydroquebec.com/transenergie/fr/commerce/raccordement\\_transport.html](http://www.hydroquebec.com/transenergie/fr/commerce/raccordement_transport.html)

## Province of Ontario

The current connection requirements for all resources can be found in Chapter 4 appendices 4.2 and 4.3 of the Market Rules. <http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-rules/mr-chapter4appx.pdf?la=en>

The Independent Electric System Operator (IESO) is in the process of making updates to these requirements to be more specific about the requirements that apply to all DERs (not just storage). <http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Updates-to-Performance-Requirements-Market-Rule-Appendices-4-2-and-4-3>

The IESO is working on several white papers. The one that was posted in 2019 called “**Exploring Expanded DER Participation in the IESO-Administered Markets**” sets out the participation models that

exist for DER in wholesale markets in general and in the IESO-Administered Markets (IAM) today and also identify the range of options that exist for expanded participation in the future. In addition, this paper provides a working definition of DER, sets out principles for integrating them into wholesale markets, offers an initial review of participation models in other jurisdictions, and identifies key barriers that may limit DER participation in the IAMs.

<http://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.pdf?la=en>

As noted above, the Ontario Energy Board is also engaging in several stakeholder activities in this area. Below are the links to those activities. The Ontario Energy Board has combined the first two initiatives into one engagement.

- 1. Responding to Distributed Energy Resources (DER)\*** - The purpose of this initiative is to develop a more comprehensive regulatory framework that facilitates investment and operation of DER based-on value to consumers and supports effective DER integration so the benefits of sector evolution can be realized.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/responding-distributed-energy-resources-ders>

- 2. Utility Remuneration\*** - The purpose of this initiative is to identify how to remunerate utilities in ways that make them indifferent to traditional or innovative solutions, better supports their pursuit of least cost solutions, strengthens their focus on long-term value and requires them to reflect the impact of sector evolution in their system planning and operations.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/utility-remuneration>

- 3. DER Connections Review** – The purpose of this initiative to review its requirements regarding the connection of distributed energy resources (DER) by licensed electricity distributors. The purpose of this initiative is to identify any barriers to the connection of DER, and where appropriate to standardize and improve the connection process. The review will be focused on connection of electricity generation and storage facilities connected to the distribution system, either in front or behind the distributor's meter.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/distributed-energy-resources-der-connections-review>

The contact for this information would be Customer Relations ([customer.relations@ieso.ca](mailto:customer.relations@ieso.ca))

## Province of New Brunswick

Within the province, DER is referred to as “Embedded Generation” or “Distributed Generation.”

Regulation from the New Brunswick Energy and Utility Board may be found here:

<http://laws.gnb.ca/en/ShowPdf/cs/2013-c.7.pdf>

Énergie NB Power’s embedded generation may be found here:

<https://www.nbpower.com/en/products-services/embedded-generation/>

## Appendix F, ISO New England

ISO-NE specific Inverter requirements are as follows in the below table and the link

[Inverter Source Requirement Document of ISO New England](#)

The following additional performance requirements are applied in one NPCC Area and are provided as an example:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

**Table I: Inverters' Voltage Trip Settings**

| Shall Trip – IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) Category II |                                   |                  |                                                                                                                          |                                 |                                      |
|-------------------------------------------------------------------|-----------------------------------|------------------|--------------------------------------------------------------------------------------------------------------------------|---------------------------------|--------------------------------------|
| Shall Trip Function                                               | Required Settings                 |                  | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) default settings and ranges of allowable settings for Category II |                                 |                                      |
|                                                                   | Voltage (p.u. of nominal voltage) | Clearing Time(s) | Voltage                                                                                                                  | Clearing Time(s)                | Within ranges of allowable settings? |
| OV2                                                               | 1.20                              | 0.16             | Identical                                                                                                                | Identical                       | Yes                                  |
| OV1                                                               | 1.10                              | 2.0              | Identical                                                                                                                | Identical                       | Yes                                  |
| UV1                                                               | 0.88                              | 2.0              | Higher (default is 0.70 p.u.)                                                                                            | Much shorter (default is 10 s)  | Yes                                  |
| UV2                                                               | 0.50                              | 1.1              | Slightly higher (default is 0.45 p.u.)                                                                                   | Much longer (default is 0.16 s) | Yes                                  |

**Table II: Inverters' Frequency Trip Settings**

| Shall Trip Function | Required Settings |                  | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III |                  |                                      |
|---------------------|-------------------|------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------|------------------|--------------------------------------|
|                     | Frequency (Hz)    | Clearing Time(s) | Frequency                                                                                                                                              | Clearing Time(s) | Within ranges of allowable settings? |
| OF2                 | 62.0              | 0.16             | Identical                                                                                                                                              | Identical        | Yes                                  |
| OF1                 | 61.2              | 300.0            | Identical                                                                                                                                              | Identical        | Yes                                  |
| UF1                 | 58.5              | 300.0            | Identical                                                                                                                                              | Identical        | Yes                                  |
| UF2                 | 56.5              | 0.16             | Identical                                                                                                                                              | Identical        | Yes                                  |

**Table III: Inverters' Voltage Ride-through Capability and Operational Requirements**

| Voltage Range (p.u.)  | Operating Mode/ Response | Minimum Ride-through Time(s) (design criteria) | Maximum Response Time(s) (design criteria) | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) for Category II |
|-----------------------|--------------------------|------------------------------------------------|--------------------------------------------|------------------------------------------------------------------------|
| $V > 1.20$            | Cease to Energize        | N/A                                            | 0.16                                       | Identical                                                              |
| $1.175 < V \leq 1.20$ | Permissive Operation     | 0.2                                            | N/A                                        | Identical                                                              |
| $1.15 < V \leq 1.175$ | Permissive Operation     | 0.5                                            | N/A                                        | Identical                                                              |
| $1.10 < V \leq 1.15$  | Permissive Operation     | 1                                              | N/A                                        | Identical                                                              |

|                         |                                     |                                                                                                                                                                          |      |                     |
|-------------------------|-------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------|---------------------|
| $0.88 \leq V \leq 1.10$ | Continuous Operation                | infinite                                                                                                                                                                 | N/A  | Identical           |
| $0.65 \leq V < 0.88$    | Mandatory Operation                 | Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.:<br>$T = 3 \text{ s} + \frac{8.7 \text{ s}}{V - 0.65 \text{ p.u.}}$<br>$\frac{1}{V_{VRT}} \text{ p.u.}$ | N/A  | Identical           |
| $0.45 \leq V < 0.65$    | Permissive Operation <sup>a,b</sup> | 0.32                                                                                                                                                                     | N/A  | See footnotes a & b |
| $0.30 \leq V < 0.45$    | Permissive Operation <sup>b</sup>   | 0.16                                                                                                                                                                     | N/A  | See footnote b      |
| $V < 0.30$              | Cease to Energize                   | N/A                                                                                                                                                                      | 0.16 | Identical           |

The following additional operational requirements can be used. Provided as an example:

- a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

**Table IV: Inverters' Frequency Ride-through Capability**

| Frequency Range (Hz)    | Operating Mode                                   | Minimum Time(s) (design criteria) | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) for Category II |
|-------------------------|--------------------------------------------------|-----------------------------------|------------------------------------------------------------------------|
| $f > 62.0$              | No ride-through requirements apply to this range |                                   | Identical                                                              |
| $61.2 < f \leq 61.8$    | Mandatory Operation                              | 299                               | Identical                                                              |
| $58.8 \leq f \leq 61.2$ | Continuous Operation                             | Infinite                          | Identical                                                              |
| $57.0 \leq f < 58.8$    | Mandatory Operation                              | 299                               | Identical                                                              |
| $f < 57.0$              | No ride-through requirements apply to this range |                                   | Identical                                                              |

**Table V: Grid Support Utility Interactive Inverter Functions Status**

| Function                                          | Default Activation State                                      |
|---------------------------------------------------|---------------------------------------------------------------|
| SPF, Specified Power Factor                       | OFF <sup>2</sup>                                              |
| Q(V), Volt-Var Function with Watt or Var Priority | OFF<br>Default value: 2% of maximum current output per second |
| SS, Soft-Start Ramp Rate                          | ON                                                            |
| FW, Freq-Watt Function OFF                        | OFF                                                           |

## Appendix G, State Renewable and Green Energy Requirements

### New York State

70% renewable energy by 2030  
85% reduction of Greenhouse Gas emissions by 2050  
6,000 MW of distributed solar by 2025  
3,000 MW of energy storage by 2025  
Carbon free electricity system by 2040

### Connecticut

Carbon free electricity system by 2040  
Renewable Portfolio Standard - <https://portal.ct.gov/PURA/RPS/Renewable-Portfolio-Standards-Overview>

### Vermont

90% of Vermont's overall energy needs from renewable sources by 2050  
Reduce Vermont's greenhouse gas (GHG) emissions by 50% from the 1990 baseline level by 2028, and by 75% from the 1990 level by 2050

### New Hampshire

20% to 25% reduction in Greenhouse Gas emissions by 2032  
25.2% renewable energy by 2025

### Rhode Island

100% renewable energy by 2030  
1,000 MW of new clean energy installed in 2020

### Maine

80% renewable energy by 2030

# NYISO DER Participation Model: Aggregations & Roadmap

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James Pigeon

MANAGER, DISTRIBUTED RESOURCES INTEGRATION

**NPCC Regional Standards Committee**

October 15, 2020, Virtual Conference

# FERC Order No. 2222

- FERC issued Order No. 2222 (Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs) on September 17, 2020.
- The description of the NYISO's DER market design reflects the rules accepted by FERC in December 2019.
- The NYISO is still evaluating whether and what changes to its rules may be necessary to comply with Order No. 2222, and therefore the concepts and rules described in this presentation may change.

# DER Definition for the Market Design

- **Distributed Energy Resource (“DER”):** (i) a facility comprising two or more Resource types behind a single point of interconnection with an Injection Limit of 20 MW or less; or (ii) a Demand Side Resource; or (iii) a Generator with an Injection Limit of 20 MW or less, that is electrically located in the NYCA.
- **DER must be capable of responding in real-time to NYISO dispatch instructions.**

# Transmission Nodes

# Transmission Node Overview

- **The ISO, in coordination with the Transmission Owners, shall establish the set of Transmission Nodes in the New York Control Area**
  - All Transmission Nodes will be identified in ISO Procedures
- **Aggregators will work with Transmission Owners to determine which ISO identified Transmission Node each individual DER/Facility electrically maps to**
  - Only DER/Facilities that map to the same Transmission Node may be aggregated together
- **Aggregators may enroll one or more Aggregations at a Transmission Node**

# Transmission Node Background

- **Transmission Nodes reflect the collection of electrically similar facilities to which individual DER may aggregate as an Aggregation with a single PTID**
- **The DER Roadmap outlined the need to:**
  - Consider all Transmission Nodes that allow the NYISO to best represent DERs impact on the transmission system
  - Deliver more granular pricing data to incent efficient locational investment

# DER Aggregations: Overview, Rules & Participation

# DER Aggregation Approach

- **Aggregations grouped at a Transmission node allow the NYISO to continue to support system reliability leveraging its wholesale markets**
  - Requiring Aggregations at Transmission Nodes will allow the NYISO to effectuate dispatch in a manner that will effectively secure transmission constraints on the system while sending efficient price signals
  - This Transmission Node level granularity, instead of Load Zone level, will more effectively relieve transmission constraints thereby resulting in lower overall total production cost

# DER Market Participation

- **The DER participation model will only be available to Aggregations**
  - An Aggregation consists of two or more individual resources, except that Demand Side Resources and individual facilities that can reduce load and inject energy (i.e., transition from being Load to Supply without an infeasible operating range), will be permitted to individually use the DER participation model as a single-resource Aggregation
- **Individual facilities in an Aggregation will participate under the market rules for either:**
  - A DER Aggregation (when there are multiple Resource types in the Aggregation), or
  - The specific Resource type (when there is a single Resource type in the Aggregation)
    - For an Aggregation of Intermittent Power Resources, the technology type of each Resource in the Aggregation must be the same (E.g., Resources depending on wind as their fuel)

# Basics for all Types of Aggregations

- Resources will be permitted to aggregate to meet minimum requirements and performance obligations for eligible participation models
- The Aggregator will be the NYISO Market Participant
- The Aggregation will be a group of one or more resources participating in the NYISO Market, represented by a PTID
  - Bids will represent the offer of the Aggregation
  - Performance will be measured in aggregate
  - Financial settlements will be in aggregate
    - The NYISO intends to separately process the injection, withdrawal and load reduction data to ensure accurate settlements

# Aggregation & Ancillary Services

- **Aggregations will be eligible to supply the Ancillary Service Products for which all DER within the Aggregation are eligible to supply**
  - Example 1: An Aggregation would be eligible to supply Regulation only if all DER in the Aggregation are eligible to supply Regulation
  - Example 2: If one resource in the Aggregation is only eligible to supply 30-Minute Non-Synchronous Reserves, the entire Aggregation is only eligible to supply 30-Minute Non-Synchronous Reserves

# Dual Participation

# Dual Participation

- **The NYISO's market design allows resources that provide Wholesale Market services to also provide services to another entity (e.g., the utility or a host facility)**
  - The NYISO believes that providing resources with the flexibility to meet wholesale and distribution system needs will deliver the maximum benefit to New York electricity consumers
  - Resources participating in the wholesale markets will continue to be obligated to follow all applicable NYISO market rules and utilize good utility practices
- **Dual participation concept applies to all resources, not just DER Aggregations**
  - Effective May 1, 2020, Generators and Demand Side Resources electrically located in the NYCA may simultaneously participate in the ISO-administered wholesale markets and in programs or markets operated to meet the needs of distribution systems located in the NYCA.

# Requirements

- **Dual participating resources are required to:**
  - Comply with all NYISO market rules for the services offered to the wholesale market
    - Non-compliance may result in financial penalties
  - Appropriately offer into the wholesale markets to reflect any non-wholesale (e.g., retail) obligations
    - Resources are required to follow NYISO dispatch instructions at all times;
    - Resources submit offers to NYISO when providing non-wholesale service
    - Resources receive payments for Energy or Ancillary Services scheduled through these offers

# Next Steps

- **Q2 2021: Deploy SD-WAN infrastructure for additional secure communications of scada data**
- **Q4 2022: Deploy software to enable participation of DER aggregations**

# Our mission, in collaboration with our stakeholders, is to serve the public interest and provide benefit to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policymakers, stakeholders and investors in the power system



# DER Interconnection Requirements

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**Thinh Nguyen**

**Senior Manager, Interconnection Projects**

**NPCC Regional Standards Committee**

October 15, 2020

# Agenda

- **Background**
- **Interconnection Process for DERs**

# Background

# Background\*

- Today's presentation will review NYISO's interconnection process for DERs seeking the following interconnection services:
  - Energy Resource Interconnection Service (ERIS)
  - Capacity Resource Interconnection Service (CRIS)

**\*FERC issued Order No. 2222 (Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs) on September 17, 2020. The NYISO is currently evaluating what changes to the rules and processes discussed in this presentation, if any, may be necessary to comply with Order No. 2222.**

# Interconnection Process for DERs

# Interconnection Processes Applicable to DERs

- **NYISO's interconnection procedures govern the interconnection of the facility if:**
  - Developer intends to make wholesale sales and
  - Developer proposes to interconnect to (i) transmission or (ii) distribution facilities on which there is already a generator making wholesale sales (*i.e.*, “FERC-jurisdictional distribution”)
- **NY Standardized Interconnection Requirements (SIR) govern the interconnection of the facility if:**
  - Developer is interconnecting to portions of the distribution system other than “FERC-jurisdictional distribution” and the resource is less than or equal to 5 MW
- **Utility interconnection procedures govern the interconnection of resources if the interconnection is not subject to the NYISO or SIR processes**
  - Interconnection Service for SIR or Utility-level interconnection is based on the applicable interconnection agreement
  - Facilities that proceed through the SIR or utility interconnection processes must have an interconnection agreement that allows wholesale sales

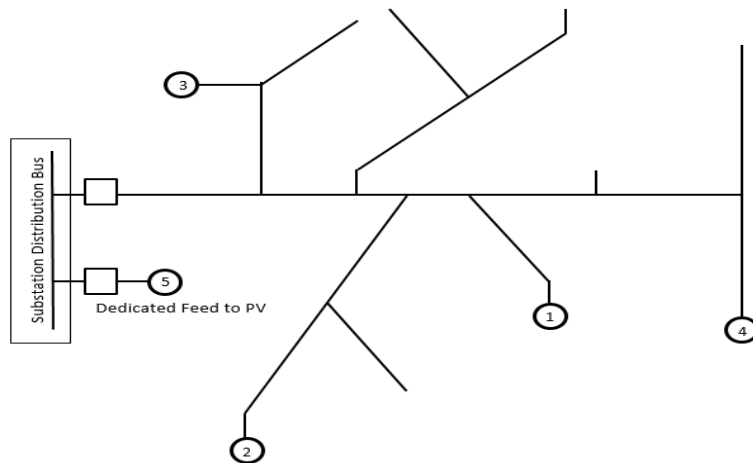
# Determining the Applicable Interconnection Process for ERIS

- **A developer may request a determination from the NYISO regarding whether its proposed interconnection is subject to the NYISO's SGIP**
  - This may be requested under Section 32.1.1.4 of Attachment Z to the OATT
  - This may also be requested as part of a pre-application request (a \$1000 request for information regarding a proposed interconnection prior to submitting an Interconnection Request)
    - See Section 32.1.2 of Attachment Z to the OATT

# Determining the Applicable Interconnection Process for ERIS (cont.)

| Intended Market | Interconnection Point *                                                                    | Project Size | Study Process |
|-----------------|--------------------------------------------------------------------------------------------|--------------|---------------|
| Wholesale       | NYS Transmission System or Distribution subject to NYISO's OATT Interconnection Procedures | > 5MW        | NYISO         |
|                 |                                                                                            | ≤ 5MW        | NYISO         |
|                 | Distribution not subject to NYISO's OATT Interconnection Procedures                        | > 5MW        | Utility       |
|                 |                                                                                            | ≤ 5MW        | SIR           |
| Retail          | NYS Transmission System or Distribution subject to NYISO's OATT Interconnection Procedures | > 5MW        | Utility       |
|                 |                                                                                            | ≤ 5MW        | Utility       |
|                 | Distribution not subject to NYISO's OATT Interconnection Procedures                        | > 5MW        | Utility       |
|                 |                                                                                            | ≤ 5MW        | SIR           |

# Determining the Applicable Interconnection Process for ERIS (cont.)



| <u>Interconnection Order</u>                    | <u>Intended Market</u> | <u>Study Process</u> |
|-------------------------------------------------|------------------------|----------------------|
| 1 <sup>st</sup>                                 | NYISO                  | Utility or SIR       |
| 1 <sup>st</sup> goes in-service<br>then retires | NYISO                  | n/a                  |
| 2 <sup>nd</sup>                                 | NYISO                  | NYISO                |
| 3 <sup>rd</sup>                                 | Non-NYISO              | Utility or SIR       |
| 4 <sup>th</sup>                                 | NYISO                  | NYISO                |
| 5 <sup>th</sup>                                 | NYISO                  | Utility or SIR       |

# NYISO's SGIP

- **NYISO SGIP (OATT Attachment Z) is the NYISO's interconnection process for the following Small Generating Facilities 20 MW or less:**
  - **New facilities 20 MW or less that meet both of the following criteria:**
    - Facility proposes to interconnect to FERC-jurisdictional facilities (*i.e.*, transmission facilities or distribution facilities on which there is already a generator making wholesale sales); and
    - Facility intends to make wholesale sales (via injection)
  - **Existing facilities 20 MW or less that make material modifications or material increases to their facilities**
    - If an increase to the facility results in the facility exceeding 20 MW, the modification/increase is subject to the Large Facility Interconnection Procedure
    - Qualifying Facilities that seek the right to participate in the wholesale market will be studied in the NYISO's interconnection process under certain circumstances (depending upon the proposed point of interconnection, whether the facility is new, whether, if existing, the facility increasing its output, etc.)

# NYISO's Interconnection Queue Administration

- **Projects assigned Queue position based on date Interconnection Request (IR) received**
  - Demonstration of Site Control is required with a Small Generator IR
- **NYISO Queue is not a “Hard Queue” in which IRs are evaluated in sequential order**
  - Projects can advance on different schedules
  - Small generators may be studied in clusters if interconnecting in close proximity (See Att. Z, Section 32.3.5.3.2)
- **Status of Queue Projects is updated monthly on NYISO public website**

# SGIP – Normal Study Process

## ■ Optional Feasibility Study (FES)

- Customer may opt to waive the FES unless it proposes multiple POIs
- FES is a high level study that evaluates proposed Point of Interconnection (and alternative POIs as requested) and the proposed configuration
- The focus of the FES is on the local system
- FES study report includes preliminary nonbinding cost estimate for SUFs

## ■ System Impact Study (SIS)

- May be waived upon mutual agreement of customer, NYISO and CTO
- Intermediate level study that evaluates project impact on system reliability
- Includes updated nonbinding cost estimate for SUFs
- Not subject to review by stakeholders and does not require Operating Committee approval

## ■ Facilities Study (FS)

- May be waived upon mutual agreement of customer, NYISO and CTO
- Facilities Study determines binding cost estimates and cost allocation for Local SUFs
- Not subject to a Class Year study unless non-Local SUFs are identified (or the project is larger than 2 MW and requesting CRIS)

# Process for Evaluation of CRIS Requests

- **Resources larger than 2 MW requesting CRIS**
  - Required for any resource larger than 2 MW that requests CRIS – even if the resource is not subject to the NYISO’s interconnection procedures
  - CRIS request must be evaluated in a Class Year Study or Expedited Deliverability Study
    - Class Year Study evaluates a group of CRIS requests together and determines deliverability and if not deliverable, the respective cost allocation for System Deliverability Upgrades
    - Expedited Deliverability Study evaluates a group of CRIS requests together and determines whether the requested CRIS are deliverable or not
      - No cost allocation

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- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policymakers, stakeholders and investors in the power system



# **New York State Reliability Council (NYSRC) High Renewables Capacity Study**

## **NPCC DER Forum**

Dr. Mayer Sasson, NYSRC Executive  
Committee (EC) Chair

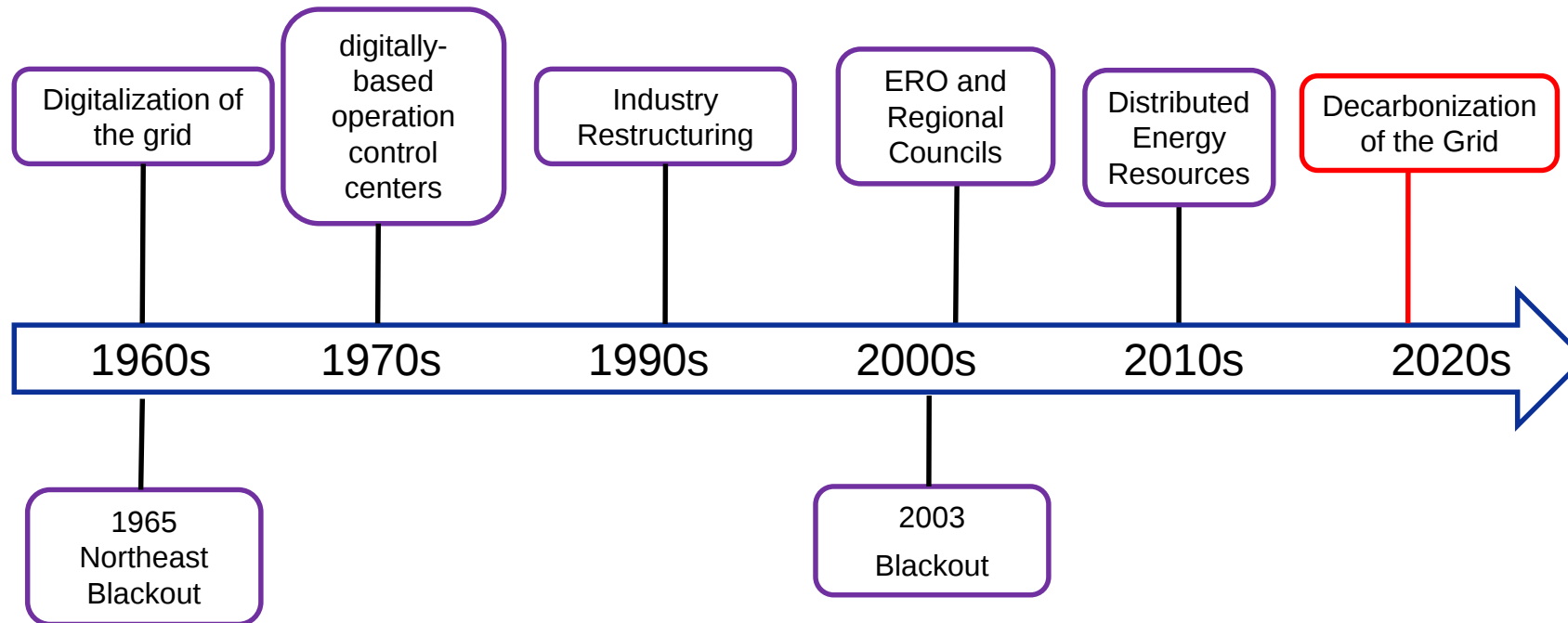
Howard Kosel, Member ICAP  
Subcommittee (ICS)

October 15, 2020

# Acknowledgments and References

- New York State Reliability Council (NYSRC) High Renewable White Paper:  
<http://nysrc.org/PDF/Reports/HR%20White%20Paper%20-%20Final%204-9-20.pdf>
- Additional materials referenced from the following recent NYISO and Brattle studies:
  - NYISO's "Reliability and Market Considerations For A Grid in Transition":  
<https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220+Final.pdf/61a69b2e-0ca3-f18c-cc39-88a793469d50?t=1576874483489>
  - Brattle Study "New York's Evolution to a Zero Emission Power System":  
<https://www.nyiso.com/documents/20142/12610513/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study.pdf/6a93a215-9db3-d5a0-6543-27b664229d3e>

# Sixty Years of Key Developments of the Electrical Grid



# Introduction

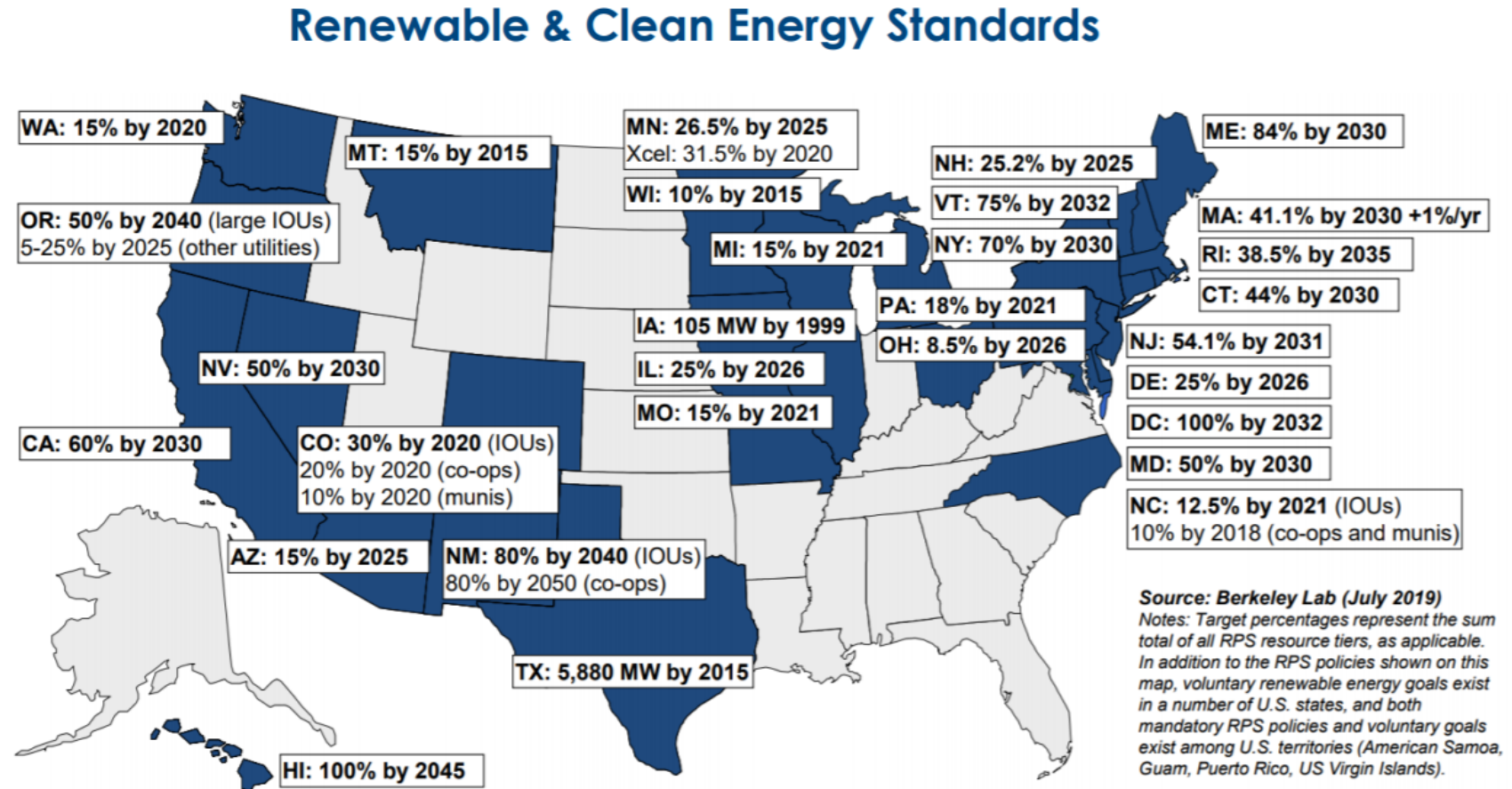
- Many regions within NPCC adopting decarbonization targets
- While initiatives vary, there are many common themes
  - Complete elimination of fossil generation by a target date
  - Policies to integrate intermittent renewables and energy storage
  - Retention of aging nuclear units
- As well as common challenges to meet reliability standards
  - Increased need for balancing and regulation, requiring fast responding resources
  - Electrification leading to steep winter peaks
  - Resource Adequacy planning exacerbated by less predictable resource availability
- This presentation will focus on New York as a representative case for ambitious de-carbonization goals
- What is being covered is applicable to the entire NPCC footprint
  - Each state or province may have different renewable targets

# Attributes of the Electric Grid That Must be Maintained

- Attributes
  - Reliability: Ensure adequate supply resources to maintain electric service under a range of conditions and contingencies
  - Resilience: Harden the infrastructure to withstand major weather events but also maintain the ability to quickly recover from blackouts
  - Frequency Response and Transient Stability: Maintain the ability of the electric grid to respond to disturbances
- The electric system is poised to play a central role in the societal transformation to a clean energy future
- The challenge will be to not compromise on the key attributes of the electric system while this transformation unfolds

# Decarbonization Policies Around the United States

- As of early May 2020, 16 states/territories have adopted 100% clean/renewable energy system mandates of targets
- New York is the first entire RTO system moving to 100% clean

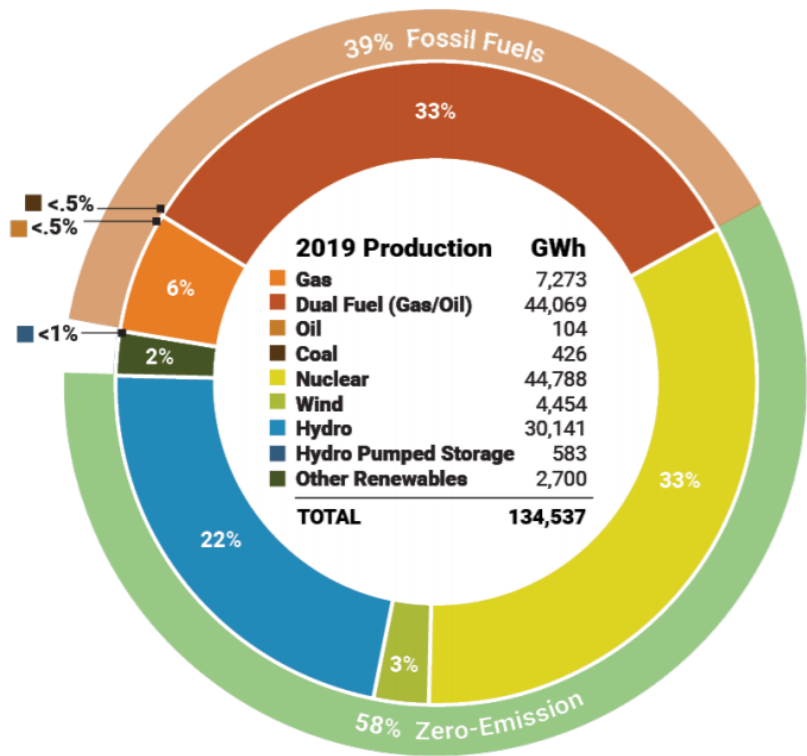


Source: Galen Barbose, "U.S. Renewables Portfolio Standards 2019 Annual Status Update," Lawrence Berkeley National Lab, July 2019. [rps.lbl.gov](https://rps.lbl.gov)

# New York State Climate Leadership and Community Protection Act (CLCPA)

- Signed into New York State Law in July 2019
- Net zero economy wide GHG emissions by 2050
  - Minimum 85% reduction in direct GHG emissions (compared to 1990 levels)
  - Remaining GHG emissions could be met by “offsets” such as ecosystem restoration and carbon capture
- 70% of New York State electric demand from renewable sources by 2030
- Complete elimination of GHG emissions from the electric grid by 2040
  - Electric generators will not be permitted to rely on offsets

# New York's Clean Energy Goals



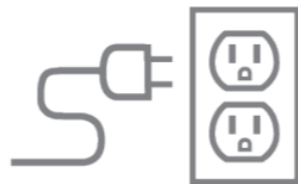
## Climate Leadership and Community Protection Act (CLCPA) Goals



Renewables  
**70%  
by 2030**



Offshore Wind  
**9,000 MW  
by 2035**



Energy Efficiency  
**185 trillion British Thermal  
Units (BTU) reduction by 2025**

Zero-Emission  
Electric Sector  
by 2040



Distributed Solar Energy  
**6,000 MW  
by 2025**



Battery Storage  
**3,000 MW  
by 2030**

 New York ISO

Source: NYISO, "Reliability and Market Considerations For A Grid in Transition"

# Why was a Study Performed?

- Given the CLCPA 70x30 and 100x40 renewable goals, the NYSRC set out to study
  - Impact on the IRM in terms of ICAP and UCAP
  - Need for new modeling in MARS
- The Installed Capacity Margin (IRM) defines the percentage of capacity (ICAP) over peak load necessary to meet the NPCC and NYSRC Minimum Capacity Margin
  - Probability of load disconnection not exceeding one day in 10 years, that is,  $LOLE \leq 0.1$
- Expected to be one of several studies necessary to fully understand impact on reliability
  - Challenge arises from the variability and intermittency of wind and Front of the Meter (FTM) PV generation
- 12,000 MW of renewables were added to the latest 2020-21 IRM study Base Case

# Methodology Matters



- Process
  - “As Found” system is a physical system with all of its resources: therefore, few loss-of-load events
  - To move towards an LOLE = 0.1, resources must be removed and possibly shifted until transmission constraints bind, to increase loss of load events
  - Calculations are performed in terms of Unforced Capacity (UCAP)
  - Physical capacity is expressed in terms of Installed Capacity (ICAP)
- Factors that affect the results
  - The process used to decide which resources to remove and/or shift affects results
  - How the initial translation from ICAP to UCAP and the final translation UCAP to ICAP are made also affect results

# Results

- The UCAP version of the Installed Capacity Reserve Margin (IRM) is the Unforced Capacity Reserve Margin (URM):

$$\text{IRM} = \text{NYCA ICAP}_{@ 0.1 \text{ LOLE}} / \text{Peak Load}$$

$$\text{URM} = \text{NYCA UCAP}_{@ 0.1 \text{ LOLE}} / \text{Peak Load}$$

- Capacity market works in UCAP terms

| Case           | NYCA IRM | NYCA URM | Zone J IRM | Zone J URM | Zone K IRM | Zone K URM |
|----------------|----------|----------|------------|------------|------------|------------|
| Base case      | 118.6%   | 105.0%   | 83.9%      | 74.2%      | 102.3%     | 93.5%      |
| High Renewable | 142.9%   | 107.4%   | 97.9%      | 77.2%      | 131.6%     | 99.4%      |
| % Delta        | 24.3%    | 2.4%     | 14.0%      | 3.0%       | 29.3%      | 5.9%       |
| MW Delta       | 7,837    | 775      | 1,631      | 355        | 1,515      | 305        |

# Unexpected Difference in Total NYCA UCAP for Base Case and HR Case at LOLE Criteria

- Theoretically, there should not be a difference
  - The Base Case determined the amount of UCAP needed for the system to be at an LOLE of 0.1
  - In the High Renewable (HR) Case, additional resources reduce (improve) the LOLE to  $< 0.1$  and equivalent capacity must be removed to return to an LOLE of 0.1
  - The IRM is higher in the HR Case but so is the average NYCA EFORD (26% vs 12%)
- NYCA UCAP@0.1 LOLE in Base Case theoretically expected to be equal to NYCA UCAP@0.1 LOLE in HR Case
  - In both cases, no additional resources are required beyond those needed for system to be at LOLE of 0.1
  - Practically, the study shows there is a difference
  - Method is highly dependent on resource location and existing transmission topology

# Renewable Resources Unforced Capacity

- The white paper utilized historical 8,760 hourly curves for the availability of renewable resources
- The Zonal Availability Factor table shows the deterministically determined UCAP conversion factors for each resource type
  - Utilized resource availability during the highest load summer months (June - August)
  - $ICAP \times Availability\ Factor = UCAP$
  - Used as a proxy for EFORD
    - Availability Factor is equivalent to  $1 - EFORD$
- These factors were used to determine:
  - The initial UCAP for each renewable resource
  - The IRM and URM
  - Approximate derate factors of renewables
- California, MISO and PJM (proposal) calculate the availability factors in terms of the reliability value they contribute to prevent loss of load

Zonal Availability Factors by Resource Type

| Zone | FTM PV | On-Shore Wind | Off-Shore Wind |
|------|--------|---------------|----------------|
| A-C  | 31%    | 15%           |                |
| D    |        | 14%           |                |
| E    |        | 17%           |                |
| F    | 28%    |               |                |
| G    | 28%    |               |                |
| J    |        |               | 29%            |
| K    | 30%    |               | 34%            |
| NYCA | 29%    | 16%           | 32%            |

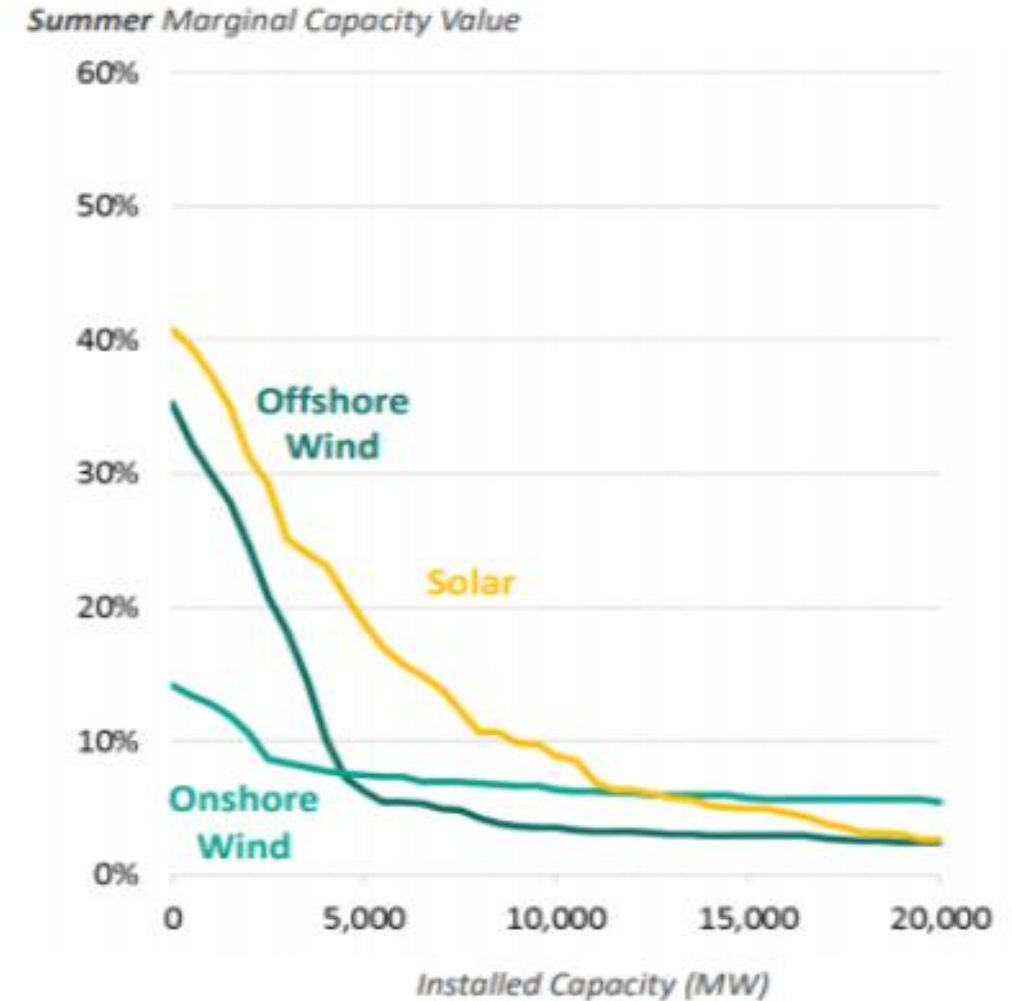
# Reliability Value of Renewables

- PJM Proposed Approach (taken from a 10/17/19 PJM presentation by Patricio Rocha Garrido)
  - Develop a Resource Adequacy case that meets the 1 day in 10 years Loss of Load Expectation (LOLE) criteria (this is the **Base Case**)
  - Add historical or representative hourly system-wide wind/solar output shapes to the Base Case. The LOLE in this **HR Case** will now be less than 0.1 days/year.
  - Increase the peak load in the **HR Case** until the LOLE is back at 0.1 days/year.
  - The difference between the final peak loads in the **HR Case** and the **Base Case** represents the reliability value or UCAP of the renewable resources
  - These studies are known as Effective Load Carrying Capability (ELCC)
    - Capacity Value studies are often used synonymously but differ slightly in that they measure how much generation can be displaced by the renewable resources
- As renewables penetration increases, the reliability value of renewables decreases while the reliability value of conventional resources remains constant

# Resource Adequacy: Capacity Reliability Value

- Capacity Reliability Value is a measure of a resource's reliability contribution or their ability to avoid loss of load events (LOLE)
- It is a measure of how much incremental load can be carried (ELCC) or generation can be removed (Capacity Value) without degrading reliability with the same amount of incremental renewable capacity installed
- Increasing penetration of intermittent resources leads to declining capacity reliability values
  - Numerous studies have led to the same conclusion
- Dispatchable and flexible technologies will be required to maintain resource adequacy criterion

**Chart is illustrative** based on the Brattle study “New York’s Evolution to a Zero Emission Power System”



Source: Brattle, “New York’s Evolution to a Zero Emission Power System”

# Observations

- Location of added renewable resources affects transmission constraints and thereby results
- Taken together with not accounting more precisely for the reliability value of renewables, leads to a difference in the UCAP resources between the two cases studied
  - In the studies performed, the High Renewable case had 775 MW more than the Base Case at LOLE = 0.1
  - This may be overstated by not accounting for the reliability value of renewables
- Once the reliability value of renewables is considered, the UCAP difference between cases may go down, but the actual ICAP IRM will correspondingly increase

# NYSRC EC Guidance to ICS for Further Work

- The High Renewable case studied is prompting the NYSRC / NYISO to review the removal / shifting process for determining the IRM to see if changes are warranted
- The Availability Factor of renewable resources must be revisited to more accurately reflect their contribution to reliability
  - The availability of renewables is fundamentally different than that of conventional resources
- The introduction of storage resources will bring their own set of issues and must be studied

# Testing and analysis of the dynamic and transient behavior of inverters used in solar residential project



# Test and analysis of the dynamic and transient behavior of inverters used in solar residential project

HQ TransÉnergie

Vincent Morissette, Julie Lacroix, Pierre-Luc Martel, Charles Desbiens, Jean-François Haché

IREQ

Dmitry Rimorov, Olivier Tremblay



# Agenda

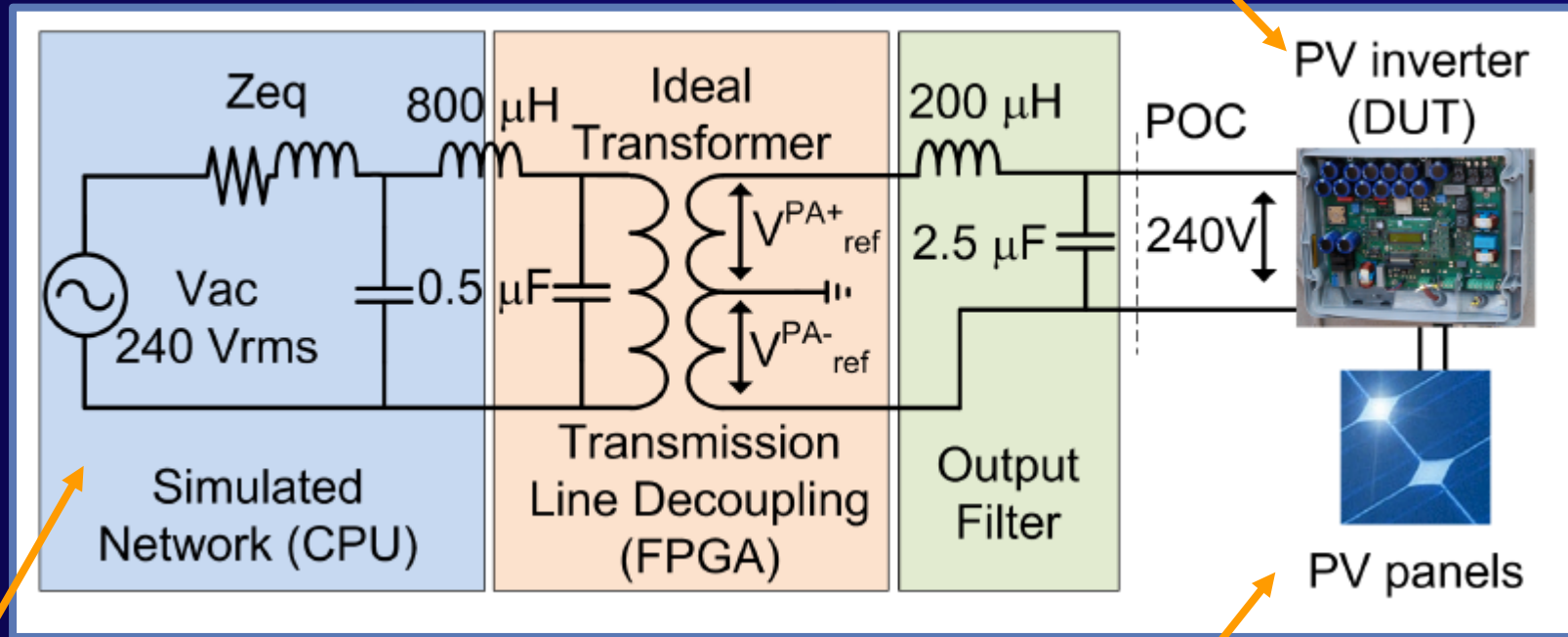
1. Introduction
2. Power-hardware-in-the-loop
3. Tested cases
4. Results
5. Conclusion
6. References

# Introduction

- Increased penetration of solar residential photovoltaic (PV) is a concern for transmission network planning.
- We tested voltage and frequency ride-through.
- Then, we did additional tests with Hypersim and power hardware in the loop. It allowed us to test: faults, dynamic and transient phenomena of different network events with a wide frequency range (up to 25kHz). We have performed in-depth analysis of ride-through performance.

# Power-hardware-in-the-loop tests (IREQ simulation laboratory)

Equipement under test



Different real time network events  
with Hypersim simulator

PV emulator

## Devices under test

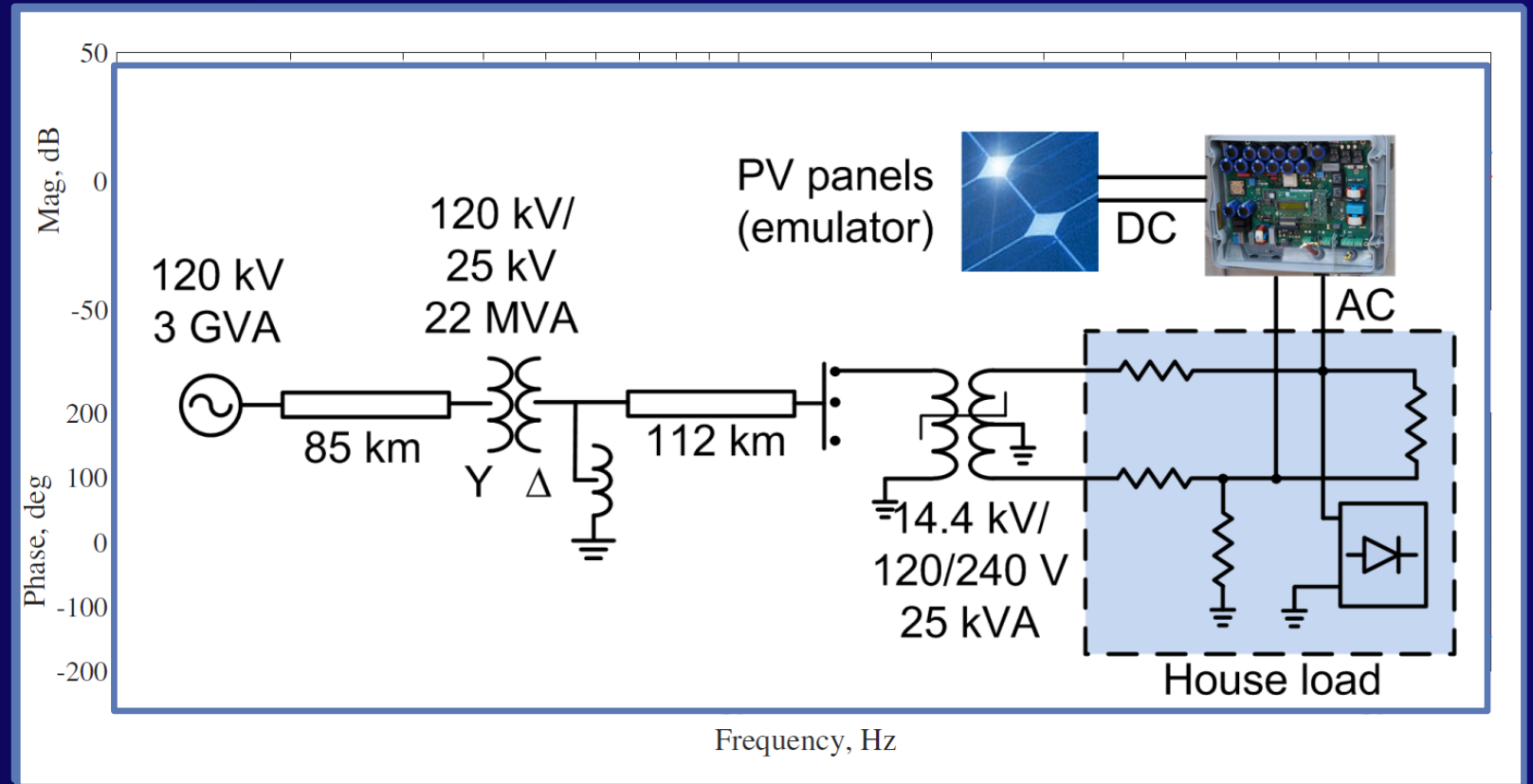
| Inverter ID | Type      | Nominal power, VA | Tested power, VA | Programming capabilities | MPPT |
|-------------|-----------|-------------------|------------------|--------------------------|------|
| A           | Microinv  | 280               | 280              | Limited/none             | yes  |
| B           | Microinv  | 1400              | 300              | Limited/none             | yes  |
| C           | Smart inv | 5000              | 2000             | Protection and control   | yes  |
| D           | Smart inv | 3300              | 2000             | Protection and control   | no   |

MPPT : Maximum power point tracking

# Tests cases

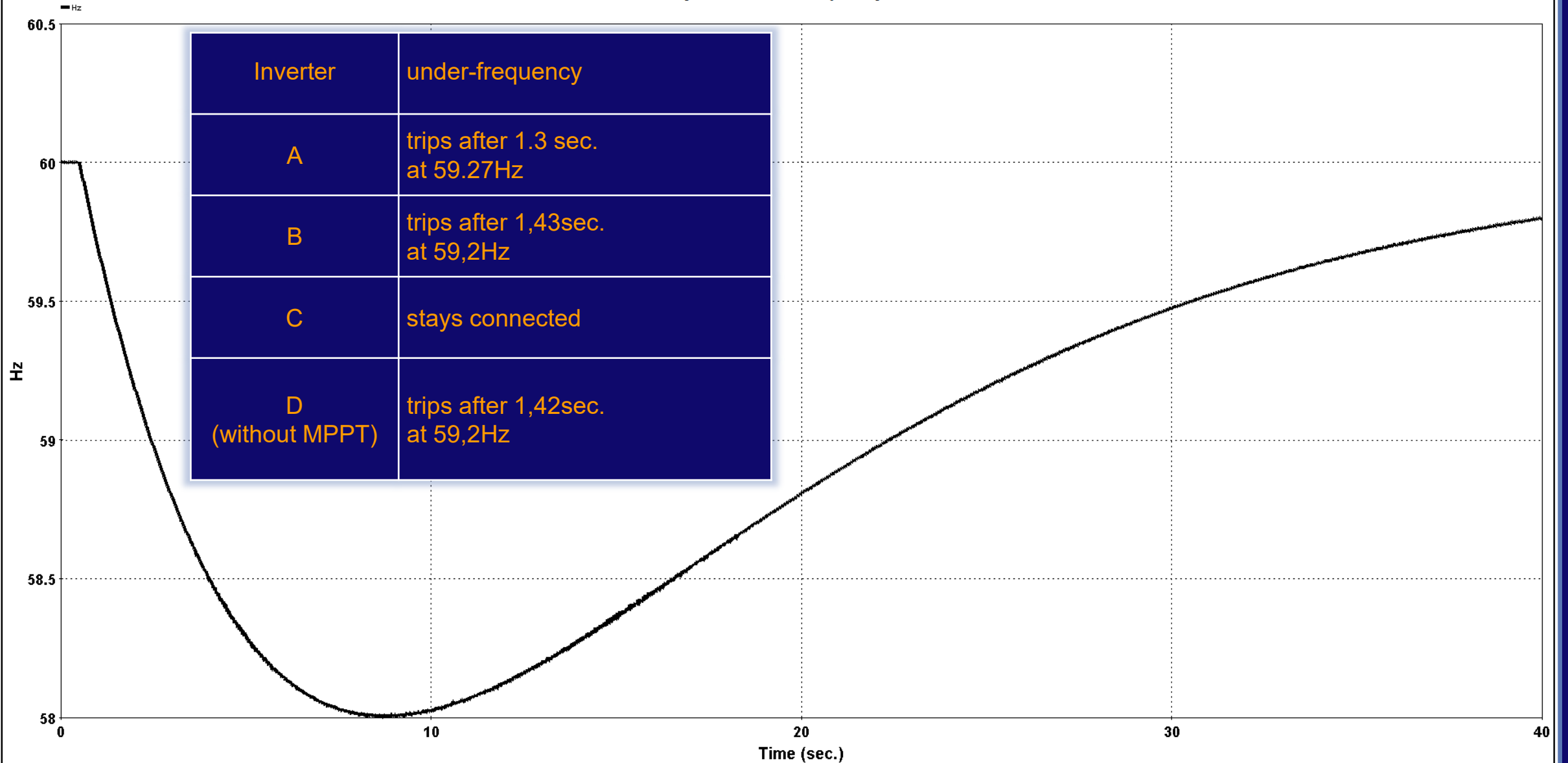
## Hypersim tests :

- Dynamic under frequency
- Dynamic over frequency
- Low voltage ride through
- Low voltage dynamic event
- Rate of change of frequency
- Sudden phase angle shift
- Decrease the system strength
- Network faults in weak network condition and high penetration level
- Frequency response

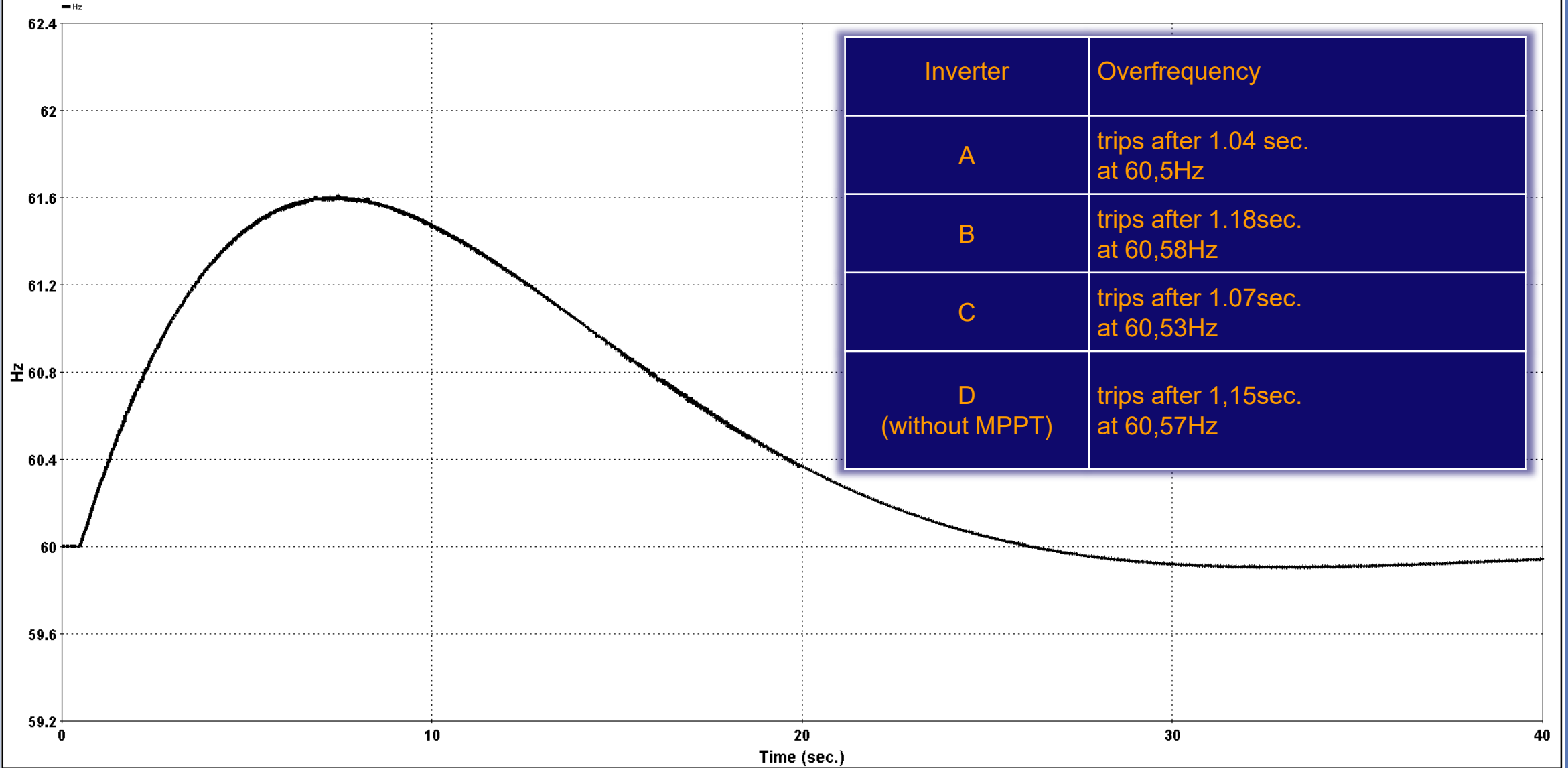


Voltage and frequency ride-through

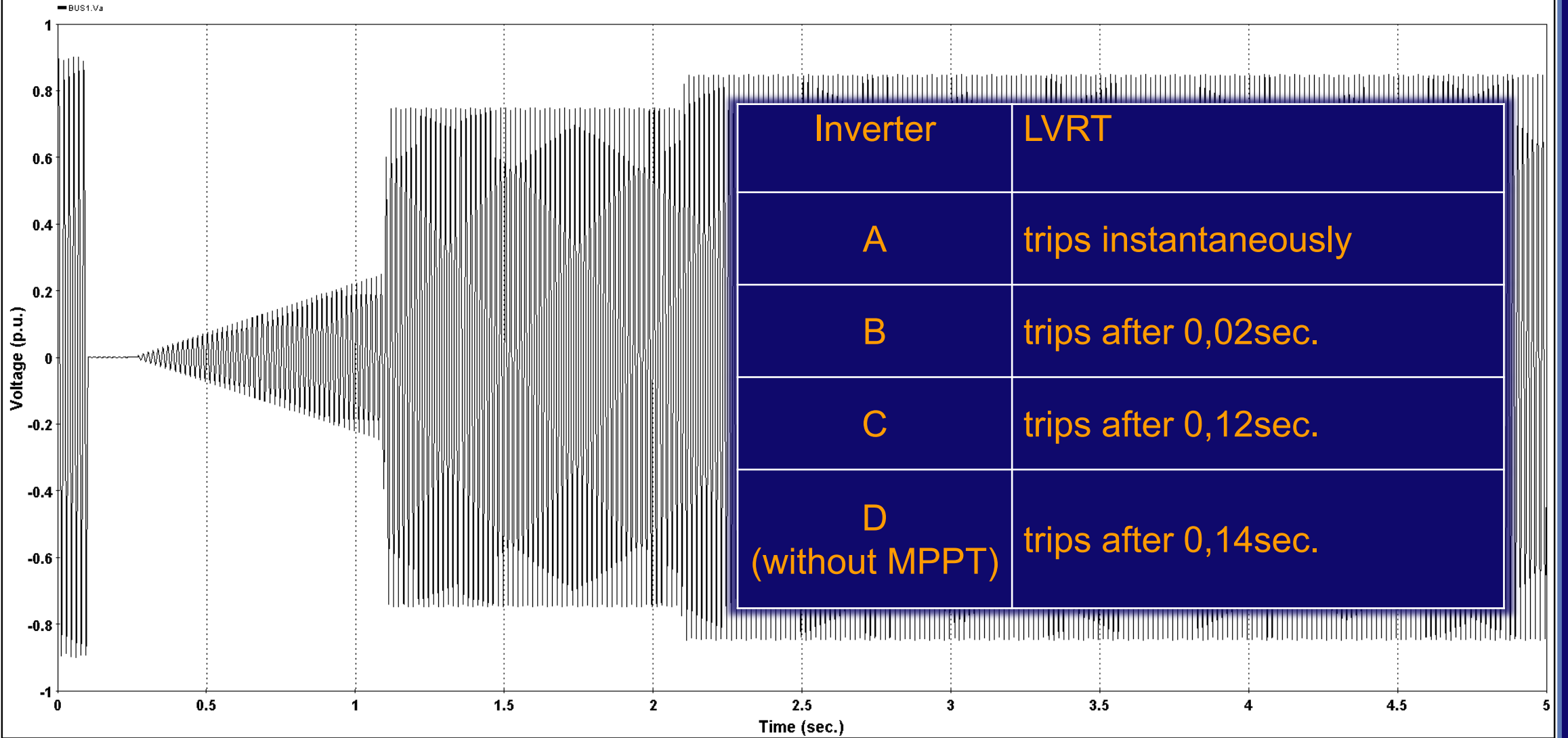
Dynamic under frequency



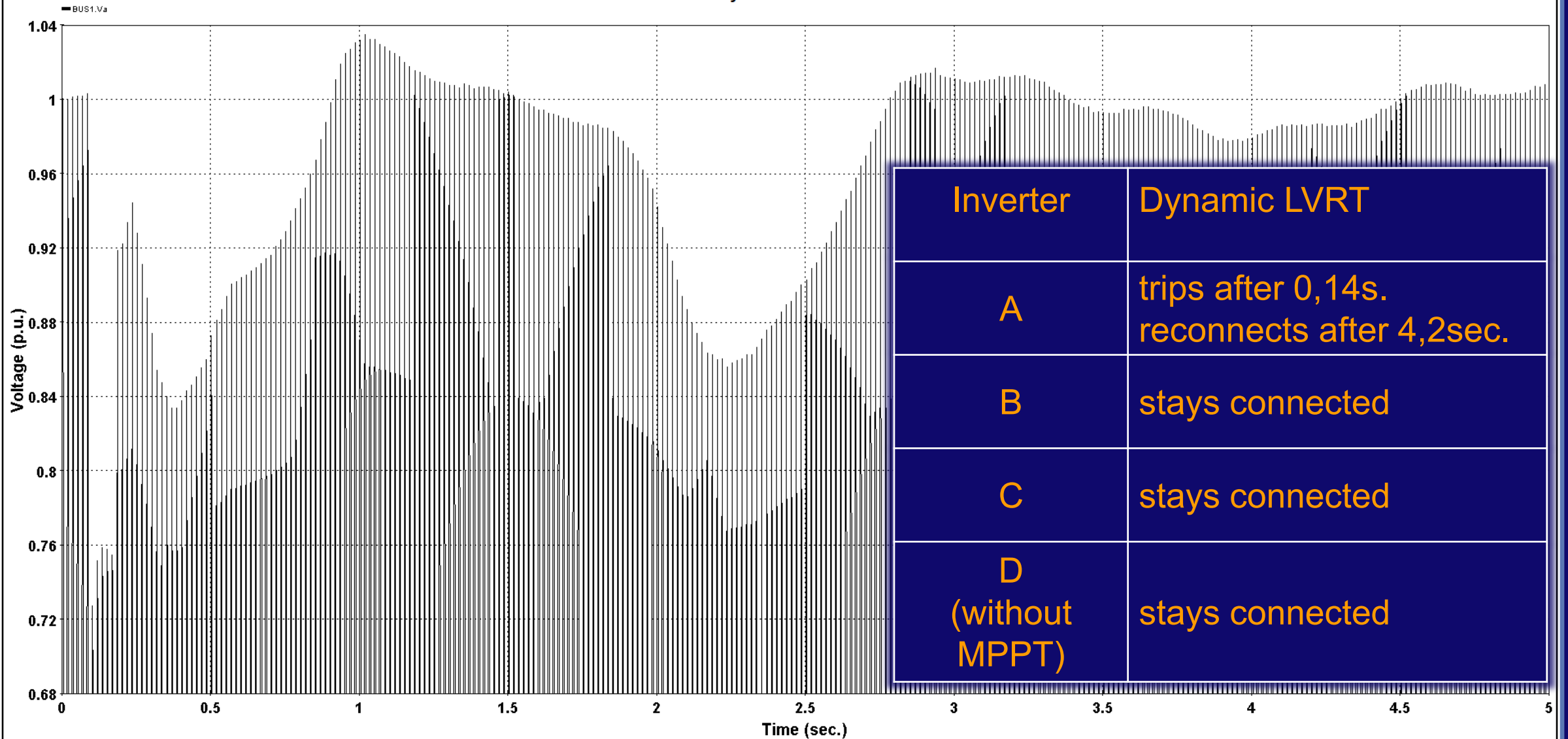
Dynamic over frequency



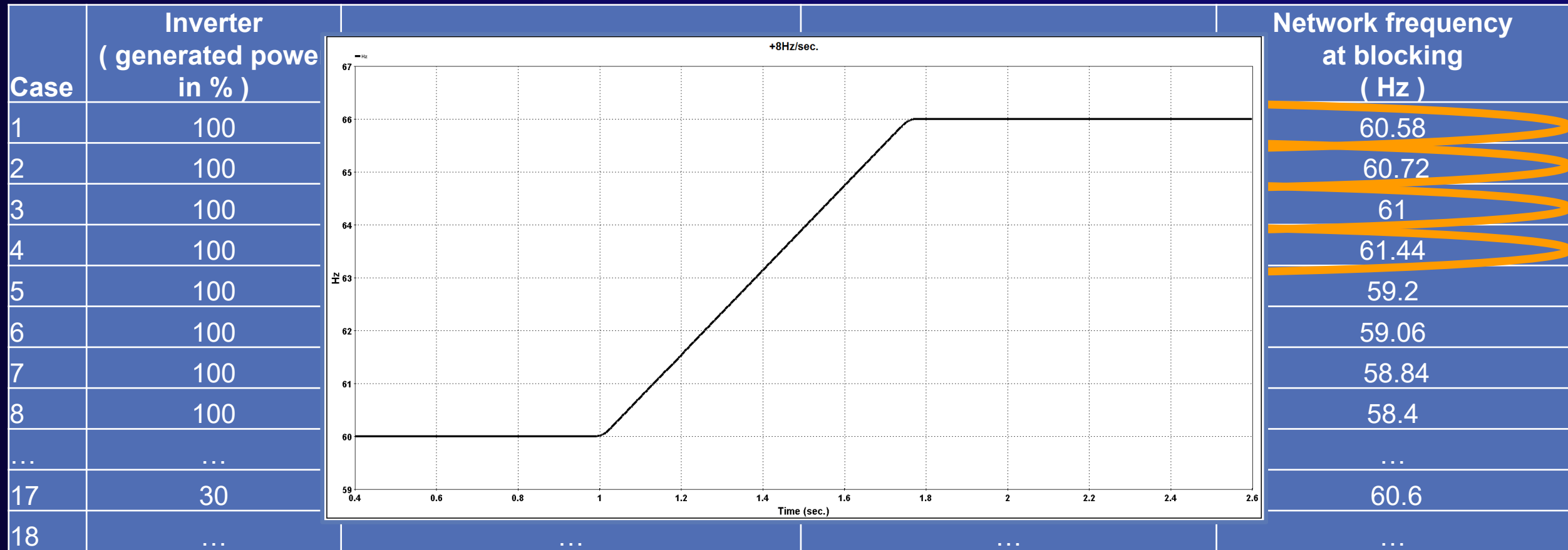
# LVRT



Dynamic LVRT

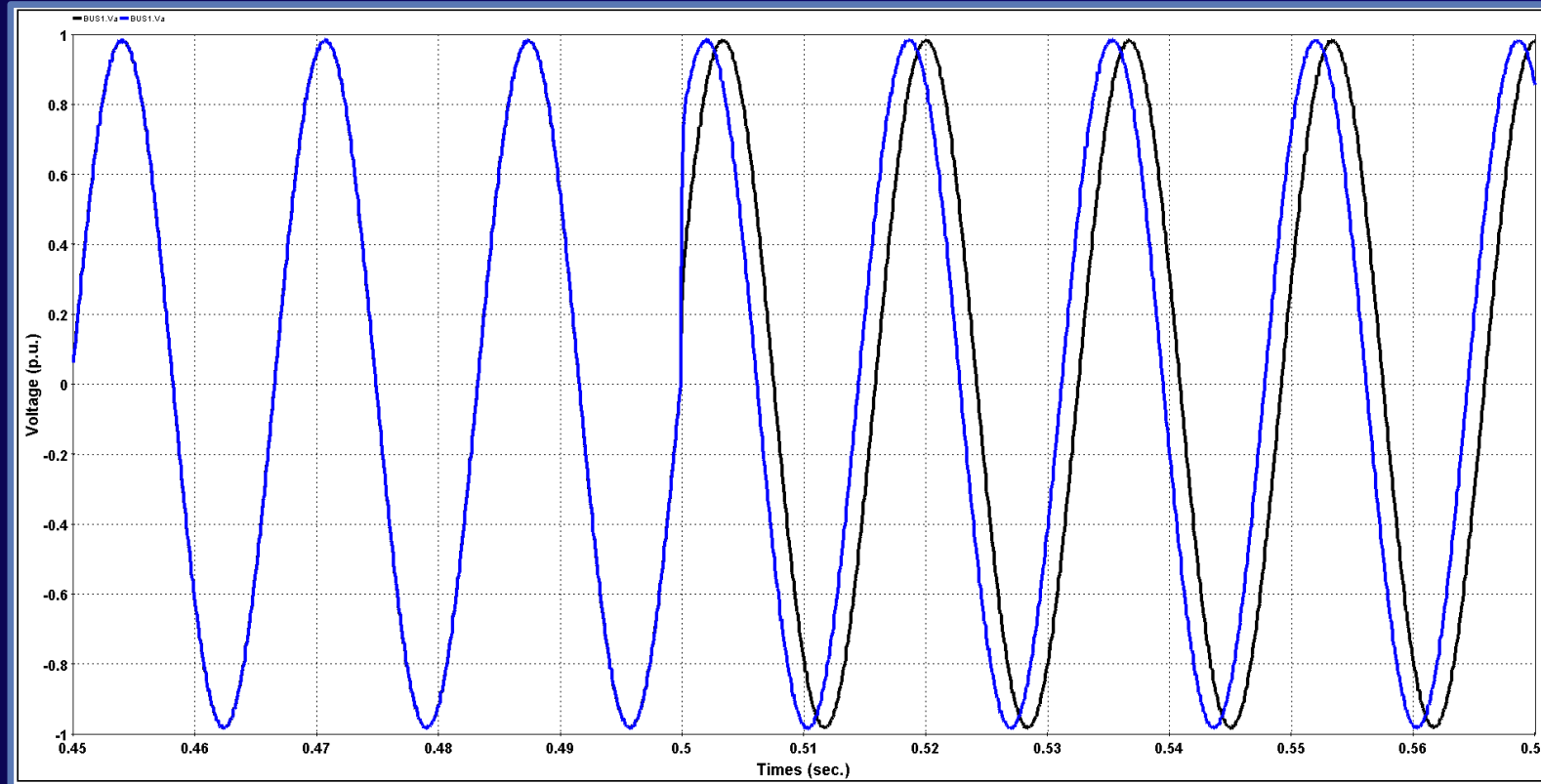


# Rate of change of frequency



The rate of change of frequency affects the delay before the inverter blocking or the total operating time of the frequency protection.

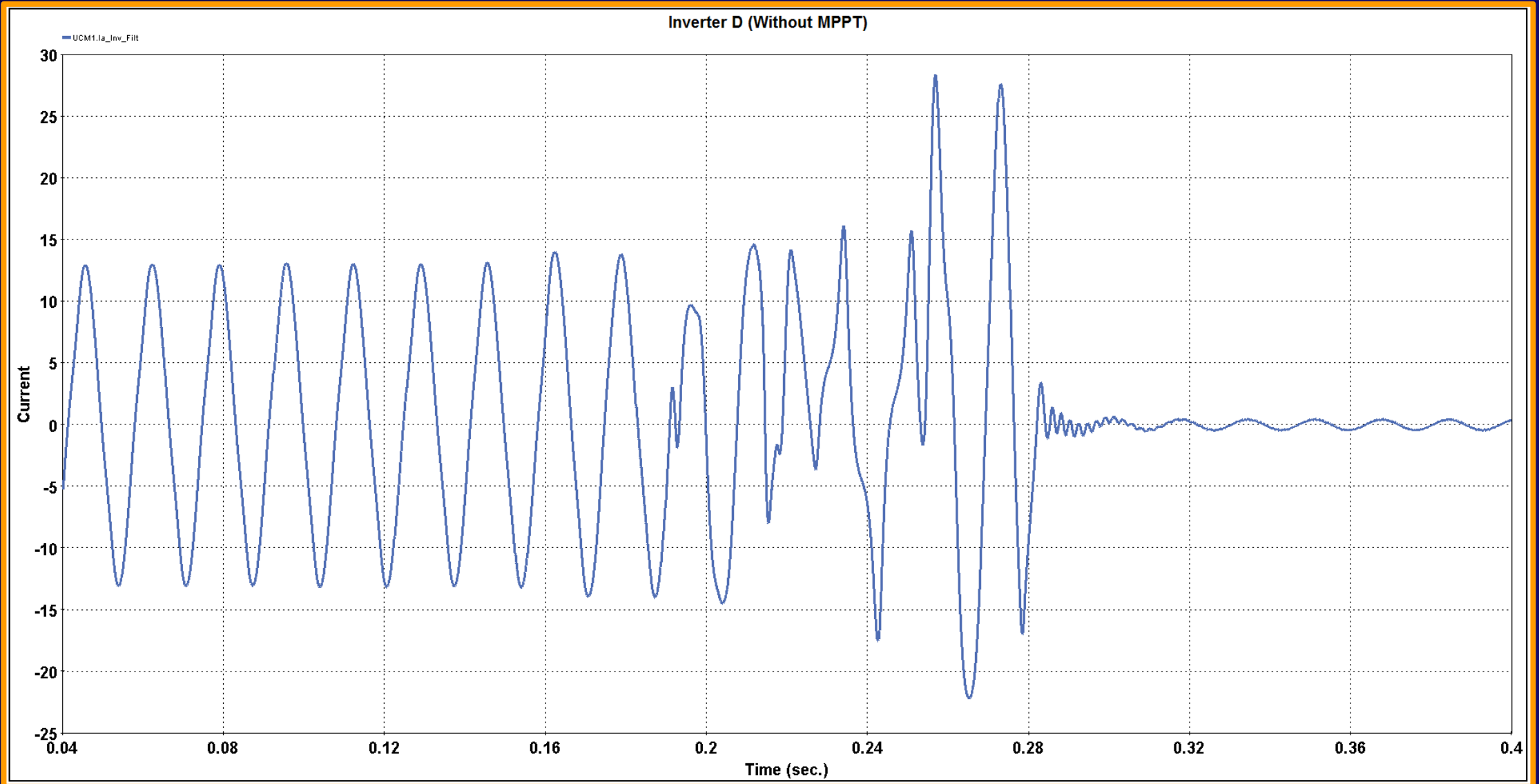
# Sudden voltage phase angle shift (15°, 30° and 45°)



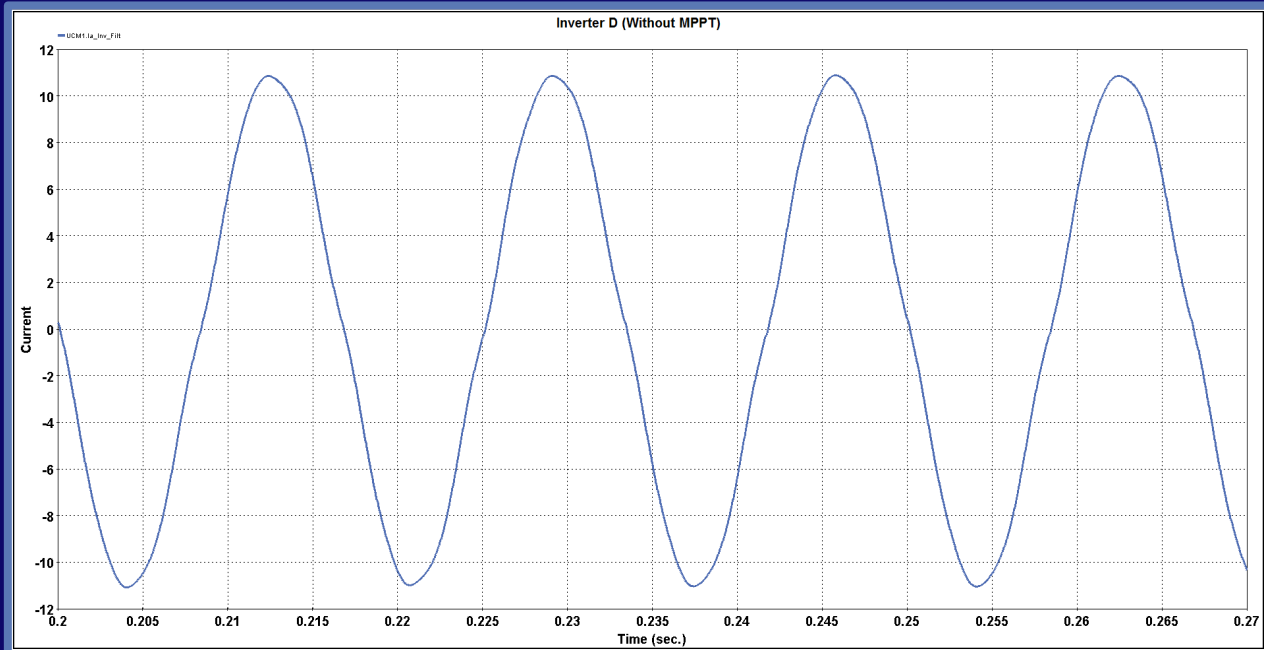
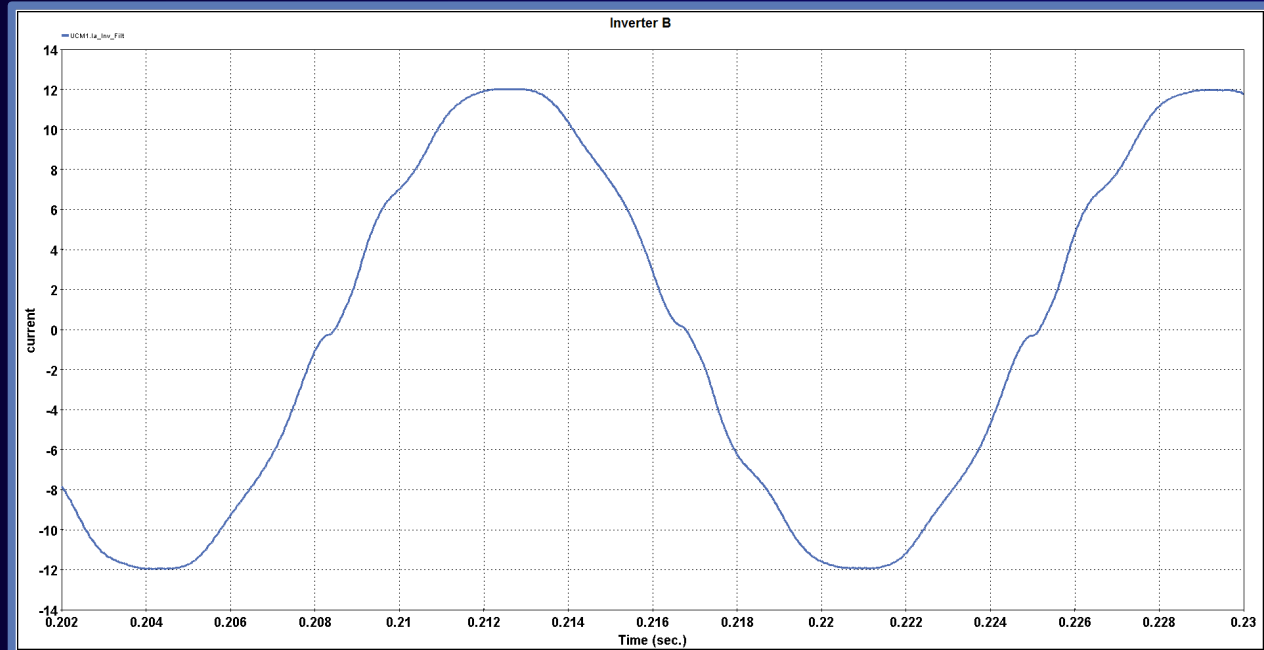
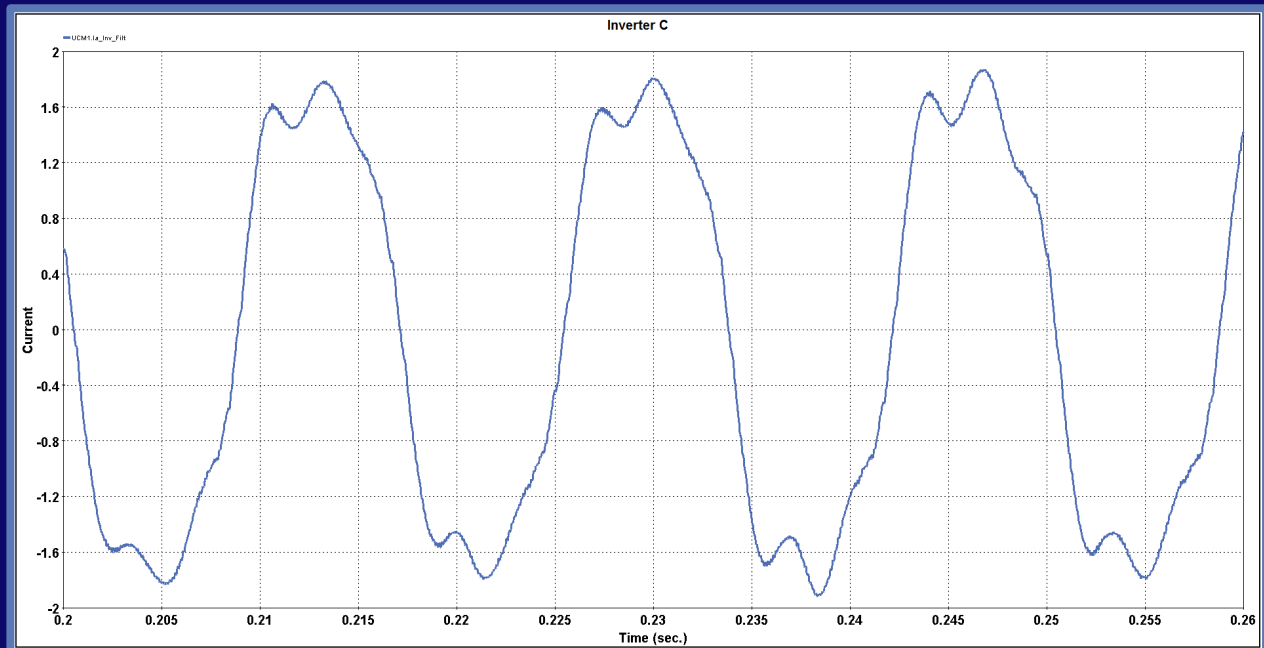
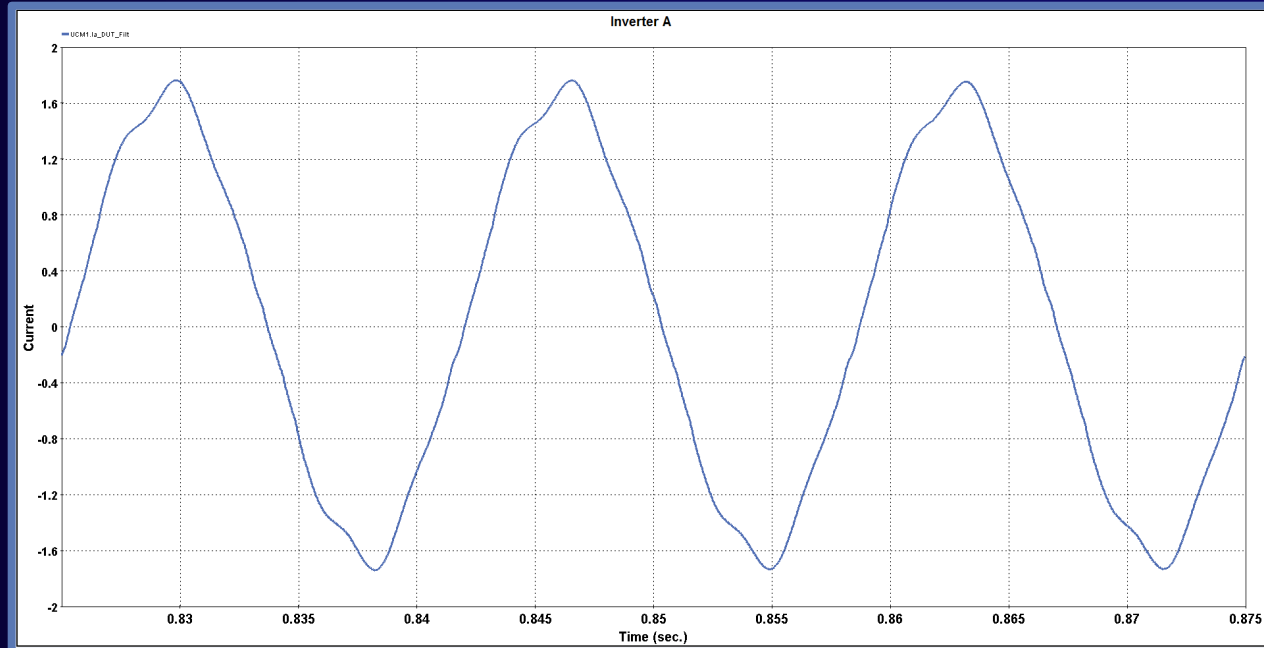
- 1 inverter block for a phase shift of 30° in 9msec.
- 2 inverters block for a phase shift of 45° in respectively 148msec. and 28 msec.
- 1 inverter did not block at 15, 30 and 45°

Weak source

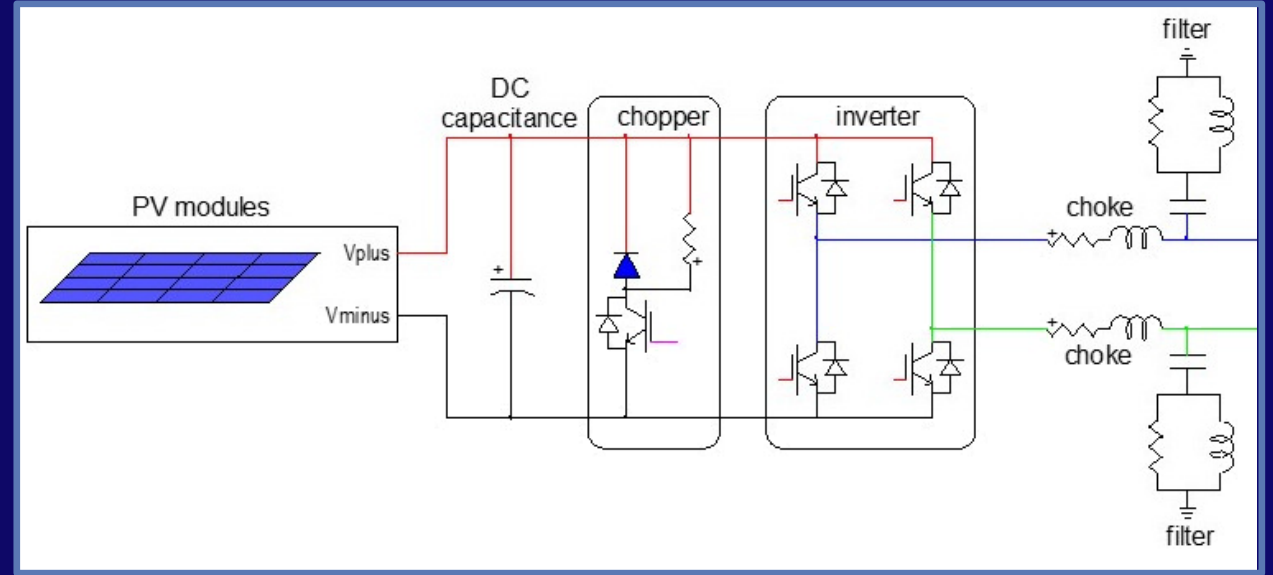
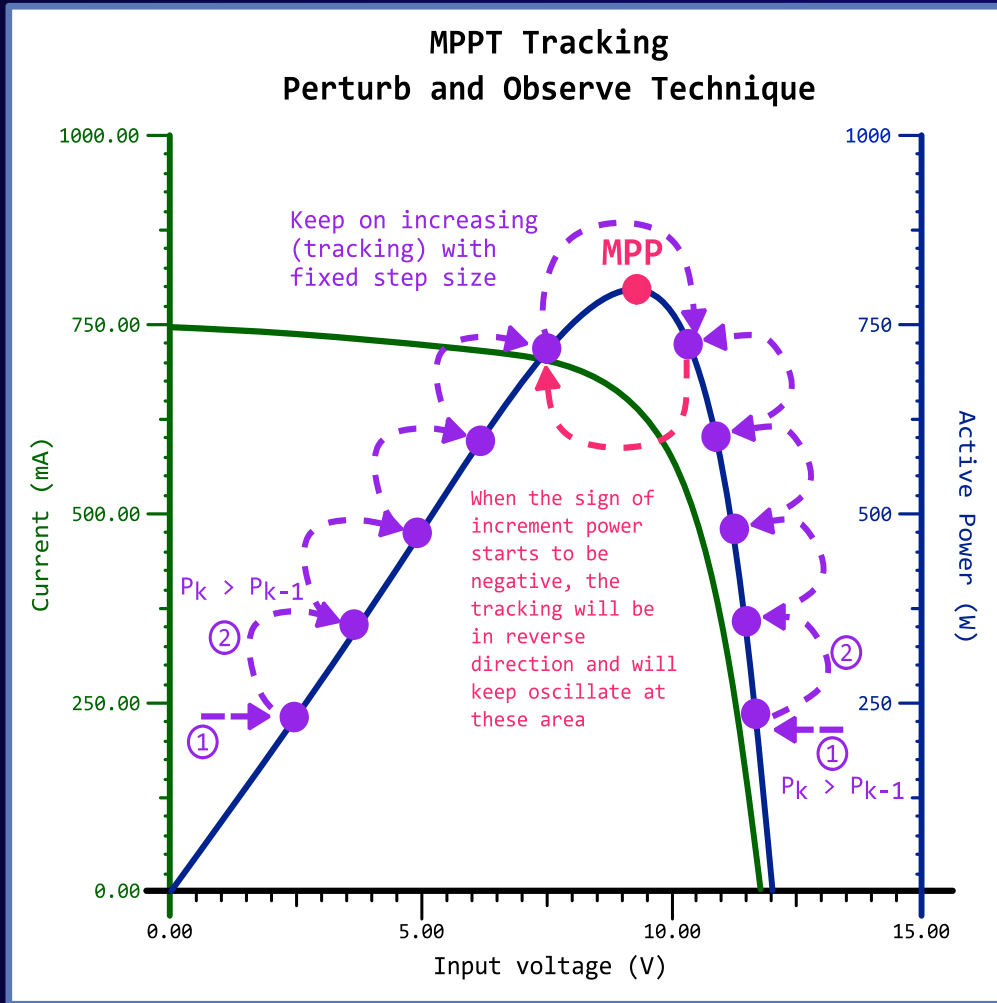
Increase network source impedance / until inverter trip or until a connexion incapacity  
Previous source impedance value = weak network condition



# Inverter connect to a weak source (steady state)



# Maximum power point tracking (MPPT)



- Nonlinear characteristic of the PV panel (V-I curve)
- The results suggest that the PV dynamic is influenced by the MPPT

# Linear analysis

# Linear analysis

PV inverter (DUT) is a “black box”

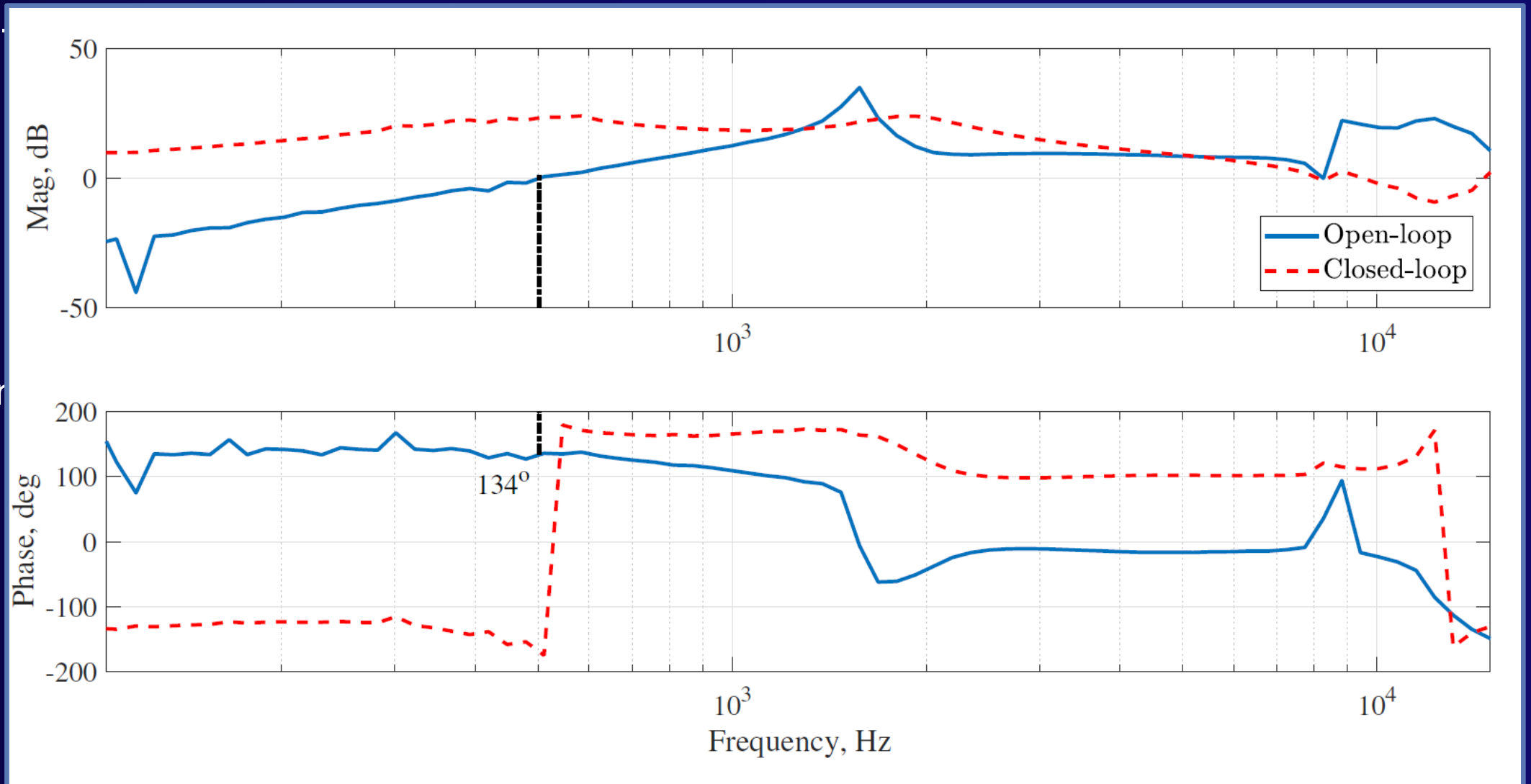
- Analytical (linearized) model not available

Frequency response was measured by the direct method

- Superimpose low level voltage modulation with frequency  $f$  on a fundamental
- Measure  $f$  component of DUT current
- Calculate impedance at  $f$
- Vary  $f$

# Linear analysis

Closed-loop



Gain ar

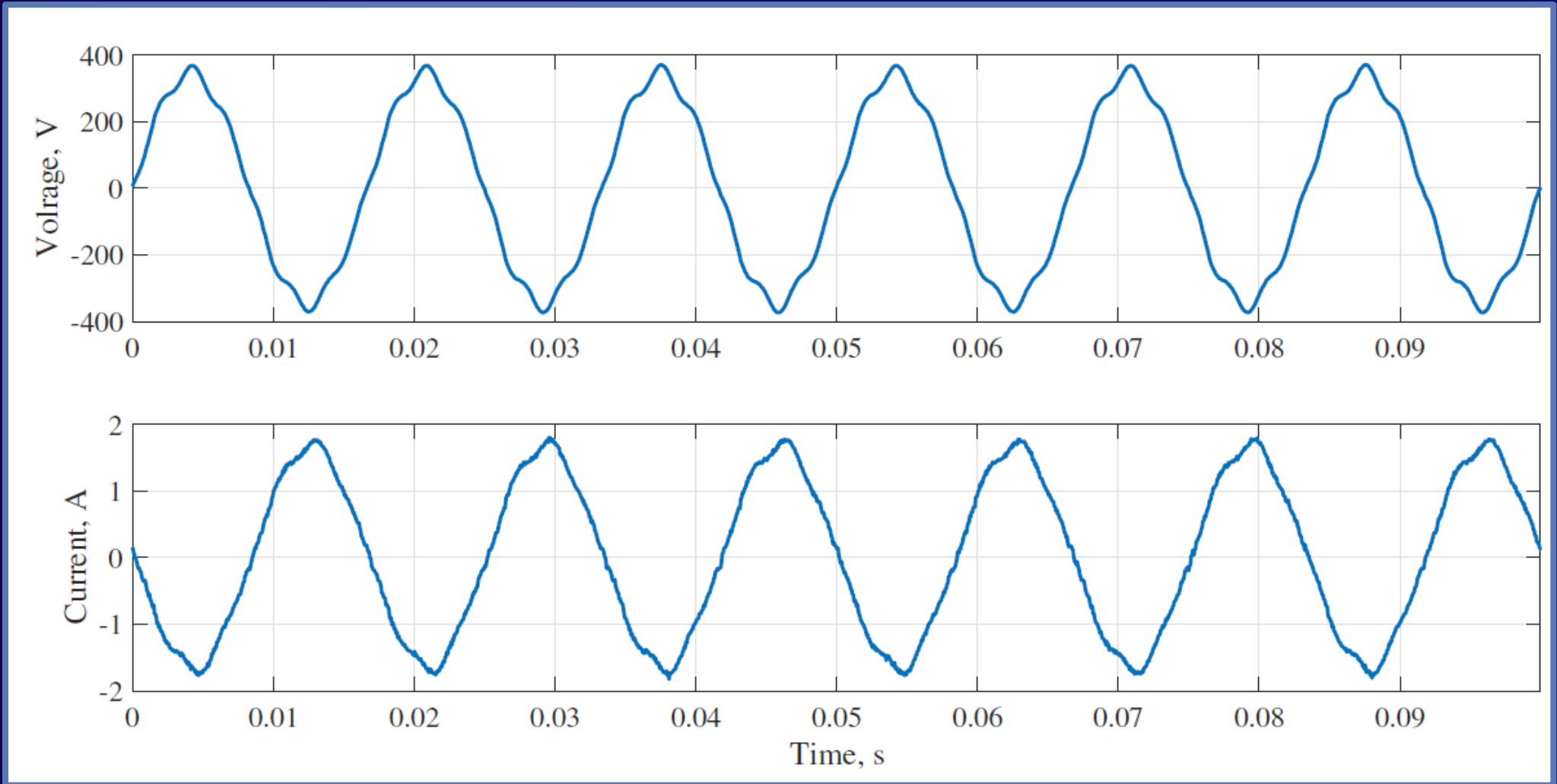
# Linear analysis

| ID | $n_r S_p$ |                      |          | $5S_p$               |          |
|----|-----------|----------------------|----------|----------------------|----------|
|    | $n_r$     | Phase margin,<br>deg | $f$ , Hz | Phase margin,<br>deg | $f$ , Hz |
| A  | 28        | 14                   | 546      | 29                   | 321      |
| B  | 27        | 21                   | 322      | 10                   | 127      |
| C  | 23        | 46                   | 502      | 25                   | 216      |
| D  | 6         | 29                   | 301      | 27                   | 301      |

- Gain margins were not determined (limited frequency range)
- Stability margins decrease as SCL decreases
- Frequency of resonance decreases as SCL decreases

$n_r$  : Short-circuit ratio between the point of connexion and the power produced by the inverter.  
SCL: Short-circuit level

# Experimental results, simple network



- Inverter A : Voltage distortion is observed
- Any small disturbance in the grid causes the inverter to trip

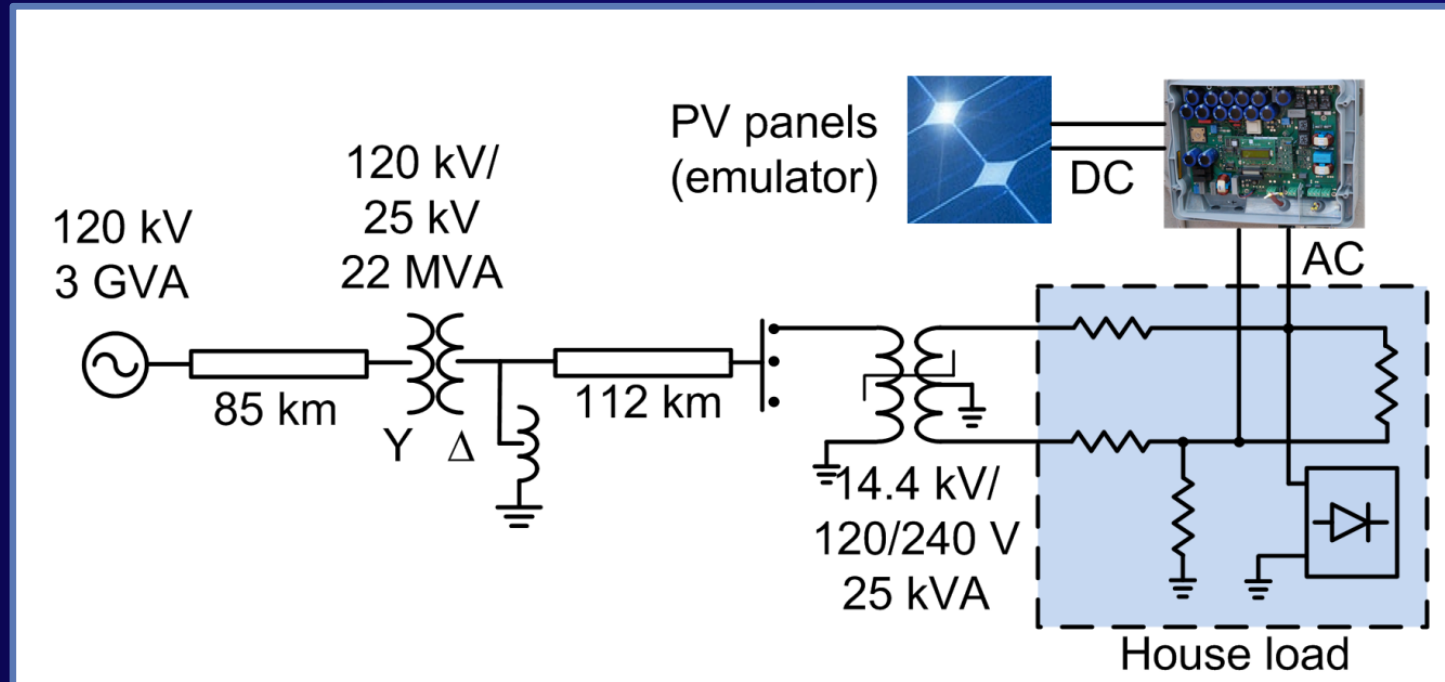
Model based on existing distribution feeder  
in rural Quebec

Low short circuit level  
+  
high PV penetration level

# Test results: distribution feeder model

Model based on existing distribution feeder in rural Quebec

- Includes nonlinear house load
- Variable number of houses (current multiplier)
- Low load, high PV production conditions with overall active power supplied to the grid



# Test results: distribution feeder model

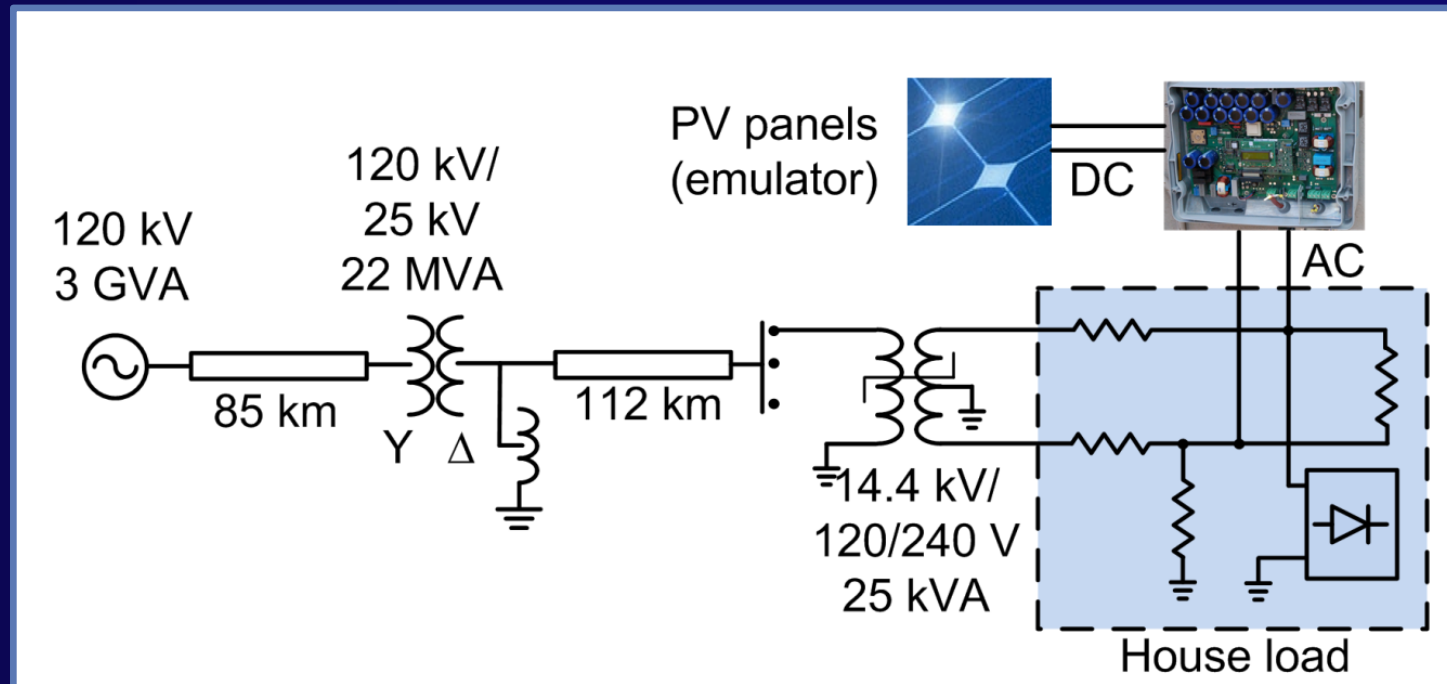
| ID | Number of houses | $n_r$ | Observed behavior                                                          |
|----|------------------|-------|----------------------------------------------------------------------------|
| A  | 10               | 140   | DUT voltage distortion, reconnection problems                              |
| B  | 41               | 34    | DUT voltage distortion, undamped DUT current oscillations at low frequency |
| C  | 4                | 250   | Sustained undamped DUT voltage and current oscillations                    |
| D  | 150              | 9     | DUT voltage waveform distortion                                            |

$n_r$  : Short-circuit ratio between the point of connexion and the power produced by the inverter.

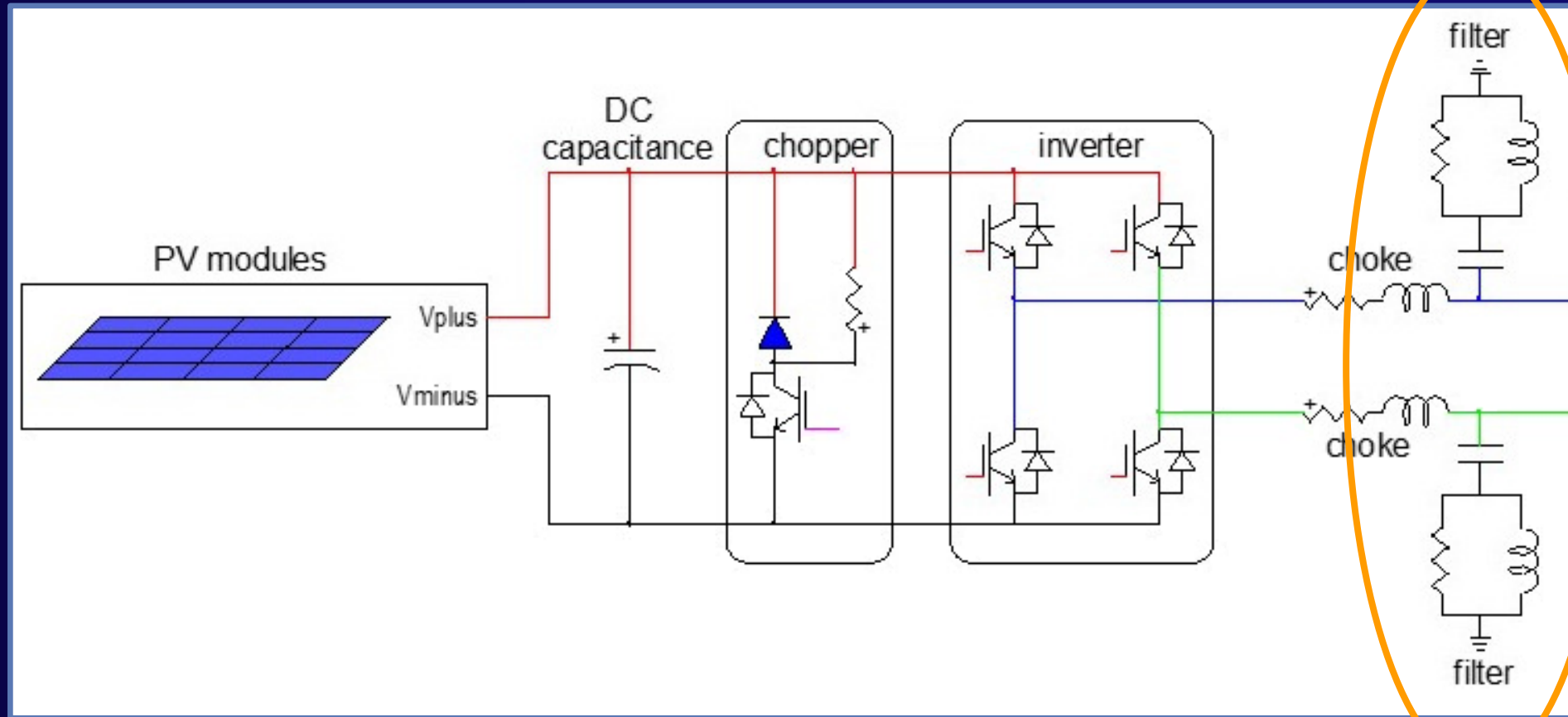
Source impedance / or penetration level = Resonant frequency \

Adverse effects of resonance conditions :

DUT voltage and current distortion, oscillation, reconnection problems, disconnection after a disturbance in the grid



# EMT generic model



- All inverters have filter to reduce switching harmonics.
- Some inverter have also an active filtering control strategy that can reduce low harmonics.
  - That reactive component plays a role in resonances observed in our tests.

# Conclusions

- Some commercially available residential PV inverters are better than others to meet voltage and frequency ride-through requirements. Overfrequency ride-through is challenging and the rate of change have to be consider.
- The nonlinear characteristics of the PV panel must be taken into account in models and simulations.
- Increasing the PV penetration level or decreasing the source strength can cause instability (resonances).
  - \* need to study summer network with high penetration level of PV and light load
  - \* a high penetration scenario can be specific to certain areas: a local network, a substation, a distribution line
- The MPPT and the filters are two important components to represent in the PV EMT (Electromagnetic transients) models to study resonances and instability observed.
- The residential load, mainly resistive, is moving to be more reactive. It has a destabilising effect.

# References

- [1] D. Rimorov, O. Tremblay, J-F Haché, V. Morissette, C. Desbiens, J. Lacroix, P-L Martel, « Power Hardware-in-the-loop testing of residential PV inverters in the conditions of weak network », IEEE PESGM, 2020.
- [2] O. Tremblay, H. Fortin-Blanchette, R. Gagnon, and Y. Brissette, “Contribution to stability analysis of power hardware-in-the-loop simulators,” IET Generation, Transmission & Distribution, vol. 11, no. 12, pp. 3073–3079, 2017.
- [3] O. Tremblay, D. Rimorov, R. Gagnon, and H. Fortin-Blanchette, “A multi-time-step transmission line interface for power hardware-in-the-loop simulators,” IEEE Transactions on Energy Conversion, pp. 1–1, 2019.



# ISO-NE Distribution-Connected Generation Interconnection, Modeling, & Study Procedures

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*NPCC DER Forum*

Brad Marszalkowski

SENIOR ENGINEER



# Purpose of the Presentation

- Provide guidance regarding the procedural and technical requirements for new Distribution-Connected Generation
- Discuss stakeholder coordination and Affected System Operator (ASO) Studies

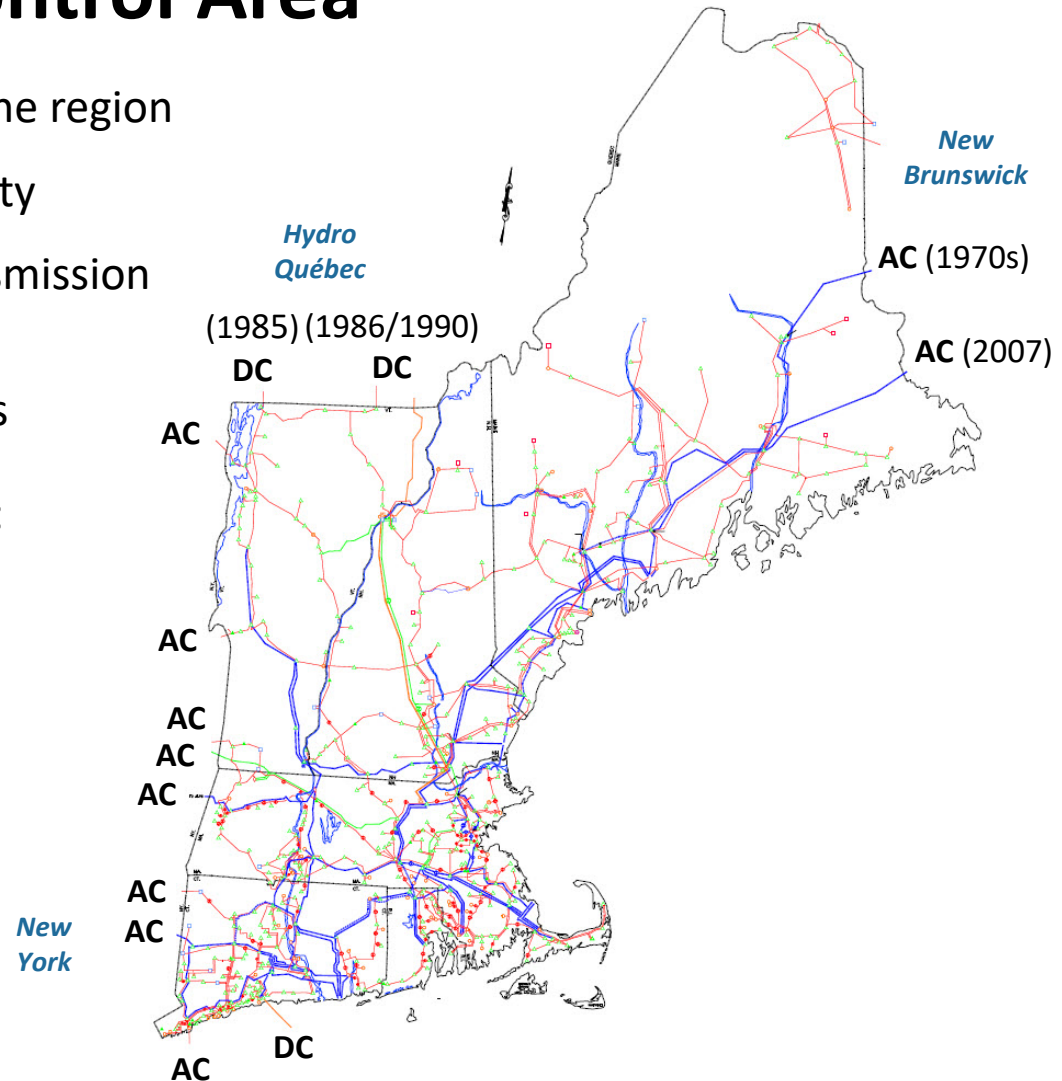


# BACKGROUND



# ISO New England Control Area

- **350** dispatchable generators in the region
- **31,200 MW** of generating capacity
- **9,000 miles** of high-voltage transmission lines (115 kV and above)
- **13** transmission interconnections to neighboring power systems in New York and Eastern Canada:
  - New York (8 AC ties, 1 DC tie)
  - Hydro Québec (2 DC ties)
  - New Brunswick (2 AC ties)
- Region's all-time summer peak demand set on August 2, 2006 at **28,130 MW**
- Region's all-time winter peak demand set on January 15, 2004 at **22,818 MW**



Note: AC stands for Alternating Current and DC stands for Direct Current

# TARIFF REQUIREMENTS



# What are FERC Jurisdictional Distribution Facilities?

# What are State Jurisdictional Distribution Facilities?

## FERC Jurisdictional Facilities

FERC jurisdictional Distribution Facilities are Distribution Facilities that are being used for FERC jurisdictional purposes (i.e., to facilitate sales of electricity at wholesale) and are subject to the ISO Tariff.

## State Jurisdictional Facilities

State jurisdictional Distribution Facilities are Distribution Facilities that are not being used for FERC jurisdictional purposes (i.e., to facilitate sales of electricity at wholesale).



**A Distribution-Connected Generator developer should contact the ISO or the owner of the Distribution Facilities to determine whether the facilities are state or FERC jurisdictional. The Distribution Company and the ISO will coordinate the identification of Jurisdiction – as necessary.**



# What interconnection process does a new Distribution-Connected Generator follow?

- The status of the distribution facility at the time of the interconnection request is a factor in determining which interconnection process applies
- A developer proposing to interconnect a Distribution-Connected Generator to a:
  - State jurisdictional Distribution Facility needs to follow the associated state interconnection process
  - FERC jurisdictional Distribution Facility needs to follow the ISO interconnection process under Schedule 22 or 23 of the OATT, as applicable



**The state interconnection process will apply if a Distributed-Connected Generator is interconnecting to a FERC jurisdictional facility and the project will:**

- **Produce energy to be consumed only on the retail customer's site,**
- **Not sell its energy into the ISO markets, or**
- **Sell 100% of its output as a Qualifying Facility to the interconnecting utility**



# What interconnection process applies to a generator that is being modified?

- A Distribution-Connected Generator that was interconnected under the state interconnections process and is now being modified needs to follow the state interconnection process if the Distribution Facility to which it is connected is still state jurisdictional
  - Otherwise, they would need to follow the ISO interconnection process under Schedule 22 or 23 of the OATT
- A Distribution-Connected Generator that was interconnected under the FERC interconnection process and is now being modified needs to follow the ISO interconnection process under Schedule 22 or 23 of the OATT
  - A request to participate in the ISO markets for an existing behind-the-meter generator may trigger the ISO interconnection process



# To Whom does a new Distribution-Connected Generator apply?

## If subject to the ISO interconnection process

Interconnections that are subject to the ISO's interconnection process are administered in accordance with Schedules 22 and 23 of the OATT

- Interconnection request forms are available electronically in the Interconnection Request Tracking Tool (IRTT), which is located on the ISO Website
  - A requestor must create an account in IRTT in order to gain access
- Interconnection requests are completed within and submitted to the ISO using the IRTT

## If subject to the state interconnection process

State jurisdictional interconnection applications are available from the Distribution Company/owner of the state jurisdictional Distribution Facility

- Completed applications are to be submitted to the Distribution Company/owner of the state jurisdictional Distribution Facilities



# What type of Interconnection Service may be requested under Schedules 22 and 23?

- There are two levels of Interconnection Service available under Schedules 22 and 23:
  - Network Resource Interconnection Service (energy); and
  - Capacity Network Resource Interconnection Service (energy and capacity)
- All Distribution-Connected Generators that interconnect under Schedules 22 and 23 are eligible to participate in the ISO markets
- Depending on the purpose of the interconnection, a Distribution-Connected Generator that interconnected under state interconnection procedures may be eligible to participate in the ISO markets
  - E.g., a generator interconnected behind the meter or for retail consumption does not have the interconnection rights to put power onto the grid



# Proposed Plan Approval (I.3.9)

- In addition to an interconnection request submittal, a new Distribution-Connected Generator or a modification to an existing Distribution-Connected Generator resulting in an increase or a change in its operating characteristics may need to submit a Proposed Plan Application pursuant to Section I.3.9 of the Tariff
  - This is true regardless of the jurisdiction of the interconnection process
  - If the Generator Owner is not a Market Participant, the interconnecting Transmission Owner will submit on the generator's behalf
- Distribution-Connected Generators that are 5 MW require a proposed plans application
- Distribution-Connected Generators that are 1 MW to less than 5 MW may only require a less than 5 MW Notification Form
- Distribution-Connected Generators that are less than 1 MW do not have an I.3.9 requirement



# STAKEHOLDER COORDINATION & DATA COLLECTION



# Coordination Practices

- **Stakeholder Review & Information Exchange**
  - New interconnections (>1MW) must submit either a Small Generator Notification or Proposed Plan Application regardless of POI
  - Interconnections are channeled through the Reliability Committee which allows affected parties to have a chance to voice concerns (I.3.9 process)
  - Transmission System Impact Studies (SIS) sometimes needed based on size or location of interconnection
- **What we do with the information**
  - Tracking DER interconnections
  - Determination of study requirements
  - Data from forms and SIS used in steady state and dynamics modeling



## 9.0 Attachment 3 – Generator Notification Form for Units or Changes of Less Than 5 MW

ISO NEW ENGLAND GENERATOR NOTIFICATION FORM FOR  
UNITS OR CHANGES OF LESS THAN 5 MW

ISO New England Planning Procedure 5-1

Page 1 of 4

Submit Completed Form to [ProposedPlans@iso-ne.com](mailto:ProposedPlans@iso-ne.com)Contact Customer Service at 413-540-4220 or [custserv@iso-ne.com](mailto:custserv@iso-ne.com) to begin market system asset registration process

Applicant \_\_\_\_\_ Date \_\_\_\_\_  
 Generation Owner (if different than Applicant) \_\_\_\_\_  
 Contact Person \_\_\_\_\_  
 Phone # (\_\_\_\_) \_\_\_\_\_ Fax # (\_\_\_\_) \_\_\_\_\_ E-mail \_\_\_\_\_

1. Station Name \_\_\_\_\_
- a. Location/Interconnection Point (Indicate point of coupling with utility system by specifying distribution feeder or transmission line name(s) or substation name. Distribution facilities should include the transmission facility substation(s) that the distribution facilities are supplied from.)  
 \_\_\_\_\_
- b. Address of Plant  
 Street Address \_\_\_\_\_  
 Town or City \_\_\_\_\_  
 County \_\_\_\_\_ State \_\_\_\_\_ Zip Code \_\_\_\_\_
- c. Unit/Aggregate Generation Asset Identification \_\_\_\_\_

Net ratings entered in below should reflect the netting of auxiliary loads from the gross unit rating(s) that are directly related to the operation of the unit/aggregate generation.

|                            | Winter<br>(0 or higher Deg F)* | Winter<br>(20 Deg F) | Summer<br>(50 or higher Deg F)** | Summer<br>(90 Deg F) |
|----------------------------|--------------------------------|----------------------|----------------------------------|----------------------|
| Gross Unit Rating (MW)     |                                |                      |                                  |                      |
| Net Unit Rating (MW)       |                                |                      |                                  |                      |
| Unit Rating (Lagging MVAR) |                                | N/A                  |                                  |                      |
| Unit Rating (Leading MVAR) |                                | N/A                  |                                  |                      |

\* Enter all values in this column corresponding to the temperature of 0 degree F or greater at which gross facility output will be the highest. As an example, if the maximum gross facility output occurs at 12 degrees F, all values in this column shall correspond to the 12 degree F operating condition.

\*\* Enter all values in this column corresponding to the temperature of 50 degrees F or greater at which net unit facility output will be the highest. As an example, if the maximum net facility output occurs at 67 degrees F, all values in this column shall correspond to the 67 degree F operating condition.

Application Identification No. \_\_\_\_\_

d. What is the maximum net power injection at the point of interconnection? \_\_\_\_\_

- e. Is there load reduced by operating this generation? (Check Yes or No) ☐ Yes ☐ No  
 If "Yes:"

By how much is the load reduced? \_\_\_\_\_

Where is the load located? \_\_\_\_\_

2. Type of Application (Check one)

☐ Construction ☐ Capacity Change

3. Requested Commercial Operation Date \_\_\_\_\_

4. Is the unit equipped with under-frequency protection? (Check yes or no) ☐ Yes ☐ No

If "Yes:"

- a. Has the host utility reviewed the settings? ☐ Yes ☐ No

- b. Will the unit be tripped for under-frequency conditions in the area above the curve in Figure 1 of Standard PRC-006-NPCC? ☐ Yes ☐ No

- i. If "Yes," has additional automatic load shedding been provided equivalent to the amount of generation to be tripped? ☐ Yes ☐ No

- c. Will the unit be tripped in conjunction with dropping low voltage feeder during load shedding? ☐ Yes ☐ No

- i. If "Yes," has the host utility ensured that sufficient automatic load shedding capability will be available to system operators? ☐ Yes ☐ No

Note: A "No" response to b.i or c.i is grounds for rejection.

5. Provide the following information on fuel used by the unit.

- a. List the unit's primary energy source code (from "Energy Sources" listed on the following page)  
 \_\_\_\_\_

- b. List the unit's secondary energy source code (from "Energy Sources" listed on the following page)  
 \_\_\_\_\_

6. Will the unit have black start capability? (Check Yes or No) ☐ Yes ☐ No

If "Yes," can it be operated on its own auxiliaries prior to synchronization with the system? ☐ Yes ☐ No

7. Provide the following information on the interconnection point.

- a. Specify the interconnection bus name and the voltage level the unit is connected to.  
 \_\_\_\_\_

- b. Specify the modeled PSS/E bus name and number that is electrically closest to where the unit is interconnected.  
 \_\_\_\_\_

(Check the appropriate box and provide appropriate diagram(s))

☐ The unit is connected to the power system at transmission voltage (69 kV or higher). Provide an electrical one-line diagram showing all essential devices including GSU impedance, station arrangements, station service and connections to the bulk power system, including the voltage levels below 69 kV.

☐ The unit is connected to the distribution system. Provide one-line diagram(s) showing the unit connection and where the distribution network connects to the bulk power system.

8. Has an interconnection request been submitted for the new unit or change of less than 5 MW? Yes ☐ No ☐

- a. If "Yes," when was the interconnection request submitted and to whom?  
 \_\_\_\_\_

- b. If "No," when will the interconnection request be submitted and to whom?  
 \_\_\_\_\_

## 7.0 Attachment 1 – Generation Proposed Plan Application

## GENERATION PROPOSED PLAN APPLICATION

ISO New England Planning Procedure 5-1

Page 1 of 2

Applicant \_\_\_\_\_ Date \_\_\_\_\_

Contact Person \_\_\_\_\_ Phone \_\_\_\_\_

1. Station Name and Location \_\_\_\_\_

Unit Identification \_\_\_\_\_

|                            | Winter<br>(0 or higher Deg F)* | Winter<br>(20 Deg F) | Summer<br>(50 or higher Deg F)** | Summer<br>(90 Deg F) |
|----------------------------|--------------------------------|----------------------|----------------------------------|----------------------|
| Gross Unit Rating (MW)     |                                |                      |                                  |                      |
| Net Unit Rating (MW)       |                                |                      |                                  |                      |
| Unit Rating (Lagging MVAR) |                                | N/A                  |                                  |                      |
| Unit Rating (Leading MVAR) |                                | N/A                  |                                  |                      |

\* Enter all values in this column corresponding to the temperature of 0 degrees F or greater at which gross facility output will be the highest. As an example, if the maximum gross facility output occurs at 12 degrees F, all values in this column shall correspond to the 12 degree F operating condition.

\*\* Enter all values in this column corresponding to the temperature of 50 degrees F or greater at which net facility output will be the highest. As an example, if the maximum net facility output occurs at 67 degrees F, all values in this column shall correspond to the 67 degree F operating condition.

2. Type of Application

☐ Construction ☐ Capacity Change

3. Requested Commercial Operation Date \_\_\_\_\_

4. Will the facility be equipped with a functioning governor? ☐ Yes ☐ No (A "No" response may be grounds for rejection pursuant to OP 14.)5. Is the unit equipped with under-frequency protection? ☐ Yes ☐ No

If "Yes:"

a. Has the host utility reviewed the settings? ☐ Yes ☐ Nob. Will the unit be tripped for under-frequency conditions in the area above the curve in Figure 1 of Standard PRC-006-NPCC? ☐ Yes ☐ Noi. If "Yes," has additional automatic load shedding been provided equivalent to the amount of generation to be tripped? ☐ Yes ☐ No

Application Identification No. \_\_\_\_\_

Revision 12

ISO-NE Public

16

## GENERATION PROPOSED PLAN APPLICATION

ISO New England Planning Procedure 5-1

Page 2 of 2

c. Will the unit be tripped in conjunction with dropping low voltage feeders during load shedding?

☐ Yes ☐ Noi. If "Yes," has the host utility ensured that sufficient automatic load shedding capability will be available to system operators? ☐ Yes ☐ No

Note: A "No" response to b.i or c.i is grounds for rejection.

6. Provide the following information on fuel used by the unit

a. List the unit's primary fuel \_\_\_\_\_ and secondary fuel \_\_\_\_\_.

7. Will the unit have black start capability? ☐ Yes ☐ Noa. If "Yes," can it be operated on its own auxiliaries prior to synchronization with the system? ☐ Yes ☐ No

8. Attach an electrical one-line diagram showing all essential devices including GSU impedance, station arrangements, station service and connections to the transmission system (69 kV and higher), including the voltage levels.

9. Is a Transmission Proposed Plan Application required? ☐ Yes ☐ No

a. If "Yes," identify the Transmission Applications associated with this Application, the Governance Participant responsible for filing and the date the Application was/will be submitted.

10. System Reliability Studies

Short Circuit ☐ Completed ☐ Planned ☐ Not NeededLoad Flow ☐ Completed ☐ Planned ☐ Not NeededStability ☐ Completed ☐ Planned ☐ Not NeededOther \_\_\_\_\_ ☐ Completed ☐ Planned ☐ Not Needed

Application Identification No. \_\_\_\_\_

Revision 12

ISO-NE Public

17

ISO-NE PUBLIC

15

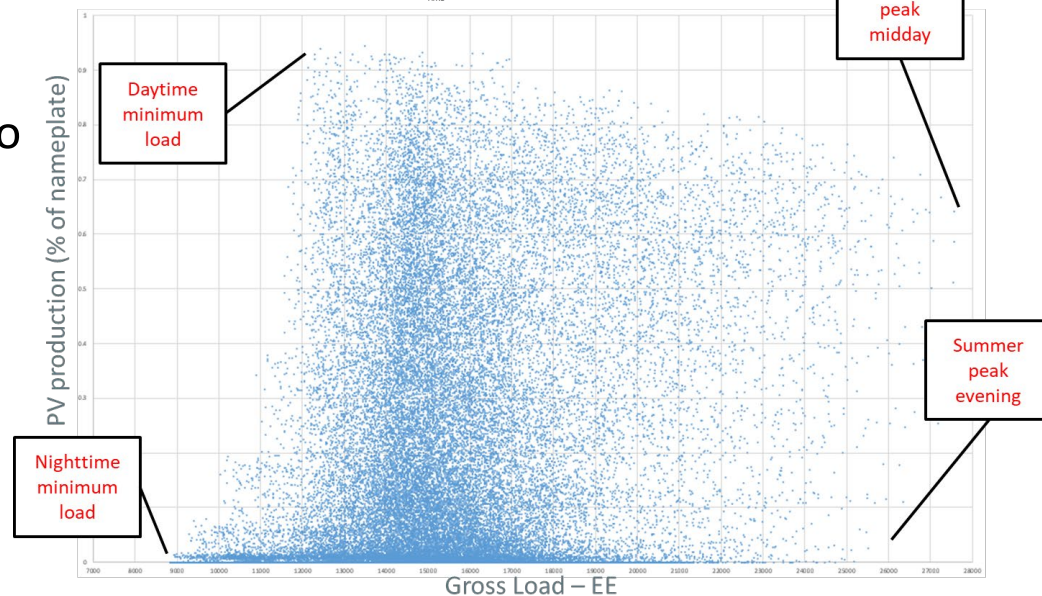
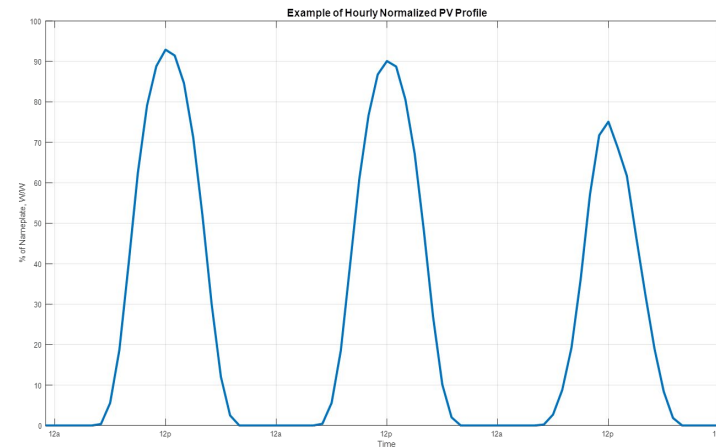
# ISO-NE DER MODEL DEVELOPMENT



# Study Conditions/Assumptions

*Modeling assumptions within dynamics cases*

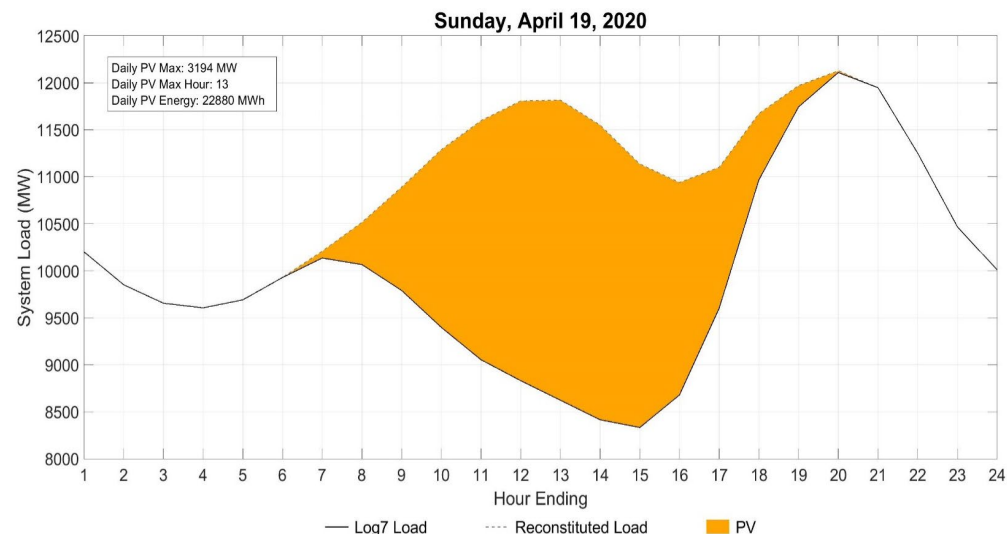
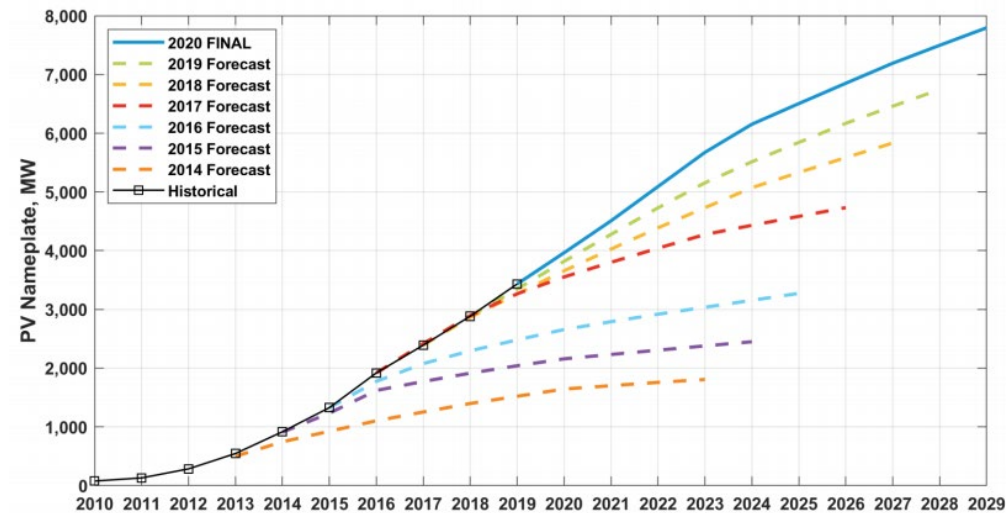
- DER in NE primarily solar
  - Normalized PV profiles used
  - Fractional value multiplied by nameplate of PV installation for total output
- Battery Energy Storage
  - Operational Characteristics such as charging and discharging
  - State of Charge (SOC) can also be important
- Time of year
  - PV outputs differ based on available irradiance which differs based on time of year
  - Gross loads and DER penetration levels



# Study Conditions/Assumptions

*Modeling assumptions within dynamics cases (cont.)*

- Year of Study
  - DER penetration increasing as states continue to solar incentives
  - Utilization of synchronous units decreasing, and retirements more likely, as load is reduced
  - DER mix will change based on study year
  - DER interconnection requirements are dependent on year project applied (IEEE 1547-2003, IEEE 1547-2018, ISO-SRD, etc)



# DER Modeling Practices

## U-DER & R-DER Modeling assumptions

- DER (MW  $\geq 5$ )
  - Referred to as U-DER
  - Explicitly tracked & modeled as generators in cases
  - Use NERC & WECC modeling guidelines and equivalencies
  - Specific dynamic models to be provided by developer (2<sup>nd</sup> gen renewable energy models)
- DER (1 < MW < 5)
  - Generally referred to as R-DER
  - Locational data is tracked (both address and electrical interconnection)
  - Modeled at low side of distribution bus
  - DER\_A model is used and parametrized based on requirements coincident with application approval date
- DER (MW  $\leq 1$ )
  - Referred to as R-DER with unknown location
  - Output values come from PV forecast
  - Currently modeled as negative loads distributed across dispatch zones and normalized according to load at each bus
  - No dynamic models are added

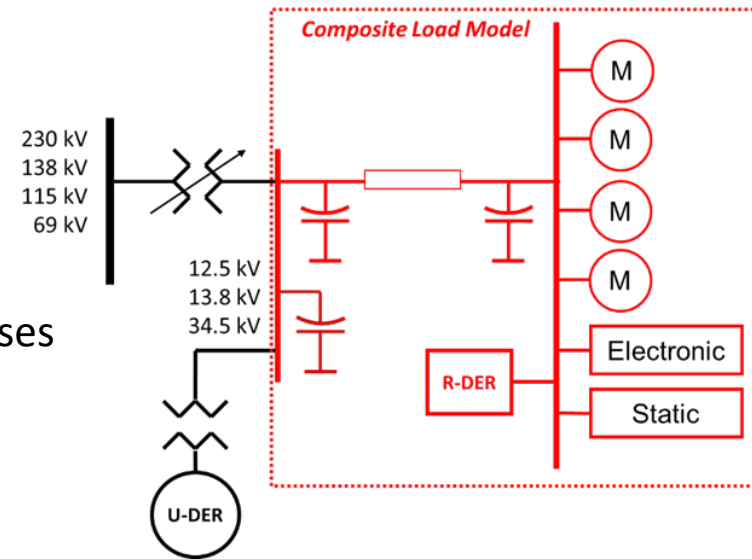


Table 2.1: Default DER\_A Model Parameters

| Param <sup>no</sup> | IEEE Std. 1547-2003 Default | IEEE Std. 1547a-2014 Default | CA Rule 21 Default     | IEEE Std. 1547-2018 Category II Default | Notes    |
|---------------------|-----------------------------|------------------------------|------------------------|-----------------------------------------|----------|
| trv                 | 0.02                        | 0.02                         | 0.02                   | 0.02                                    | † Note 1 |
| dbd1                | -99                         | -99                          | -99                    | -99                                     | † Note 1 |
| dbd2                | 99                          | 99                           | 99                     | 99                                      | † Note 1 |
| kqv                 | 0                           | 0                            | 0                      | 0                                       | † Note 1 |
| vref0               | 0                           | 0                            | 0                      | 0                                       | † Note 2 |
| tp                  | 0.02                        | 0.02                         | 0.02                   | 0.02                                    | †        |
| tiq                 | 0.02                        | 0.02                         | 0.02                   | 0.02                                    | †        |
| ddn                 | 0                           | 0                            | 20                     | 20                                      | Note 3   |
| dup                 | 0                           | 0                            | 20                     | 20                                      | Note 3   |
| fbd1                | -99                         | -99                          | -0.0006                | -0.0006                                 | Note 3   |
| fbd2                | 99                          | 99                           | 0.0006                 | 0.0006                                  | Note 3   |
| femax               | 0                           | 0                            | 99                     | 99                                      | Note 3   |
| femin               | 0                           | 0                            | -99                    | -99                                     | Note 3   |
| pmax                | 1                           | 1                            | 1                      | 1                                       | † Note 4 |
| pmin                | 0                           | 0                            | 0                      | 0                                       | Note 4   |
| dpmx                | 99                          | 99                           | 99                     | 99                                      | †        |
| dpmn                | -99                         | -99                          | -99                    | -99                                     | †        |
| tpord               | 0.02                        | 0.02                         | 5                      | 5                                       | Note 3   |
| imax                | 1.2                         | 1.2                          | 1.2                    | 1.2                                     | † Note 4 |
| vl0                 | 0.44                        | 0.44                         | 0.49                   | 0.44                                    | Note 5   |
| vl1                 | 0.44+V <sub>base</sub>      | 0.44+V <sub>base</sub>       | 0.49+V <sub>base</sub> | 0.44+V <sub>base</sub>                  | Note 5   |
| vh0                 | 1.2                         | 1.2                          | 1.2                    | 1.2                                     | Note 5   |
| vh1                 | 1.2-V <sub>base</sub>       | 1.2-V <sub>base</sub>        | 1.2-V <sub>base</sub>  | 1.2-V <sub>base</sub>                   | Note 5   |
| tv0                 | 0.16                        | 0.16                         | 1.5                    | 0.16                                    | Note 5   |
| tv1                 | 0.16                        | 0.16                         | 1.5                    | 0.16                                    | Note 5   |
| tvh0                | 0.16                        | 0.16                         | 0.16                   | 0.16                                    | Note 5   |
| tvh1                | 0.16                        | 0.16                         | 0.16                   | 0.16                                    | Note 5   |

\*Reference [https://www.nerc.com/comm/PC\\_Reliability\\_Guidelines\\_DL/Reliability\\_Guideline\\_DER\\_A\\_Parameterization.pdf](https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf)

# DER Modeling Practices

## *U-DER & R-DER Modeling assumptions (cont.)*

- Voltage/Frequency control modes
  - Most DER's installed without reactive power output, or at fixed PF as voltage/frequency control is often not allowed on feeders
  - Both 2<sup>nd</sup> generation WECC models and DER\_A model support voltage and frequency control setups for the few that do
- Constant power factor mode
  - Power factor equal to 1 in most cases
    - Modeling of R-DER in loadflow requires adjustment of DER (P & Q) to account for avoided distribution losses and maintain planned power factors of TOs/DOs at distribution transformers
- Distribution Loss Assumption
  - Current assumption of transmission and distribution losses is 8%
    - Transmission – 2.5% (calculated by PSSE)
    - Distribution – 5.5% (included in calculation of loads)
  - Increased penetration of DER on distribution feeders can change distribution losses



# AFFECTED SYSTEM OPERATOR STUDIES



# Why is it important to study Distribution-Connected Generation?

- Overall bulk system ride-through performance
  - No individual project of 5 MW or greater, nor more than 20 MW of dispersed energy resources can trip offline for a design contingency per ISO-NE Planning Procedure 3
- (Possible) Provision of bulk system Essential Reliability Services such as voltage and frequency response
  - Projects 1 MW and greater registering in the markets may need to provide voltage control per ISO Operating Procedure 14 (OP-14)
  - Projects 10 MW and greater registering in the markets must provide frequency control per ISO Operating Procedure 14 (OP-14)
  - TO may have their own requirements for units that are not registered in the markets
- Impacts on transmission connected generators
  - Reduced system strength due to fewer online synchronous resources
- Impacts on specific transmission equipment or system performance caused by large accumulations of distribution-connected generators at specific substations



# Overall Bulk System Ride-Through Performance

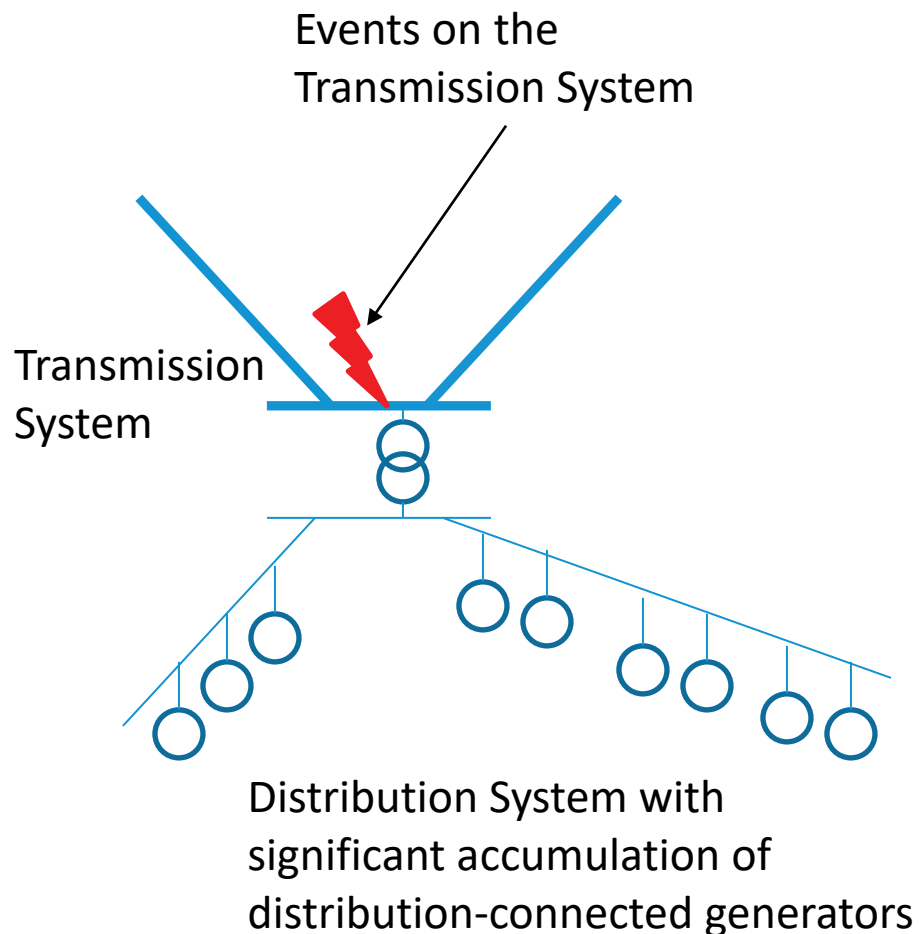
*Addressed through interim IEEE 1547 Implementation*

- ISO New England plans and operates the transmission system to ensure that the **loss of a large source of supply** (source loss) does not adversely impact the reliability of the Eastern Interconnection
- Historically, the concern has been source loss due to large generators being disconnected or going unstable and tripping
- Tripping of large quantities of distributed energy resources (DER) for a transmission fault would add to source loss
- If total source loss exceeds the amount allowed by the planning criteria, a system upgrade would be required, and this could **negatively impact** the benefits of state policies to encourage renewable energy
- The acceptable maximum source loss is limited by New England's interconnections to other regions to **approximately 1,200 MW** for normal design contingencies



# Bulk System Essential Reliability Services

*To be addressed through the full implementation of IEEE 1547*



- Future system operation conditions may include scenarios where the majority of on-line generation will be distribution-connected
- The bulk system must still exhibit stable voltage and frequency responses to system events
- Essential reliability services such as voltage and frequency response may be provided by distributed generation – OR – additional upgrades may be required on the transmission system

# Study Requirements

*Per ISO-NE Planning Procedures 3, 5-1, 5-3, & 5-6*

- Affected system operator studies are required by the planning procedures
- All individual non-FERC jurisdictional projects 5MW or greater require full level III analysis (Steady State, Short Circuit, Stability, possibly EMT)
- Groups of projects individually less than 5MW's that are electrically close and aggregate to 20MW or more require full level III analysis
- Non-FERC jurisdictional studies are completed by the interconnecting TO and reviewed by the ISO.



## Other Coordination

*A review of the successful outcome achieved as a result of the work with the Massachusetts Technical Standards Review Group*



# Interim Solution

- Due to the rapid growth of solar PV in New England and because the timeline for full implementation of the revision to IEEE 1547 is 2020 or later, ISO New England pursued an interim solution for obtaining **ride-through** for voltage and frequency variations\*
- Inverters meeting the requirements of UL 1741 SA have the capabilities required by ISO New England in the interim
- Choosing performance requirements for these inverters required input from distribution engineers, solar PV developers, and inverter manufacturers
- The ISO worked with the Massachusetts Technical Standards Review Group (TSRG) to get input from these entities

\* Technical details are provided in the Appendix



# Interim Solution

- Development of inverter performance requirements and an implementation plan required addressing multiple issues
  - Transmission reliability
  - Distribution protection
  - Retaining maximum trip time
  - Anti-islanding protection
  - Conformance with the revised IEEE 1547
  - Allowing time for manufacturers to develop software to implement ISO New England settings
- Balancing these and other issues, ISO New England and the Massachusetts TSRG developed a Preferred Utility-Required Profile and an implementation plan



# Interim Solution – Timeline for Massachusetts

- The ISO's interim solution was adopted in 2018 across multiple utility systems
- The following schedule was implemented in Massachusetts
  - All inverter-based solar PV projects  $\leq 100\text{kW}$  with applications submitted on or after June 1, 2018 are subject to the ISO New England Source Requirement Document
  - All inverter-based solar PV projects  $> 100\text{ kW}$  with applications submitted on or after March 1, 2018 are subject to the ISO New England Source Requirement Document
  - Inverter-based solar PV projects with applications submitted prior to the above dates were encouraged to comply with the ISO New England Source Requirement Document with the approval of the interconnecting utility



# Interim Solution – Timeline for Rest of New England

- National Grid implemented the same requirements in Massachusetts and Rhode Island
- Eversource and United Illuminating required that all Connecticut inverter-based solar PV project applications submitted on or after June 1, 2018 be subject to the ISO New England Source Requirement Document
- Eversource and Unitil required that all New Hampshire inverter-based solar PV project applications submitted on or after June 1, 2018 be subject to the ISO New England Source Requirement Document
- Maine and Vermont utilities implemented the interim solution as of September 1, 2018 and November 2, 2018, respectively



# NEXT STEPS AND ADDITIONAL CONSIDERATIONS

*Full Implementation of IEEE 1547-2018*



# Potential Benefits of Full Implementation

- IEEE 1547-2018 defines the requirements to support the provision of Essential Reliability Services by distribution-connected resources, including:
  - Voltage response
  - Frequency response
- Utilizing the response capabilities of today's inverters could:
  - Reduce the transmission and distribution upgrades needed to ensure the reliable addition of distribution-connected resources
  - Enable the continued addition of further distribution-connected resources in a reliable manner



# Next Steps

- The ISO is working with Municipal Utilities and Co-ops to implement the ISO New England Source Requirement Document on their systems
- The ISO is working with the Massachusetts TSRG on the full implementation of IEEE 1547-2018
  - More than 50 responsibilities have been identified in IEEE 1547-2018
  - Area Electric Power System (EPS) Operators have a role in more than 40 of these responsibilities, some of which require input from the Regional Reliability Coordinator and the Responsible Transmission Planners
  - A subcommittee of the Massachusetts TSRG has plans to meet at least monthly to make the decisions required for the full implementation of IEEE 1547-2018



# Additional Considerations

- After several TSRG meetings on the implementation of 1547-2018, a few additional issues have surfaced
  - Utilities expressed the need for early identification of required updates to state regulations to allow time for those regulations to be revised
  - Utilities expressed concerns about the interaction between frequency regulation (frequency droop) and anti-islanding protection for existing and new DERs
  - Transmission Operators expressed the need for considering 1547-2018 “enter service” settings in black start studies
  - Transmission planners expressed the need to track the location of the various additions of DERs (1547-2003, ISO-NE SRD and 1547-2018)
  - Developers expressed the need to choose communication protocols to allow lead time for the manufacturers



## A circular collage of icons representing various aspects of sustainable energy and environmental management. The icons include solar panels, wind turbines, factories with smokestacks, recycling bins, electric vehicles, and energy storage batteries. The entire graphic is rendered in a dark blue color.

# APPENDIX A

*Interim implementation – technical details*



# Interim Solution Voltage Trip Settings

| Shall Trip – IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) Category II |                                   |                  |                                                                                                                          |                                 |                                      |
|-------------------------------------------------------------------|-----------------------------------|------------------|--------------------------------------------------------------------------------------------------------------------------|---------------------------------|--------------------------------------|
| Shall Trip Function                                               | Required Settings                 |                  | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) default settings and ranges of allowable settings for Category II |                                 |                                      |
|                                                                   | Voltage (p.u. of nominal voltage) | Clearing Time(s) | Voltage                                                                                                                  | Clearing Time(s)                | Within ranges of allowable settings? |
| OV2                                                               | 1.20                              | 0.16             | Identical                                                                                                                | Identical                       | Yes                                  |
| OV1                                                               | 1.10                              | 2.0              | Identical                                                                                                                | Identical                       | Yes                                  |
| UV1                                                               | 0.88                              | 2.0              | Higher (default is 0.70 p.u.)                                                                                            | Much shorter (default is 10 s)  | Yes                                  |
| UV2                                                               | 0.50                              | 1.1              | Slightly higher (default is 0.45 p.u.)                                                                                   | Much longer (default is 0.16 s) | Yes                                  |



# Interim Solution Voltage Ride-Through Capability and Additional Operational Requirements

| Voltage Range (p.u.)    | Operating Mode/ Response            | Minimum Ride-Through Time(s) (design criteria)                                                                                                                   | Maximum Response Time(s) (design criteria) | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) for Category II |
|-------------------------|-------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------|------------------------------------------------------------------------|
| $V > 1.20$              | Cease to Energize                   | N/A                                                                                                                                                              | 0.16                                       | Identical                                                              |
| $1.175 < V \leq 1.20$   | Permissive Operation                | 0.2                                                                                                                                                              | N/A                                        | Identical                                                              |
| $1.15 < V \leq 1.175$   | Permissive Operation                | 0.5                                                                                                                                                              | N/A                                        | Identical                                                              |
| $1.10 < V \leq 1.15$    | Permissive Operation                | 1                                                                                                                                                                | N/A                                        | Identical                                                              |
| $0.88 \leq V \leq 1.10$ | Continuous Operation                | infinite                                                                                                                                                         | N/A                                        | Identical                                                              |
| $0.65 \leq V < 0.88$    | Mandatory Operation                 | Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.:<br>$T_{VRT}$<br>$= 3 \text{ s} + \frac{8.7 \text{ s}}{1 \text{ p.u.}} (V - 0.65 \text{ p.u.})$ | N/A                                        | Identical                                                              |
| $0.45 \leq V < 0.65$    | Permissive Operation <sup>a,b</sup> | 0.32                                                                                                                                                             | N/A                                        | See footnotes a & b                                                    |
| $0.30 \leq V < 0.45$    | Permissive Operation <sup>b</sup>   | 0.16                                                                                                                                                             | N/A                                        | See footnote b                                                         |
| $V < 0.30$              | Cease to Energize                   | N/A                                                                                                                                                              | 0.16                                       | Identical                                                              |

The following additional operational requirements shall apply for all inverters:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.



# Interim Solution Frequency Trip Settings

| Shall Trip Function | Required Settings |                     | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.)<br>default settings and ranges of allowable settings<br>for Category I, Category II, and Category III |                     |                                            |
|---------------------|-------------------|---------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------|--------------------------------------------|
|                     | Frequency<br>(Hz) | Clearing<br>Time(s) | Frequency                                                                                                                                                    | Clearing<br>Time(s) | Within ranges<br>of allowable<br>settings? |
| OF2                 | 62.0              | 0.16                | Identical                                                                                                                                                    | Identical           | Yes                                        |
| OF1                 | 61.2              | 300.0               | Identical                                                                                                                                                    | Identical           | Yes                                        |
| UF1                 | 58.5              | 300.0               | Identical                                                                                                                                                    | Identical           | Yes                                        |
| UF2                 | 56.5              | 0.16                | Identical                                                                                                                                                    | Identical           | Yes                                        |

# Interim Solution Frequency Ride-Through Capability

| Frequency Range (Hz)    | Operating Mode                                   | Minimum Time(s) (design criteria) | Comparison to IEEE Std 1547-2018 (2 <sup>nd</sup> ed.) for Category II |
|-------------------------|--------------------------------------------------|-----------------------------------|------------------------------------------------------------------------|
| $f > 62.0$              | No ride-through requirements apply to this range |                                   | Identical                                                              |
| $61.2 < f \leq 61.8$    | Mandatory Operation                              | 299                               | Identical                                                              |
| $58.8 \leq f \leq 61.2$ | Continuous Operation                             | Infinite                          | Identical                                                              |
| $57.0 \leq f < 58.8$    | Mandatory Operation                              | 299                               | Identical                                                              |
| $f < 57.0$              | No ride-through requirements apply to this range |                                   | Identical                                                              |

# Interim Solution Grid Support Utility Interactive Inverter Functions Status

| Function                                          | Default Activation State                                     |
|---------------------------------------------------|--------------------------------------------------------------|
| SPF, Specified Power Factor                       | OFF                                                          |
| Q(V), Volt-Var Function with Watt or Var Priority | OFF                                                          |
| SS, Soft-Start Ramp Rate                          | ON<br>Default value: 2% of maximum current output per second |
| FW, Freq-Watt Function                            | OFF                                                          |



# EPRI T&D Research Related to Effective System Grounding

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Tom Key, [tkey@epri.com](mailto:tkey@epri.com)

## Northeast Power Coordinating Council DER Forum Webinar

October 15, 2020



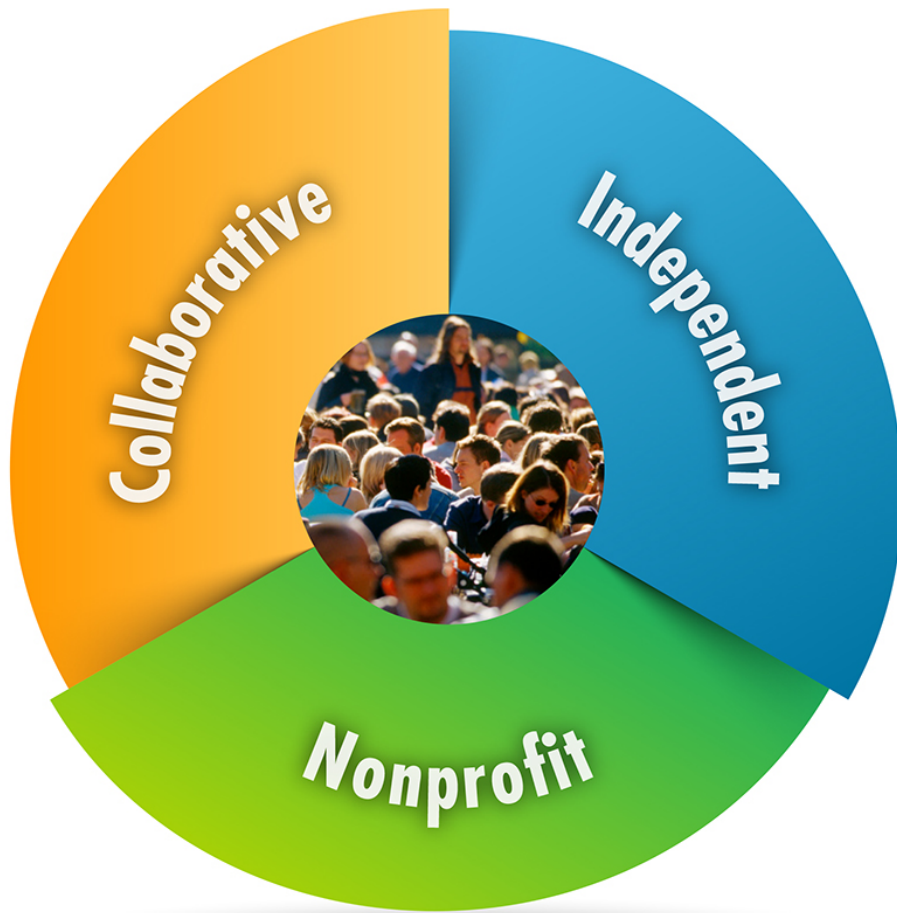
**SOLAR ENERGY  
TECHNOLOGIES OFFICE**  
U.S. Department Of Energy

This presentation is, in part, supported by the U.S. Department of Energy, Solar Energy Technologies Office under Award Number DE-EE0009019 Adaptive Protection and Validated MODELS to Enable Deployment of High Penetrations of Solar PV (PV-MOD).

# Presentation Outline

- EPRI IGES (Integrated Grid & Energy Systems) Research
- Effective Grounding and DER
- Revisited Grounding Practices with Inverters
- Interesting Results
- Interest Group on DER T&D Coordination
- Q&A

# Three Key Aspects of EPRI



## Independent

Objective, scientifically based results address reliability, efficiency, affordability, health, safety, and the environment

## Nonprofit

Chartered to serve the public benefit

## Collaborative

Bring together scientists, engineers, academic researchers, and industry experts

**Our Members...**450+ participants in more than 30 countries

# Integrated Grid & Energy Systems at EPRI

Strategic Energy & Env Planning

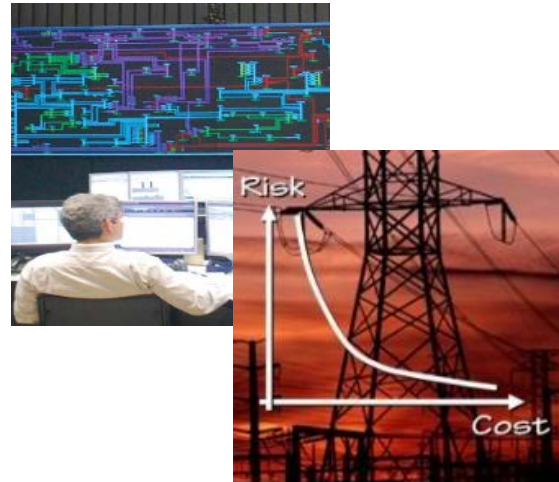
Long-Term System Planning

Real-Time Operations

Energy, Environment  
& Climate Policy



Transmission  
Operations



Bulk System DER &  
Renewables  
Integration



Distributed Energy  
Resource Integration



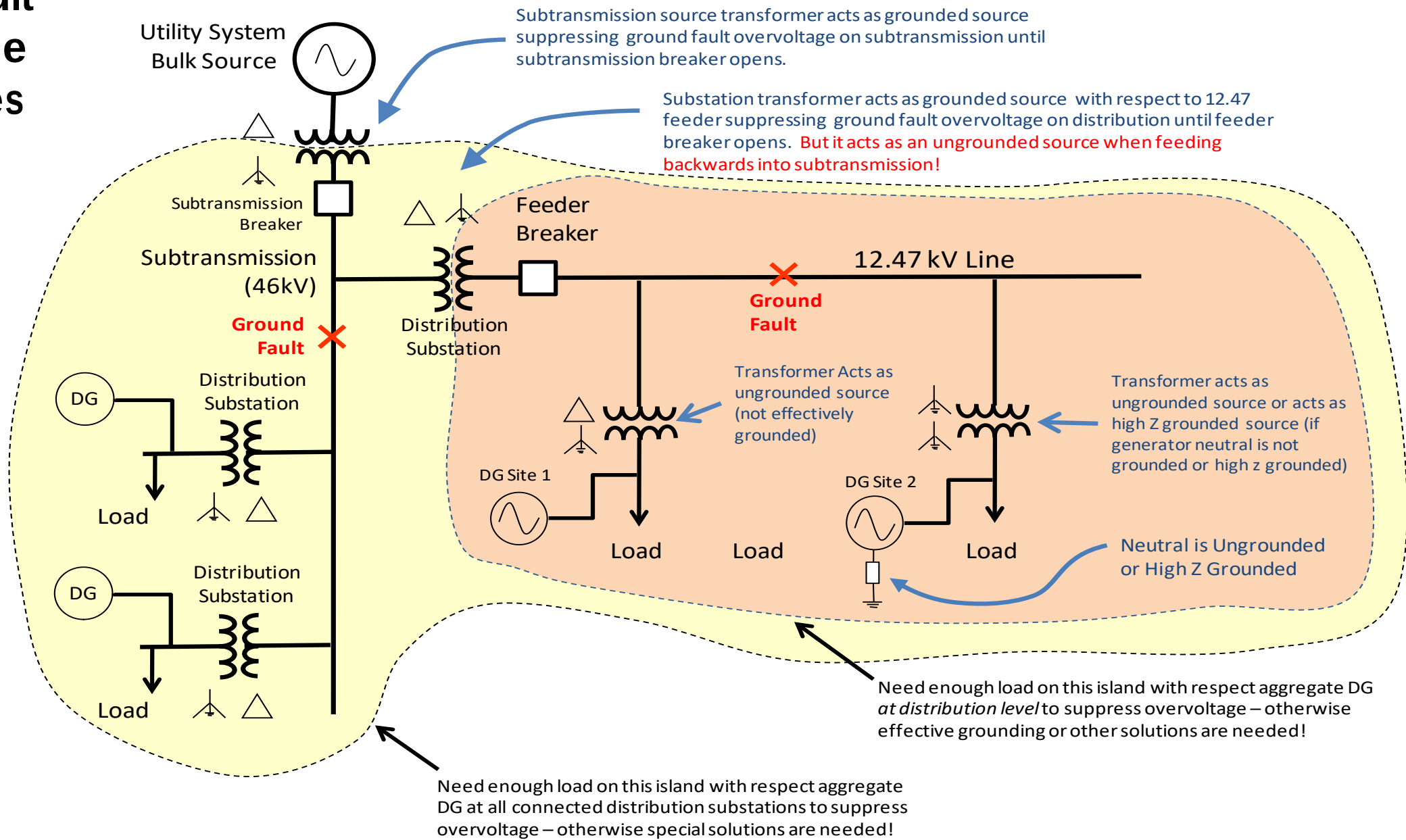
Integrated Energy System  
Planning, Fuels &  
Markets

Transmission  
Planning

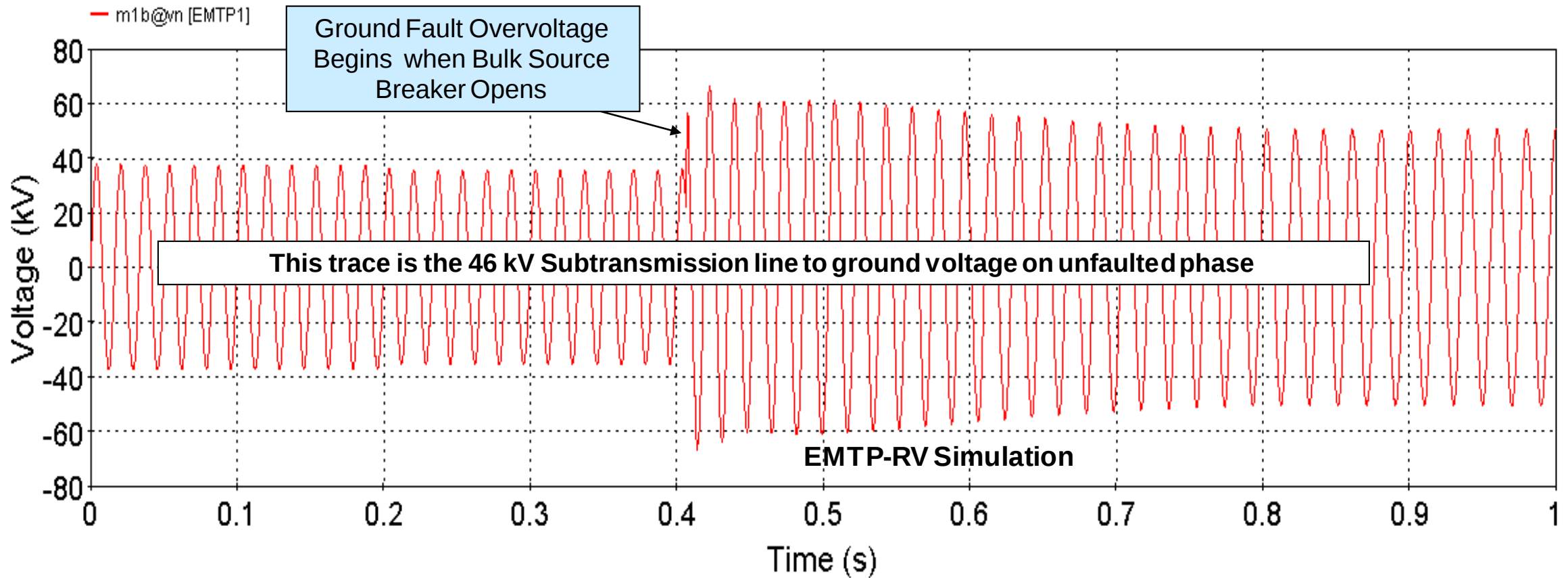
Distribution  
Operations  
& Planning

Energy Storage  
Systems Integration

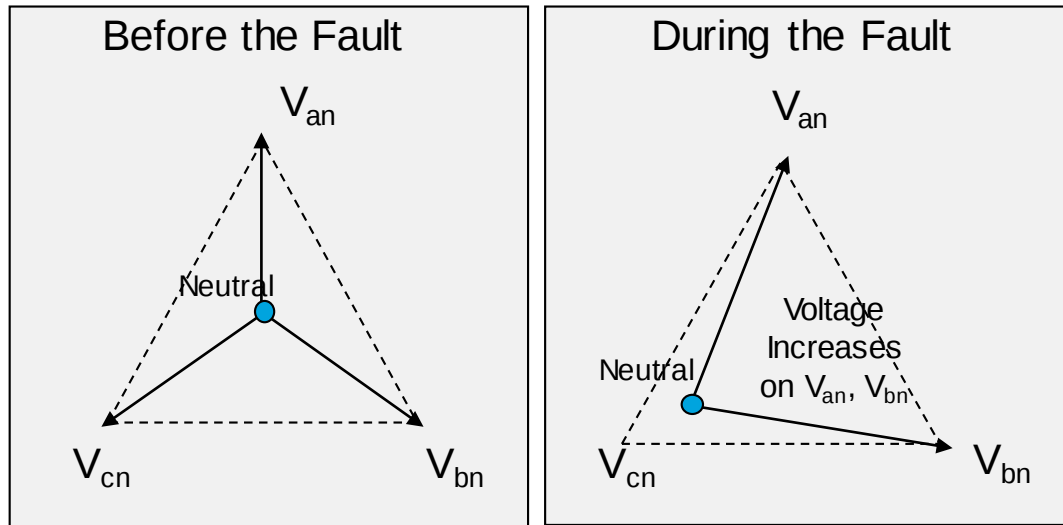
# Ground Fault Overvoltage Island Zones



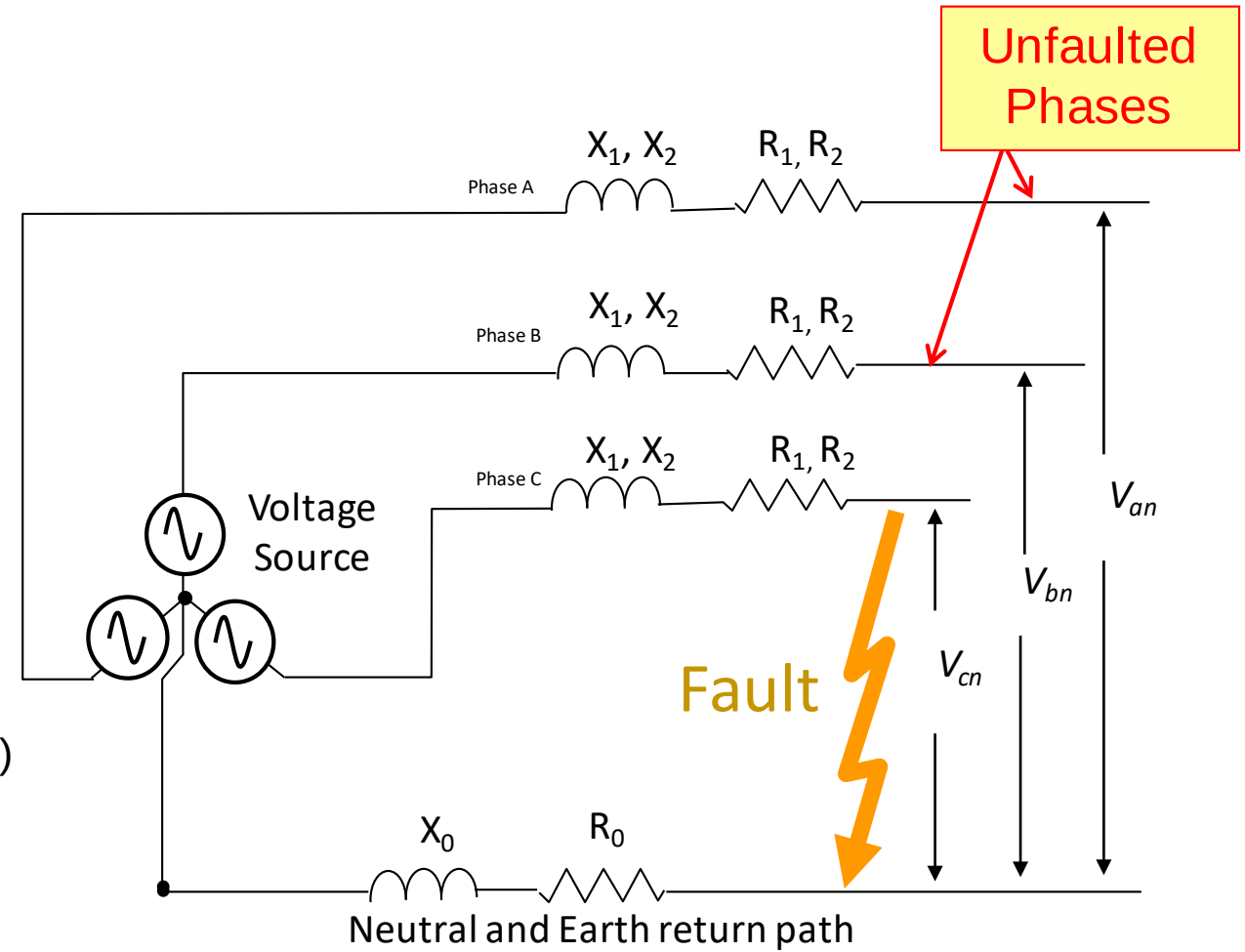
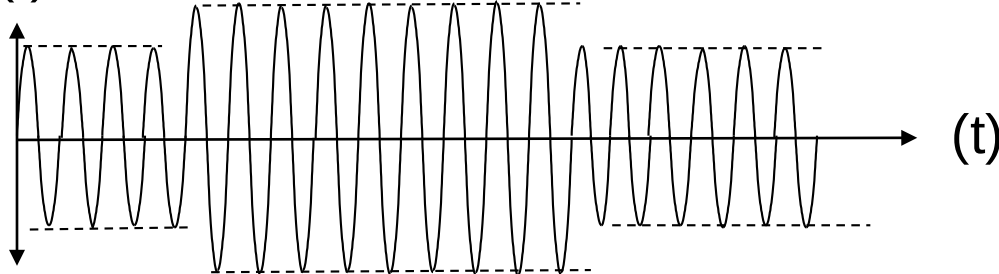
# Example of EMTP Simulation of 46 kV Subtransmission Level Ground Fault Overvoltage Caused by ICE DER.



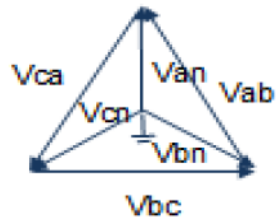
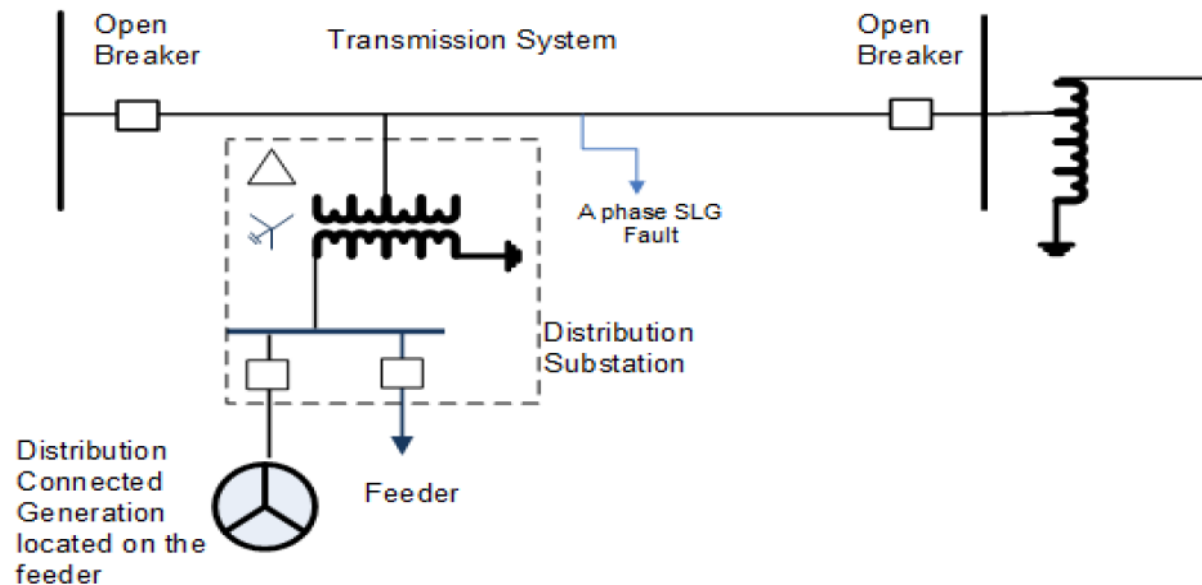
# Voltage Swell (TOV) Caused By Neutral Shift During Fault



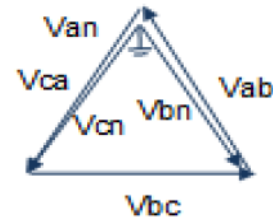
$V(t)$  Voltage swell during ground fault (unfaulted phases)



# Additional High Penetration Considerations.



Normal Unfaulted Voltages



A phase SLG Fault Voltages

## Overvoltage Issues

- ❑ PG&E Distribution XFMRs are typically HV grounded however there are many fused with the HV winding ungrounded, and several that are Delta connected.
- ❑ High penetration DER can result in overvoltage issues.
  - High penetration is >50% of minimum load.
- ❑ Transmission protection systems isolate the fault from the grid
- ❑ DER keeps unfaulted phases energized at Line-Line Potential
- ❑ System must be insulated to withstand magnitude (1.73pu) and (2 seconds) of over-voltage.

# PROTECTION FROM UNINTENDED ISLANDING AND SUBSTATION PRIMARY GFO CAUSED BY DG INFEED



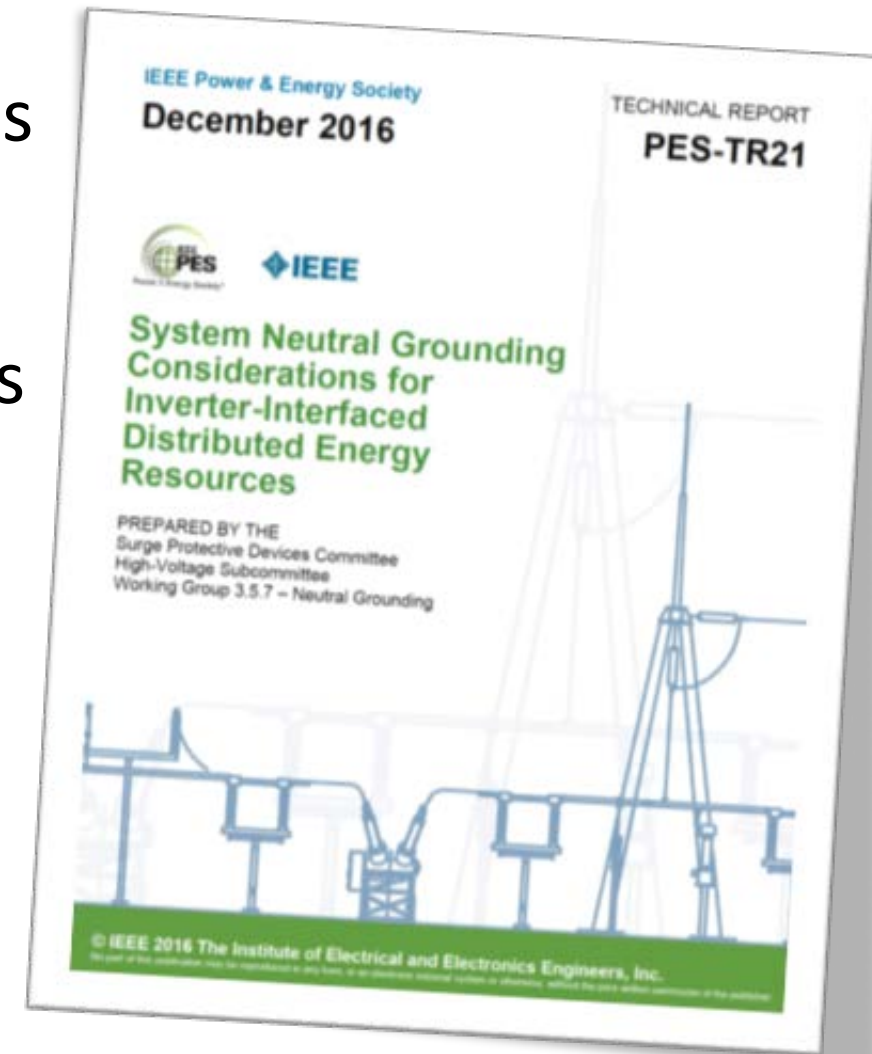
Alternative to  
3VO protection  
and monitoring  
arrester current  
([3002011008](#))

# Neutral Grounding Guidelines, IEEE C62.92 Series:

Classical  
Effective  
grounding  
Practices  
for  
synchronous  
machines

- C62.92.1 – Introduction and definitions
- C62.92.2 – Synchronous generator systems
- C62.92.3 – Generator auxiliary systems
- C62.92.4 – Distribution systems
- C62.92.5 – Transmission and sub-transmission systems
- C62.92.6 – Systems supplied by current-regulated sources

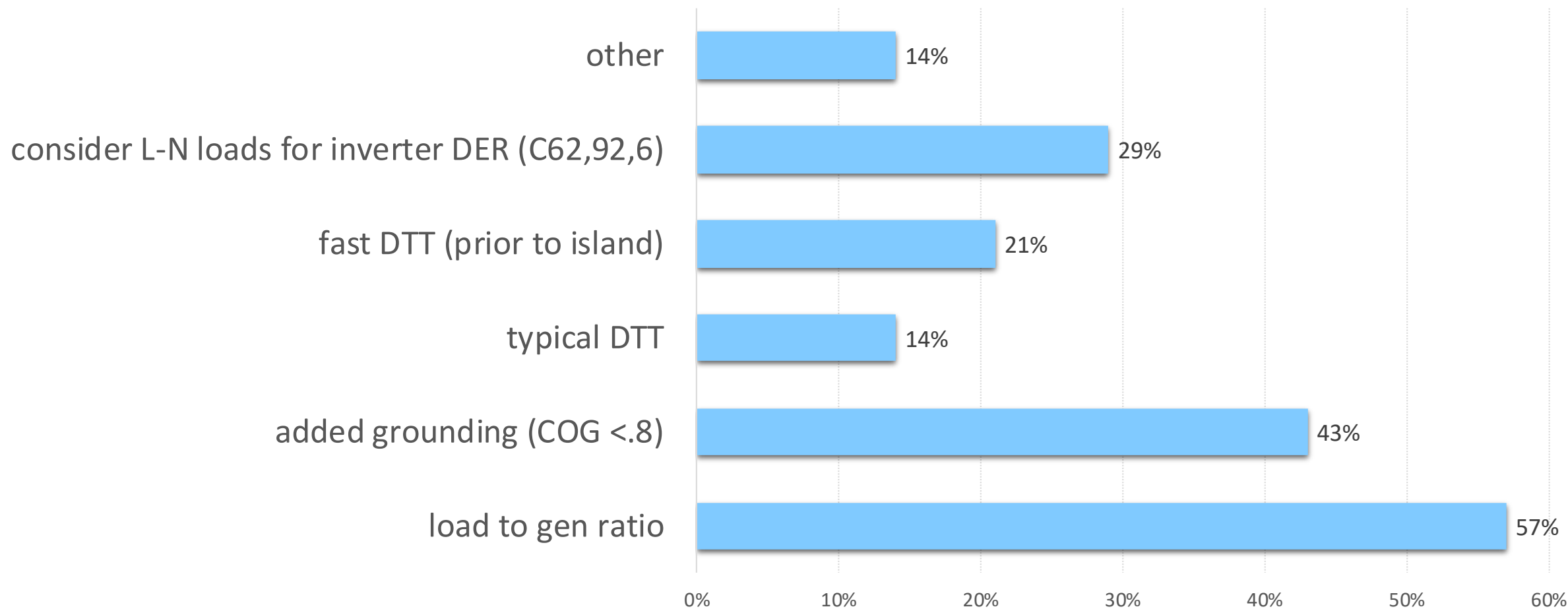
↖  
New guideline is meant for the special characteristics of **Inverter Sources**



# Conventional Notion of an “Effectively” Grounded Power System

- Effective grounding is defined as a Coefficient of Grounding (CoG)
  - ➡  **$CoG \leq 0.8 \text{ pu}$  limits GFO to  $0.8 \times V_{L-L}$  or  $0.8 \times \sqrt{3} \sim 138\%$  of  $V_{L-g}$**
  - $\therefore$  effective grounding is a system condition defined by voltages
  - $CoG \equiv V_{L-G(\text{fault})} / V_{L-L(\text{no fault})}$
  - $X_0/X_1 \leq 3, R_0/X_1 \leq 1$  are an approximation (works for synchronous generators)
- Conventional situation:
  - Relatively low impedance of rotating generator sources dominates system
  - Loads and other shunt impedances are relatively unimportant to fault and GFOV calculations
  - Thus, a voltage source with a low  $X_0/X_1$  will yield effective grounding when energizing any practical system

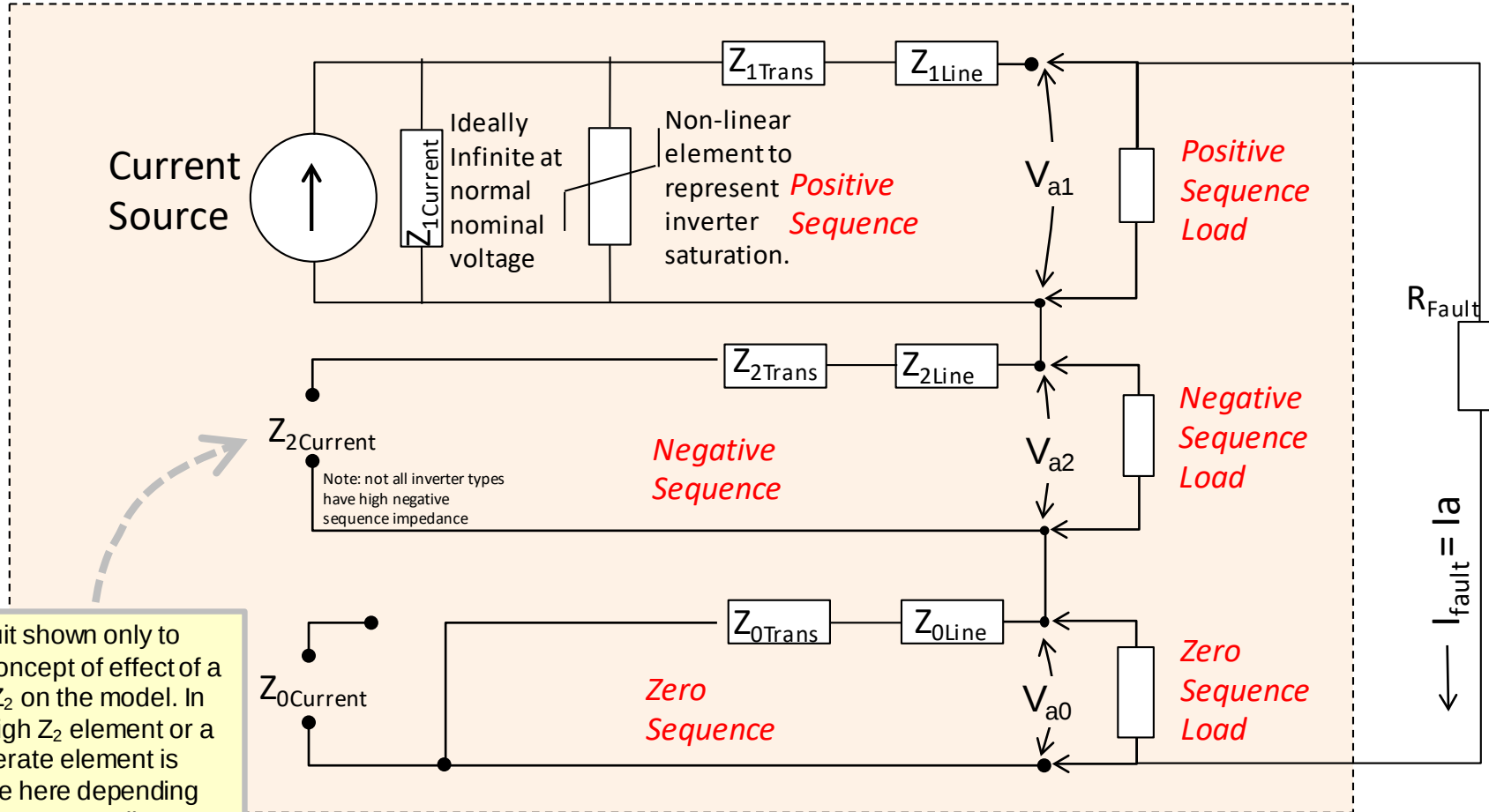
# What are your most recent practices with regard to GFO prevention with inverter DER > 1MW?



**\*multiple answer question**

# Symmetrical Component Model:

Single Line to Ground Fault, loads included, inverter with saturable current source, Delta low side to grounded-wye high side transformer and extremely high or infinite inverter  $Z_2$



## Faulted Phase A:

$$I_a = I_{a1} + I_{a2} + I_{a0}$$

$$V_a = V_{a1} + V_{a2} + V_{a0} + R_f I_a$$

$$V_a = 0 \text{ when } R_{fault} = 0$$

## Unfaulted Phases B and C:

$$I_b = I_c = 0$$

$$V_b = a^2 V_{a1} + a V_{a2} + V_{a0}$$

$$V_c = a V_{a1} + a^2 V_{a2} + V_{a0}$$

## Key Takeaways:

- A very large inverter negative sequence impedance can create severe unfaulted phase voltage despite the presence of a low impedance zero sequence path
- The loads themselves must be included to analyze the neutral shift and resulting GFO that occurs

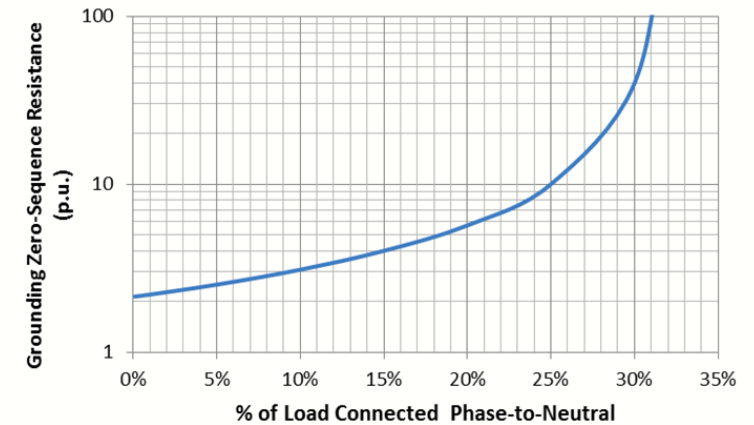
Open circuit shown only to illustrate concept of effect of a very high  $Z_2$  on the model. In reality, a high  $Z_2$  element or a more moderate element is appropriate here depending on the inverter controller design.

# Can Grounded Load (L-N) Mitigate GFO



## Need for Supplemental Ground Sources

- Although supplemental ground sources are unnecessary for 100% L-N load, resistive ground source is preferred if one is applied
- Figure below shows grounding resistance required for effective grounding as a function of percentage of L-N load
- No ground source needed if L-N loads are > 33% of total
- This is almost always the case on multi-grounded wye (4-wire) feeders
- Three-wire feeders have only L-L loads, but are designed to tolerate GFOV, and added ground sources are highly disruptive to their protection schemes



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# Borrego Solar at NY ITWG May 2018

- **Barriers Introduced by The Utilities:**
  - Complete Rejection of Three-Wire Inverters on the Basis of Effective Grounding
  - Different Design Requirements for Three-Wire Inverters in Each Territory
- **Influx of Three-Wire Inverter Applications Recently Which Brought This Issue to Light**
  - Major Industry Shift to New 1500V UL Listed Inverters
    - Significant labor savings of \$0.04-0.05 per watt
    - Extremely restrictive on manufacturers which may be used - Only One Manufacturer with Four-Wire
    - Projects cannot be built without these inverters under the new incentives
  - No Central Inverters have a Three-Wire Configuration
    - Limits entire industry to only string inverter designs
    - Power Conversion System (PCS) inverters for battery storage are all three-wire
  - Other Utility Territories (MA, CA, & IL) and a Majority of Utilities in NY Allow Three-Wire Inverters
    - Approved equipment list on ITWG website includes three-wire inverters
- **Goals of this Conversation:**
  - **Both Three-Wire and Four-Wire UL Listed Inverters Are Permitted Across the State**
  - **Agreed Upon Approaches to Interconnection Design that Mitigates Utility Concerns for Three-Wire Inverters**

# Ongoing NYSERDA Funded Research Project

***Challenge:*** Grounding practices for rotating machine DER aimed to control ground fault overvoltage in utility distribution are not well defined for ungrounded inverter-connected PV.

- *Practices are evolving and requirements appear to be inconsistent across systems*
- *Developers point out that they are uncertain what requirements must be met.*

***Study Objective:*** Define evaluation approach and methods to determine effective grounding (and/or supplemental grounding) configurations with inverter-based DER.

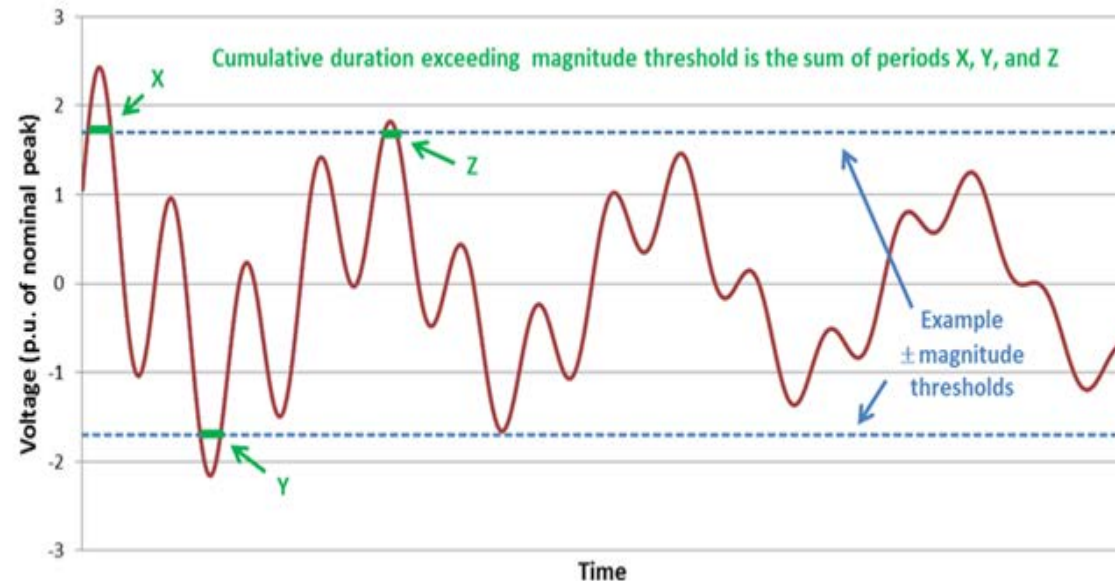
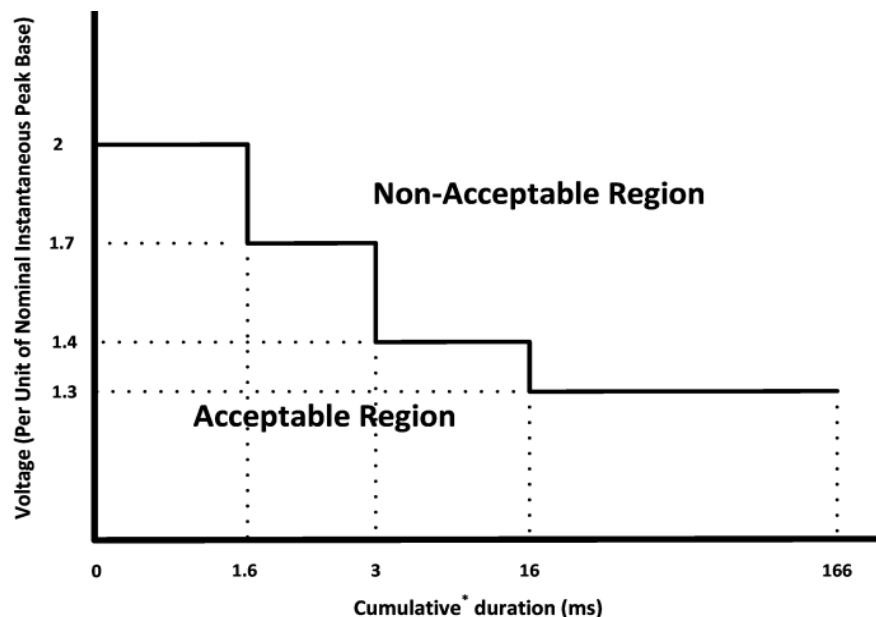
# IEEE 1547-2018 Limitation of Overvoltage Contribution

## Section 7.4.1 Limitation of overvoltage over one fundamental frequency period

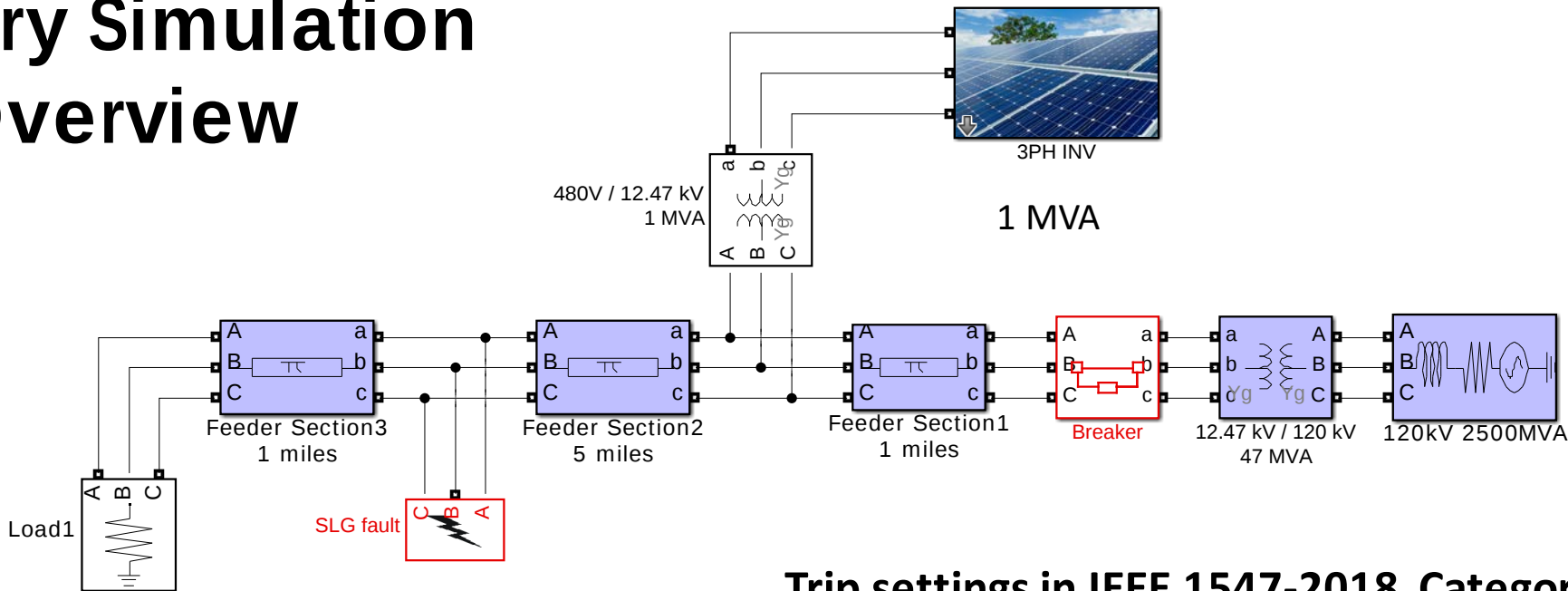
- The fundamental frequency voltage should not exceed 138% of the nominal line-to-ground fundamental frequency voltage on any portion of the Area EPS designed to operate effectively grounded.

## Section 7.4.2 Limitation of cumulative instantaneous overvoltage

- The DER shall not cause the instantaneous voltage on any portion of the area EPS to exceed the magnitudes and cumulative durations as defined in the figures below:



# Preliminary Simulation Study – Overview



**Trip settings in IEEE 1547-2018, Category III**

**Inverter overvoltage (TOV) trip settings**

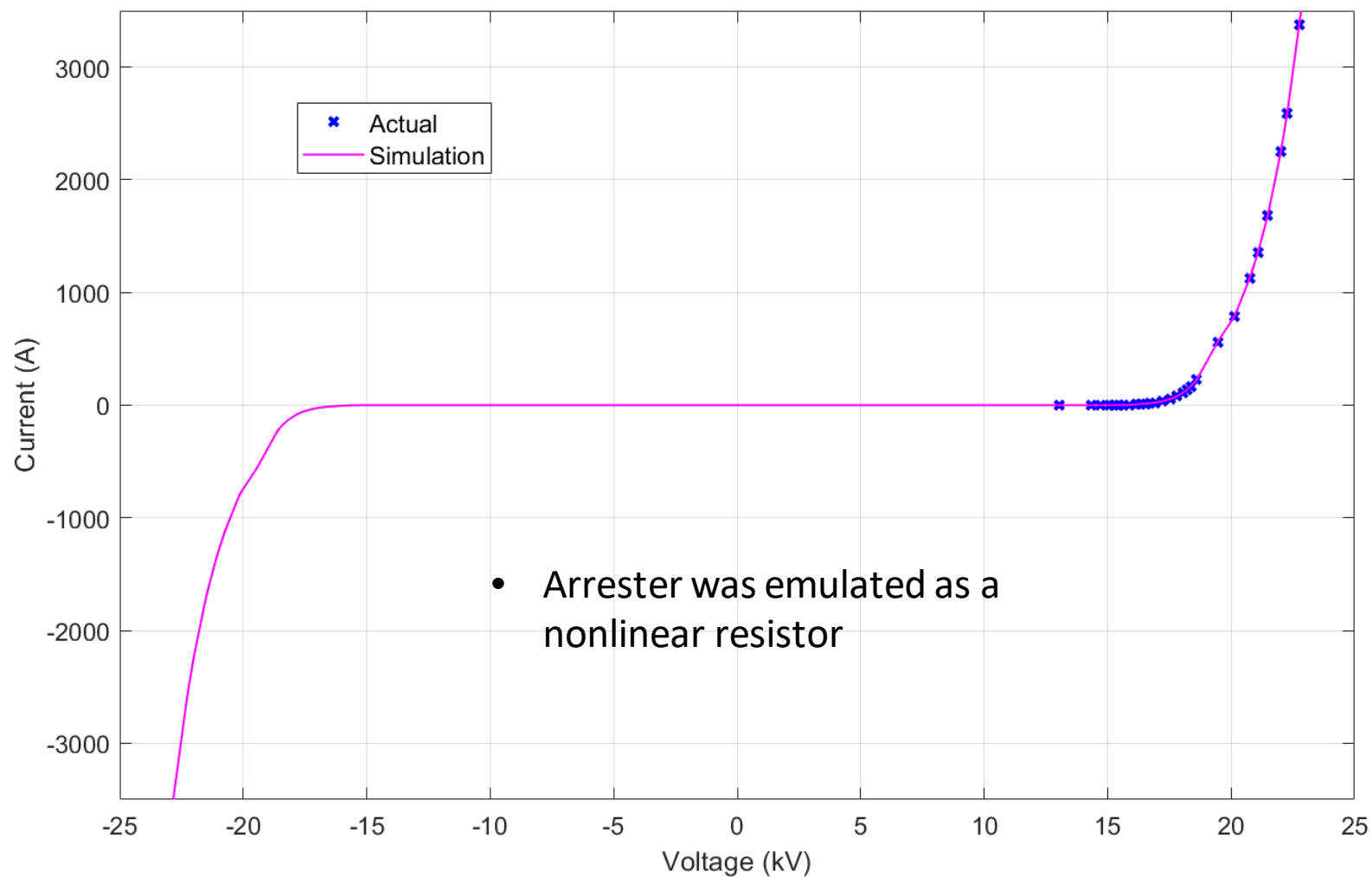
| Element | Pickup | Time Delay (cumulative) |
|---------|--------|-------------------------|
| TOV     | 2 pu   | 0.0016 sec              |
| TOV     | 1.7 pu | 0.003 sec               |
| TOV     | 1.4 pu | 0.016 sec               |
| TOV     | 1.3 pu | 0.166 sec               |

| Element              | Pickup Range | Time Delay |
|----------------------|--------------|------------|
| Undervoltage (27)    | 0.5 pu       | 1 sec      |
| Undervoltage (27)    | 0.7 pu       | 10 sec     |
| Undervoltage (27)    | 0.88 pu      | 20 sec     |
| Overvoltage (59)     | 1.1 pu       | 12 sec     |
| Overvoltage (59)     | 1.2 pu       | 0.16 sec   |
| Underfrequency (81u) | 56.5 Hz      | 0.16 sec   |
| Underfrequency (81u) | 58.8 Hz      | 299 sec    |
| Overfrequency (81o)  | 61.2 Hz      | 299 sec    |
| Overfrequency (81o)  | 62.5 Hz      | 0.16 sec   |

# Overvoltage Scenarios and Grounding

1. Load Rejection Overvoltage (LRO) in balanced 3-phase system
  - Yg/Yg DER transformer (effective grounding does not matter)
  - Main breaker opens (no ground fault)
  - Load varies from 0 pu -1 pu ( $\Delta$  or Y connected load)
2. Combined LRO and ground fault overvoltage (GFO)
  - Yg/Yg DER transformers (with and w/o supplemental grounding)
  - Permanent ground fault and main breaker opens
  - Load varies from 0 pu -1 pu (ungrounded load, spot check with 30% grounded)
3. GFO with varying amount of grounded load
  - Yg/Yg DER transformers (no supplemental grounding)
  - A permanent ground-fault happens, and the main breaker opens
  - Load to generation ratio = 1, grounded load % varies from 0% –100%

# Arresters added for all Transformers Configurations\*



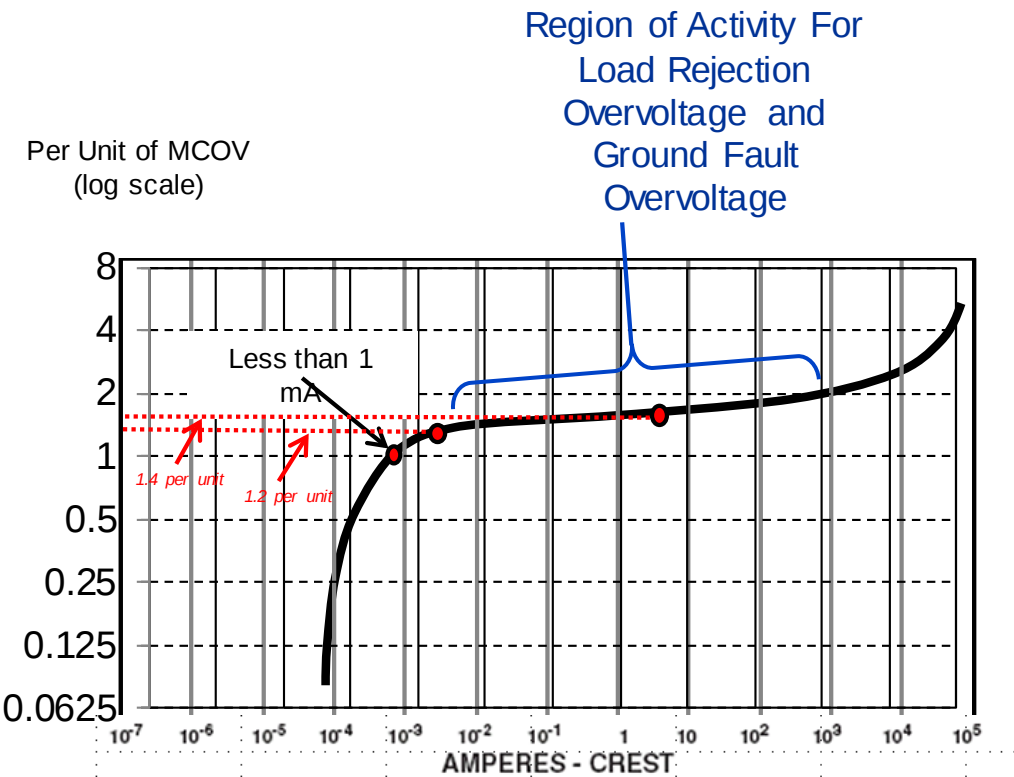
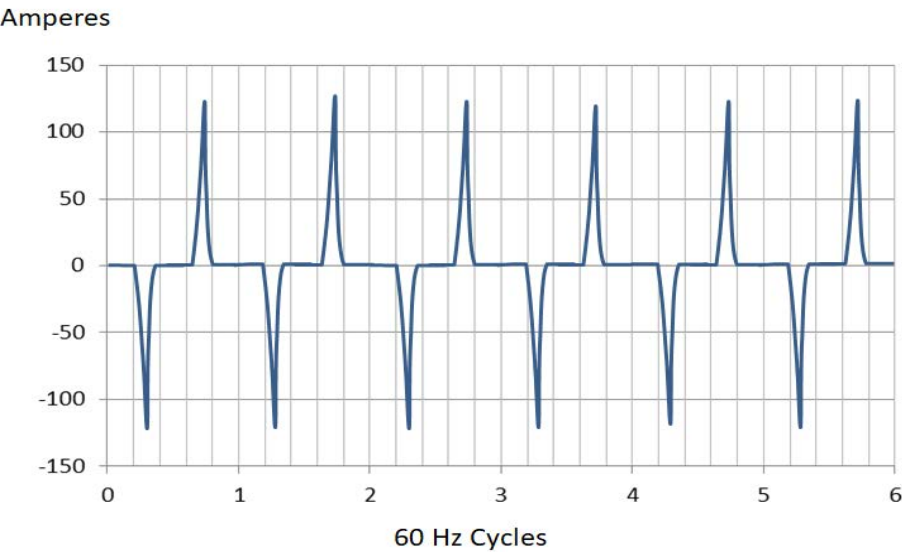
| Parameter             | Values     |
|-----------------------|------------|
| MCOV                  | 7.7 kV     |
| Type                  | Heavy duty |
| # of arrester         | 1          |
| Energy capacity (kJ)* | 17         |

- 17 kJ is single arrester energy limit, and in many situations there will be sharing
- Energy limit is based on re-application of MCOV immediately after the TOV. If the arrester is de-energized after the TOV, the actual energy capability is greater than the published value. Reason is no power follow leading to thermal runaway.

\* We included Yg/Yg, Yg/ $\Delta$  and  $\Delta$ /Yg transformer configurations for purpose of results comparison.

# Voltage-Current Characteristics of Gapless Metal Oxide

Arrester current can be very distorted with low RMS to peak ratio and energy level can be lower than a linear waveform in many cases.



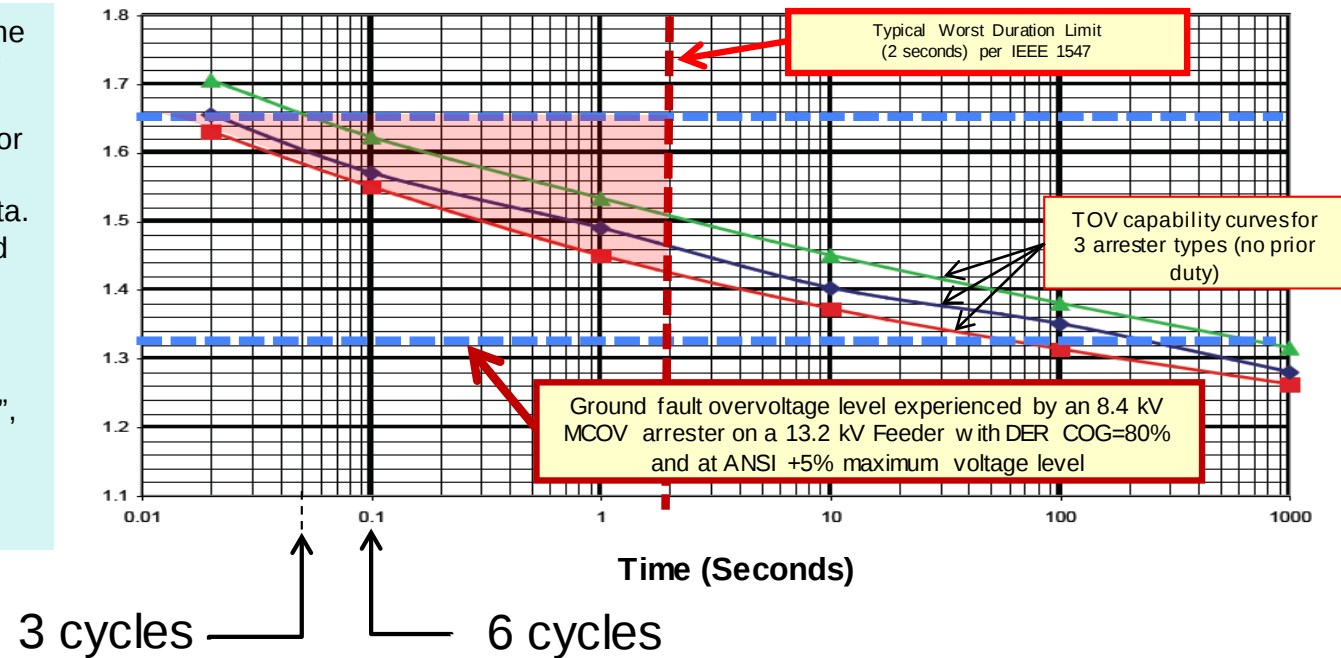
**Note:** Arrester voltage-current curve above is shown for a station class arrester only as an illustration of the general characteristic. There is a wide range of arrester product available. Curves are higher and lower than this depending on brand, class, rating, heating conditions, etc. Consult specific manufacturer's data for the exact product specified to perform a study.

# Arrester Temporary 60 Hz Overvoltage Capability (TOV)

Per Unit of Arrester  
Maximum Continuous  
Operating Voltage Rating

**Note:** For illustration only. This is one specific arrester brand (3 models of normal duty distribution class arresters are shown), all with no prior duty. Consult with arrester manufacturers for specific curve data. Prior duty would lower the withstand to a lesser value than shown.

Note also many people apply TOV curve assuming an “infinitely strong source.” DER sources are “weaker”, especially inverter sources, and the surge arrester loading effect will suppress the TOV condition.



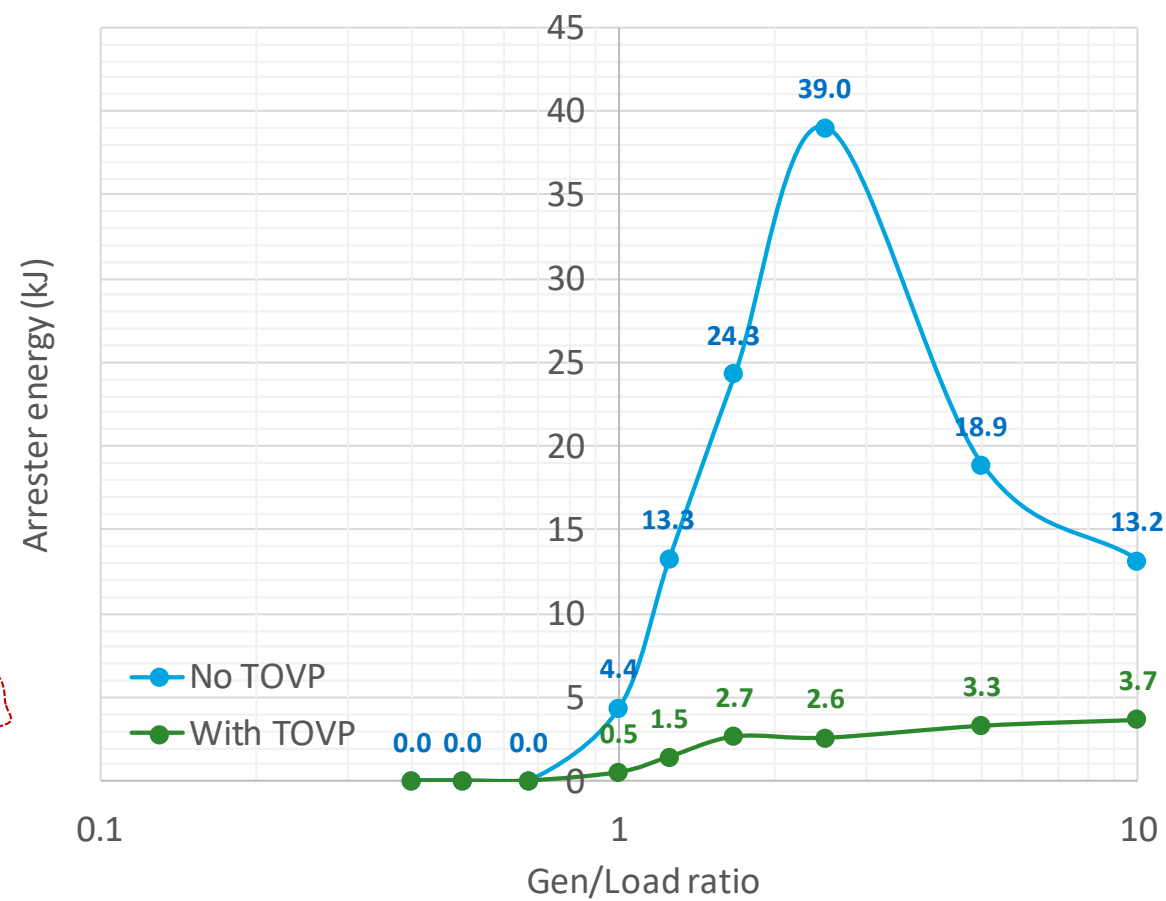
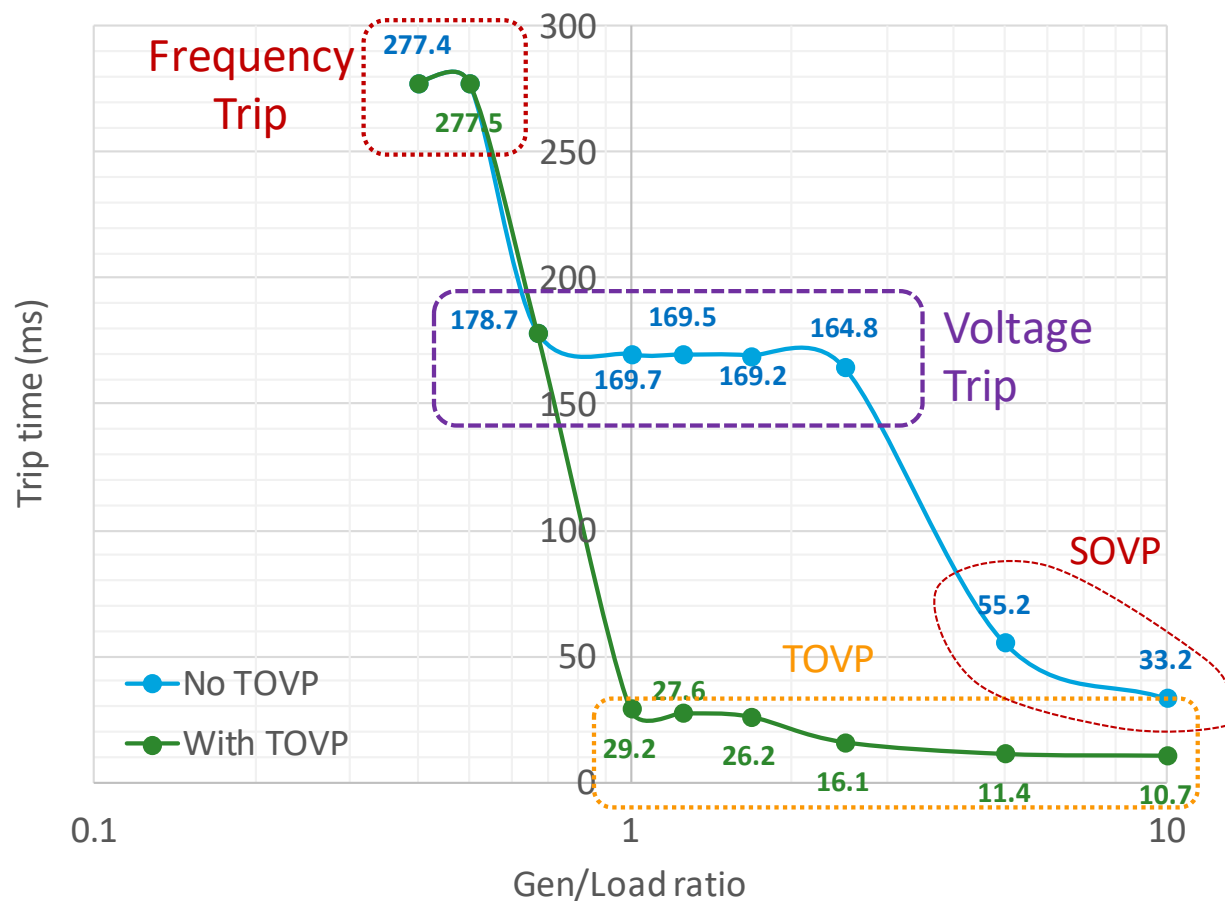
- TOV capability is tied to arrester class and protective levels – distribution arresters have higher TOV capability, but lower energy capability
- Prior duty curves should be used as GFOV may impose duty prior to TOV application
- Station or intermediate arresters on feeder-side of breakers may be exposed to GFOV
- Some energy sharing among islanded feeder arresters is expected even with limited matching

# LRO + GFO, Delta Connected Load, w/wo TOVP

Trip time

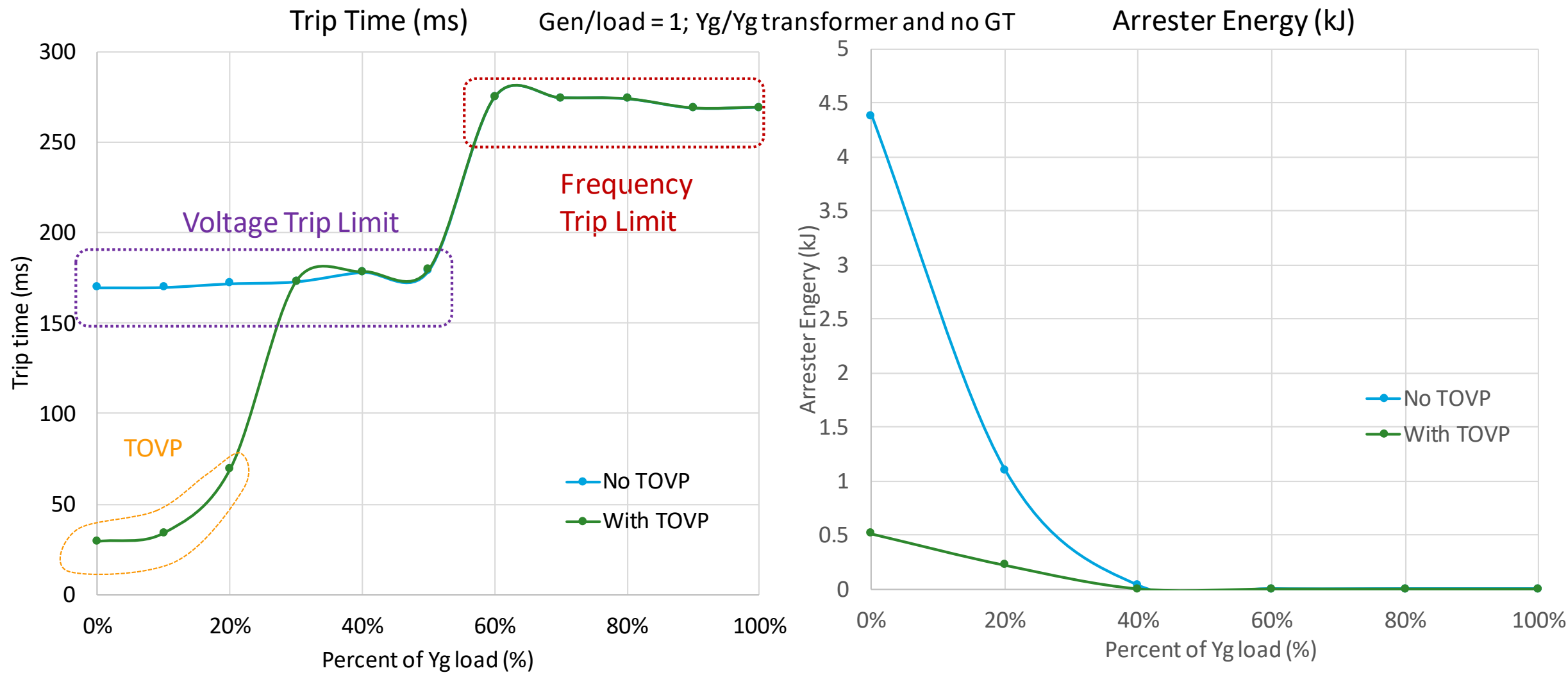
Yg/Yg transformer and no GT

Arrester energy



TOVP enables much shorter trip time and thus lower arrester energy when gen/load  $\geq 1$

# GFO, Varying Percent of Grounded Load



TOVP reduced inverter trip time and arrester energy when most of loads are not grounded

# Key findings

1. With grounded load, inverter GFO is not significant, grounding transformer only needed if load/gen ratio is low (new TOV limits in support this)
2. If load/gen ratio is low, LRO is more significant and is not mitigated by a grounding transformer. System arresters generally able to mitigate.
3. Overvoltage from LRO (no GFO) is not as severe as when LRO and GFO are combined.
4. With low load/generation ratio (cases of high DER penetration) the combination of LRO + GFO can create significant overvoltage even with grounded loads, and high arrester duty unless inverters meet the new IEEE 1547-2018 TOV limit.
5. When the new TOV limit function is in place, arrester duties from LRO and GFO are far below the critical value even for a lone distribution arrester (note sharing of energy is expected with power frequency overvoltage, e.g. LRO and GFO)

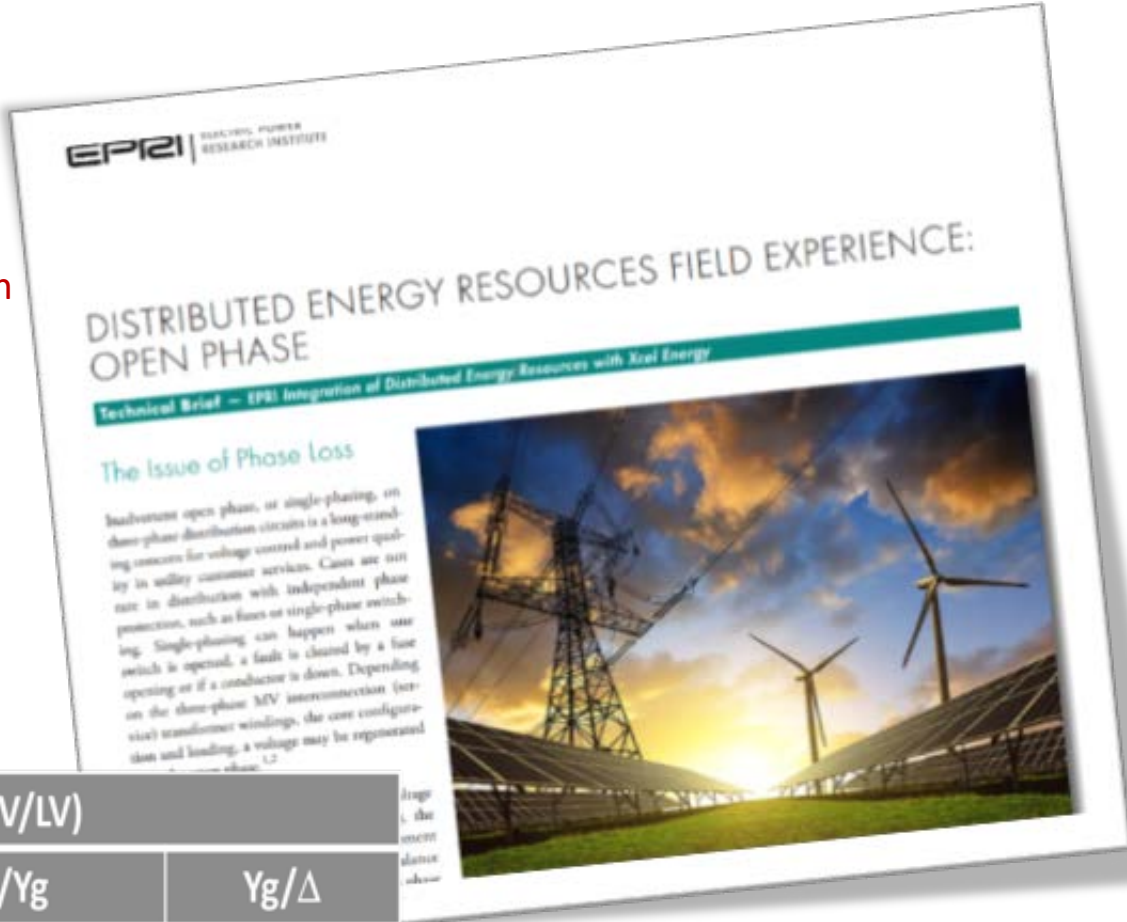
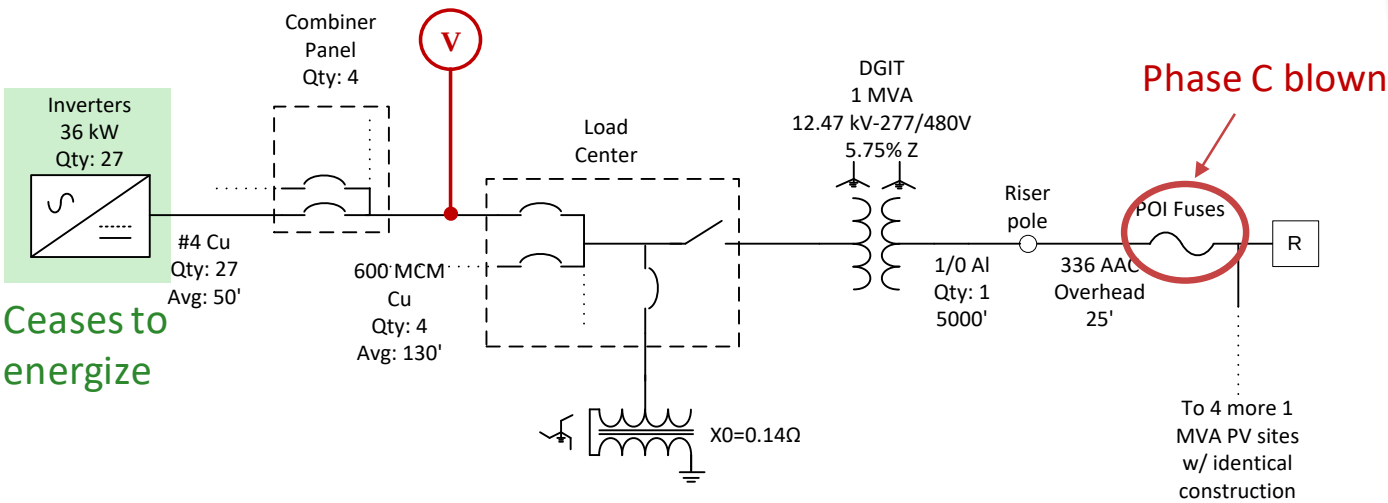
# When do you require a DER to provide additional ground source (either by a grounding transformer or a grounded-wye/delta transformer)?

| Answers                                                         | Results | %  |
|-----------------------------------------------------------------|---------|----|
| A Never                                                         | 10/76   | 13 |
| B Depending on DER size                                         | 19/76   | 25 |
| C Depending on DER type (i.e., inverter, synchronous generator) | 12/76   | 16 |
| D Other criteria                                                | 13/76   | 17 |
| No Answer                                                       | 22/76   | 29 |

# Side Effects of Supplemental Grounding Transformer

1. Feeder ground fault relaying desensitization
2. Increase in ground fault current magnitudes & durations to higher/longer than is desirable (can impact overcurrent protection devices, arc flash increase, etc.)
3. Exposure of DER ground source transformers and DER sources to undesirable zero sequence currents of fault events and load currents
4. Back-feed into open phases via the grounding transformer
5. Ground Potential Rise (GPR) and stray voltage effects near additional DER grounding sources

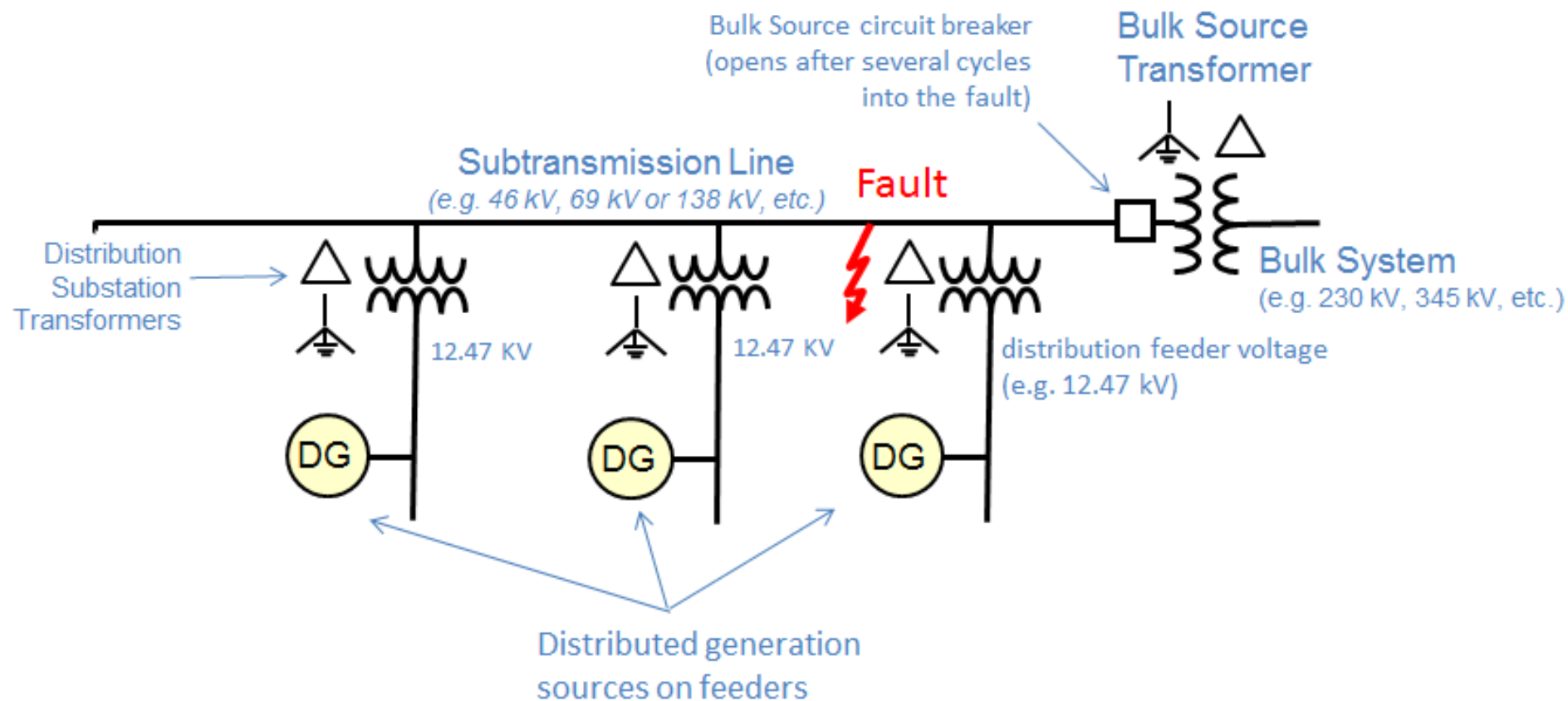
# Tech Brief on DER Open Phase



| Grounding Transformer | Capacitance* | DER Transformer Topology (MV/LV) |                |                |        |
|-----------------------|--------------|----------------------------------|----------------|----------------|--------|
|                       |              | Yg/Yg (5-leg)                    | Yg/Y (5-leg)   | Δ/Yg           | Yg/Δ   |
| ✓                     | ✓            | 1.2/1.18 pu                      | 1.11/1.08 pu   | 1.38/1.21 pu   | N/A    |
| x                     | ✓            | Ferroresonance                   | Ferroresonance | Ferroresonance | ~1 pu  |
| ✓                     | x            | 1/1 pu                           | 1/1 pu         | 1/1 pu         | N/A    |
| x                     | x            | 0.7/0.7 pu                       | 0.7/0.7 pu     | 0.4/0.4 pu     | 1/1 pu |

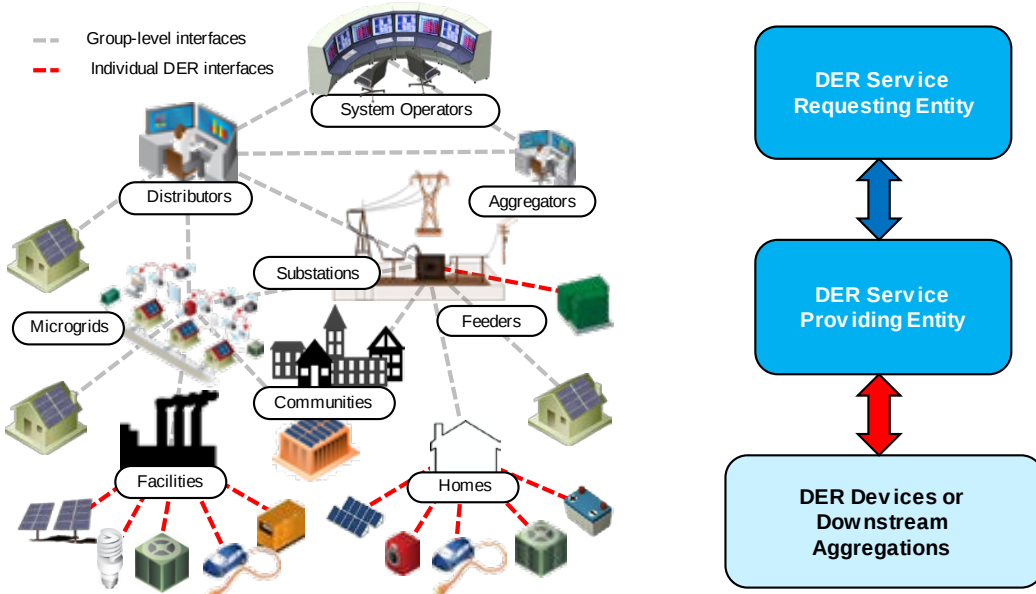
Reference:  
Distributed Energy  
Resources Field  
Experience: Open  
Phase ([3002015949](#))

# Multiple Distribution Substations



# Industry Wide Interest Group: DER Aggregations/Group Management for Coordinated Operations Across the ISO/T&D Interface

## Scope



## Background and Context

- FERC Order 2222...Very tight timeline for implementation
- Open forum, diverse stakeholders, consensus
- Outputs codified in national and international standards, e.g., IEC CIM 61968-5
- Methods developed will be implemented, tested, and certified in test events and workshops
- EPRI currently developing a plan to support ISO's with FERC 2222 plans

## Approach

- Weekly meetings: every Tuesday, 1p-2p ET, 10a-11a PT, 7p-8p CET – please contact [arenjit@epri.com](mailto:arenjit@epri.com), [bseal@epri.com](mailto:bseal@epri.com)
- Collaborative, incremental learning and specification of gaps, use cases, functions

# Questions/Comments?

# Fault simulations & protections of Nantucket 6MW Battery Energy Storage System (BESS)

Song Ji

Principal Engineer

Protection Policy & Support

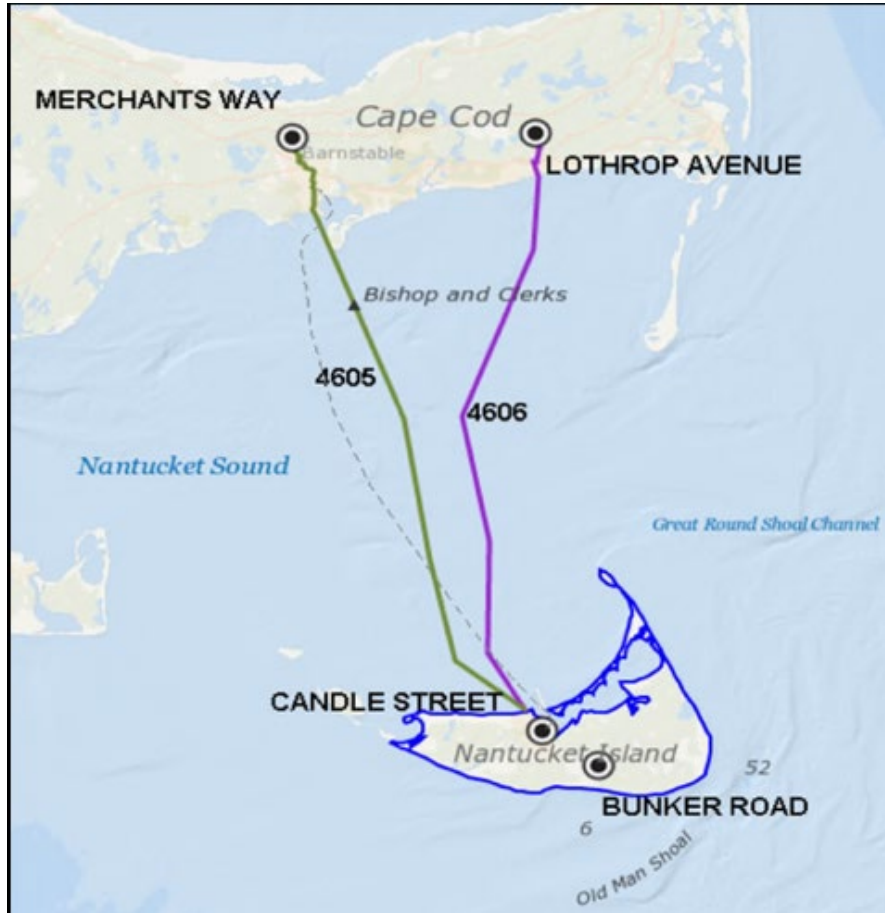
October 2020

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**nationalgrid**

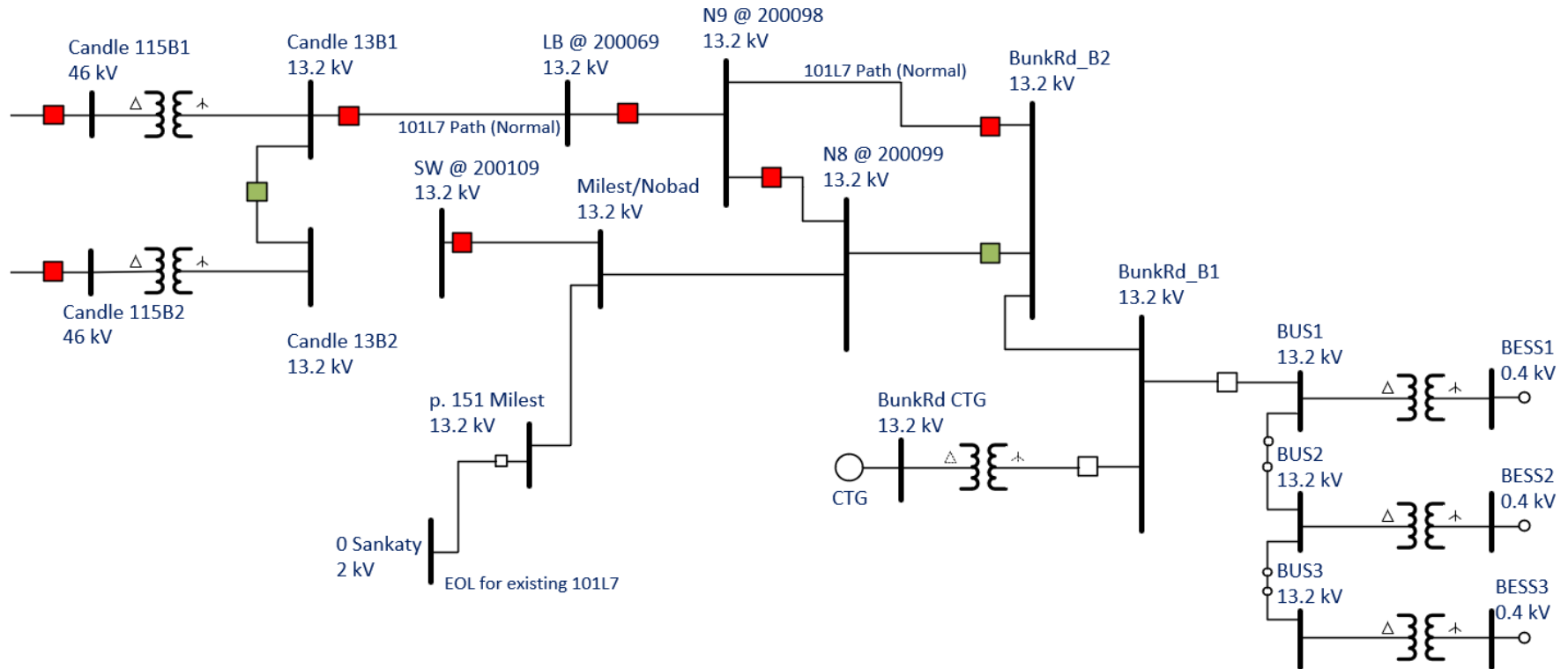
The power of action.™

# Nantucket Island & power supplies



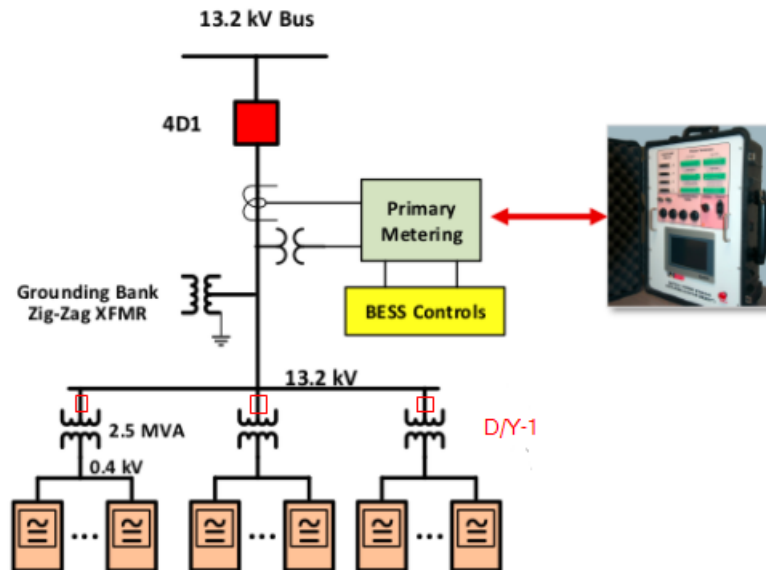
- ◆ 30-miles south from Cape Cod
- ◆ Two 46kV 30-mile submarine cables
- ◆ Backed up by diesel generators
- ◆ 3<sup>rd</sup> cable is required in next 12-year due to growing demand
- ◆ NG took proactive measures to defer the installation of 3<sup>rd</sup> cable
- ◆ Battery Energy Storage System (BESS) paired with new combustion turbine generator (CTG)

# System one line & configuration of Nantucket



- ◆ Red and green square indicate closed & open breakers
- ◆ Bunker Rd is a newly rebuilt station with BESS & CTG

# BESS at Bunker Rd substation



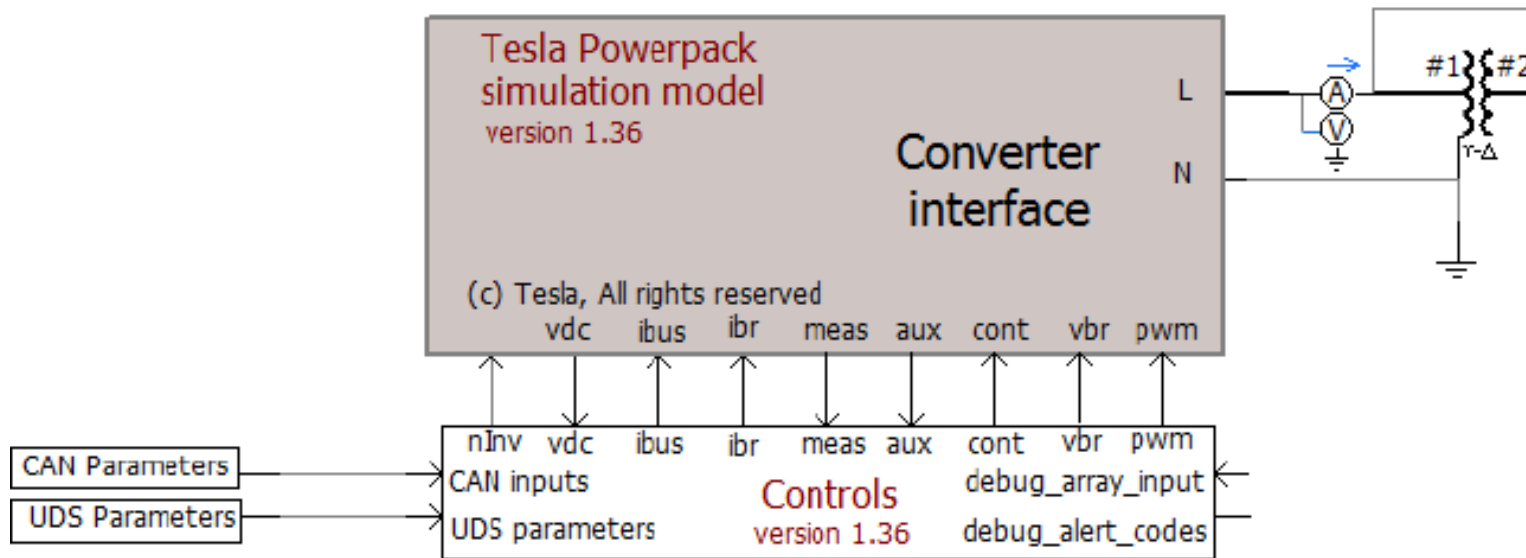
- ◆ 6MW/48MWh BESS, composed of 240 Tesla Powerpacks, provides backup power for short interruptions and load shedding.
- ◆ Grouped powerpacks with converters are connected to station 13.2kV bus through three fuse protected D/Y-1 transformer.
- ◆ Grounding bank is provided on transformer HV side

# BESS & CTG at Bunker Rd station



- ◆ Hybrid battery & CTG
- ◆ CTG can back up and recharge the BESS
- ◆ The BESS, combined with the new 15 MVA CTG, has the capacity to supply the island with peak loads if undersea cables experience an outage.
- ◆ Won 2019 Energy Storage North America (ESNA) Innovation and Champion Awards

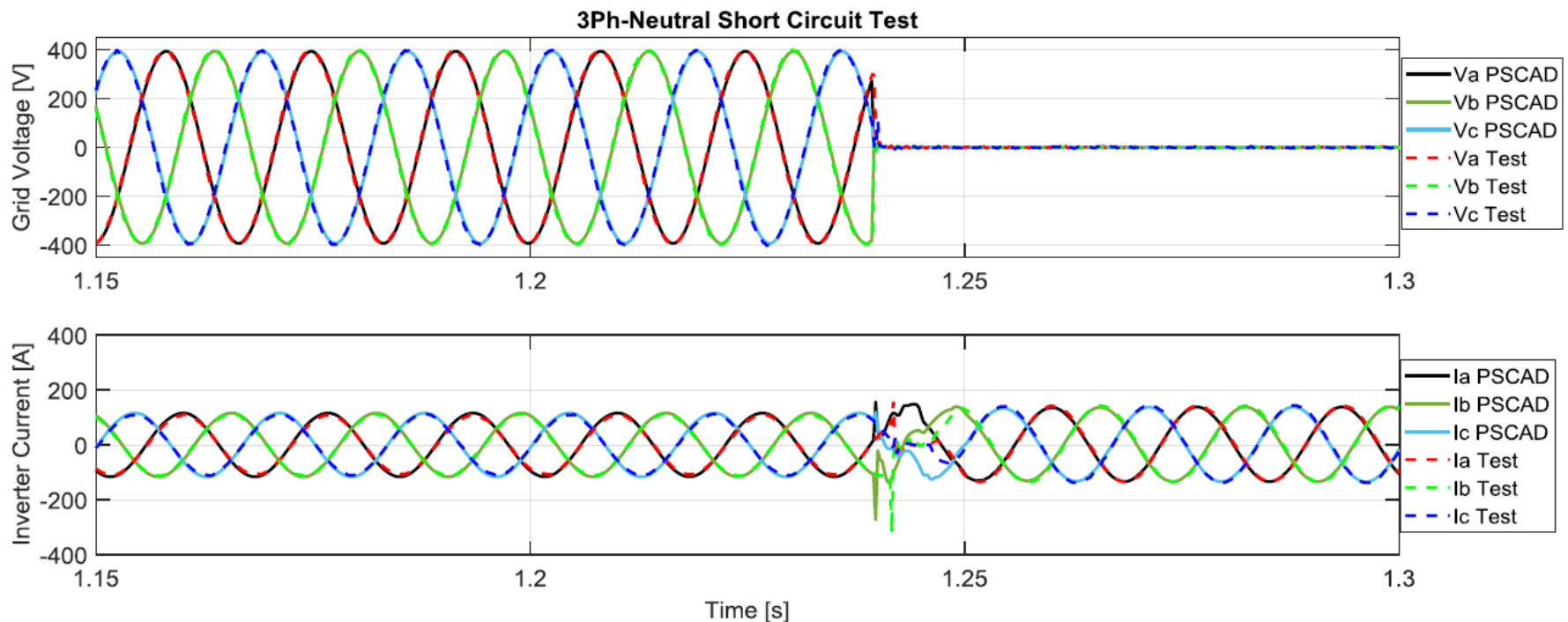
# Tesla Powerpack PSCAD Model



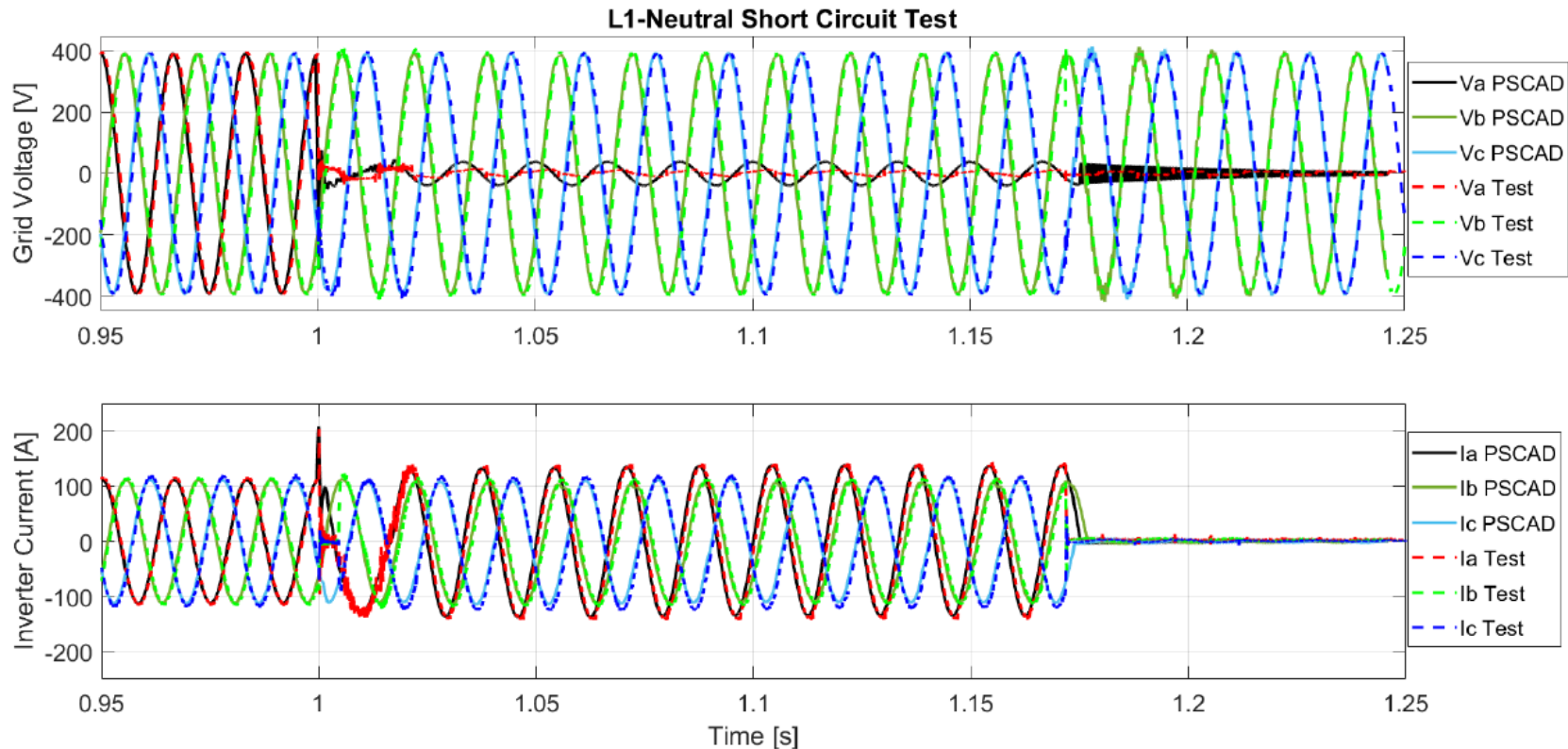
- ◆ The model is provided by vendor & proprietary;
- ◆ User can change & define parameters & variables to mimic the real operation of converter, such as voltage & current, frequency, P, Q control, etc.

# PSCAD Model Validation - 1

- ◆ Three-phase to ground & SLG fault are used to verify the model:
- ◆ BESS is in the maximum discharging mode
- ◆ Simulation results superimposed with real test measurements

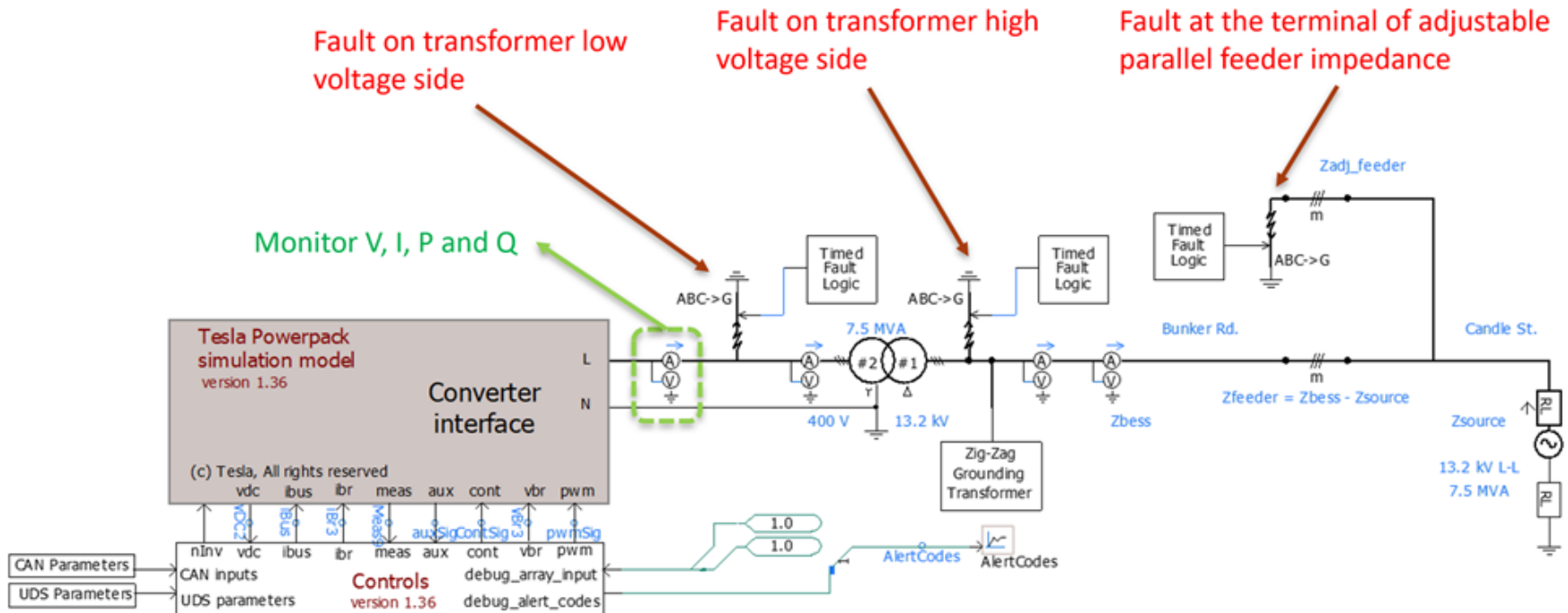


# PSCAD Model Validation - 2



- ◆ Simulation results superimposed with real test measurements
- ◆ The BESS PSCAD model is good & matches the real test data
- ◆ To build system models for simulations

# System simulation model in PSCAD



- ◆ The source is represented by Thevenin equivalent circuit;
- ◆ Transformer & feeder are modeled & fault scenarios are defined
- ◆ The desired signals are defined

# The ride through capability of BESS

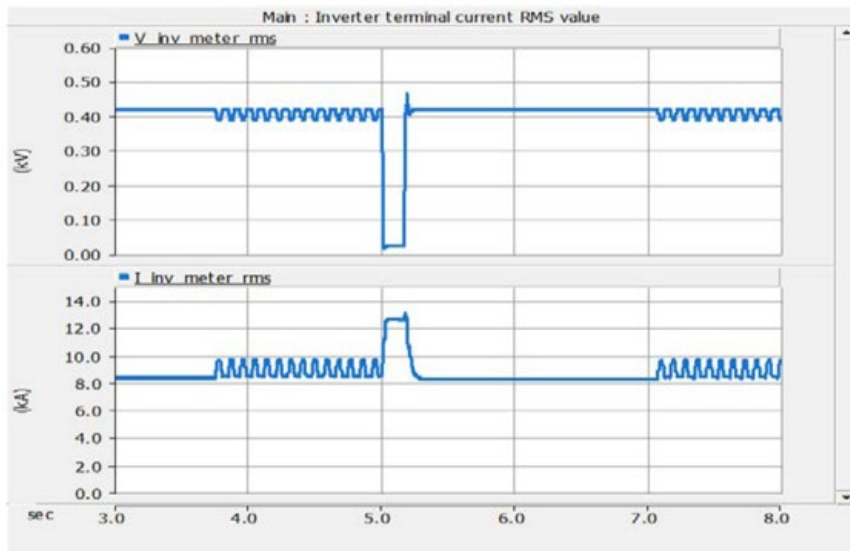
- ◆ The settings determine the converter ride-through capability during transient frequency & voltage excursions;
- ◆ To comply with the requirements from IEEE Std.1547-2018 - Interconnection & Interoperability of Distributed Energy Resources with Associated Electric Power Systems (Voluntary industry std, but adopted by authorities)

| Device                  | Pick up Setpoints | Time   |
|-------------------------|-------------------|--------|
| Under voltage 1 (27)    | 88%               | 2.0 s  |
| Under Voltage 2 (27)    | 50%               | 1.1 s  |
| Over Voltage 1 (59)     | 110%              | 2.0 s  |
| Over Voltage 2 (59)     | 120%              | 0.16 s |
| Under Frequency 1 (81U) | 58.5 Hz           | 300 s  |
| Under Frequency 2 (81U) | 56.5 Hz           | 0.16 s |
| Over Frequency 1 (81O)  | 61.2 Hz           | 300 s  |
| Over Frequency 2 (81O)  | 62.0 Hz           | 0.16 s |

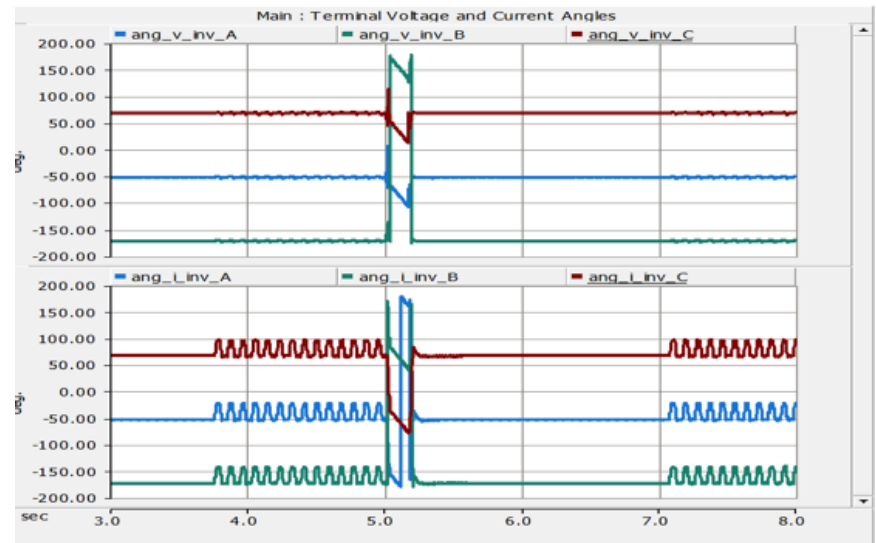
# 3-Phase Faults on Transformer HV Side - 1

- ◆ For 3 $\Phi$  fault on transformer HV voltage side, when duration is less than 11 cycles, the inverter will ride through. When fault is greater than 11 cycles, the inverter will be tripped after discharge and reconnected when voltage recovers.
- ◆ Simulation waveforms obtained from inverters

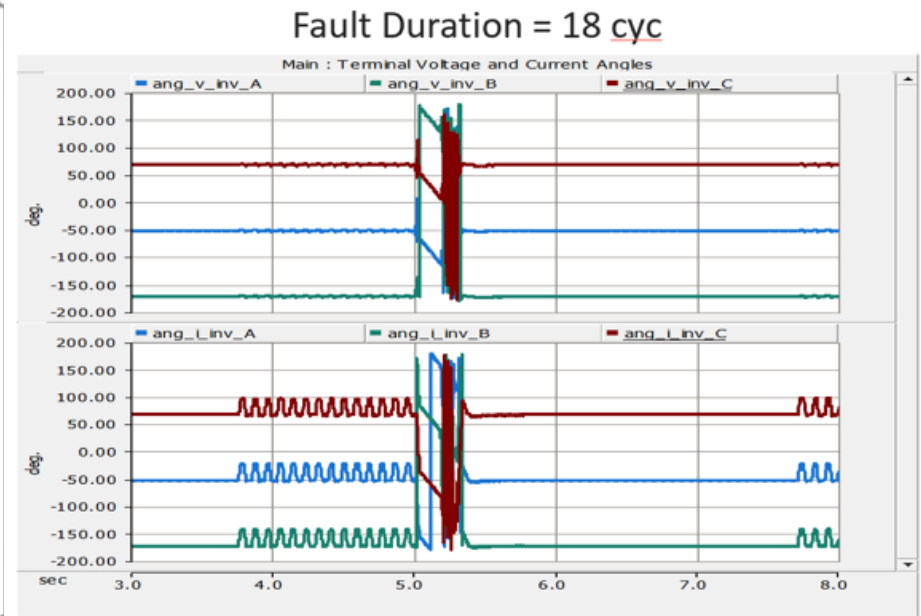
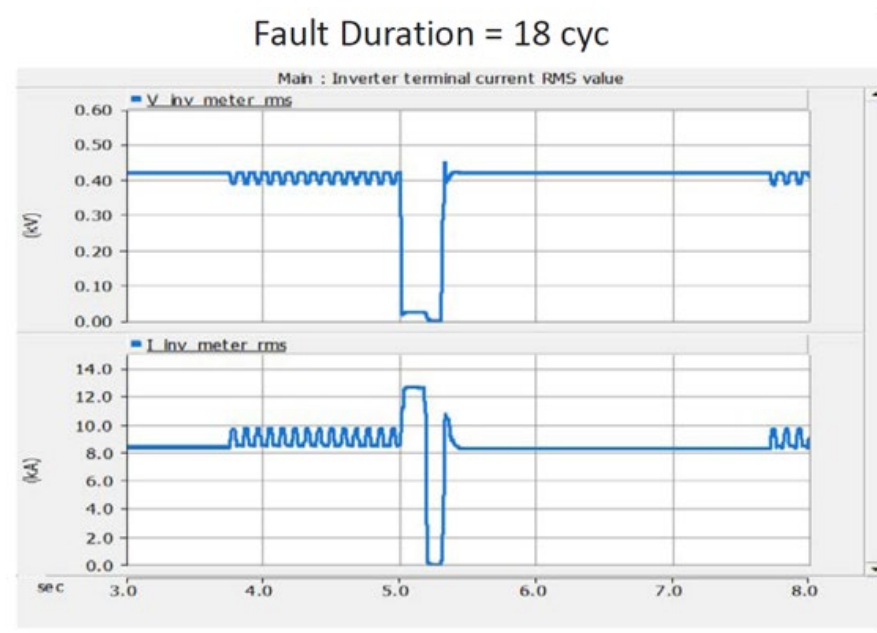
Fault Duration = 10 cyc



Fault Duration = 10 cyc

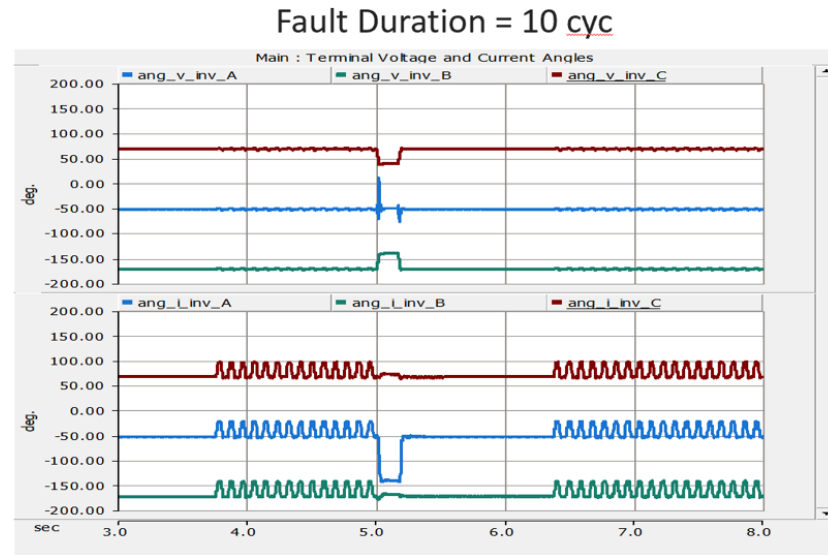
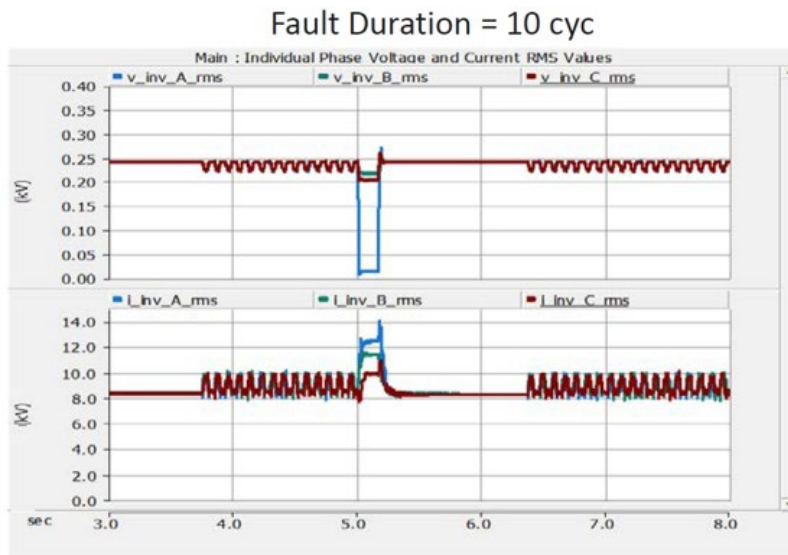


# 3-Phase Faults on Transformer HV Side - 2



- ◆ The fault current contribution is limited, it's only 1.4 times of rated;
- ◆ The fault currents are symmetrical;
- ◆ Inverters were shut-off in 11-cycle & come back after HV fault isolation.

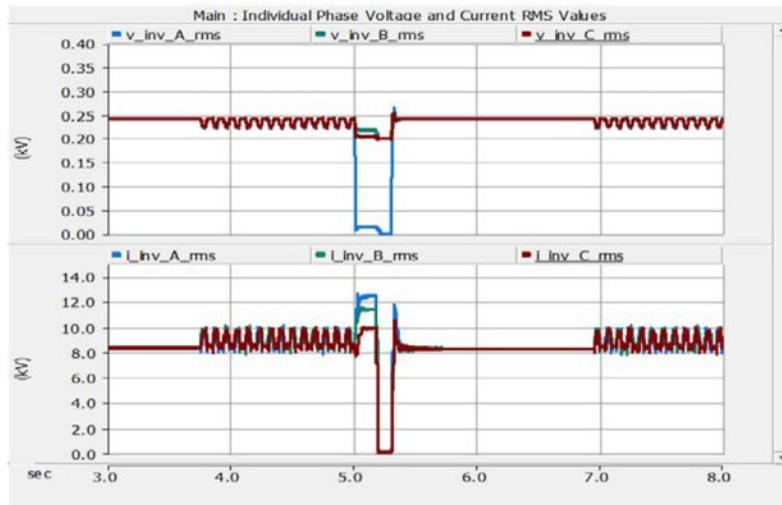
# Phase-Phase Faults on Transformer HV Side - 1



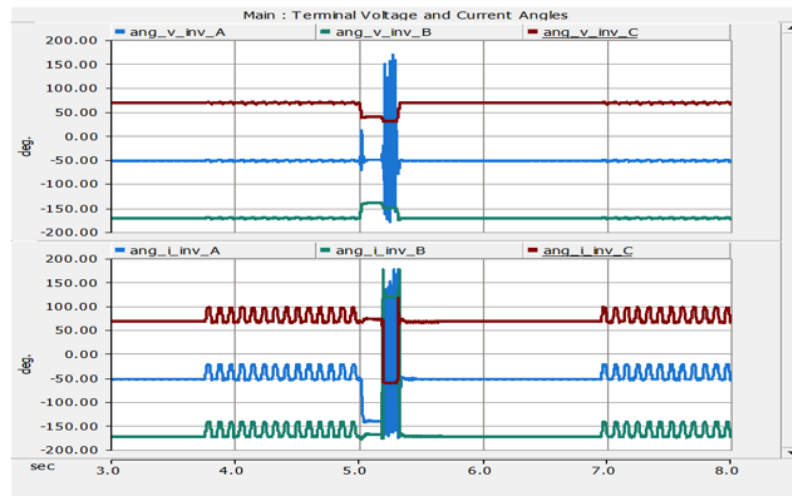
- ◆ Transformer HV side phase A-B fault with duration 10-cycle
- ◆ Measurements at inverter terminal
- ◆ Fault current contribution is still limited
- ◆ A-phase voltage is dropped while VB & VC are not much changes
- ◆  $I_A \neq I_B$  due to previous load current superimposition
- ◆ The phase angle of IB not changed &  $\angle I_{AB}$  is 30-deg

# Phase-Phase Faults on Transformer HV Side - 2

Fault Duration = 18 cyc

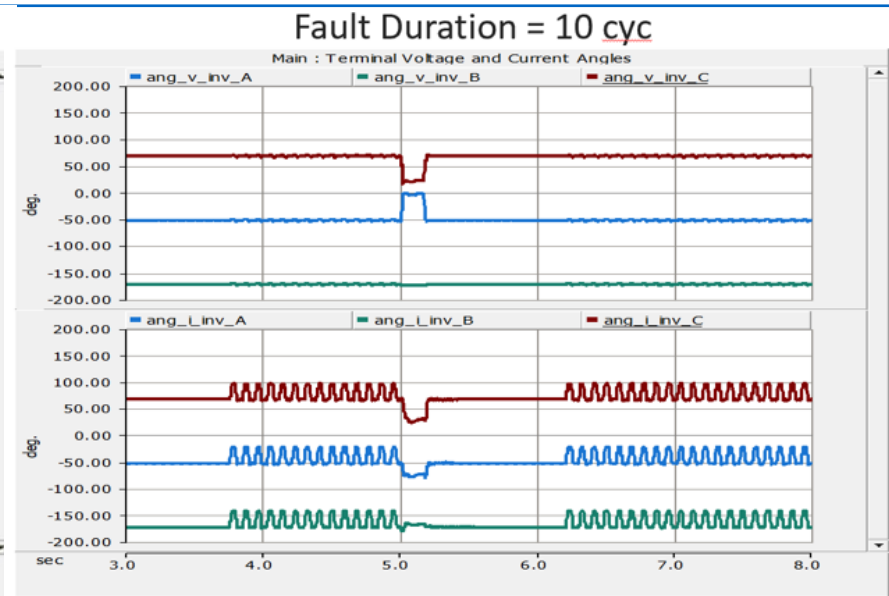
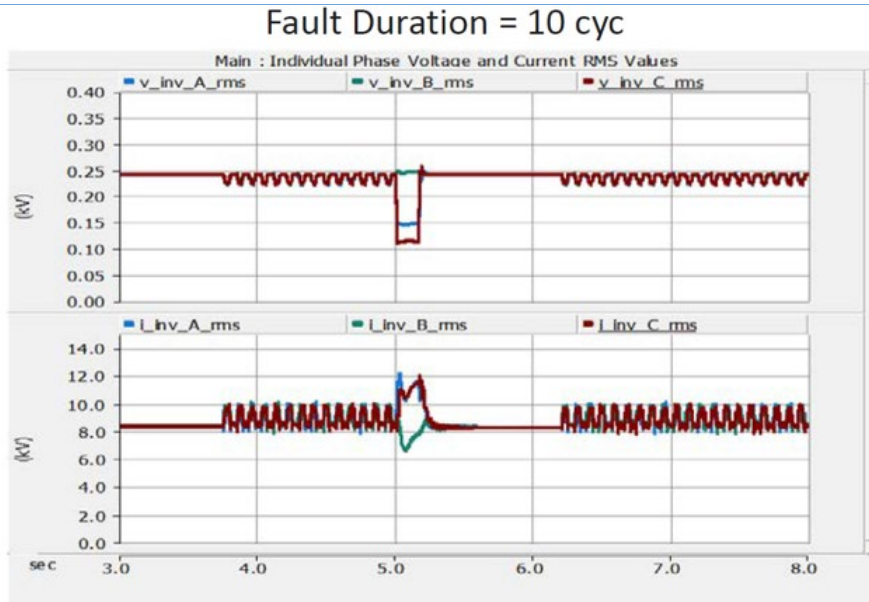


Fault Duration = 18 cyc



- ◆ Transformer HV side phase A-B fault with duration 18-cycle
- ◆ Inverters were shut-off in 11-cycle & come back after HV fault isolation.
- ◆ Voltage & current are similar to 10-cycle fault duration case

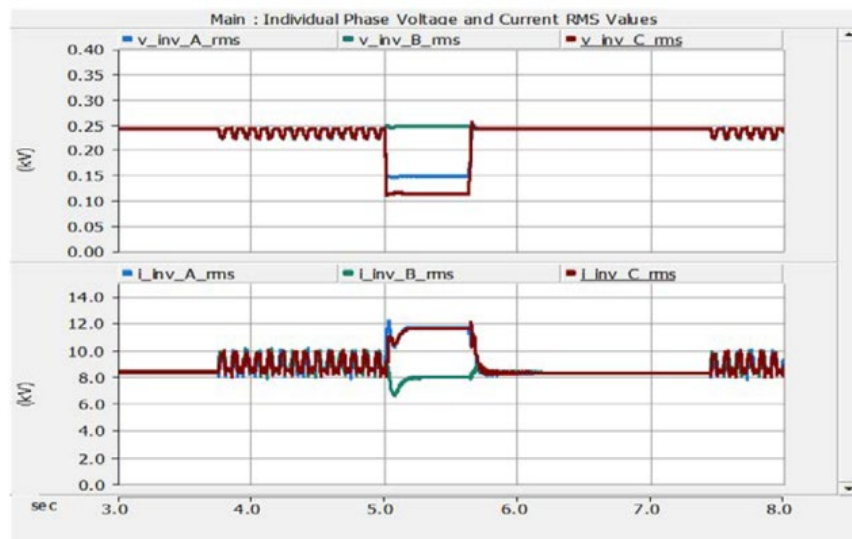
# SLG Faults on Transformer HV Side - 1



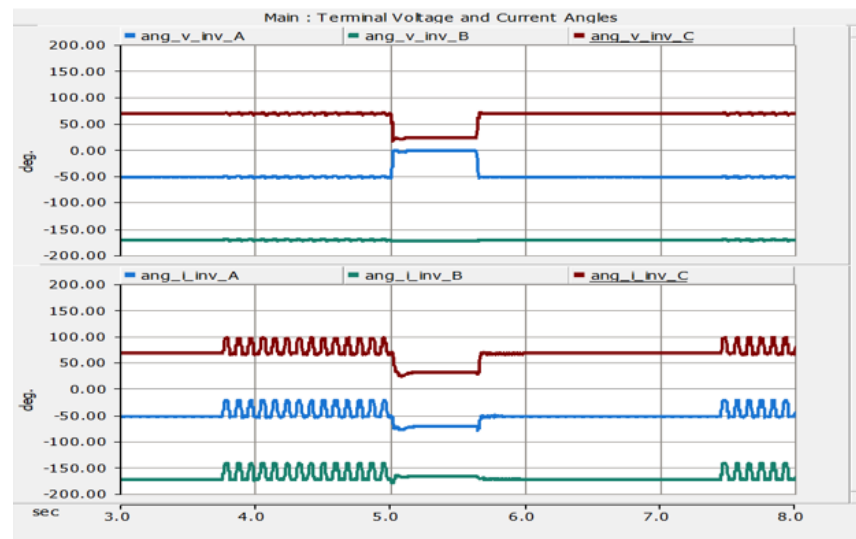
- ◆ SLG (A-GND) fault on transformer HV side with duration 10-cycle
- ◆ GND bank is connected to transformer HV delta winding
- ◆ Fault current magnitude is limited and current phase angles are symmetrical

# SLG Faults on Transformer HV Side - 2

Fault Duration = 38 cyc



Fault Duration = 38 cyc



- ◆ SLG (A-GND) fault on transformer HV side with duration 38-cycle;
- ◆ Fault current magnitude is limited & current phase angles are symmetrical;
- ◆ The inverters are able to ride through the external fault

# Challenges for feeder protections at Bunker Rd station

Feeder protections phase & GND DOC with inverter sources sitting behind:

1. No accurate model for inverter sources in ASPEN;
2. Fault current contributions from DER sources are very limited,
3. V & I behaviors are totally different from conventional rotational machine sources;
4. Makes negative sequence polarization very unreliable for 67 (directional OC);
5. End of feeder fault current may be less than max load current;
6. The vendor shall be consulted for the behavior of inverters during fault;
7. Recommend to build PSCAD model & run real-time fault simulations

# PSCAD simulation at National Grid

- ◆ NG purchased PSCAD/EMTP software for further studies
- ◆ BESS converter incorporated into NG system equivalent model
- ◆ Fault simulations were performed and current /voltage waveforms were observed
- ◆ Relay behaviors for different fault locations can be predicted.
- ◆ Fault comtrade files can be created for relay testing

## Other considerations with DER source:

1. When DER step-up transformer is D/Y connection without grounding bank on HV side, zero sequence over-voltage (59N) is required to shut-down converter or trip transformer in order to isolate SLG fault on HV side;
2. Transformer LV side 67 toward system may be required to isolate the phase fault in the transformer HV side;
3. Transformer HV side 67 is from system toward transformer/converter, load encroachment with conventional PF 0.85 may not work as P&Q transmission could be different from conventional generator. For this particular application, P & Q can work in any quadrant of  $P+jQ$  plane;

# Thanks

◆ **Questions or comments?**



# **Order No. 2222**

## *Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs*

**Date: October 15, 2020**

**David Kathan, Ph.D.**

**Federal Energy Regulatory Commission**

*Views expressed do not necessarily represent the views of the Commission or any Commissioner.*

# Order No. 2222 Summary

- Builds on Order No. 841 reforms on electric storage resources
- Finds that
  - Existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of DER aggregations in the RTO/ISO markets. (P1)
  - By removing barriers to the participation of DER aggregations in the RTO/ISO markets, the Final Rule enhances competition and, in turn, helps to ensure that the RTO/ISO markets produce just and reasonable rates. (P3)
  - RTOs/ISOs must amend their tariffs to allow DER aggregators to participate in their markets

# Definition of DERs

- Defines a DER as “any resource located on the distribution system, any subsystem thereof or behind a customer meter.” (P114)
  - These resources may include, but are not limited to, resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.
- Defines a DER aggregator as “the entity that aggregates one or more DERs for purposes of participation in the capacity, energy and/or ancillary service markets of the RTOs and/or ISOs.” (P118)
  - The DER aggregator is the RTO/ISO market participant, not the DER

# Commission Jurisdiction

- Commission exercises jurisdiction over the sales by DER aggregators into the RTO/ISO markets. (P43)
  - Consistent with the rationale in Order No. 841 (electric storage resource injecting electric energy back to grid to participate in RTO/ISO market engages in wholesale sale).
  - Consistent with *FERC v. EPSA* (Supreme Court held FERC has jurisdiction over participation in RTO/ISO markets of demand response resources).
- Nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system. (P44)
  - All DERs must comply with any applicable interconnection and operating requirements.

# Commission Jurisdiction

- The Final Rule declines to include a mechanism for all relevant electric retail regulatory authorities (RERRAs) to prohibit all DERs from participating in the RTO/ISO markets through DER aggregations, otherwise known as an opt-out. (P56)
  - Similar to the decision to decline to include an opt-out in Order No. 841, which the D.C. Circuit upheld.
- The Final Rule establishes an opt-in mechanism for small utilities (4 million MWh or less) (P64)
  - Similar to the opt-in provided in Order No. 719-A.

# DER Interconnection Jurisdiction

- Commission declines to exercise jurisdiction over the interconnection of a DER to a distribution facility when that resource interconnects for the purpose of participating in RTO/ISO markets exclusively through a DER aggregation. (P90)
  - I.e., does not apply “first use” policy from Order Nos. 2003 and 2006 to these resources.
- State or local law will govern distribution-level interconnections for DERs participating in RTO/ISO markets exclusively through an aggregation. (P92)

# Required RTO/ISO Tariff Provisions

- For each RTO/ISO, the tariff provisions addressing distributed energy resource aggregations must:
  - Allow DER aggregations to participate directly in RTO/ISO markets and establish DER aggregators as a type of market participant;
  - Allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations;
  - Establish a minimum size requirement for DER aggregations that does not exceed 100 kW;
  - Address locational requirements for DER aggregations;

# Required RTO/ISO Tariff Provisions (Cont.)

- Address distribution factors and bidding parameters for DER aggregations;
- Address information and data requirements for DER aggregations;
- Address metering and telemetry requirements for DER aggregations;
- Address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the RERRAs;
- Address modifications to the list of resources in a DER aggregation; and
- Address market participation agreements for DER aggregators.

# Details of Key Provisions

- DER aggregator is single point of RTO/ISO contact: responsible for managing, dispatching, metering and settling the individual resources. (P266)
  - If a DER aggregator makes sales of energy to RTO/ISO, it is a public utility (subject to MBR, EQR, and other requirements). (P42)
  - While the DER aggregator will be the entity primarily responsible for providing required metering and telemetry information to an RTO/ISO, RTOs/ISOs are given flexibility on whether to require metering and telemetry of individual DERs. (P267)
- Heterogenous aggregations (different resource types) must be allowed. Single resource aggregations will be allowed. (P142)
  - However, participation of demand response in DER aggregations will be subject to the opt-out and opt-in requirements of Order Nos. 719 and 719-A. (P145)
- Minimum size requirement for DER aggregations can be no more than 100 kW. Rule does not adopt a maximum size for a DER aggregation. (P171)

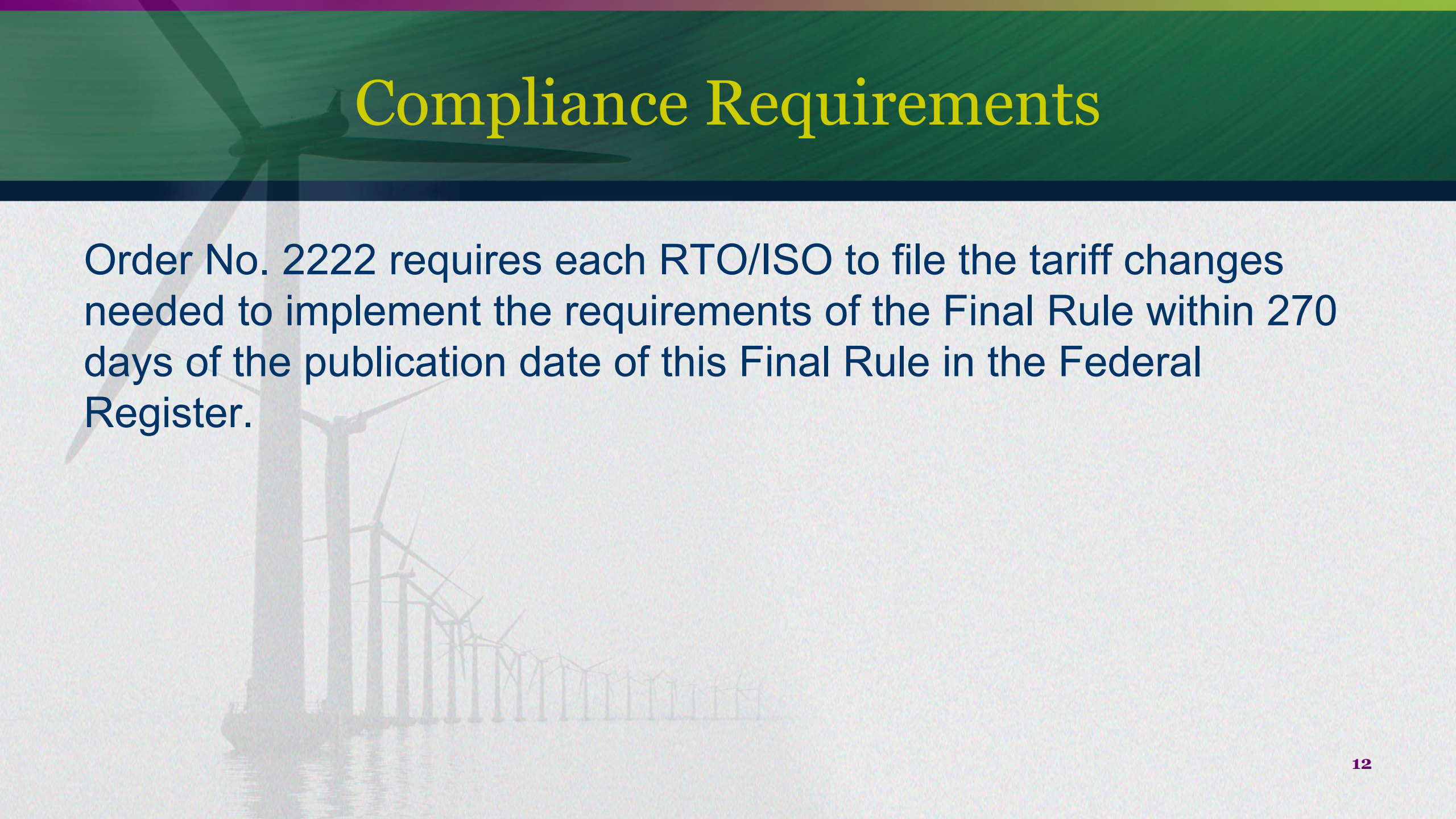
# Details of Key Provisions

- Rule does not adopt a minimum or maximum size of resources that can participate in an aggregation, but each RTO/ISO must propose a maximum size for individual DERs. (P179)
- Each RTO/ISO must propose locational requirements that are "as geographically broad as technically feasible," which may include multi-node aggregations. (P204)
- RTOs/ISOs must allow dual participation in retail programs and allow DERs to provide multiple wholesale services; they may create accounting/operational rules to avoid double payment. (P160)
  - RERRAs are able to condition a DER's participation in a retail DER program on that resource not also participating in the RTO/ISO markets (P61)

# Details of Key Provisions

- Coordination Requirements for RTOs/ISOs:
  - Must revise its tariff to establish market rules that address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and RERRAs. (P278)
  - Must incorporate a comprehensive and non-discriminatory process for timely review by a distribution utility of the individual DERs that comprise a DER aggregation. (P292)
  - Must establish a process for ongoing coordination, including operational coordination, that addresses data flows and communication among itself, the DER aggregator, and the distribution utility. (P310)
  - Must identify how it will accommodate and incorporate voluntary RERRA involvement in coordinating the participation of aggregated DERs in RTO/ISO markets. (P322)

# Compliance Requirements

The background of the slide features a large, semi-transparent image of a wind farm. In the foreground, a single large wind turbine is visible on the left, with its blades extending towards the top left. In the background, a long line of smaller wind turbines stretches across the horizon. The top of the slide is covered by a solid green horizontal bar.

Order No. 2222 requires each RTO/ISO to file the tariff changes needed to implement the requirements of the Final Rule within 270 days of the publication date of this Final Rule in the Federal Register.



# QUESTIONS?

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