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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)
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Revision History

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

Contents

Commented [HS1]: Add a section on Resource Adequacy modelling after Effective GRounding

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[1] 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"[2] 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.

[1] 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,

[2] "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[3]. 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

[3] 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 reliablity 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[4]. 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.

[4] 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 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[5].

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.

[5] 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[6]. 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

[6] 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 rang 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.)1 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)[7]. 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.

[7] This document can be found on the Department of Public Service website (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 reliably 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 form 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.

Commented [HS2]: I put this here as a placeholder. More can be said if needed.

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.

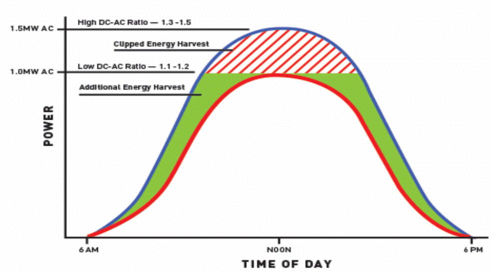


Figure 1- Storage showing Clipped and Unused Energy

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.

<u>Planning Related Recommendations Due to Changing Resource Mix</u>

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[8]
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.

<u>Analytics and simulation recommendations to deal with increase system complexity</u>

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.

[8] 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

NPCC, Inc.

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

Distributed Energy Resource (DER), BES Impact Reporting Form

Name		**Date**	
Email		Company	
Impact on Bulk Electric System		Area (NY, NE, State or Province etc.)	

Equipment Impacted

Equipment	**Location** (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,** (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.

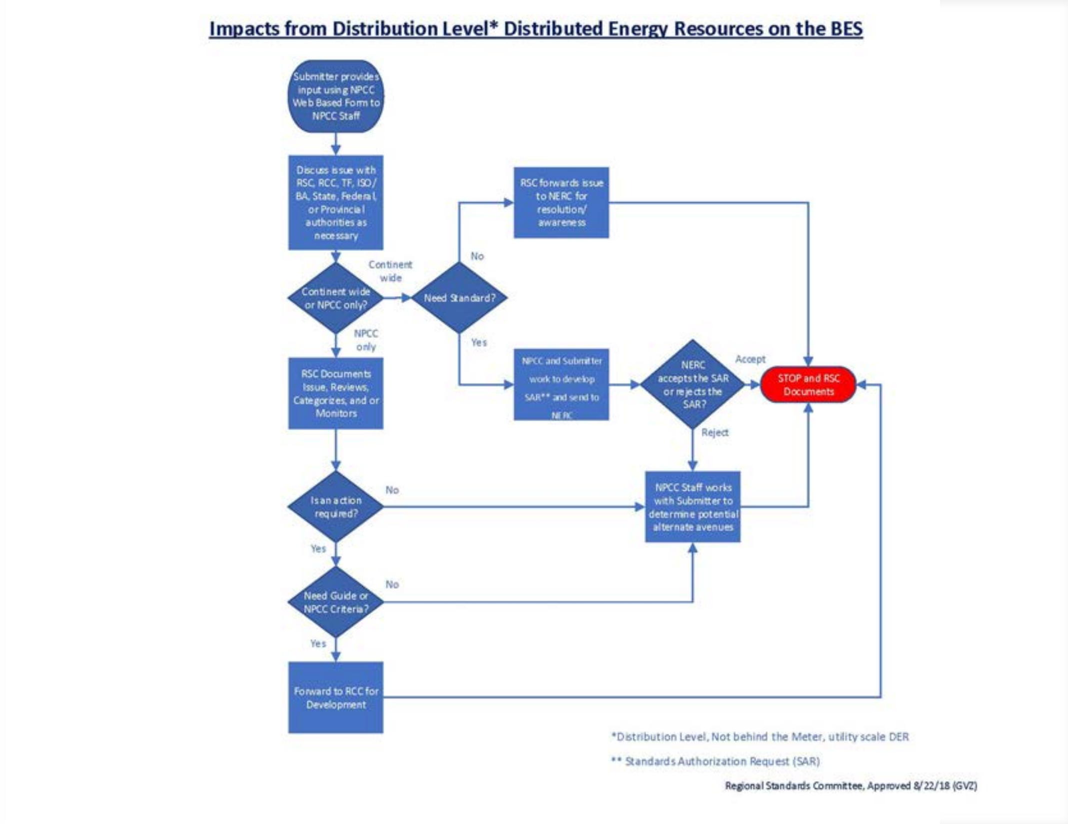
Root Cause or additional Analysis

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[9]	IESO F2 Technical Requirements

[9] 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[10]	yes	yes	yes
Frequency Response	yes[11]		yes	yes
Abnormal performance capability (ride-through) requirements for ~~inverter based~~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

[10] 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

[11] 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

recommended practices and guidance provided by SPIDERWG, in many cases, will need to be adapted to 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"[12]:

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 (here)

[12] Available here: https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf

	DER_A Model Parameterization	Guideline providing recommendations for using state-of-the-art aggregate DER dynamic models in BPS reliability studies.	Published (here)
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 (here)
	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 (here)

	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[13], 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

[13] See NERC Rule of Procedure #313 on page 15 of the NERC Rules of Procedure 3-9-2018.

requirements. NPCC's core Reliability Principles[14] and activities support the NERC Bulk Electric System and NPCC's Bulk Power System reliability.

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[15]. These critical facilities collectively are identified as the NPCC Bulk Power System[16,17].
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[18] 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."

[14] The Reliability Principles were summarized in the NPCC 2018 Strategic Review Report.
[15] 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.
[16] 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.
[17] 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
[18] 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[19] [20] 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:
    a. Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
    b. Resourcefulness – The ability to detect and manage a crisis as it unfolds.
    c. Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
    d. Adaptability – The ability to absorb new lessons from events

NERC, Model of Resilience

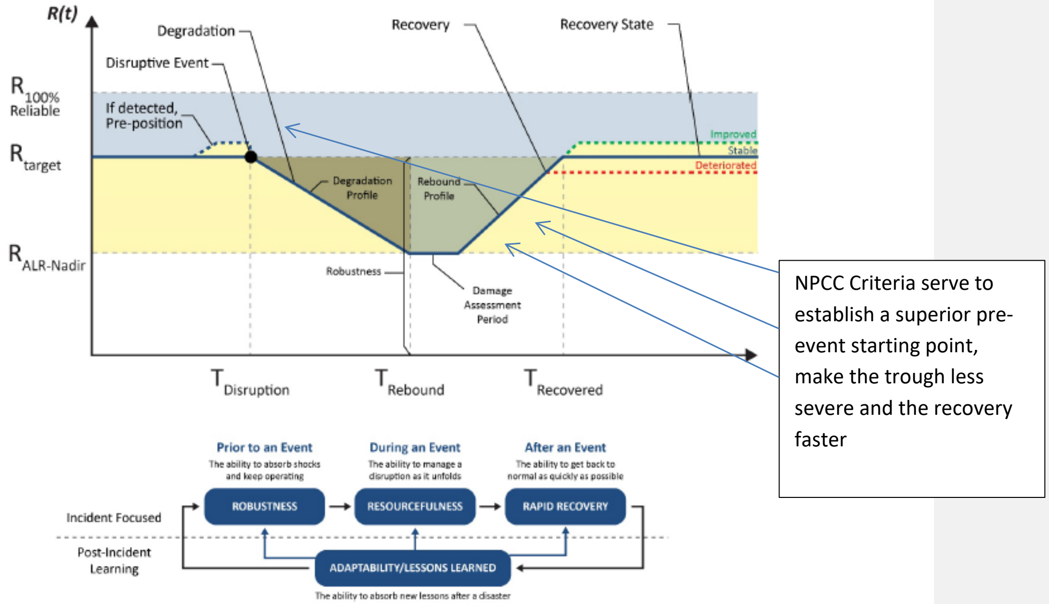


Figure 2.1

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

[19] 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.

[20] 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

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

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

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

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

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

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

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

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
PUC Rule 5.500 – Application Form
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

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 (HQCMÉ) 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_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)

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

Ènergie 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 (2nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd 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 (2nd 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 (2nd ed.) for Category II
V > 1.20	Cease to Energize	N/A	0.16	Identical
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A	Identical
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A	Identical
1.10 < V ≤ 1.15	Permissive Operation	1	N/A	Identical

0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A	Identical
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{VRT} = 3\text{ s} + \frac{8.7\text{ s}}{1\text{ p.u.}}(V - 0.65\text{ p.u.})$	N/A	Identical
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
0.30 ≤ V < 0.45	Permissive Operation [b]	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 (2nd ed.) for Category II
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ 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[2]
Q(V), Volt-Var Function with Watt or Var Priority	OFF 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

EPRI T&D Research Related to DER Integration

Devin Van Zandt, dvanzandt@epri.com
Jens Boemer, jboemer@epri.com

NPCC DER Forum Webinar

May 14, 2020

ELECTRIC POWER RESEARCH INSTITUTE

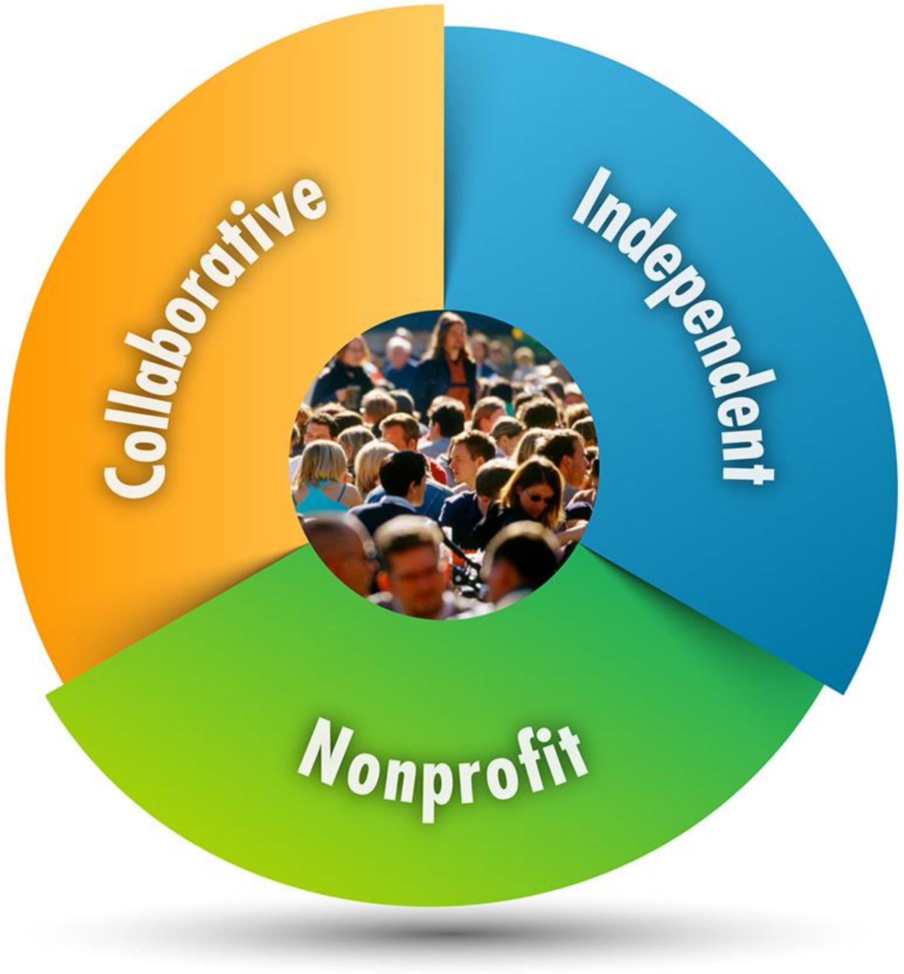
SOLAR ENERGY TECHNOLOGIES OFFICE
U.S. Department Of Energy

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 T&D Research
- EPRI COVID-19 Impacts Review
- Distribution System Topics
- Transmission System Topics
- Q&A

Three Key Aspects of EPRI



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Energy, Environment & Climate Policy

Integrated Energy System Planning, Fuels & Markets

Transmission Operations

Transmission Planning

Bulk System DER & Renewables Integration

Distribution Operations & Planning

Distributed Energy Resource Integration

Energy Storage Systems Integration

Impact on Demand of COVID-19 Shutdown

Email any insights related to COVID-19 on electricity systems to our confidential inbox: covid19-grid-impact@epri.com

Information and disclaimers about analysis

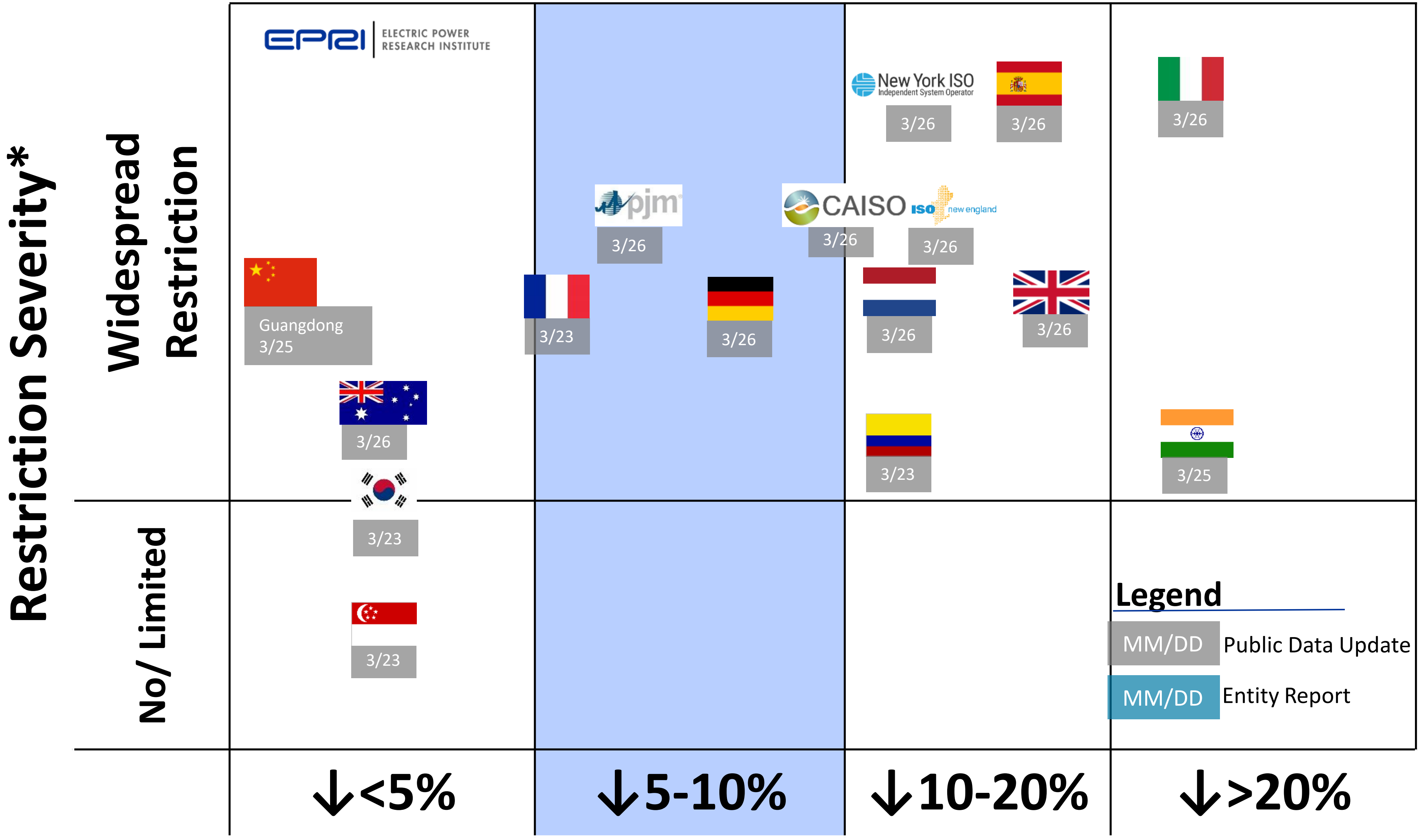
- **US and European Analysis based on publicly available data from ENTSO-E and EIA**:
  - https://transparency.entsoe.eu/ (account needed to download)
  - https://www.eia.gov/opendata/
  - Other countries based on data provided to us directly

- **Other factors are not considered but likely to impact load levels**
  - Temperature
  - Behind-the-meter resources, etc.
  - Underlying, non-COVID economic factors

- **EPRI continues to monitor and update this information**
- **Public Report Available: https://www.epri.com/#/pages/product/3002019435/**

Effective: Mar 27th

COVID-19 Demand Impact Classification



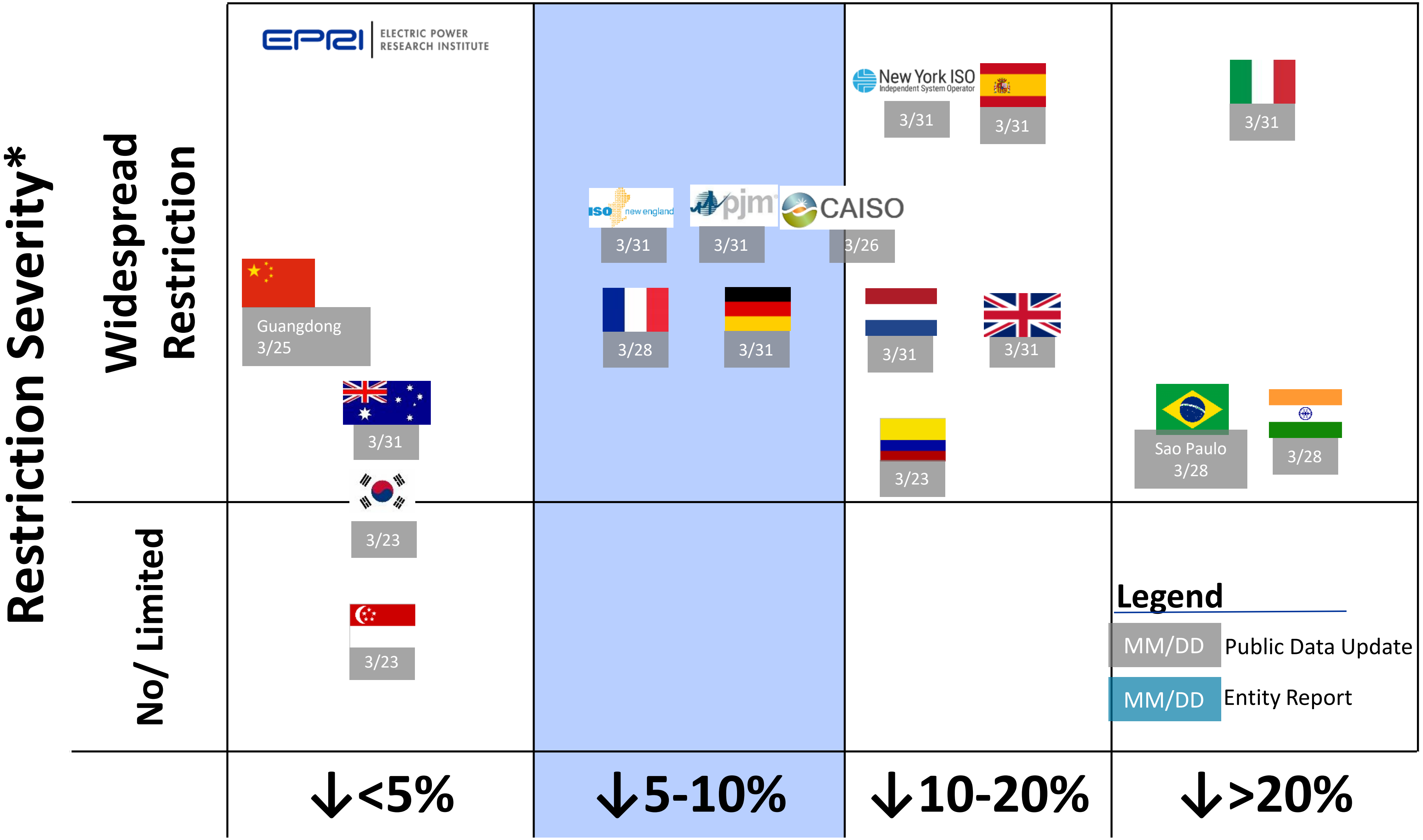
Daily Energy Impact

Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

COVID-19 Demand Impact Classification

Effective: Mar 31st



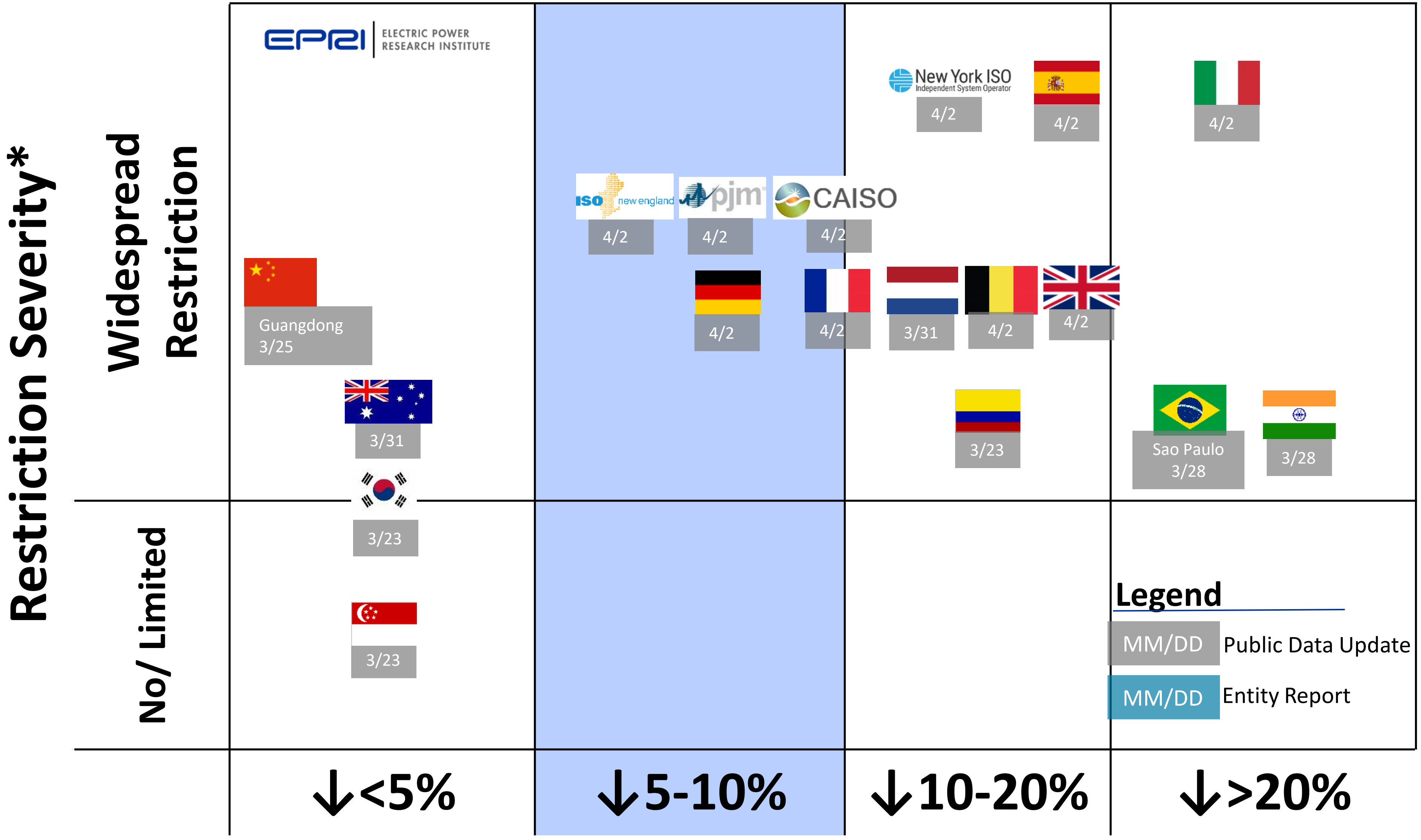
Daily Energy Impact

Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

COVID-19 Demand Impact Classification

Effective: Apr 3rd



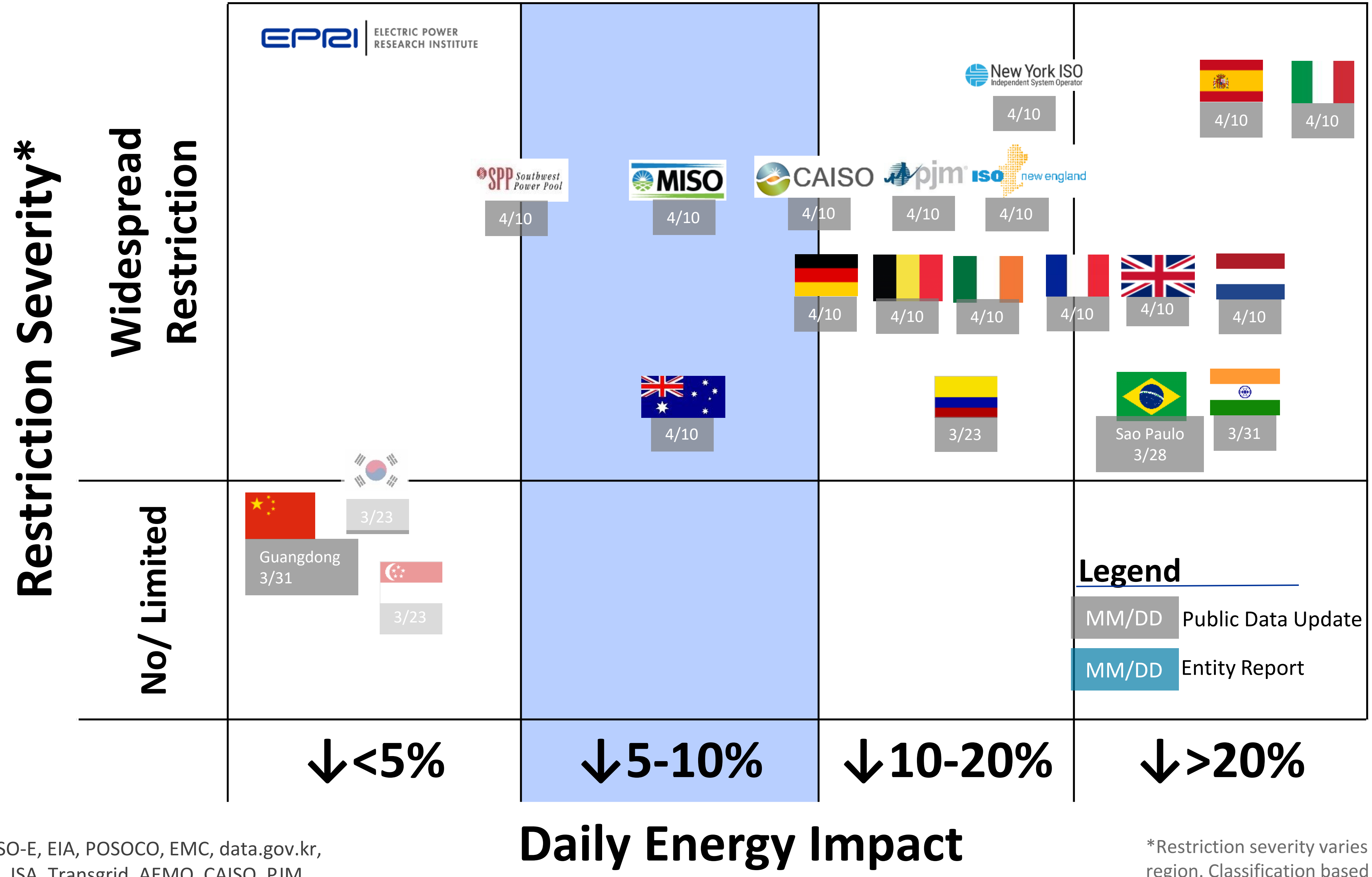
Daily Energy Impact

Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

COVID-19 Demand Impact Classification

Effective: Apr 10th

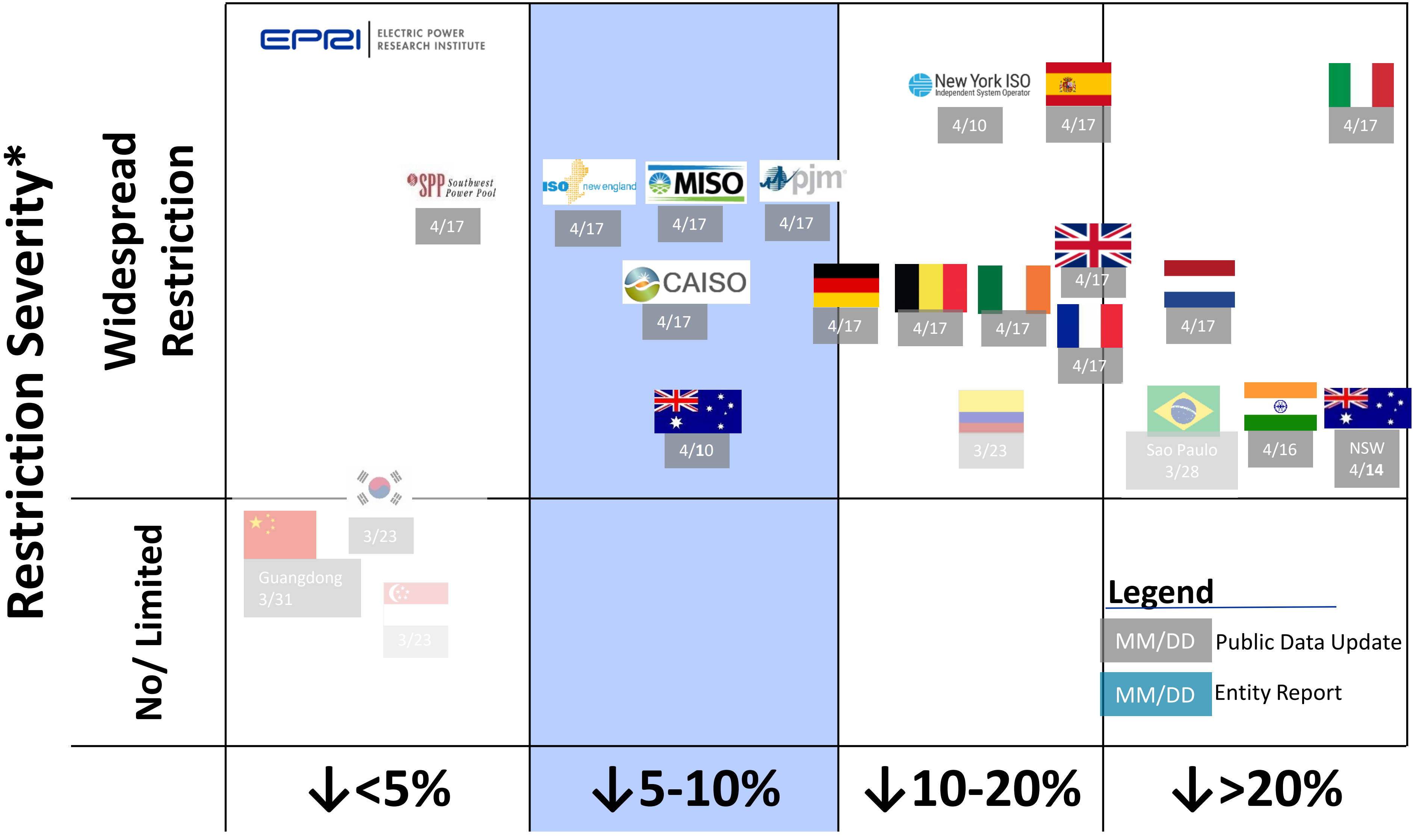


Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

COVID-19 Demand Impact Classification

Effective: Apr 17th

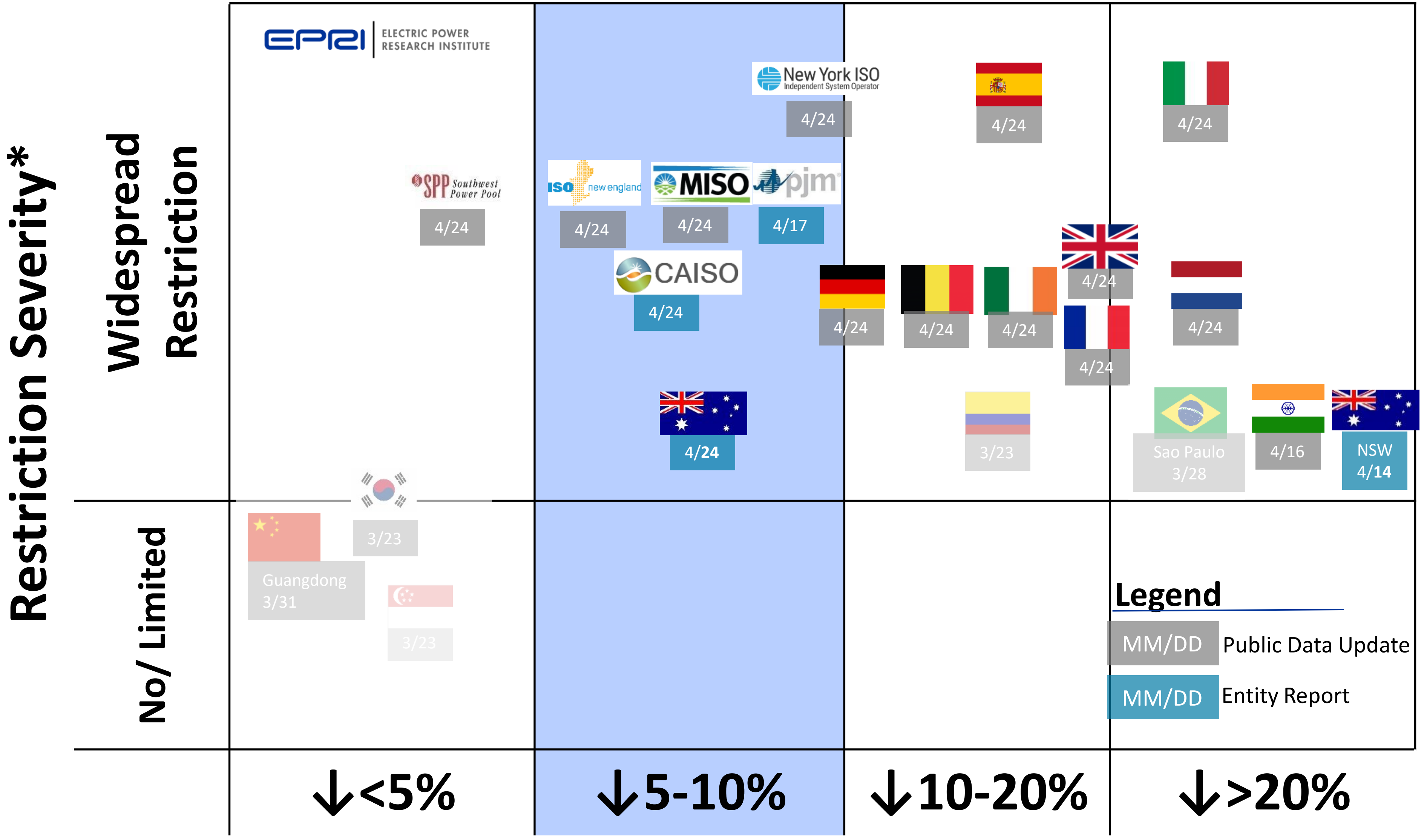


Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

Effective: Apr 24th

COVID-19 Demand Impact Classification



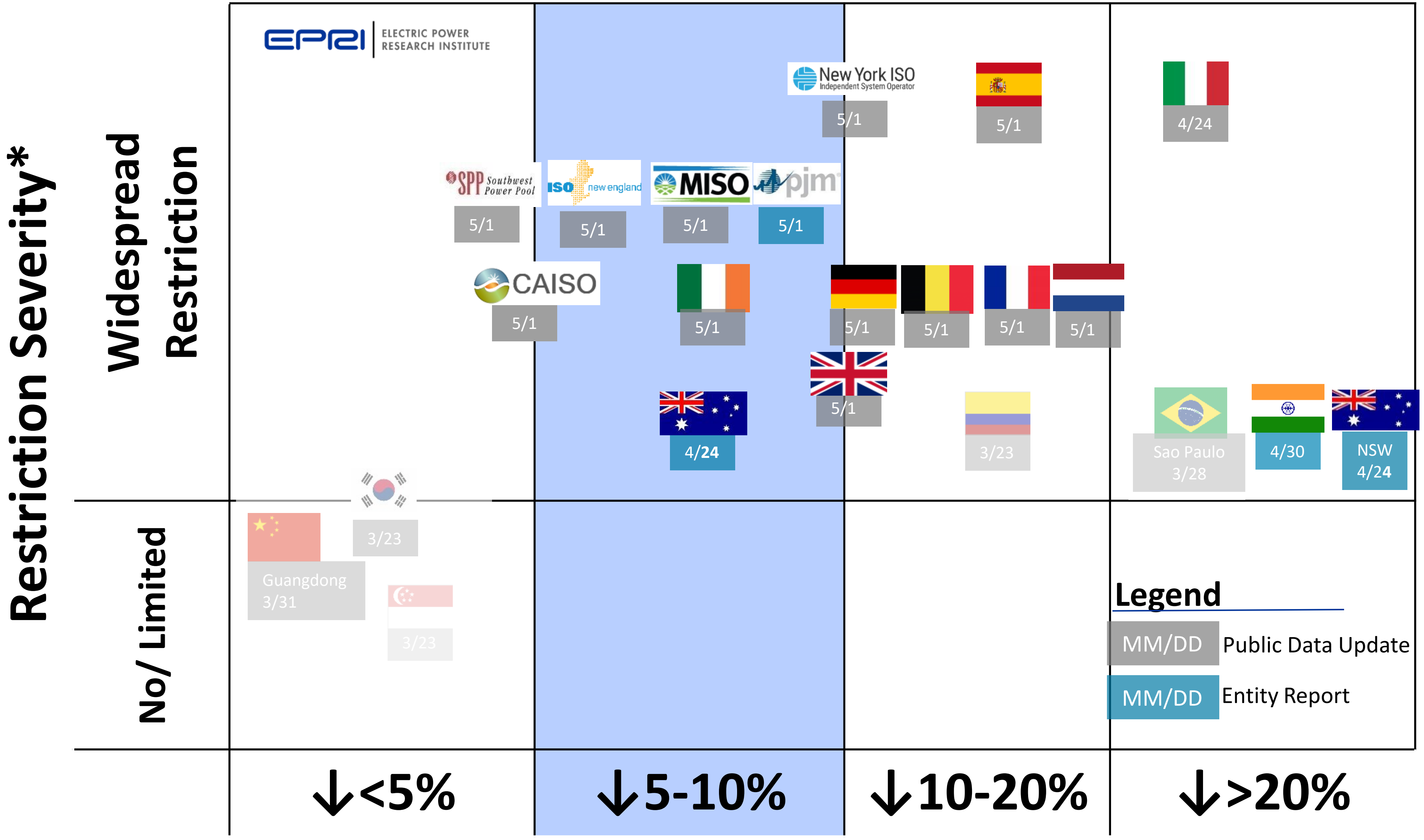
Daily Energy Impact

Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

COVID-19 Demand Impact Classification

Effective: May 1st



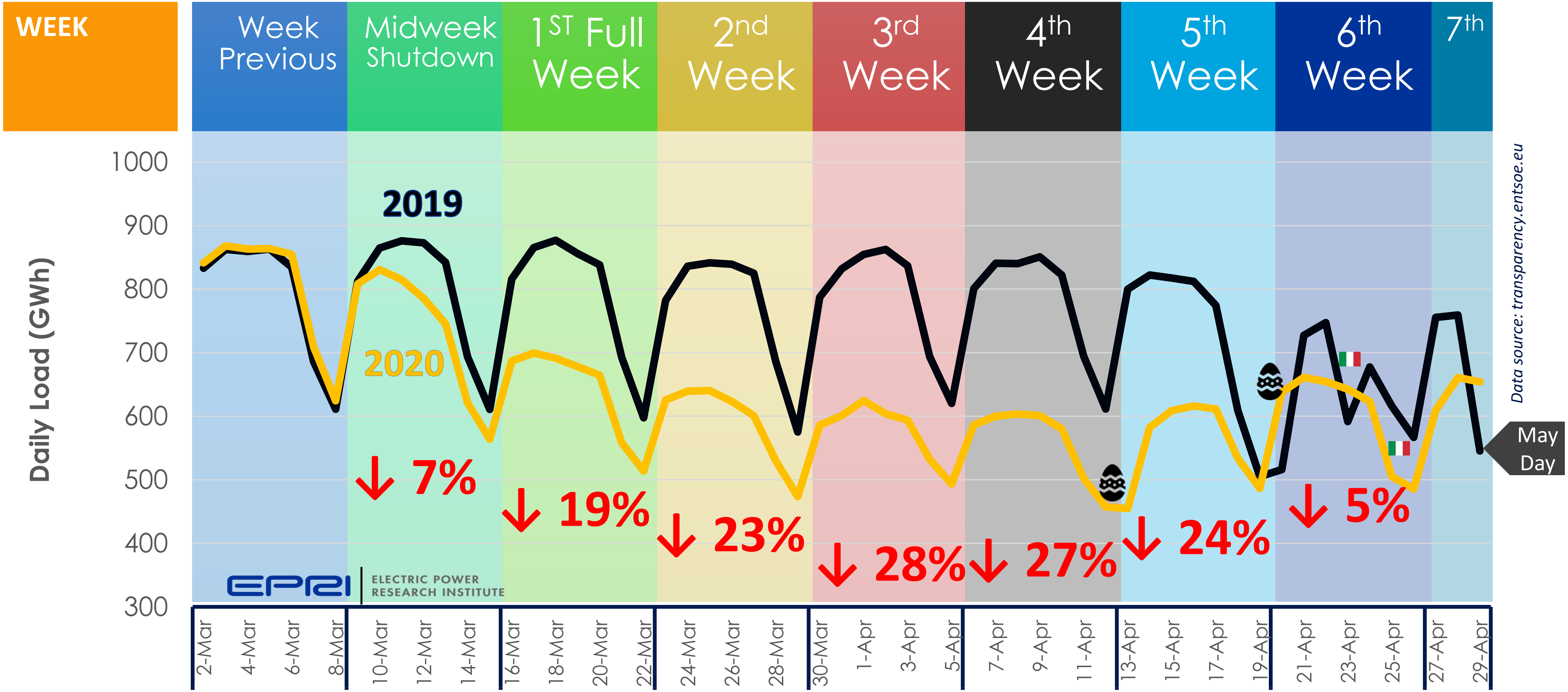
Daily Energy Impact

Data Sources: ENTSO-E, EIA, POSOCO, EMC, data.gov.kr, XM, bjx.com.cn, RTE, ISA, Transgrid, AEMO, CAISO, PJM

*Restriction severity varies substantially from region to region. Classification based on media reported restrictions

Italian Electricity Demand – 2019 vs 2020

Italia

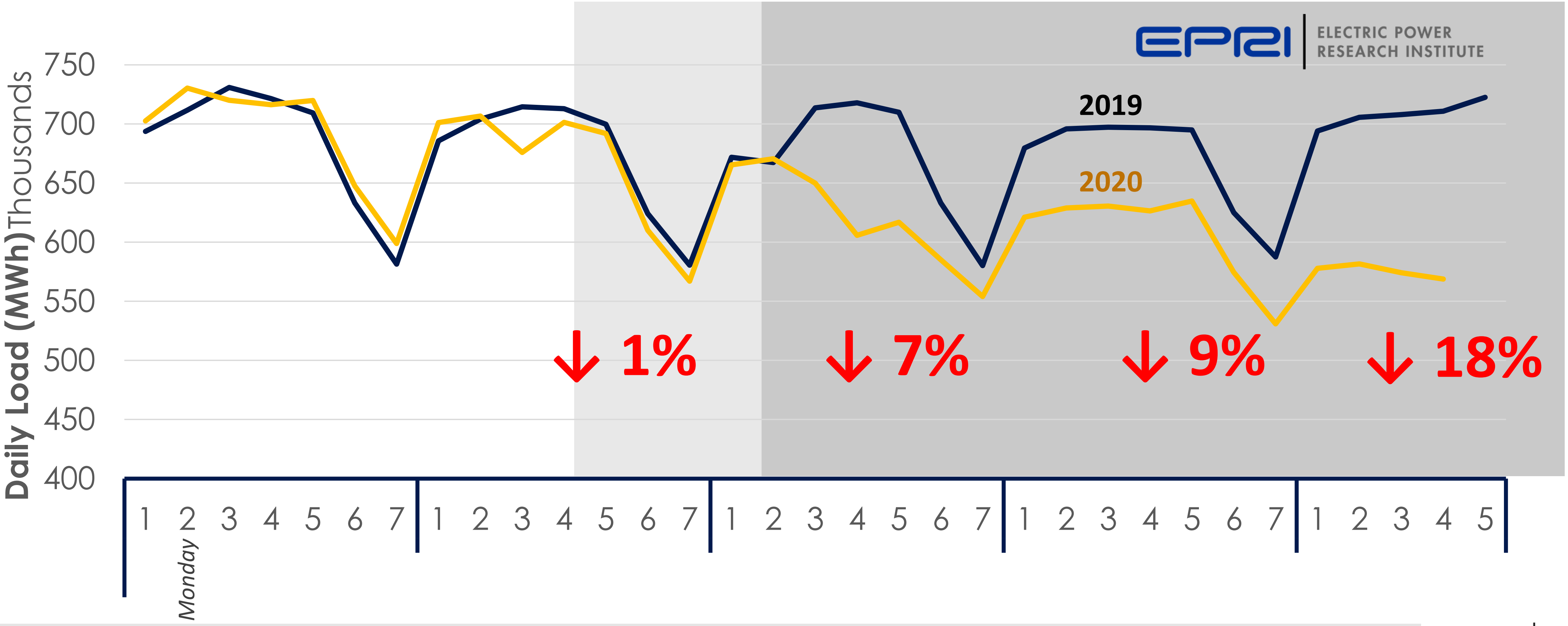


Weather and economic growth impacts not considered but clear trend observable

Spanish Load in First 4 Weeks - 2019 vs 2020

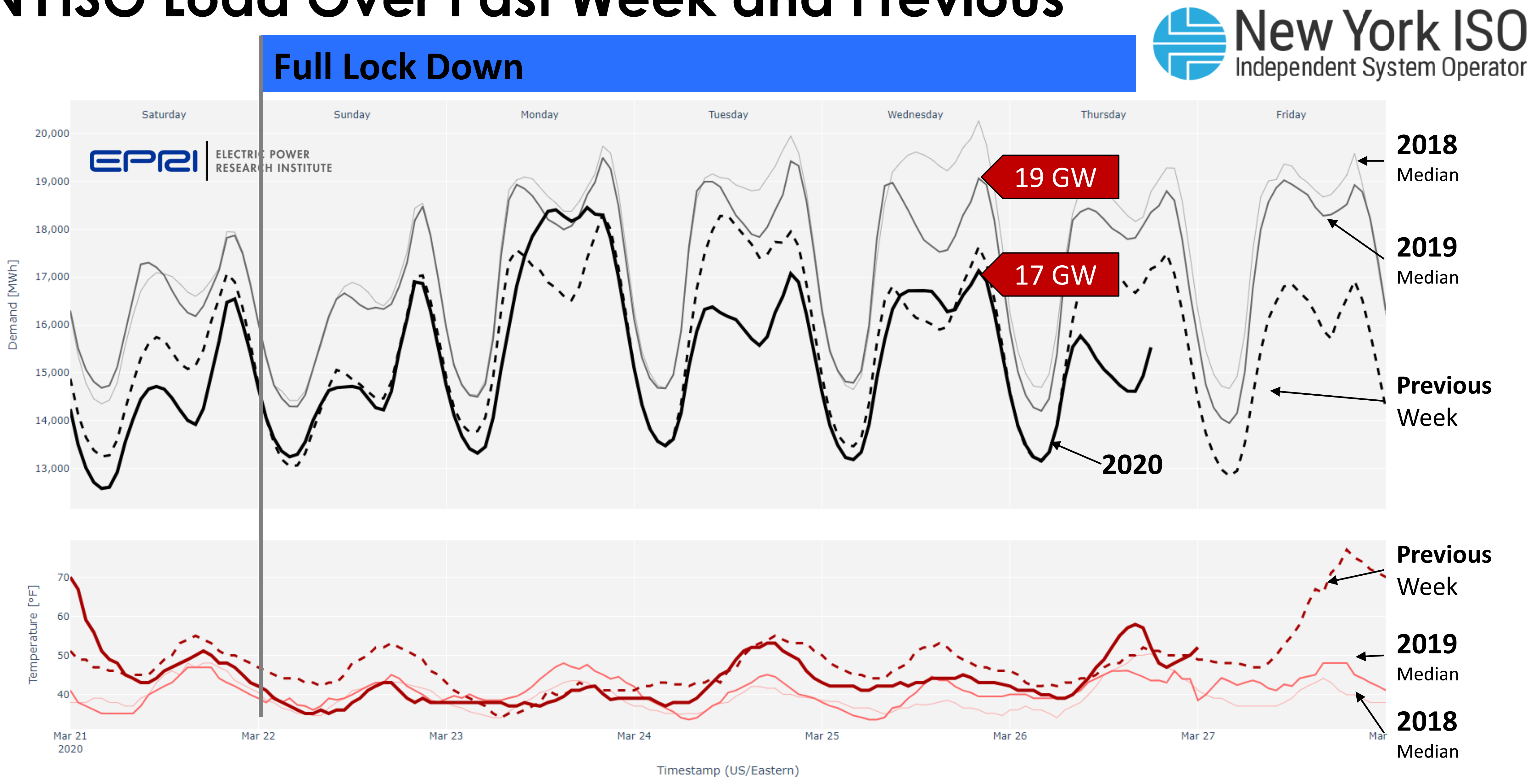
España

PHASE	Week Previous	Midweek Shutdown	First Full Week	Second Full Week	Third Week

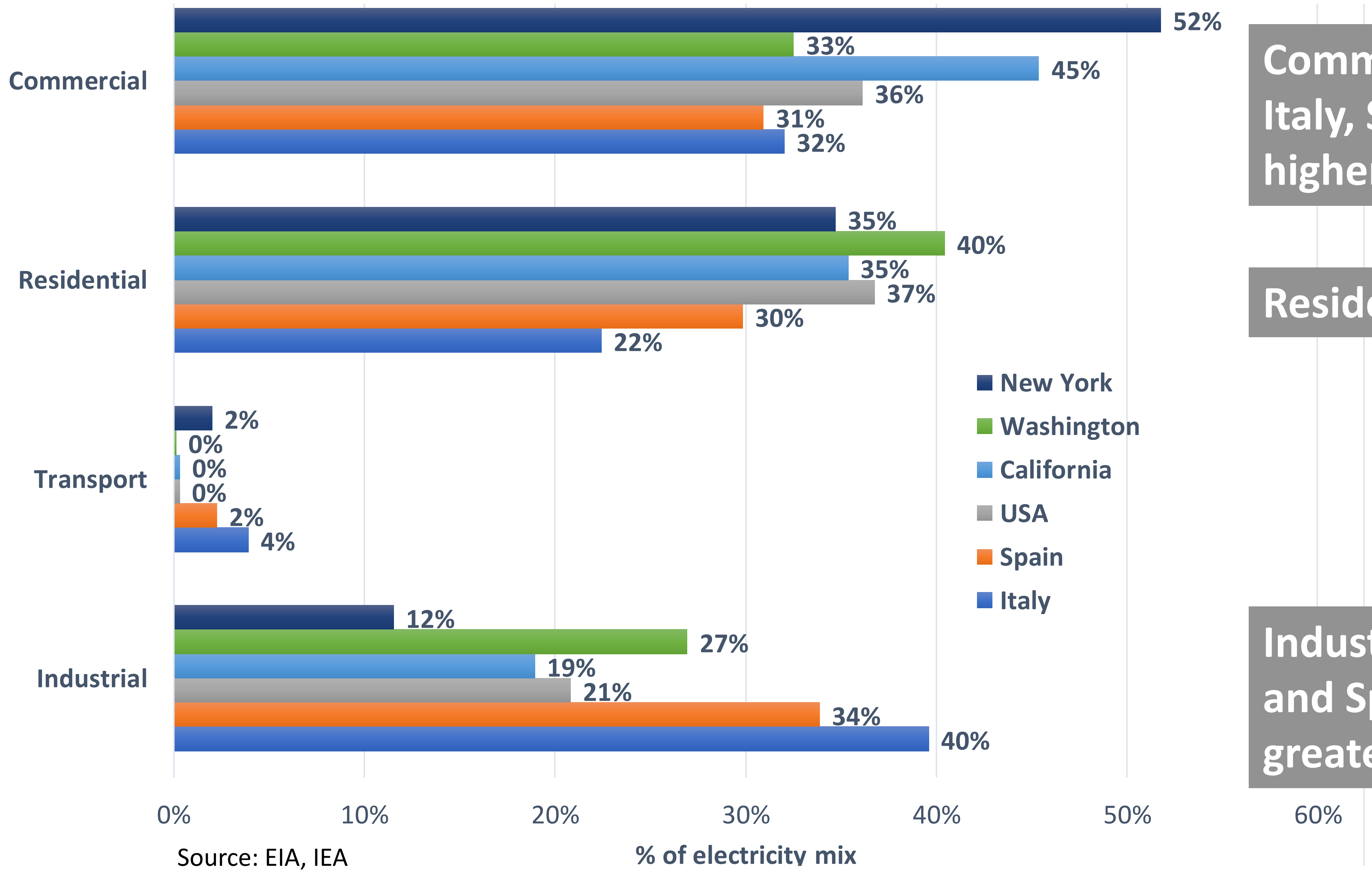


Data Source: transparency.entsoe.eu

NYISO Load Over Past Week and Previous



Comparison: Electricity Consumption Mix



Source: EIA, IEA

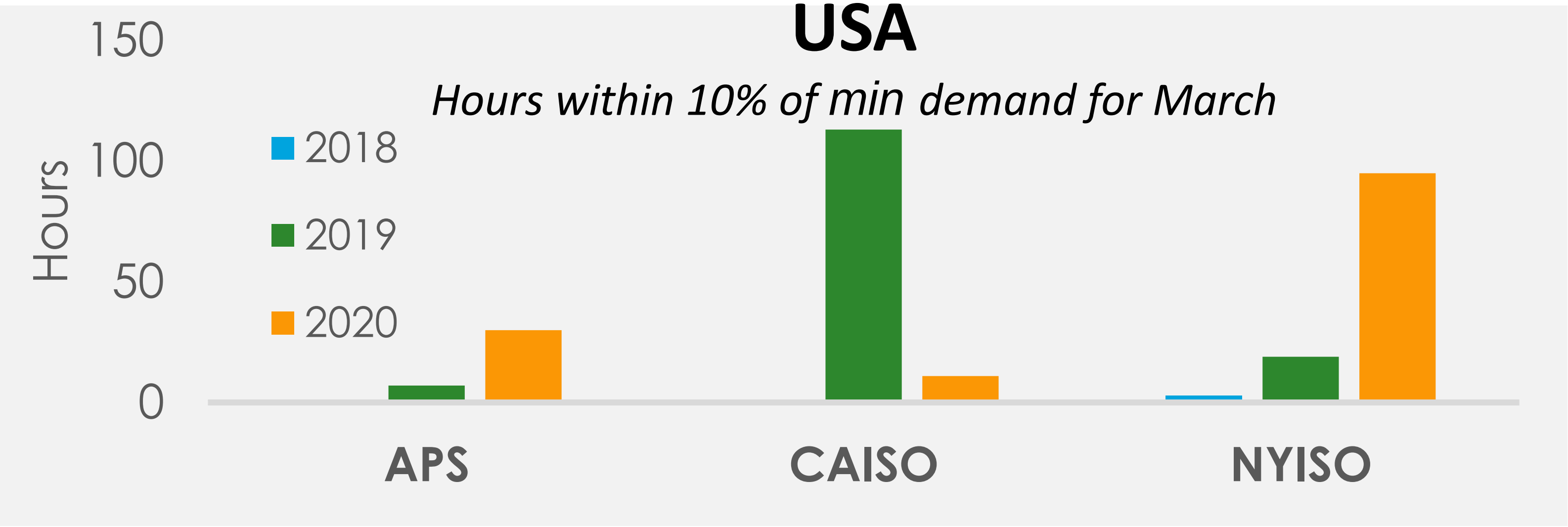
Commercial similar across Italy, Spain, and U.S, but higher in CA and NY.

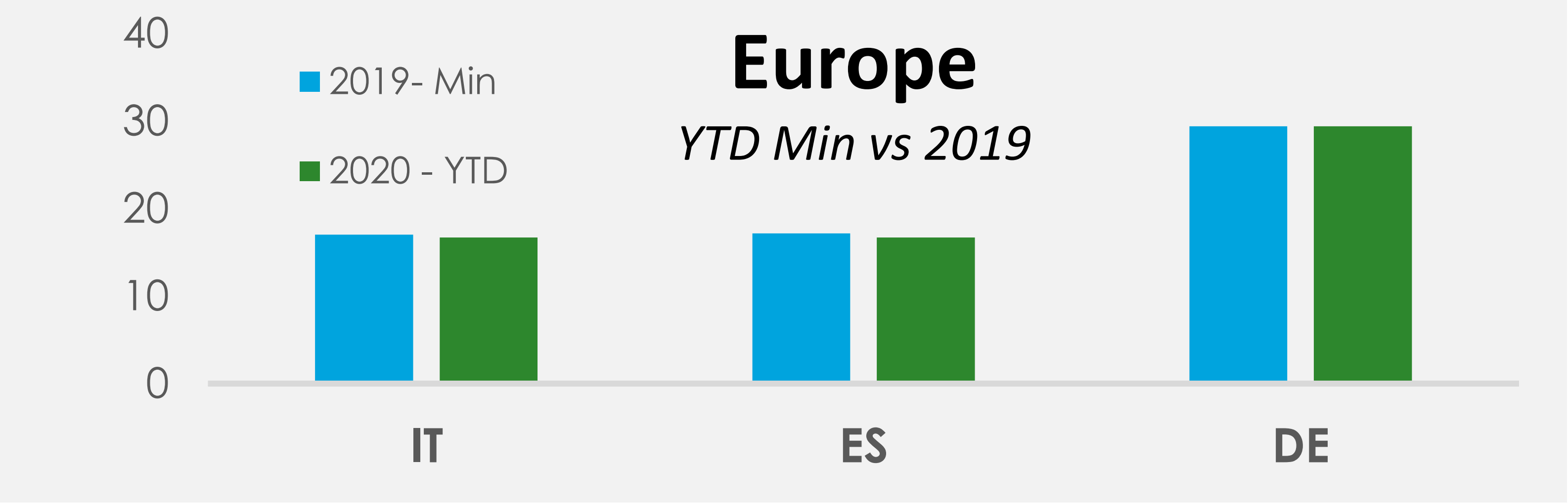
Residential lower in Italy.

Industrial higher in Italy and Spain; may result in greater impact

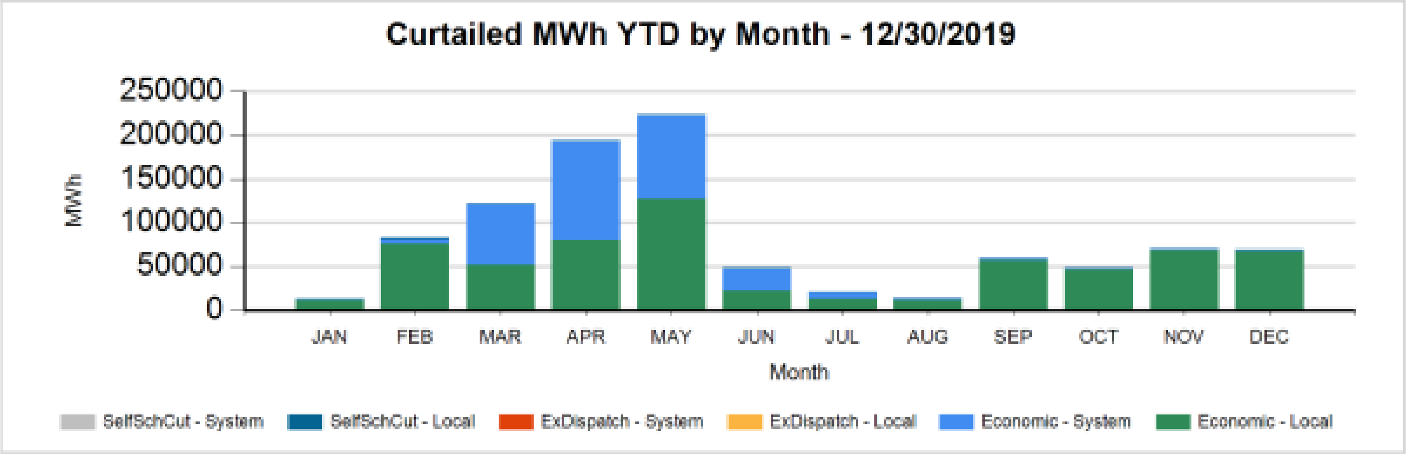
Annual and Monthly Min. Demands Records

- Several systems seeing record low minimum daily demands in US and Europe
- **78%** of extreme low demand periods in **NYISO** in March were **during day time**
- Issue **not** observed in CAISO thus far

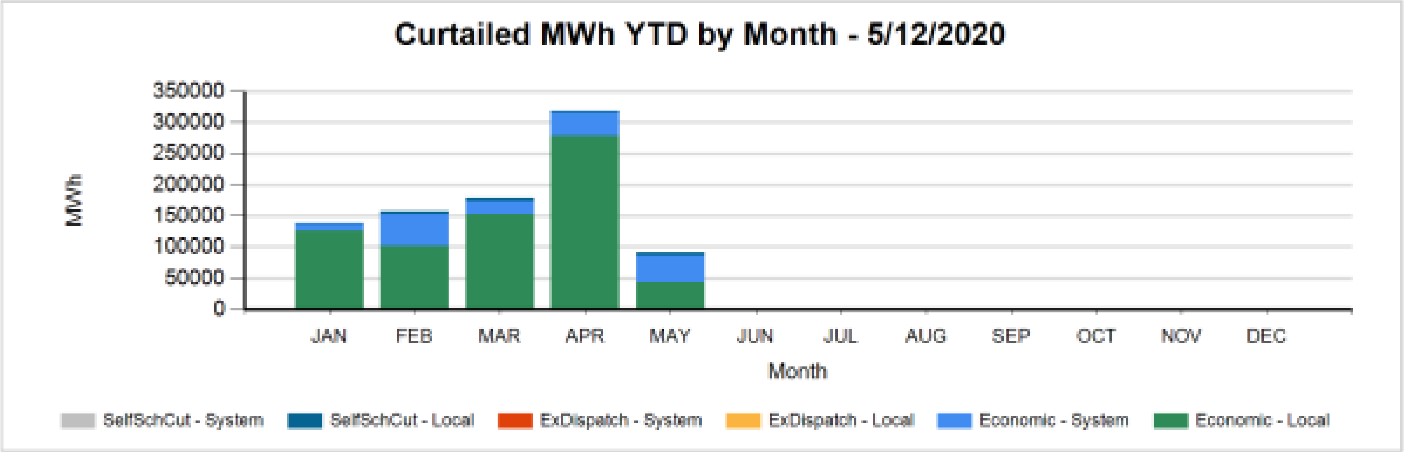




CAISO Renewable Curtailment



TYPE	YTD CURTAILED MWH - 12/30/2019
LocalEconomic	631,029
LocalSelfSchCut	6,382
SystemEconomic	327,597
TOTAL	965,007



TYPE	YTD CURTAILED MWH - 5/12/2020
LocalEconomic	702,849
LocalSelfSchCut	19,428
SystemEconomic	161,842
TOTAL	884,119

TYPE	YTD CURTAILED MWH
LocalEconomic	258,201
LocalSelfSchCut	5,529
SystemEconomic	205,636
TOTAL	469,365

88% Diff

YTD May 11, 2019

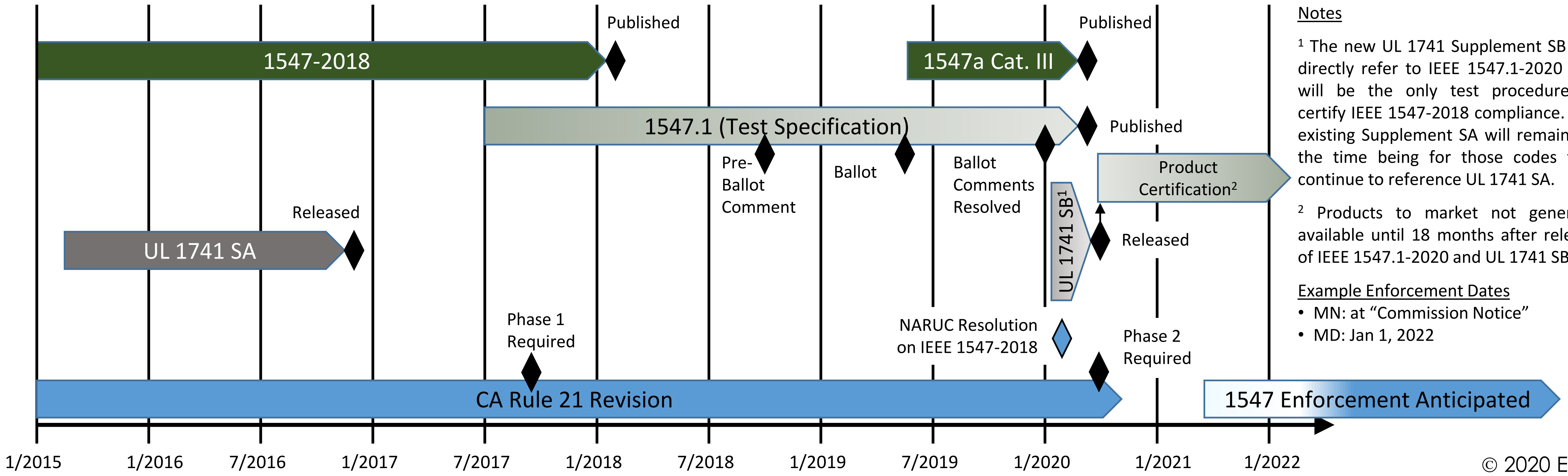
http://www.caiso.com/Search/Pages/All-WWW-Results.aspx?k=curtailment#k=curtailment#s=141

Distribution System Topics

Outline of Topics

- IEEE 1547-2018 Review and Timeline
- EPRI DER Integration Engagement
- DER Autonomous Functions
- DER Control/Management (DERMS)
- Key EPRI DER Interconnection Research

Timeline for Rollout of IEEE Std 1547™-2018 Compliant DER



Notes

[1] The new UL 1741 Supplement SB will directly refer to IEEE 1547.1-2020 and will be the only test procedure to certify IEEE 1547-2018 compliance. The existing Supplement SA will remain for the time being for those codes that continue to reference UL 1741 SA.

[2] Products to market not generally available until 18 months after release of IEEE 1547.1-2020 and UL 1741 SB.

Example Enforcement Dates
- MN: at "Commission Notice"
- MD: Jan 1, 2022

See also: https://site.ieee.org/sagroups-scc21/standards/1547rev/

Adoption of CA Rule 21 and Hawai'ian Rule 14H by inverter certification per UL 1741 SA.

Stopgap solution for **adoption of parts of IEEE Std 1547-2018** by inverter certification per UL 1741 SA.

Full adoption of IEEE Std 1547™-2018 by inverter certification per UL 1741 SB

Question from **distribution** perspective:

Need to increase DER Integration?

Question from **transmission** perspective:

Need to address bulk system reliability?

EPRI DER Integration Engagement

Adoption

- **Opportunities** to integrate DER reliably, securely, and efficiently into the grid
- **Key Considerations**
  - Consider adoption of standard at state-level
  - Specify “preferred” utility-required DER functional settings
  - Specify certification for DER equipment and potentially verification for DER facilities

Coordination

- **Opportunities** to utilize advanced DER capabilities
  - Increase distribution hosting capacity
  - Improve bulk system reliability
- **Key Considerations**
  - Functional settings
  - Performance categories
  - Communication interface
- **Coordinate across T&D**

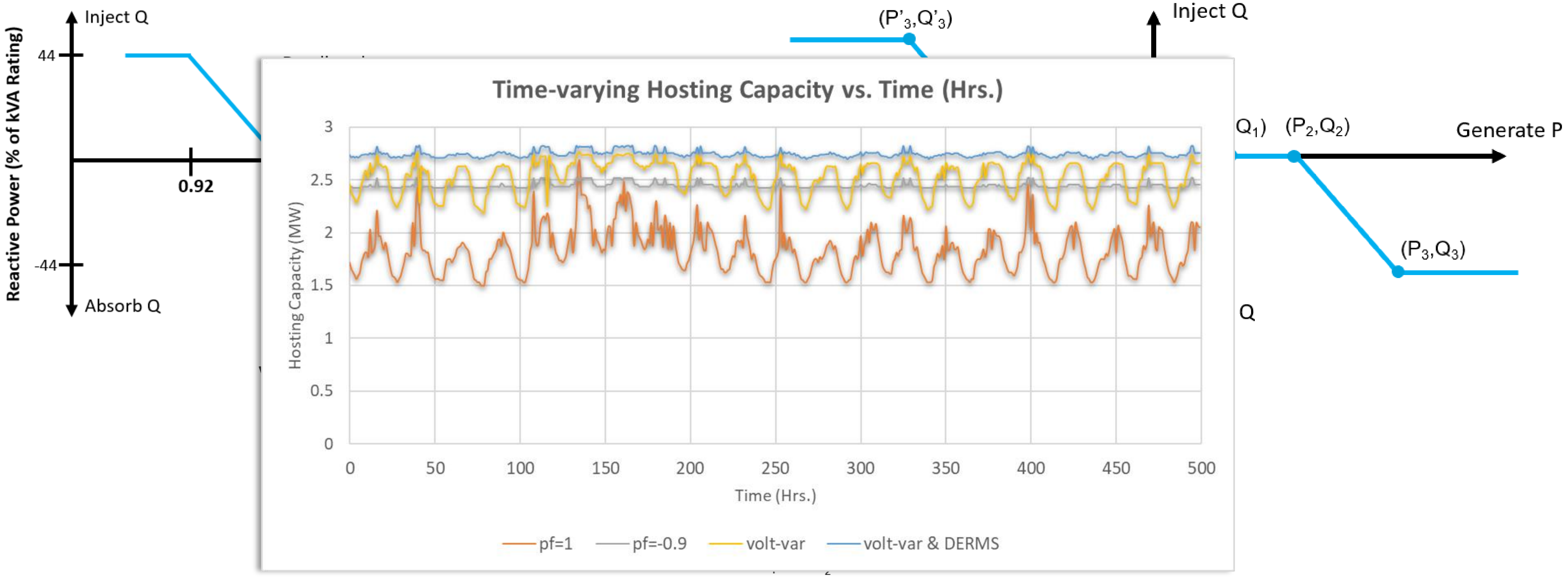
Education

- **Opportunities** to engage a broad set of stakeholders
- **Key Considerations**
  - Understand the key implications of the changes to the standard
  - Engage all parties in the education process
  - Learn how the standard may influence past regulatory decisions

Collaboration

- **Opportunities** to work collaboratively to solve issues
- **Key Considerations**
  - Engage state and federal agencies to advance understanding
  - Developers, utilities, and regulators collaborating to solve interconnection challenges
  - Perform research to understand best practices and develop policy objectives

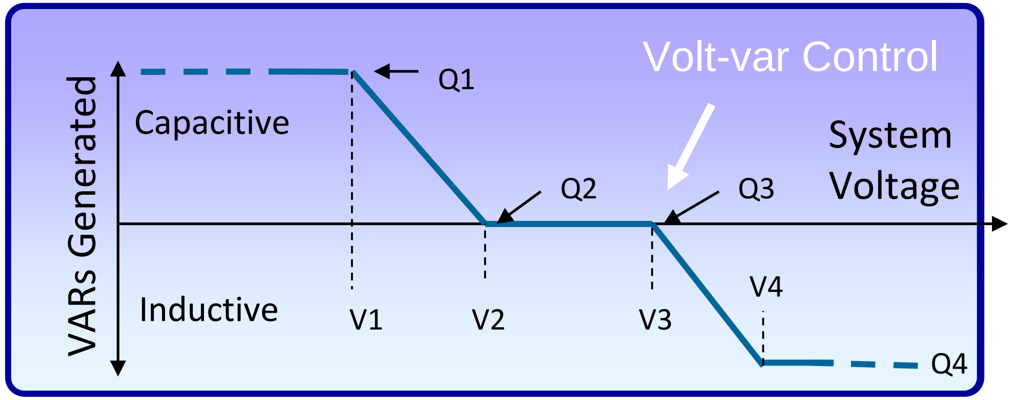
What Are Advanced Autonomous DER Functions?

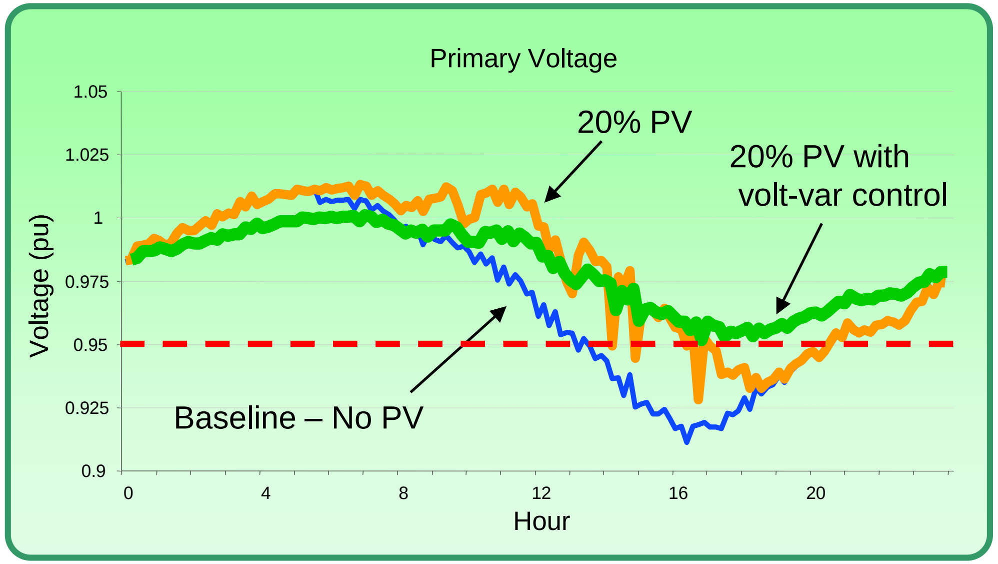


Volt-watt

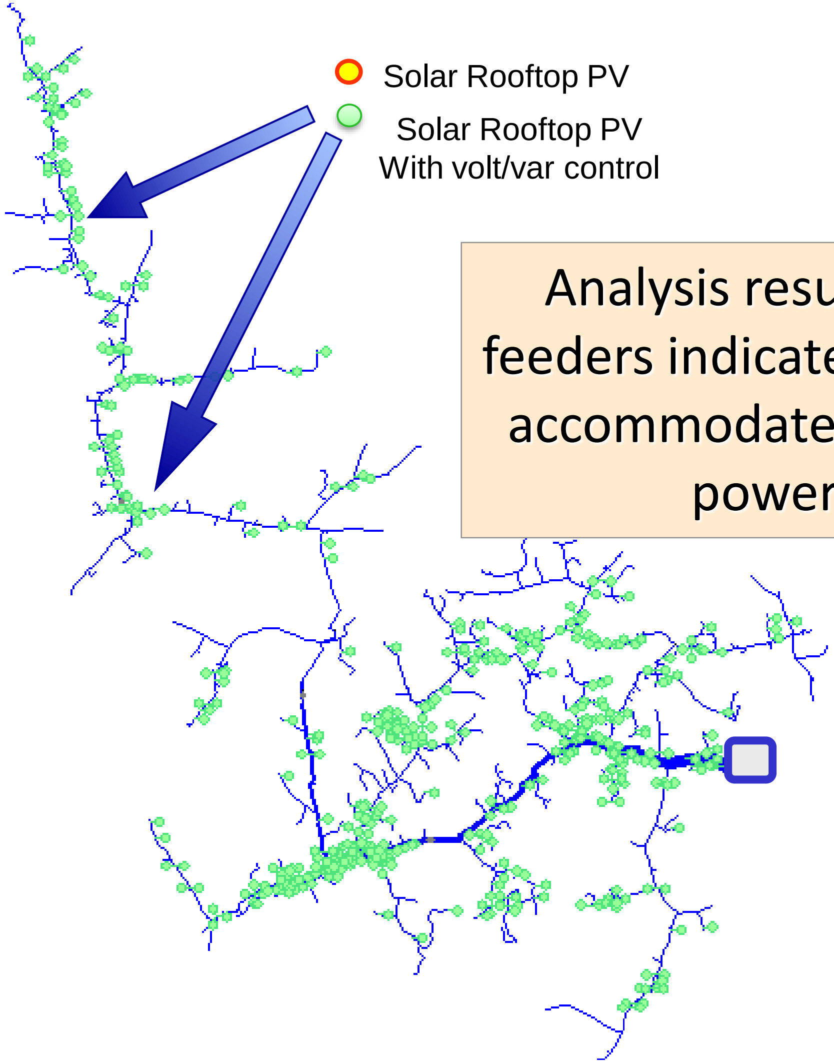
A Potential Tool to Increase the Ability to Integrate DER while Managing Distribution System Constraints

DER Reactive Power Support





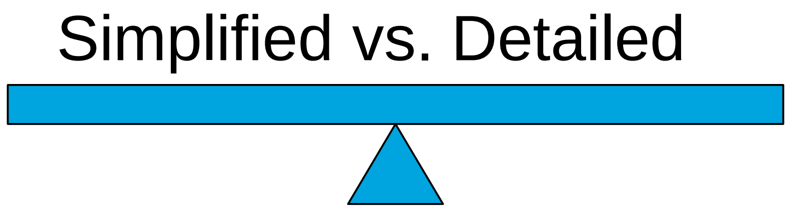
24 Hour Simulation



Analysis results from other feeders indicate more PV can be accommodated using reactive power control

DER Advanced Functions/Settings

- The Challenge
  - Already or potentially large volumes of requests
  - Requests for both small residential + large-scale
  - Cannot perform detailed study of every application… especially small residential
  - Limited field experience with latest functions/settings
- Key EPRI Research Objectives
  - Lead development of standards
  - Improve capability to integrate DER
  - Distillation of past research into guidelines
  - Develop methods for analysis



Advanced Function Actually Required in Field Today*

Utility/Region	Required Activated Function	Notes
Ameren, ComEd, MidAmerican	Volt-var (similar to CA Rule 21)…must be able to accept external commands	Associated with FEJA, up to 2MW projects initially
PG&E, SCE, SDG&E	CA Rule 21 Volt-var	Since July 2018, applies to all systems
Idaho Power	Tailored Volt-var	Applies to large, utility scale systems
Hawaiian Electric Company (HECO)	HI Rule 14 Volt-var	Since Jan. 2017, Volt-watt on selected systems
Germany DSOs	Volt-var, Q(P)	One DSO requires comms for >500kVA allowing settings adjustments
Endeavour Energy, Australia	Volt-var	Per AS/NZS 4777
NY Utilities	**Unity PF where possible, no advanced functions**	**Some demonstrations and considering in the future**

*This is not a comprehensive list and reflects data collection in progress

Potential Control Solutions to Mitigate Voltage Constraints

Autonomous/Local Control

Complexity

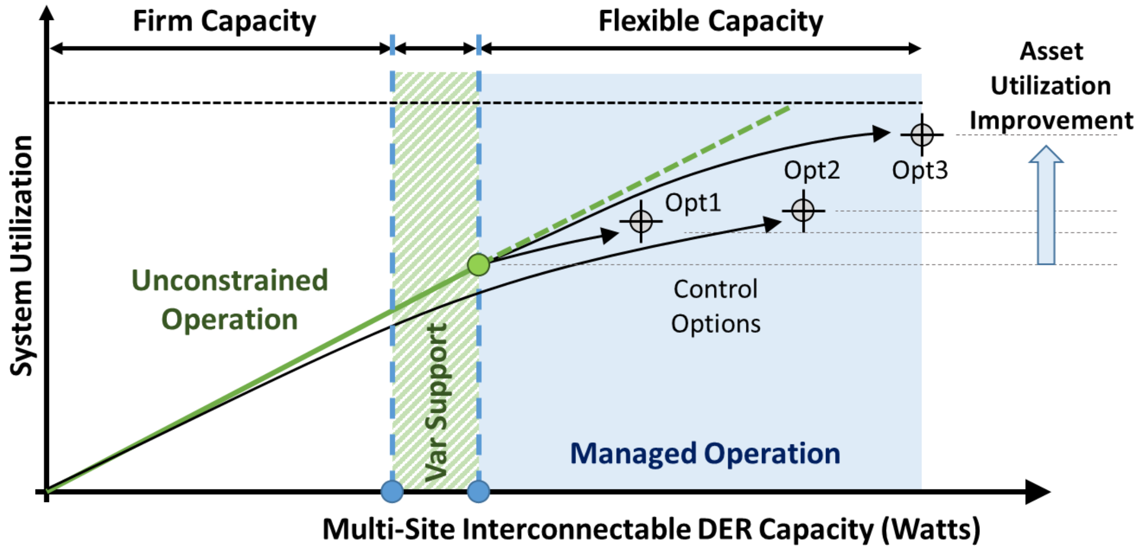
- Voltage Regulator and Capacitor Bank Settings
- DER Power Factor Adjustment
- Advanced Functions or Combination of Functions
- Tailored Advanced Settings

Managed/Global Control

- Volt-var Optimization
- Autonomous + Local DERMS
- Autonomous + Real-time DERMS
- Real-time DERMS

Transition from Firm to Flexible Resource Capacity

Maximizing DER Hosting and Grid Utilization through Flexible Interconnection Capacity Solutions (FICS)



Research Questions

- How does location affect flexibility?
- How to estimate nodal and zonal flexibility?

Scope/Approach

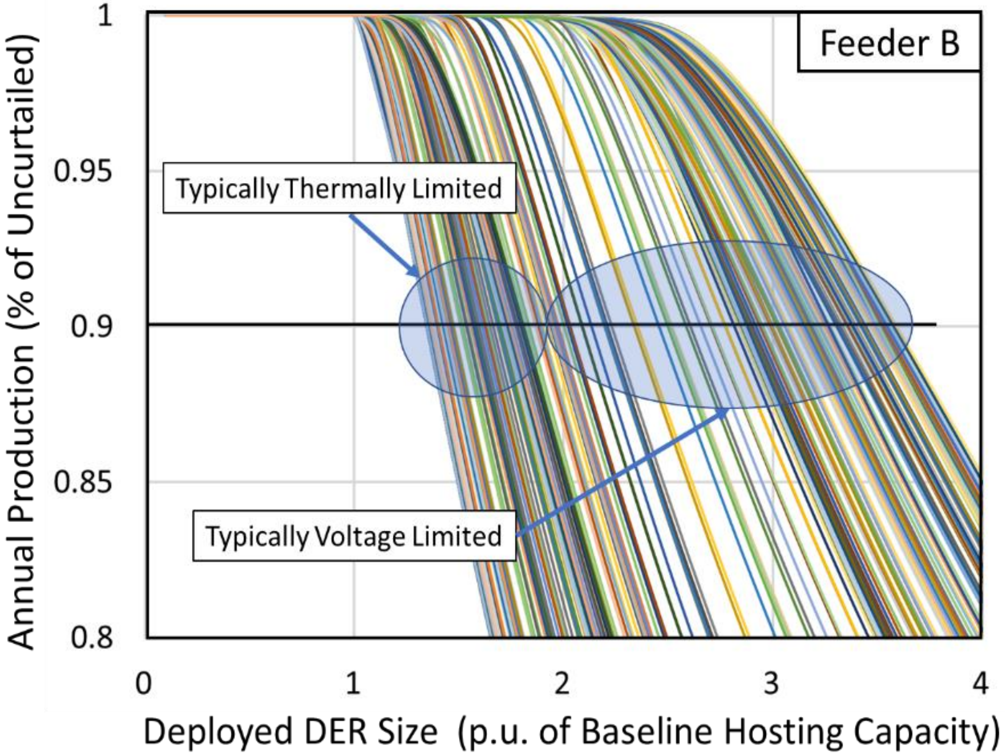
- Analyze many feeders and constraints
- Examine a broader set of load and generation forecasts
- Develop metrics to convey flexibility

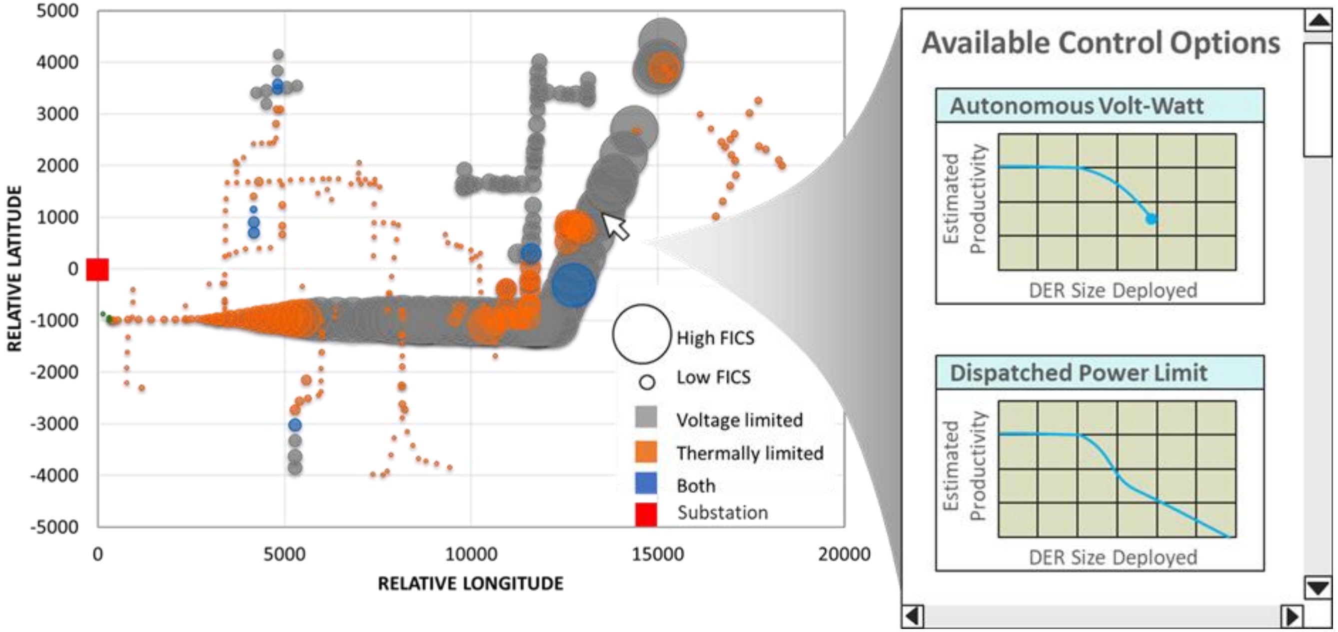
Expected Outcome

- Methodologies to quantify the impacts of Flexible Interconnection schemes
- Determine economic value

Flexible Interconnection Solutions Opportunity Guidance

FICS: Example Results





Widely Varying Flexibility Along a Feeder

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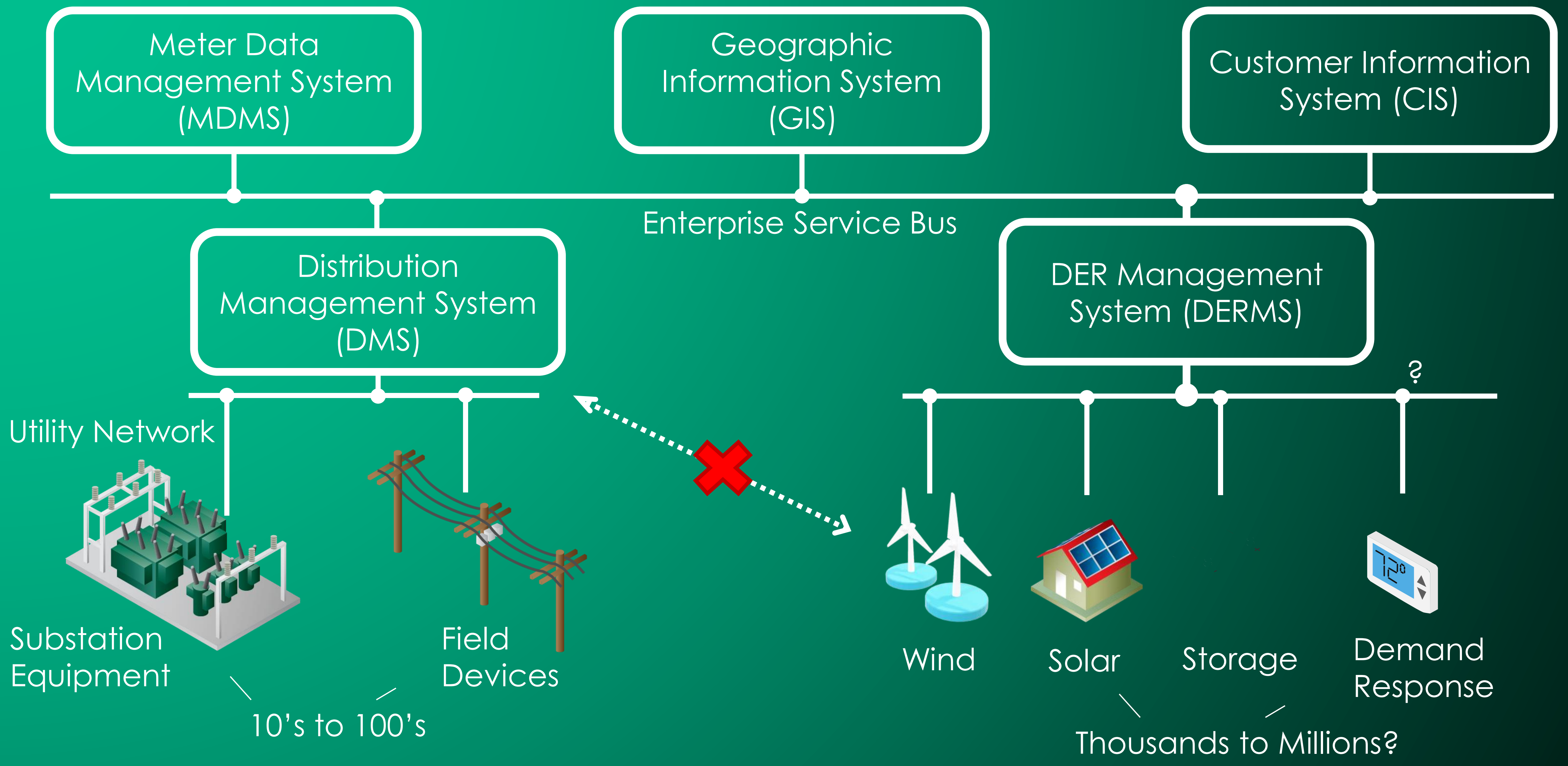
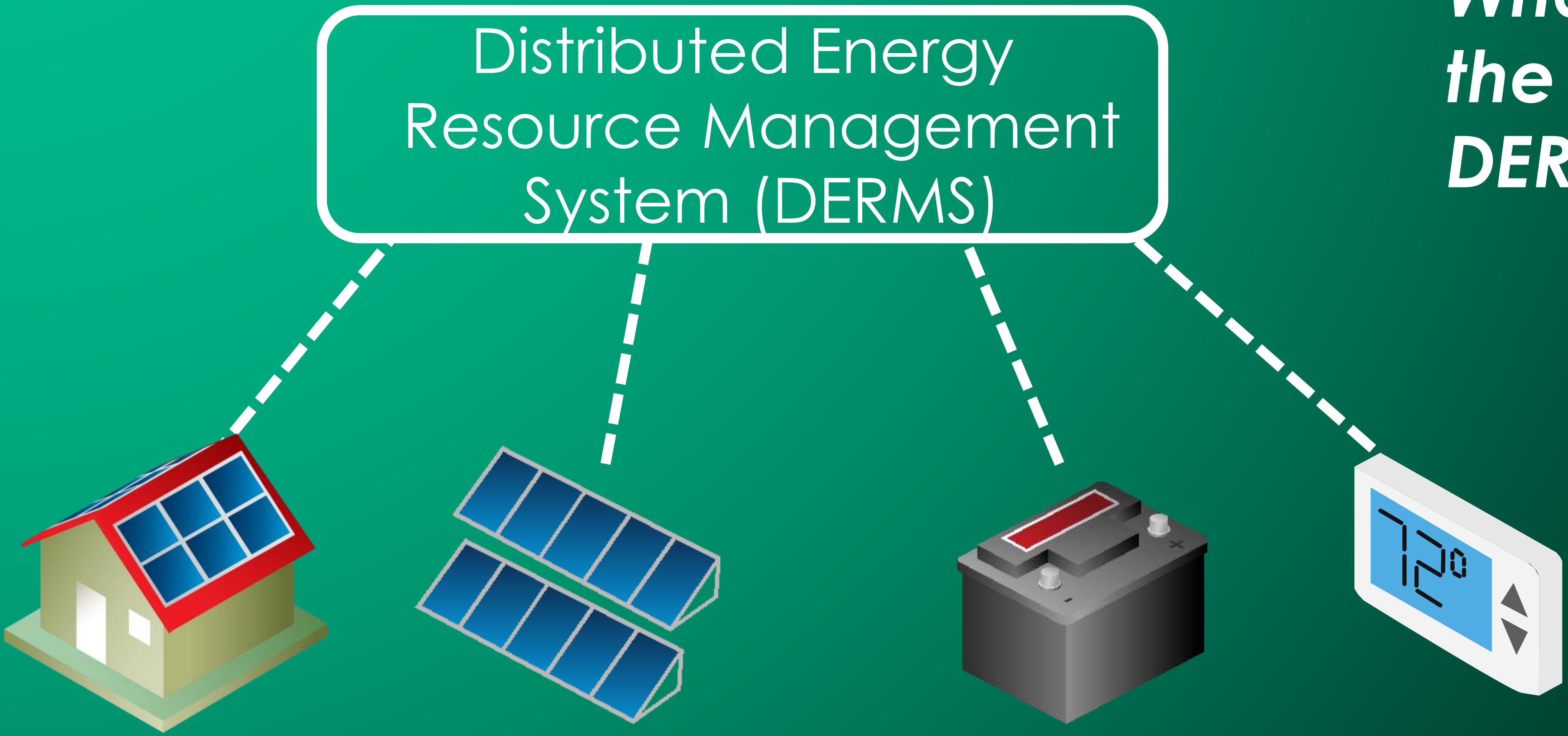
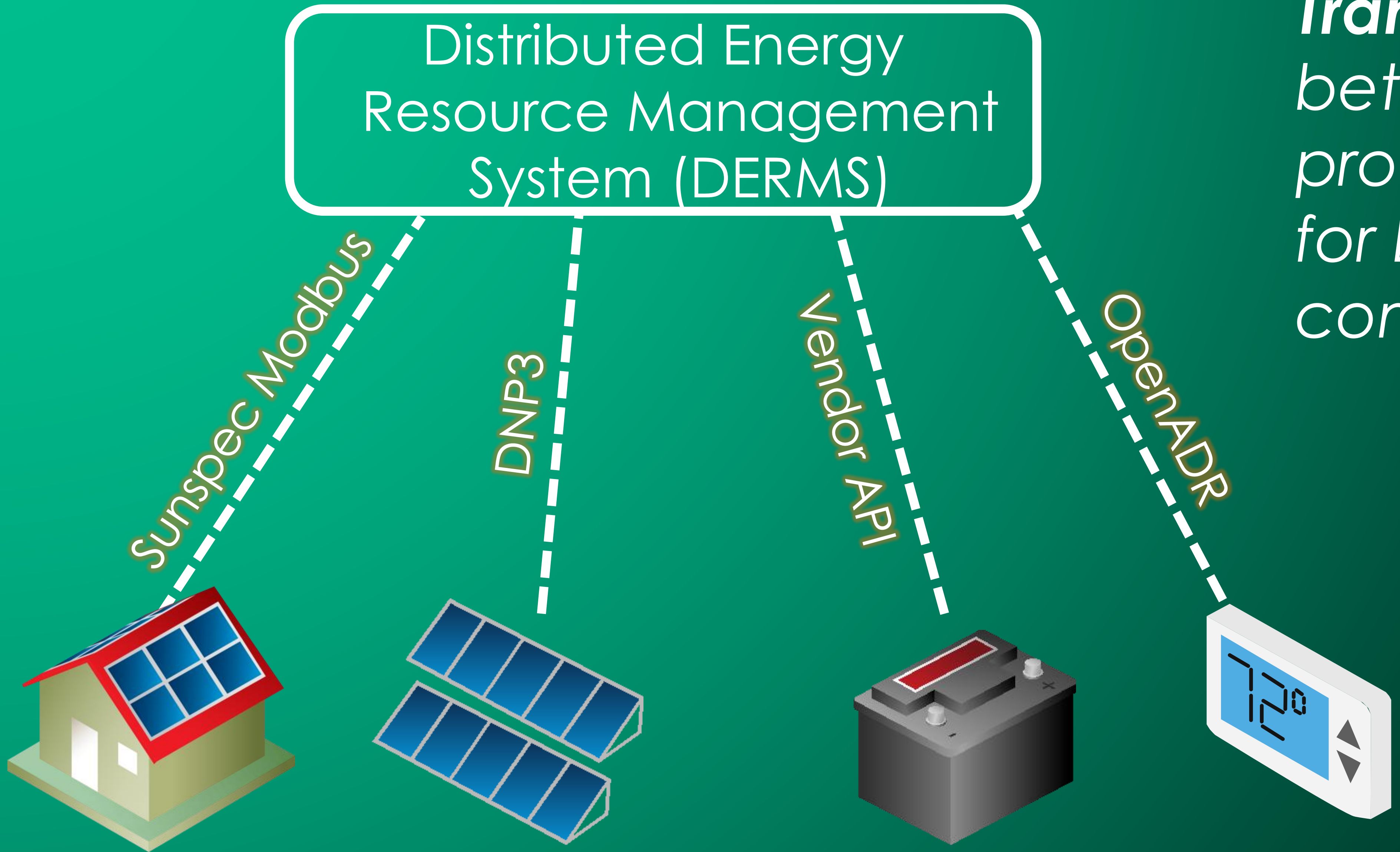


Meter Data Management System (MDMS)
Geographic Information System (GIS)
Customer Information System (CIS)
Enterprise Service Bus
Distribution Management System (DMS)
DER Management System (DERMS)
?
Utility Network
Substation Equipment
Field Devices
10's to 100's
Wind
Solar
Storage
Demand Response
Thousands to Millions?

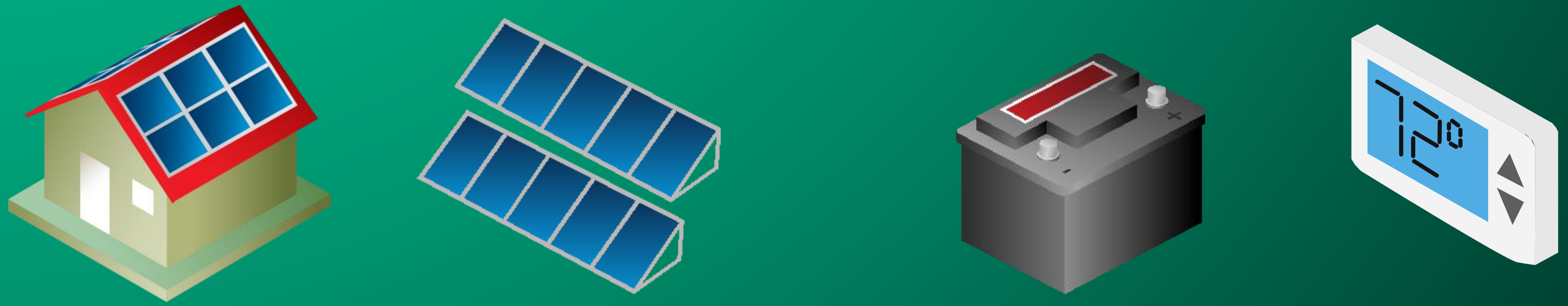


What exactly is the role of the DERMS?

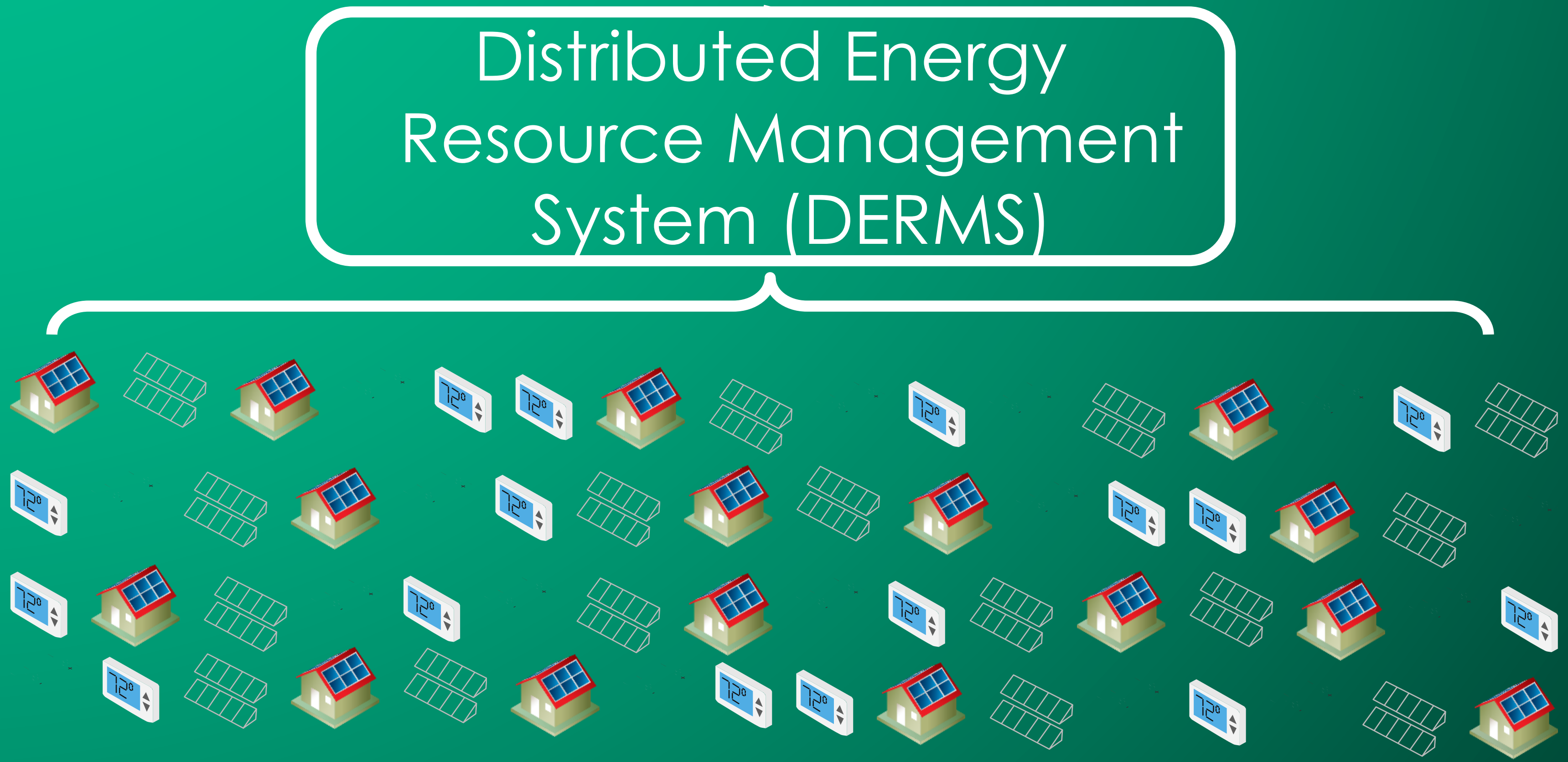


Translate *between various protocols used for DER communications*

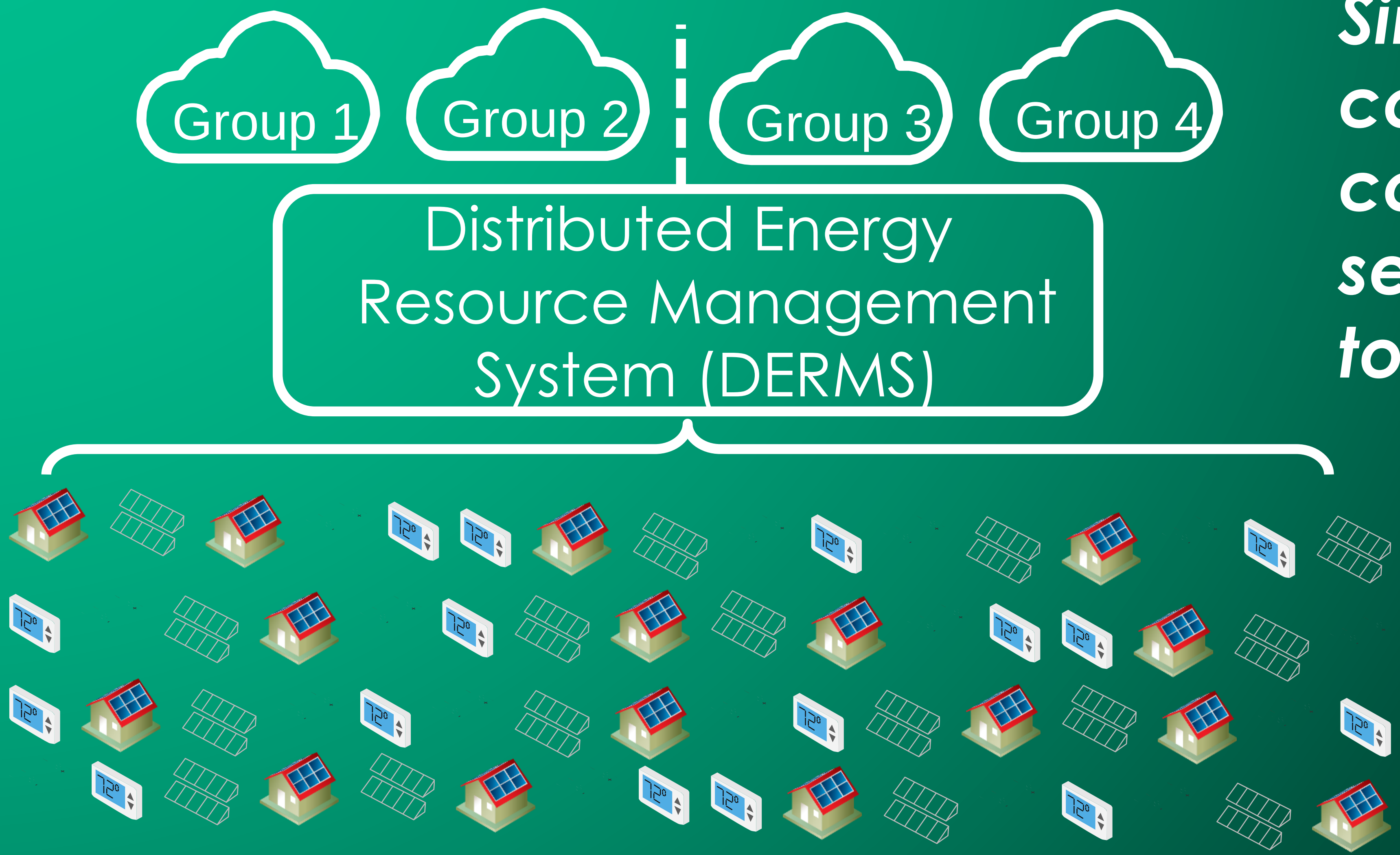
Distributed Energy Resource Management System (DERMS)



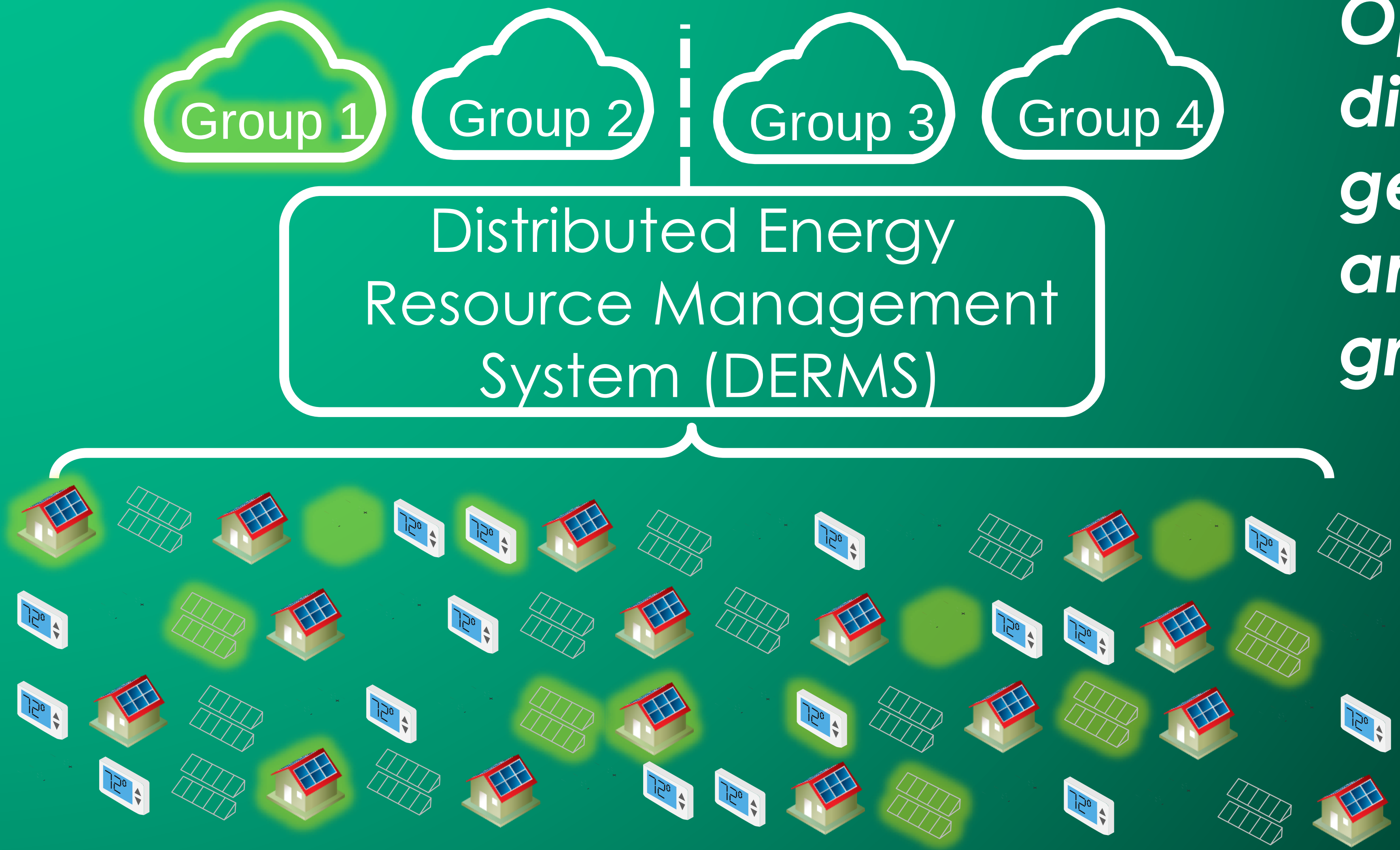
Aggregate up to millions of DER into combined, virtual resources



Aggregate up to millions of DER into combined, virtual resources



Simplify varied, complex DER commands into services useful to grid operators



Optimize dispatch of general requests amongst grouped DER

Aggregation of DER grouped resources

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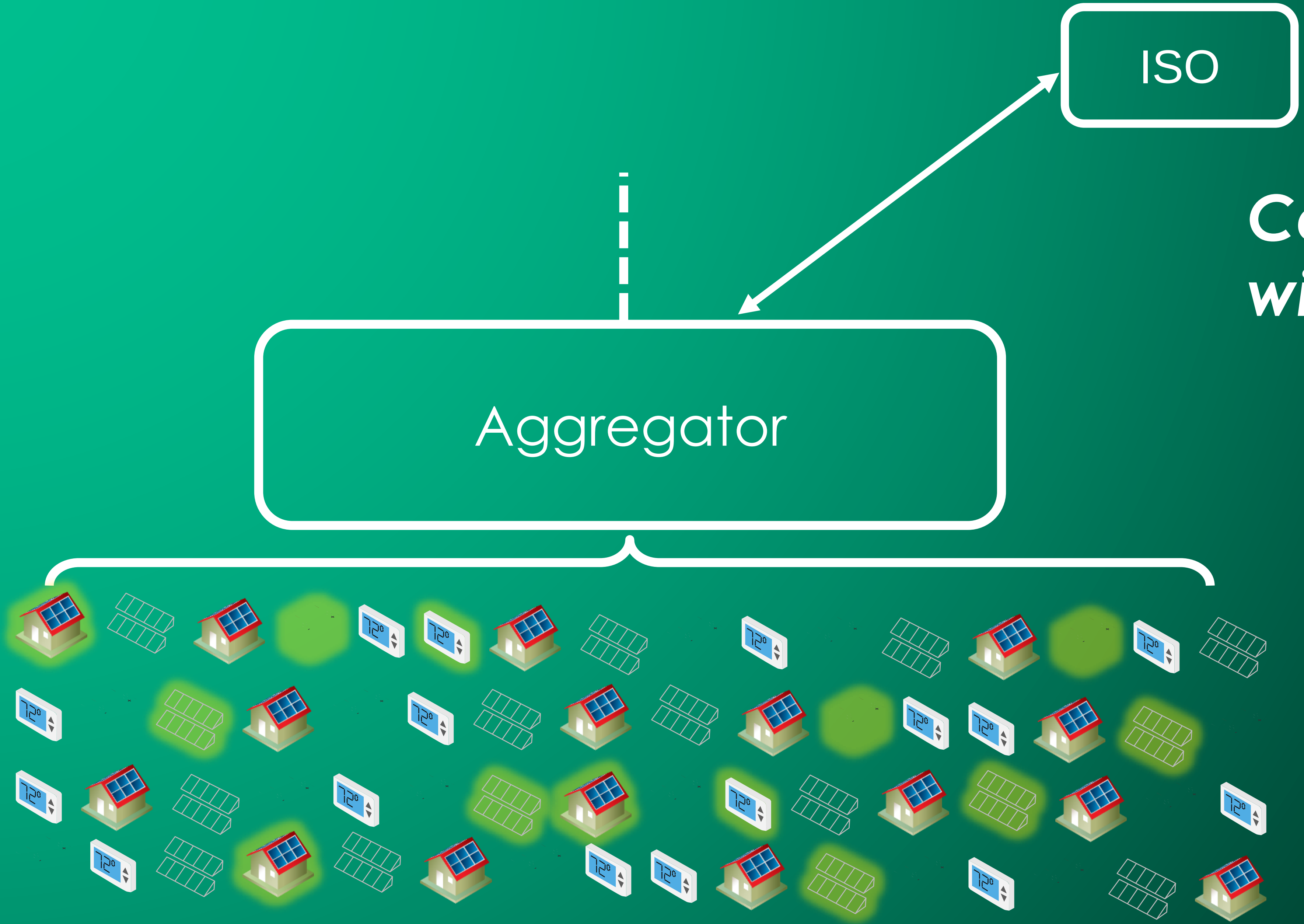
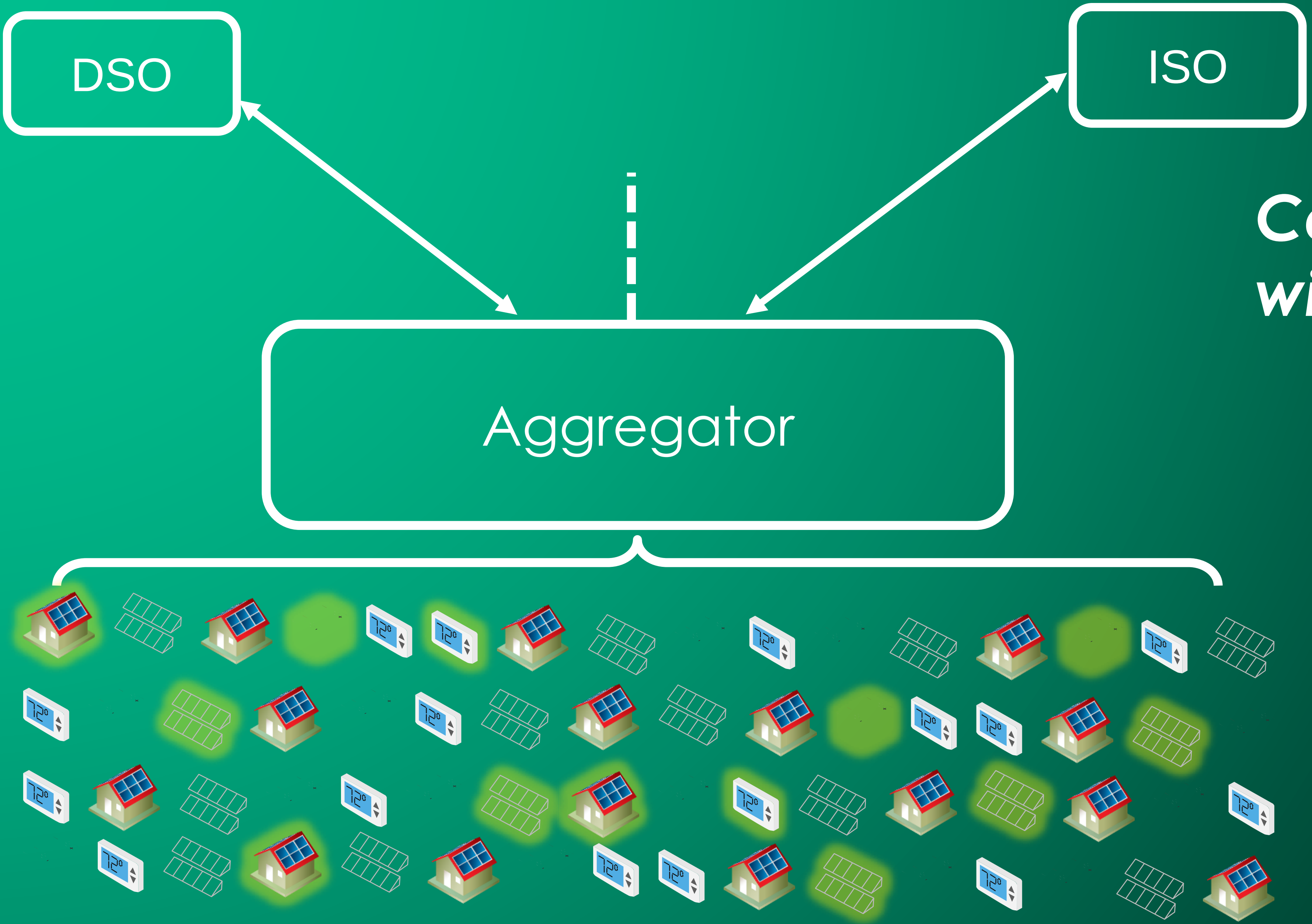


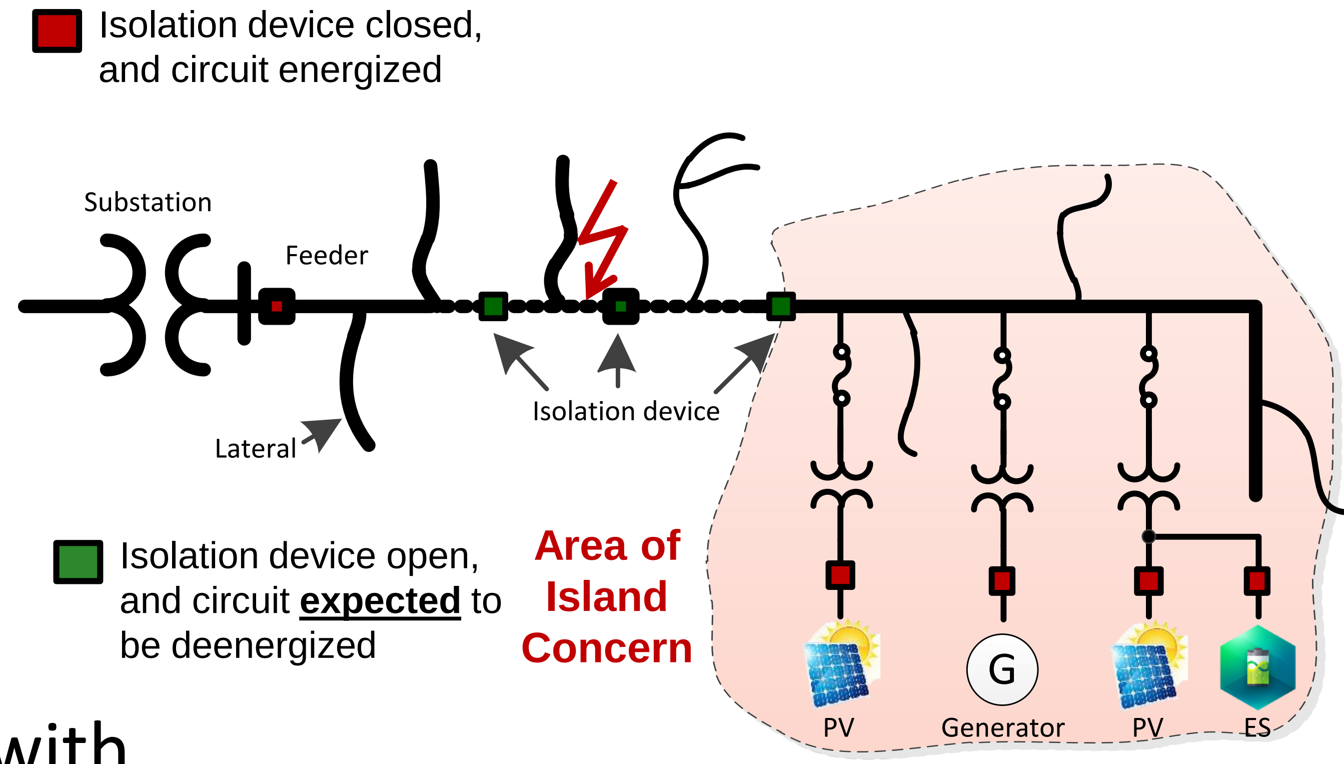
Coordination with ISO

Coordination with ISO and DSO



Summary of Key EPRI DER Interconnection Research

- Unintentional islanding detection
- Effective system grounding with inverter-interfaced DER
- Open-phase detection
- General protection coordination
- Direct transfer trip alternatives
- Field commissioning testing
- Voltage fluctuations/flicker
- Harmonic concerns
- Distribution automation impacts with DER
- Unintentional export control



Transmission System Topics

SOLAR ENERGY
TECHNOLOGIES OFFICE
U.S. Department Of Energy

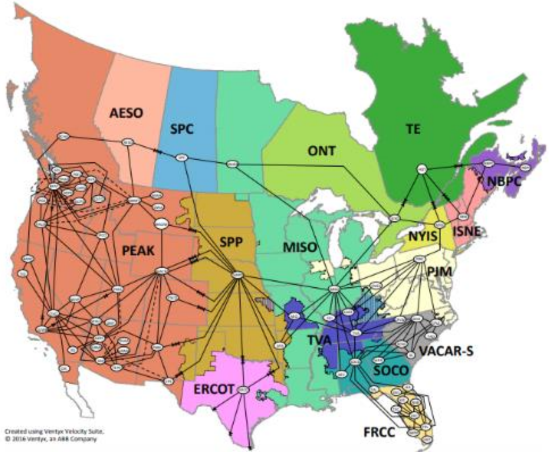
This presentation is, in part, supported by the U.S. Department of Energy, Solar Energy Technologies Office under Award Number DE-EE0009019 *Adaptive Protection and Validated MODels to Enable Deployment of High Penetrations of Solar PV (PV-MOD)*.

EPRI ELECTRIC POWER RESEARCH INSTITUTE

Aggregate DER Impacts on Bulk Power System

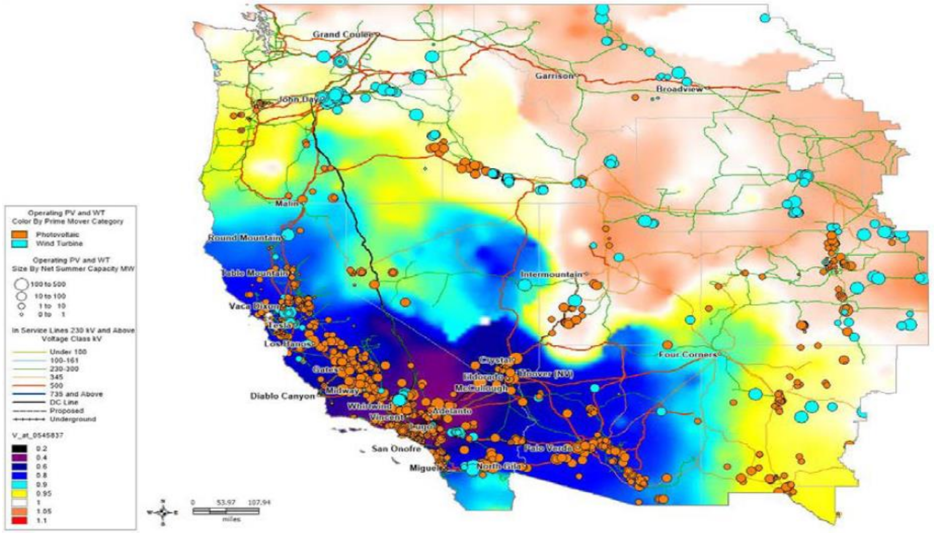
DER Frequency Tripping versus Ride-Through

- System frequency is defined by balance between load and generation
- Frequency is similar across entire interconnection
  - any DER exposed to large frequency deviations may trip simultaneously;
  - special concerns for system-split conditions
- Impact the same whether or not DER is on a high-penetration feeder
- NERC Reliability Coordinators
  - Colored entities in the map to the right



Source: NERC

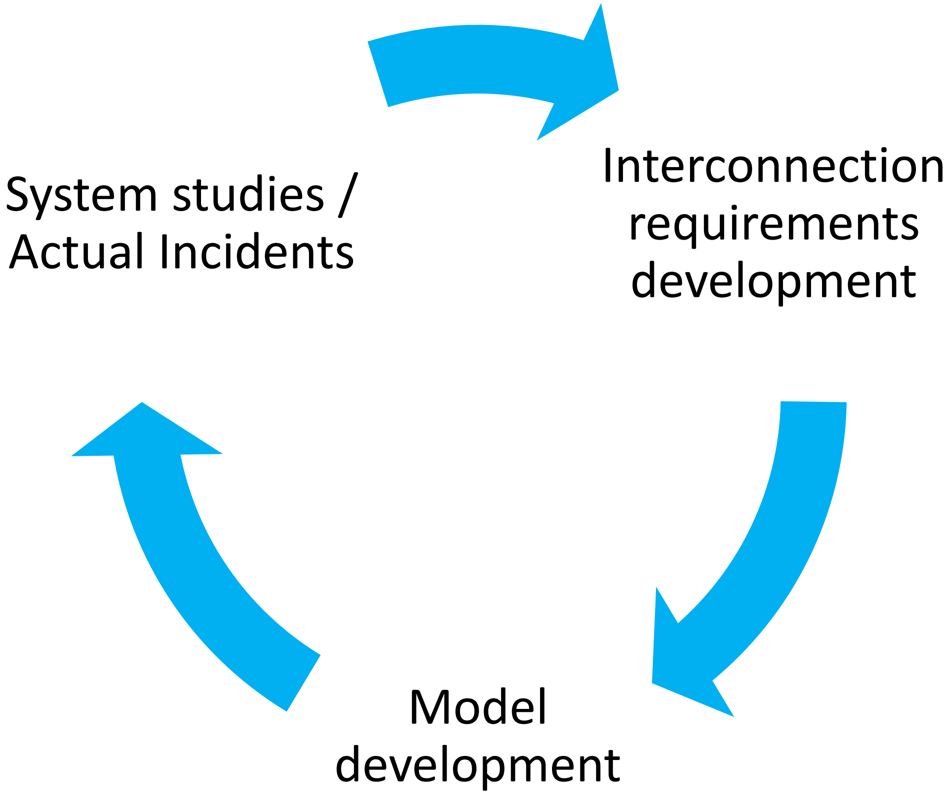
DER Voltage Tripping versus Ride-Through

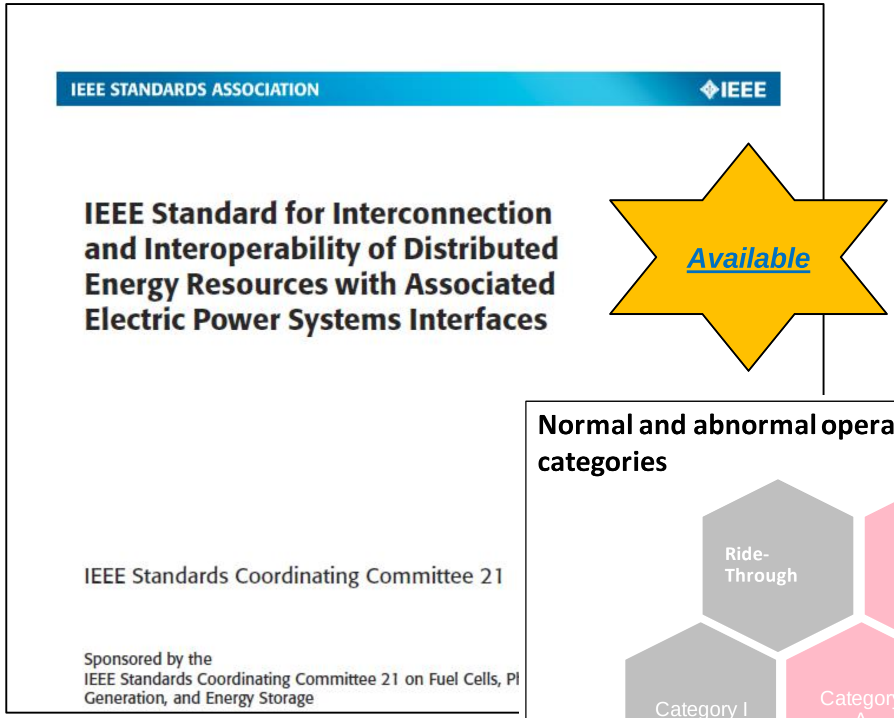


Source: SCE

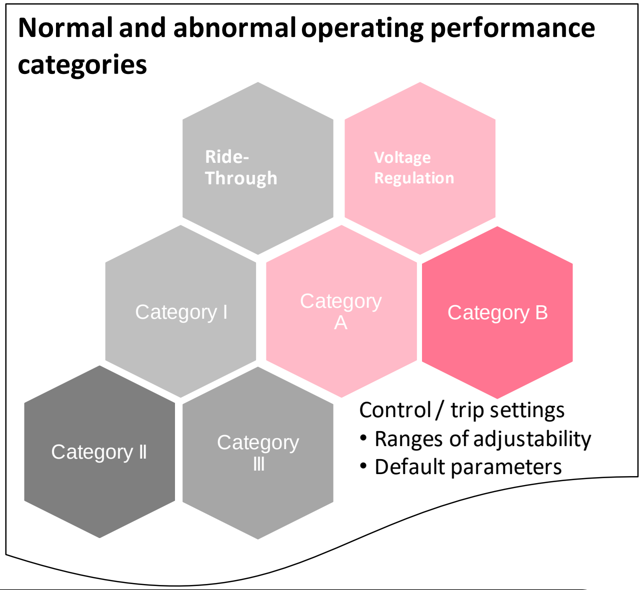
- Transmission faults can depress distribution **voltage** over very large areas
- Sensitive voltage tripping (i.e., 1547-2003) can cause massive loss of DER generation
- Resulting BPS event may be greatly aggravated

EPRI Transmission Research Related to DER





Also refer to supplemental project notice on "Navigating DER Interconnection Standards and Practices" (3002012048)



Provide guidelines and tools to create a technical basis for assignment of `abnormal performance categories' specified by IEEE Std 1547-2018.

DOE PV-MOD: Project Overview

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U.S. Department Of Energy

1. **Resource Characterization**
   - Existing Models
   - Lab Tests
   - Field Data
2. **Model Development**
   - Develop → Test → Validate
   - Unit, Plant & Aggr. Feeder/BTM
3. **Model Commercialization**
   - **Stability** (PSS/E, PSLF, …)
   - **Protection** (CAPE, CYME, …)
   - **EMT** (EMTDC, EMTP-RV, …)
   - **QSTS** (CYME, Synergi,…)
4. **Adaptive Protection Application**
   - Design
   - HIL Testing
5. Demonstration

2020

- Field data collection
- Smaller kW inverter characterization (lab testing)
- Gap analysis of PV models (dynamic, short-circuit, EMT/HIL, PQ)
- Inverter models for quasi-static time series (QSTS)

2021

- Grid scale inverter characterization (NREL)
- Develop initial versions of refined or newly developed models
- Provide model specs to vendors
- Model validation using the newly developed models

2022

- Complete model validation
- Refine models based on validation
- Finalize specs for models & work with vendors

Validated; publicly available models for various types of studies, reports detailing the work, close collaboration with industry stakeholders (NERC, WECC, IEEE etc.)

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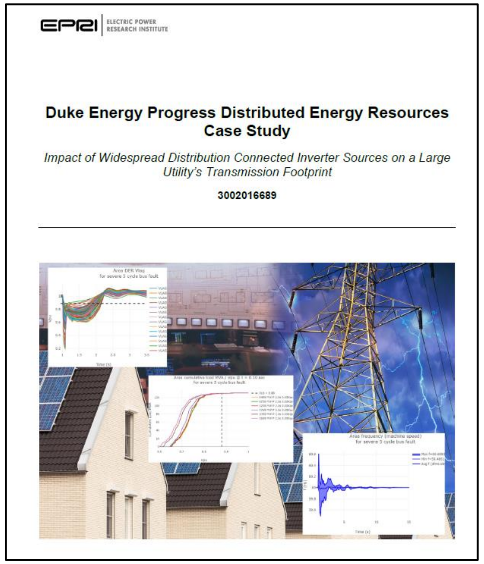
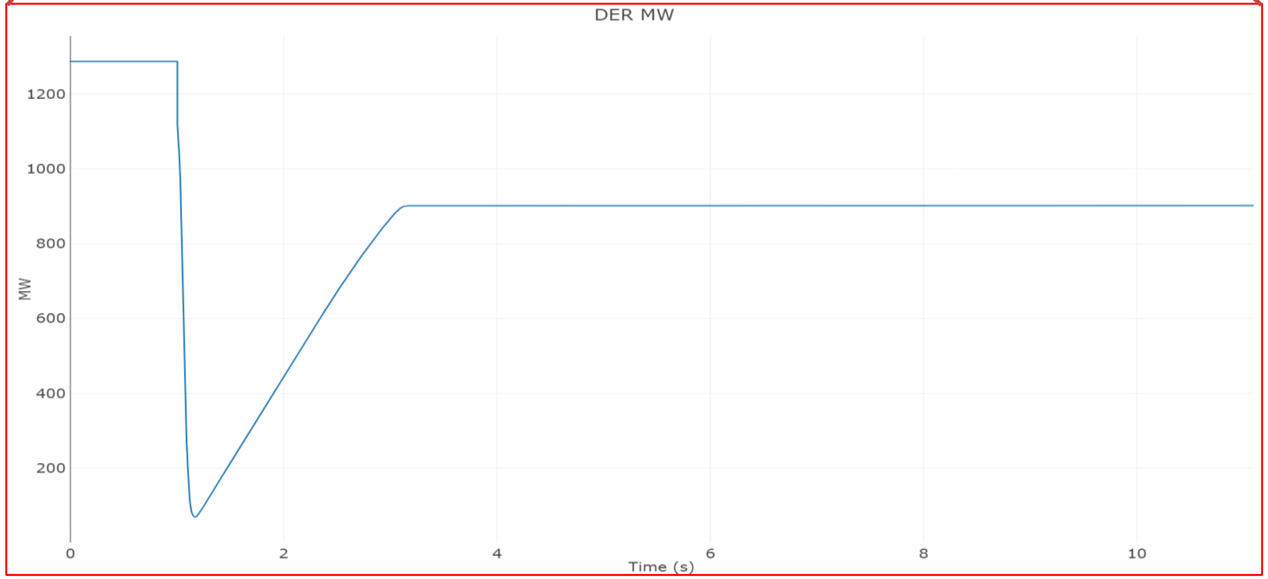
Recreation of DER Tripping Event with DER_A Model

- Comparing DER modeling performance to measured event
  - ~ 300 MW DER tripping in SCADA measurement
  - ~ 350 MW DER tripping in simulation
- Report publicly available at epri.com (Product ID: 3002016689)





Summary of load shed and generation shed

	P7 Contingency - 1			3-Φ Delayed Clearing Bus Contingency		
Scenario	MW / Mvar Load Shed	MW / Mvar Non - DER Generation Shed	MW Mvar DER Generation Shed	MW / Mvar Load Shed	MW / Mvar Non – DER Generation Shed	MW Mvar DER Generation Shed
Base Case	1858 / 513	0.0 / 0.0	N/A	1273 / 325	1858 / 485	N/A
1	2984 / 785	8672 / 1412	6600 / 183	N/A	N/A	N/A
1a	2000 / 557	0.0 / 0.0	2074 / 74	N/A	N/A	N/A
2	1992 / 555	0.0 / 0.0	0.0 / 0.0	N/A	N/A	N/A
3	1553 / 433	0.0 / 0.0	0.0 / 0.0	941 / 233	2182 / 605	1746 / 38
4	1983 / 553	0.0 / 0.0	0.0 / 0.0	N/A	N/A	N/A
5	1553 / 433	0.0 / 0.0	0.0 / 0.0	941 / 233	2182 / 605	1746 / 38
6	1553 / 433	0.0 / 0.0	0.0 / 0.0	941 / 233	2182 / 605	1746 / 38
6a	1441 / 389	0.0 / 0.0	0.0 / 0.0	928 / 228	2182 / 605	1746 / 38
7	1553 / 433	0.0 / 0.0	0.0 / 0.0	941 / 233	421 / 560	0.0 / 0.0

Impact of mom. cess. (1, 1a)

Impact of DVS (2, 3)

Impact of Q priority (4)

Impact of aggressive DVS (6, 6a)

Impact of Cat III (6a, 7)

N/A signifies either No – DER or the case had a convergence error

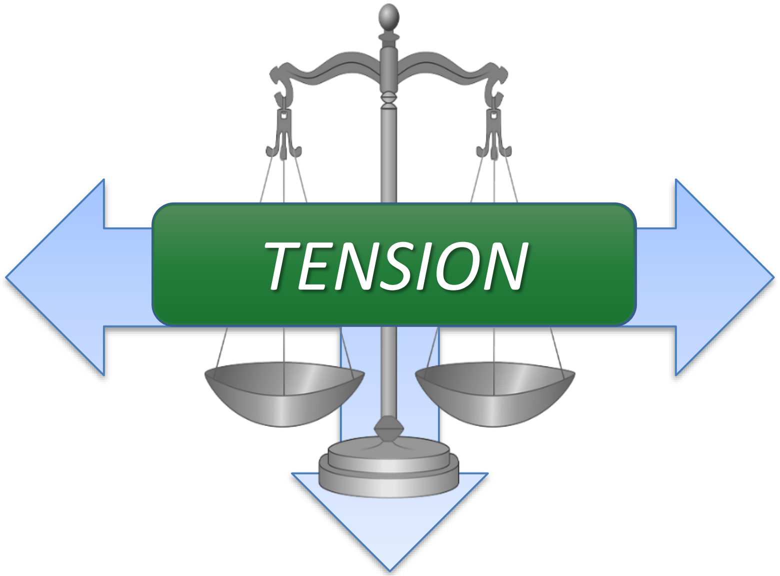
Category III voltage ride-through capability beneficial for delayed-cleared faults.
Dynamic voltage support has limited impact.

Balancing Bulk & Distribution Grid Needs

Public EPRI-U Webinars
3002014545
3002014546
3002014547

Distribution Grid Side

- Short trip times
- Ride-through *with momentary cessation*
- Voltage rise concerns
- Islanding concerns
- Protection coordination
- Safety of line workers



Bulk System Side

- Long trip times
- Ride-through *without* momentary cessation
- Reactive power support
- Frequency support

Increasing need for T&D Coordination

RTOs/ISOs Guidelines for IEEE Std 1547™-2018 Adoption

ISO New England

June 1, 2018

- Coordination between ISO-NE and the MA's utilities in the Massachusetts Technical Standards Review Group
- Reference to UL 1741 SA as a stopgap to verify DER ride-through capability in the interim
  - Harmonization of voltage & frequency trip settings with IEEE Std 1547-2018 ranges of allowable settings (Link)

PJM Interconnection

Jan 1, 2022

- Initiation of formal stakeholder proceedings in 2019
- Published PJM *Guideline for Ride Through Performance of Distribution-Connected Generators* for voluntary DER ride-through in Oct 2019 (PJM Website)
- Established minimum Ride-through requirements and trip time settings

Midcontinent Independent System Operator (MISO)

date not specified

- MN PUC requested stakeholder process, see MISO's IEEE 1547 website
- Published the MISO Guideline for IEEE Std 1547-2018 Implementation (Link)
- Established the preferred regional Ride-through capabilities and trip time settings

See also NERC's Reliability Guideline
Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018 (March 2020)

Common Performance Category / Capability Assignments

Normal Performance Categories

Power Conversion	Prime Mover / Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category B
	Wind	Category B
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category A
Induction generator	Hydro	Mutual Agreement

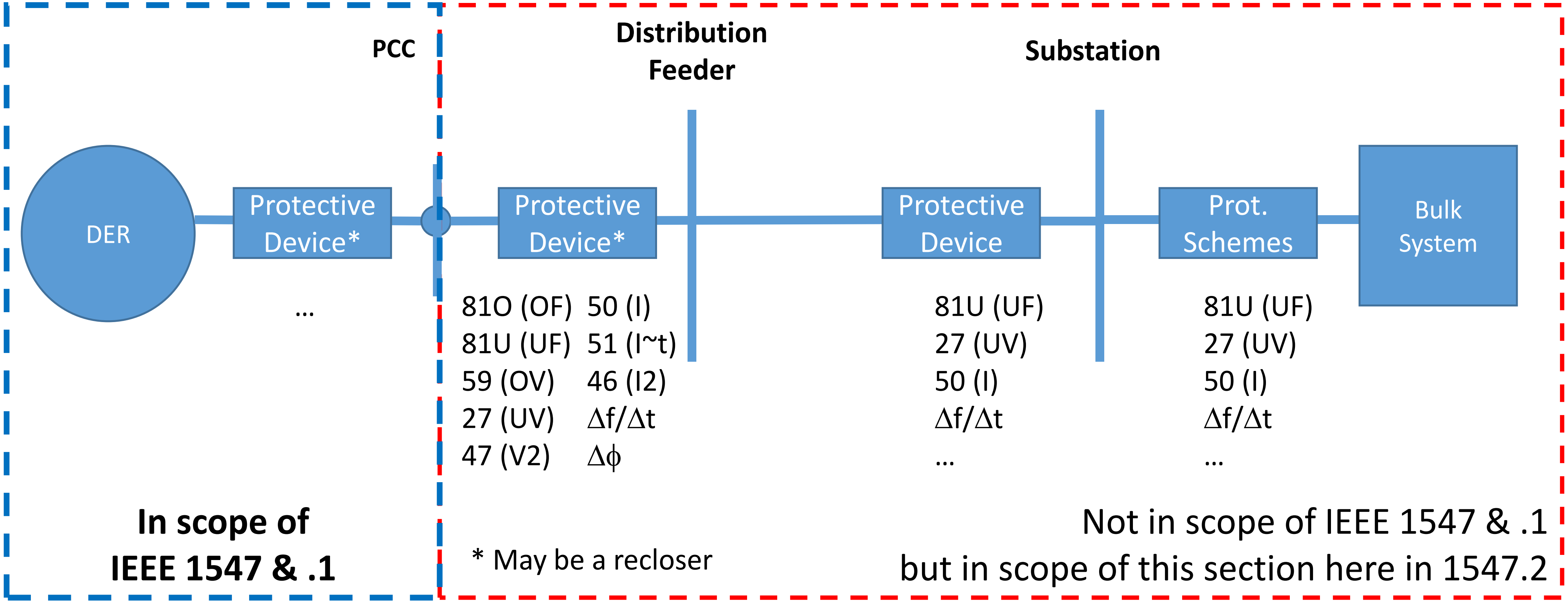
Not in scope of NPCC guidance?

Abnormal Performance Categories

Power Conversion	Prime Mover / Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category III [1] (amended)
	Wind	Category II
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category I
Induction generator	Hydro	Mutual Agreement

[1] was Category II prior to Amendment

Coordination of Distribution Protection Practices with DER Ride-Through



NPCC Specific Discussion

- Value Add of NPCC Guideline over NERC Reliability Guideline *Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018*?
  - *Abnormal performance category assignment*
  - *Functional settings impacting BPS (trip, frequency droop, etc.)*

- Work with distribution utilities regarding feeder & substation protection DER to coordinate with ride-through?

- Other Topics
  - Value of DER steady-state voltage/reactive power control?
  - Potential benefits & challenges of DER fault-related dynamic voltage support?

NPCC Reliability Guideline Could Provide Guidance to ISOs/RTOs and Distribution Providers

Together…Shaping the Future of Electricity

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Backup

Adaptive Protection and Validated MODels to Enable Deployment of High Penetrations of Solar PV (PV-MOD) / PRINCIPAL INVESTIGATOR: DR. JENS BOEMER (EPRI)

2064-1764

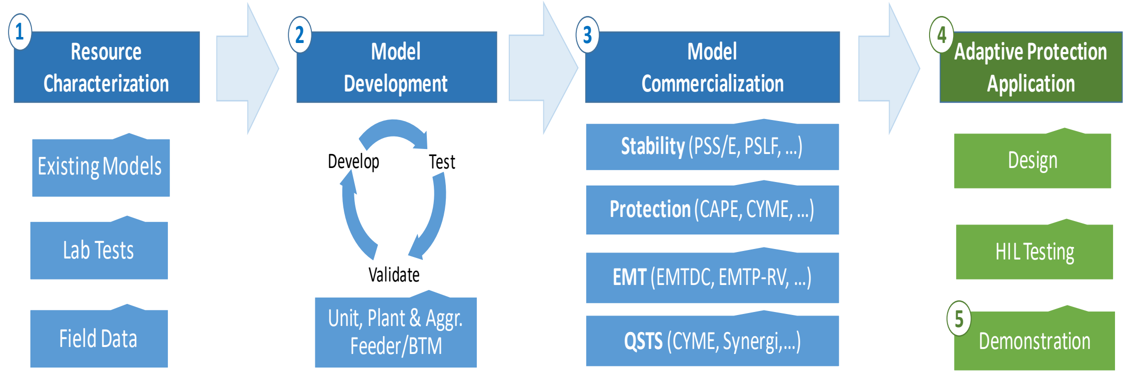
Project Objectives

Enabling deployment of higher levels of Solar PV by providing utilities, developers, and vendors with ***high-fidelity, validated*** unit and facility ***models*** *and* ***demonstrated adaptive protection schemes*** that represent and use advanced PV capabilities. ***Transformation*** of dynamic modeling approaches used in industry for planning and protection models of Solar PV by ***bridging the gap*** between model development and application-ready tools to ***ensure successful adoption***.

Technical Approach

Develop and ***validate*** high-fidelity ***models*** of solar PV facilities at ***all levels*** of the power system across ***all operational reliability time frames*** and ***integrate*** the validated models ***into commercial software tools and HIL platforms***[1] used by power system engineers to ***plan***, ***operate***, and ***protect*** transmission and distribution (T&D) systems by using EPRI's existing vendor engagement processes.

[1] Siemens PTI PSS®E, GE PSLF™, PowerWorld, DSATools TSAT, EMTP-RV, PSCAD EMTDC, DIgSILENT PowerFactory, RTDS, Opal-RT, Typhoon, Aspen OneLiner, Siemens PSS®CAPE, CYME, Synergi, and OpenDSS



Project Team

• **Lead:** EPRI • **Nat. Labs (sub):** NREL, ORNL • **Other**: Army Corps of Eng. (host site), PEACE (contractor) • **Utilities (host sites):** ConEdison, PPL • **Vendors:** FirstSolar, ASPEN (Oneliner), Siemens (CAPE), EATON (Cyme), ABB • **Utilities (support):** NERC, WECC, APS, Duke, NGrid, SoCo

Budget

Federal funds: $4.1M Cost-share: $1.5M (~27%) Total: $5.6M

Anticipated Outcomes

Year 1:	Inverter Characterization, Gap Analysis of PV Models, Initial Model Dev. & Validation, Gap Analysis and Adaptive Protection Scheme Design
Year 2:	PV Model Dev. & Refinement, Vendor Engagement, Validation, Modeling & HIL Testing of Adaptive Protection Schemes
Year 3:	PV Model Validation, & Vendor Engagement, Adaptive Protection Field Demos

Project Tasks Timetable		BP1				BP2				BP3			
		Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12
1	Project Management, Vendor Engagement & Tech Transfer												
2	Field Data Collection												
3	Inverter Characterization												
4	PV Model Development, Refinement & Vendor Engagement												
5	Industry Assessment & Adaptive Prototype												
6	Inverter Characterization												
7	PV Model Development, Refinement & Vendor Engagement												
8	Model Validation												
9	Adaptive Simulations and HIL Tests												
10	Model Validation												
11	Field Demos and Industry Guide												
12	Project Report												

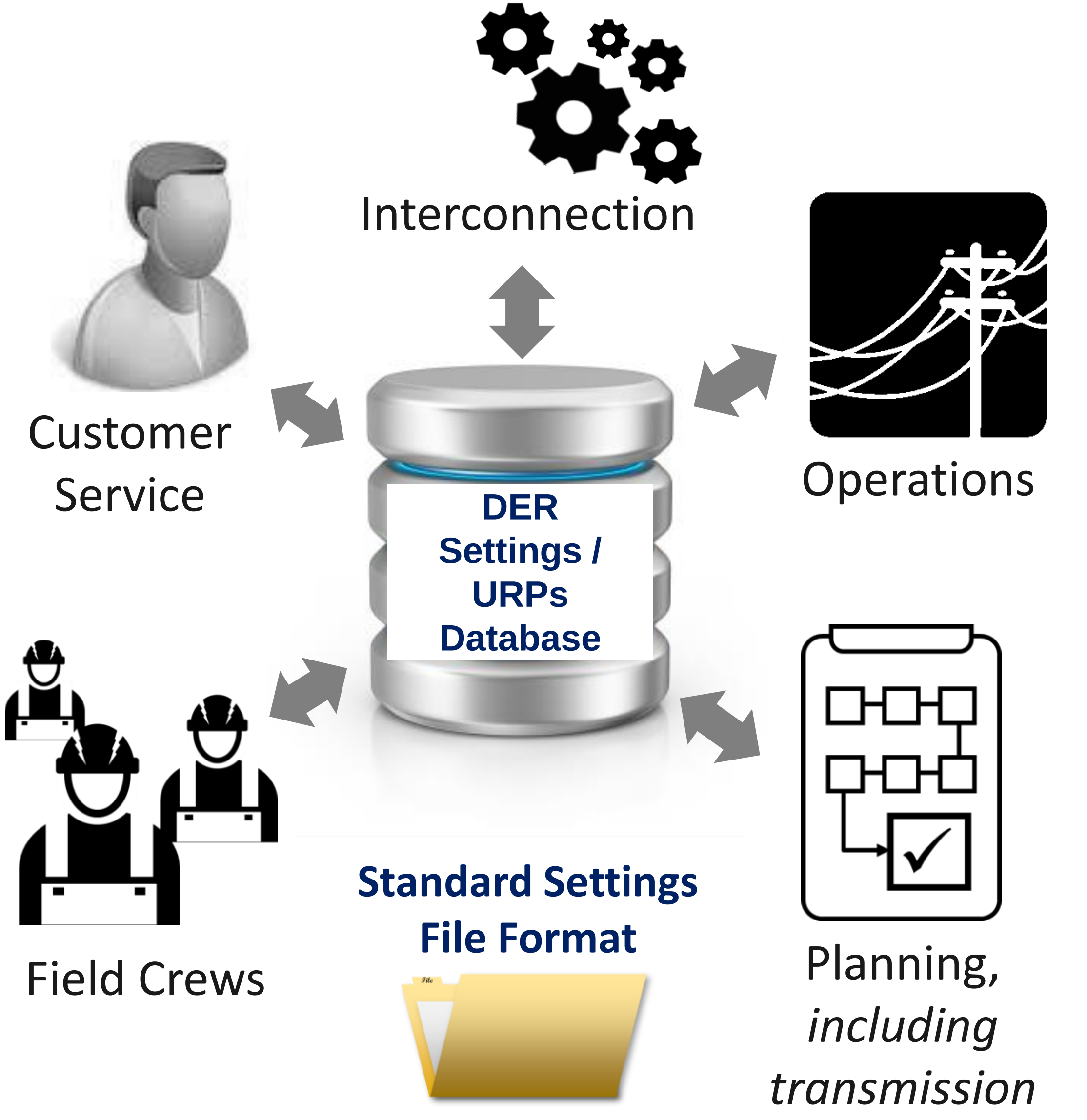
Transformative Modeling and Adaptive Protection Enabling Grid-Ready Applications

Dynamic Voltage Support is Only an Optional Requirement in IEEE 1547-2018

Function Set	Advanced Functions Capability	IEEE 1547-2003	IEEE 1547a-2014	IEEE 1547-2018	Rule 21 (Phases)	Rule 14H & UL SRDv1.1
All	Adjustability in Ranges of Allowable Settings	X	√	‡		
Monitoring & Control	Ramp Rate Control				‡ (P1)	‡
	Communication Interface			‡	‡ (P2)	‡
	Disable Permit Service (Remote Shut-Off, Remote Disconnect/Reconnect)			‡	‡ (P3)	‡
	Limit Active Power			‡	‡ (P3)	
	Monitor Key DER Data			‡	‡ (P3)	
Bulk System Reliability & Frequency Support	Frequency Ride-Through (FRT)	X	√	‡	‡ (P1)	‡
	Rate-of-Change-of-Frequency Ride-Through			‡	!!!	!!!
	Voltage Ride-Through (VRT)	X	√	‡	‡ (P1)	‡
	VRT of Consecutive Voltage Disturbances			‡	!!!	!!!
	Voltage Phase Angle Jump Ride-Through			‡	!!!	!!!
	Dynamic Voltage Support during VRT			√	[‡ (P3)]	
	Frequency-Watt	X	√	‡	‡ (P3)	‡
Legend:	X Prohibited, √ Allowed by Mutual Agreement, ‡ Capability Required					
	[…] Subject to clarification of the technical requirements and use cases, !!! Important Gap					

The DER Performance Capability & Functional Settings Challenge

- Central database(s)
  - Includes only public, non-proprietary information otherwise available in utility interconnection documents
  - EPRI: https://dersettings.epri.com
- EPRI Phase 1 (2019):
  - Storage of *.csv files + metadata, search functionality
  - Need for external DER Settings Form (Excel) to validate settings and create *.csv files
- EPRI Phase 2 (2020+):
  - Verification of uploaded settings
  - Data mining, visualization



Anticipated Scope of EPRI's DER Performance Capability and Settings Database

Long-term

IA-URP
(site specific)

Utility-Required Profile for Specific Site
- Included in site-specific interconnection agreement (IA)
- May result from site-specific interconnection screenings

Mid-term

DU-URP
(distribution utility specific)

Utility-Required Profile for Distribution Service Area
- Included in interconnection agreement template
- Specific to Distribution Utility's practices, e.g., automatic re-closing, distribution circuit characteristics, operating practices

Near-term

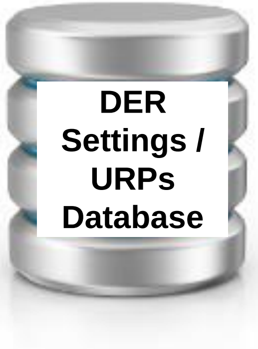
Regional-URP[1]
(state-wide or similar)

Utility-Required Profile for Region and/or ISO/RTO Reliability Region
- Consideration of distribution and bulk system impacts.
- May include some settings other than the SRD's default values

Adopted SRD[1] with Default Values
(state-wide or similar)

Source Requirements Document
- Preferably IEEE Std 1547-2018
- Otherwise: CAR21, HR14H, etc.

Database Scope



https://dersettings.epri.com/

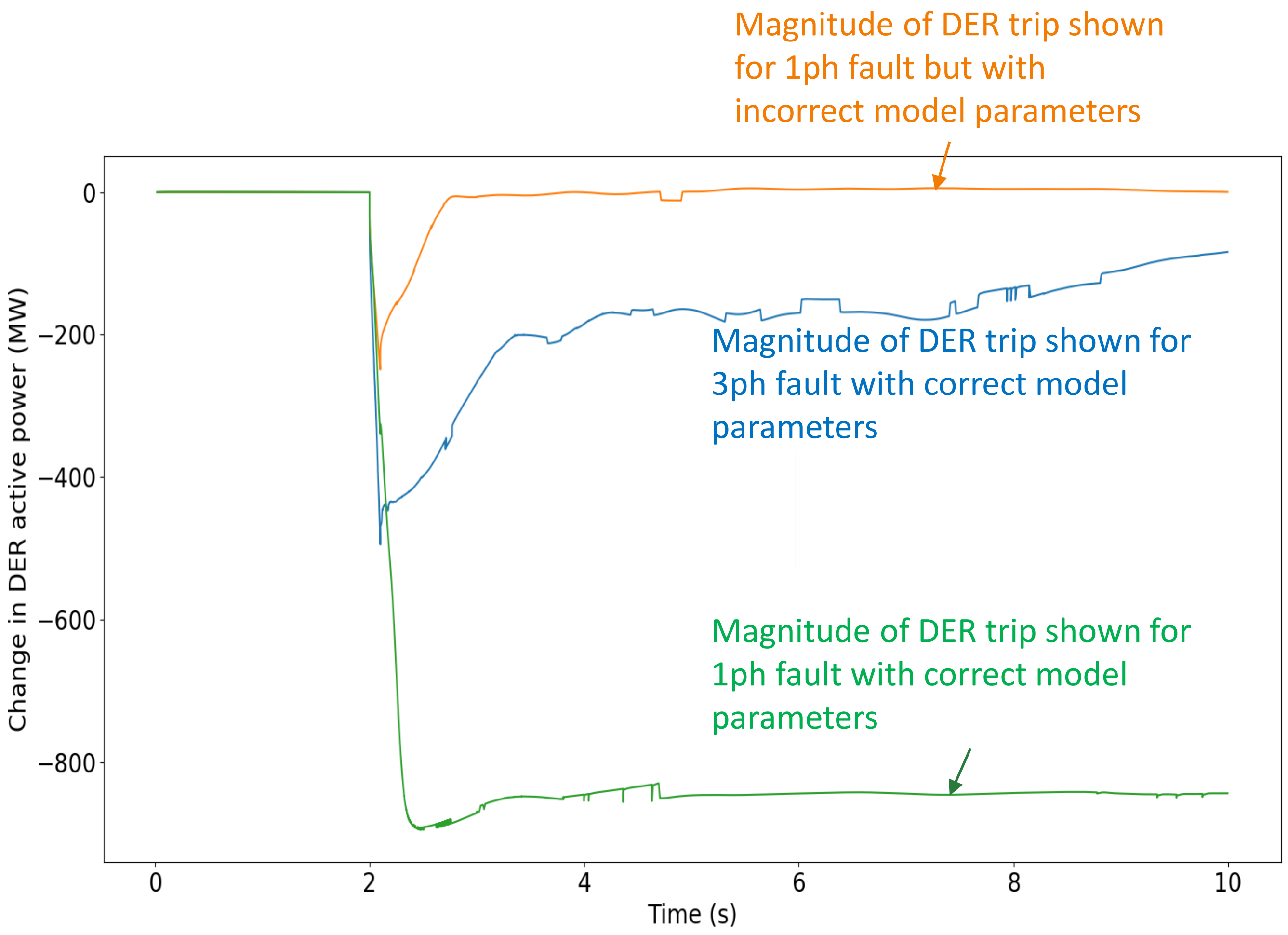
[1] Based on decision by Authority Governing Interconnection Requirements (AGIR), may be a public utilities commission or similar

Generic parameter estimation for DER_A model

- Correct parameterization of the DER_A model is crucial to obtain an accurate picture of system behavior.

How to obtain generic parameter values for the model for a variety of geographic terrain and load profiles such as:

- Urban location, commercial load
- Urban location, residential load
- Rural location, agricultural load
- Rural location, residential load



EPRI Project 1: Inverter-Based Resources Modeling and Model Validation Using Field Measurements with Focus on Bulk Power System Impacts

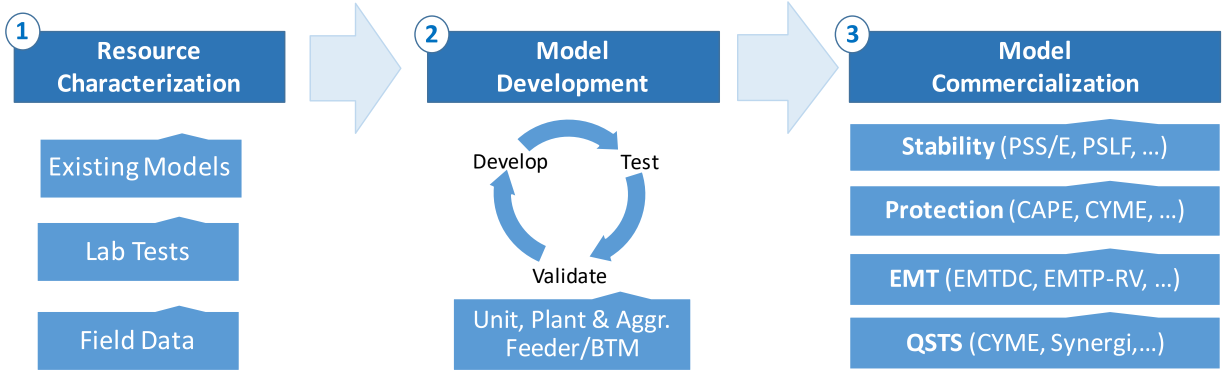
PROGRAM	40/173
PROJECT	16/3
TASK FORCE	MOD
COORDIN.	174/200

R&D Goal

Start Date: Q2/2020, Duration: 3 years

Leverage the DOE PV-MOD work to help utilities understand, test, validate, and adopt the models to improve system reliability for systems with high PV penetration

This supplemental project contributes to the $1.5M committed EPRI cost-share for the DOE PV-MOD award.



R&D Approach

- Scope includes protection, planning, and power quality models of both large-scale renewables and aggregate distributed energy resources
- Provide guidance on data collection process for field measurements
- Validate all developed models against laboratory* & field measurement disturbances; including analysis of events identified by utilities
- Help planners to gain confidence in the models by providing technical insights and guidance on how to use them in utilities' simulation platforms
- Ensure utility planners are vested in EPRI's existing vendor engagement processes to transfer the new models to commercial tool model libraries

* Leveraging joint P173/P174/P200 supplemental (3002014731) and DOE PV-MOD project

Deliverables

Deliverables are aligned to the DOE PV-MOD SOPO

- [Technical Updates] Model specs & validation
- [Webcasts] Quarterly AdvMtg & Updates

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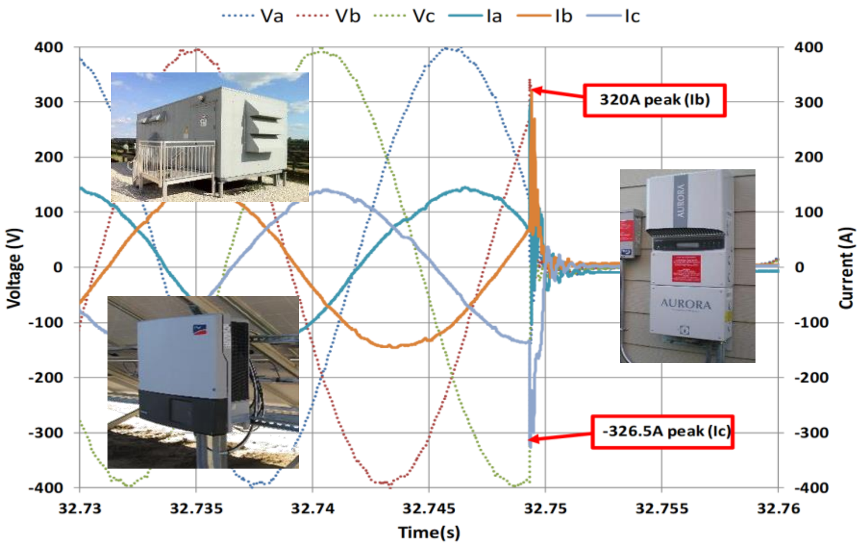
Committed

EPRI Project 2: DER Dynamic Response Characterization for Protection, Planning, and Power Quality



Objectives and Scope

- Expand industry knowledge of inverter dynamic response to grid disturbances
- Accelerate development of distribution dynamic models, evaluate and improve existing transmission aggregate DER models, and
- Identify critical parameters and ranges for sensitivity analysis.

Value

- Enhanced knowledge of commercial inverters' dynamic behavior:
  - Response to grid fault (L-L, L-L-G, L-G, and 3-phase)
  - Short-circuit current magnitude, duration, and phase
  - Active/reactive current during voltage and frequency fault ride through
  - Response to phase shift and frequency change
  - Response to single phase opening
  - Impact of out-of-phase reclosing for immunity
  - Power quality and bulk system impacts of active islanding detection
  - Reconnection time and resynchronization characteristics after trip
- Validation and improvement of existing and development of new models for protection, planning, and power quality studies.

Schedule and Cost

- Project beginning Q2 2020; Duration: 24 months
- *This supplemental project contributes to the $1.5M committed EPRI cost-share for the DOE PV-MOD award.*

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SPN Number: 3002014731

Narrow the uncertainty of inverter-based DER performance under abnormal and dynamic grid conditions.

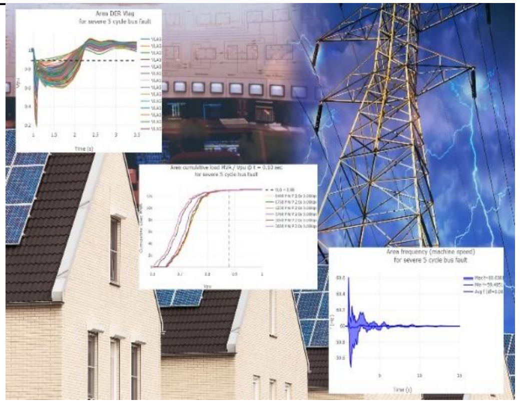
EPRI Project 3: Framework for Aggregate DER Data Pre-Processing for Transmission Planning Studies

PROGRAM	40/173
PROJECT	16/3/8
TASK FORCE	MOD
COORDIN.	174/ENV

R&D Goal

The primary R&D goal is to facilitate the entering of parameters representing the aggregate DER capacity values and performance / functional settings for transmission planning studies with DER. Among others, the framework will be capable to distinguish the amount of legacy DER (compliant to IEEE Std 1547-2003) from modern DER (compliant to IEEE Std 1547-2018) and may be linked to EPRI's DER Performance and Settings Database that is currently under development.

Maintain bulk system reliability with large amounts of distributed energy resources.



R&D Approach

- Processing of postal-code specific DER adoption forecast data based on socio-economic datasets (P174D R&D)
- Processing of distribution grid model and geographic information system (GIS) datasets
- Processing of other datasets, e.g., state databases for DER like the California Solar Energy Statistics (https://www.californiasolarstatistics.ca.gov/)

Deliverables

- [Software] Macro-Enabled Excel Spreadsheet
- [PowerPoint] Project Results Summary

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- Steven Coley (Technical Support) +1 615-542-2882 | scoley@epri.com

Please answer polling question to indicate interest

JOINT UTILITIES
OF NEW YORK

NPCC DER Forum

May 14, 2020

Dave Conroy

nationalgrid Orange & Rockland NYSEG RG&E Central Hudson conEdison

Who are the Joint Utilities?

Together, the Joint Utilities provide electric and gas service to over 13 million households, businesses, and government facilities across New York State. The Joint Utilities are comprised of:

- Central Hudson Gas and Electric Corporation (“Central Hudson”)
- Consolidated Edison Company of New York, Inc. (“Con Edison”)
- New York State Electric & Gas Corporation (“NYSEG”)
- Niagara Mohawk Power Corporation d/b/a National Grid (“National Grid”)
- Orange and Rockland Utilities, Inc. (“O&R”)
- Rochester Gas and Electric Corporation (“RG&E”)

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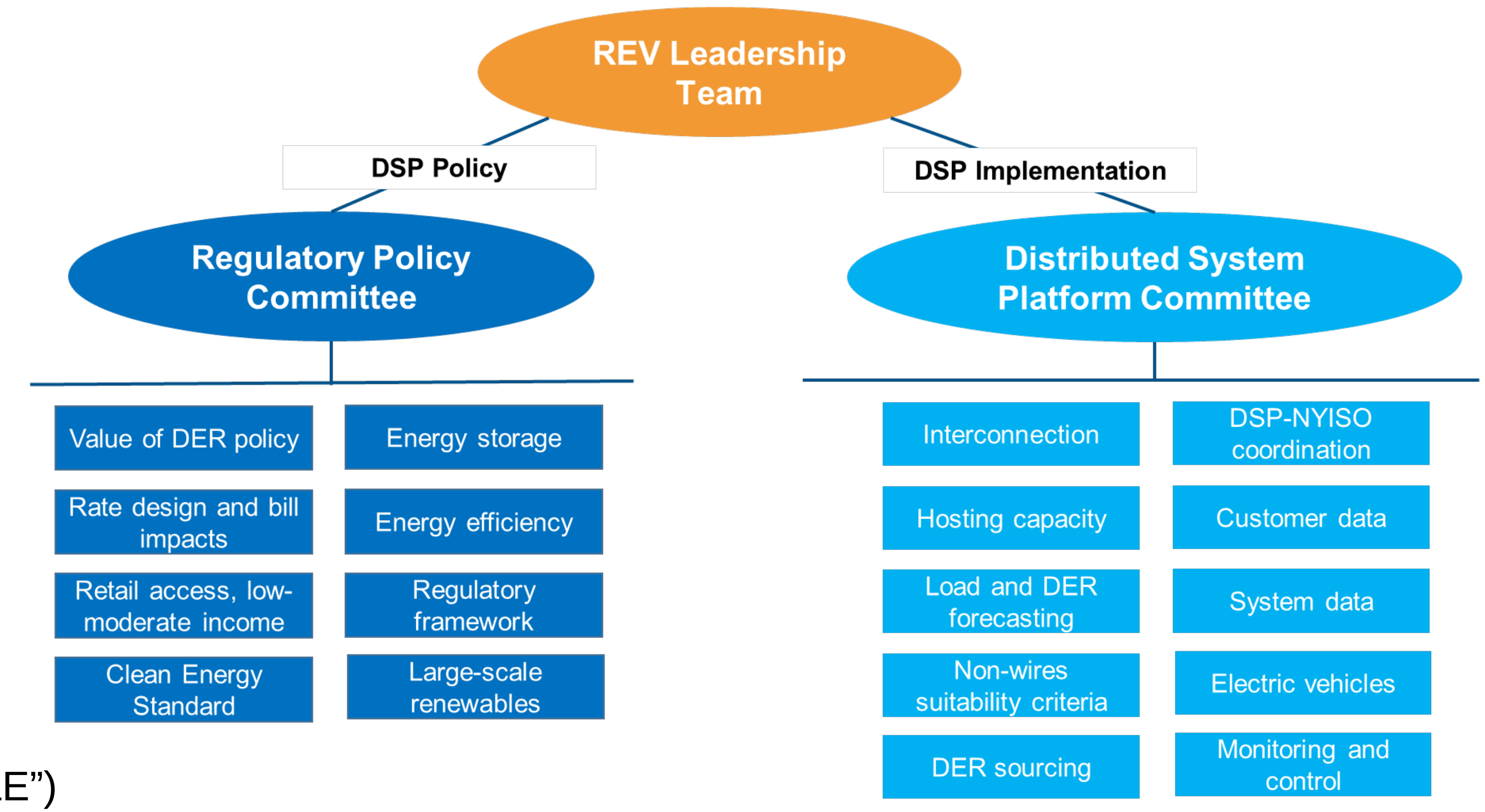

Why We Created the Joint Utilities

- First introduced by NY Department of Public Service (DPS) Staff in October 2015, the NY Public Service Commission (PSC) in April 2016 ordered the six utilities to file a joint Supplemental Distributed System Implementation Plan (DSIP)
- Acknowledgment that taking a unified approach (where practical) across the utilities would help drive greater efficiencies in achieving REV objectives
- Starting in 2016 and still ongoing, the Joint Utilities host stakeholder events to provide updates on collective progress and solicit stakeholder input
- The Joint Utilities also participate in PSC proceedings and communicate a collective position on behalf of the utilities
- Individual utility DSIP filings reflect progress and achievements of the Joint Utilities collectively in addition to progress specific to the individual utility

The PSC ordered a Supplemental DSIP "addressing the tools, processes, and protocols that will be developed jointly or under shared standards to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets"

Timeline of Key DSIP Orders and Filings

Feb 2015
PSC REV Track One Order

Oct 2015
DPS Staff DSIP Guidance; creation of Joint Utilities

Apr 2016
PSC DSIP Guidance Order

June 2016
Utilities file individual DSIPs

Nov 2016
Joint Utilities Supplemental DSIP

Mar 2017
PSC DSIP Order

May 2018
DPS Staff DSIP Guidance White Paper

July 2018
Utilities file individual DSIPs

June 2020
Utilities file individual DSIPs

2015 2016 2017 2018 2019 2020

PSC order
DPS Staff filing
Utility / JU DSIP filing

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Stakeholders Engagement at the Core of Distributed System Platform (DSP) Enablement

Hosted

80

stakeholder sessions

Nearly

200

total stakeholders

Representing

100

organizations

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Joint Utilities Accomplishments

Submitted multiple joint filings, including our flagship **Supplemental DSIP** in November 2016

Developed a common methodology for advanced **hosting capacity** maps which add sub-feeder level granularity and existing distributed energy resources

Collaborated with stakeholders to refine and streamline the **interconnection process** for DG and energy storage

Created **non-wires suitability criteria** to determine opportunities for DER to address identified system needs

Established common **monitoring and control** standards for solar PV and identified potential low-cost solutions

Coordinated on **integrated planning** topics and studies across the transmission and distribution systems to better understand operational impacts of interconnections

Enabled **dual participation** for DER and energy storage resources to access value for both distribution-level services and wholesale markets

Collaborated with stakeholders in the development and implementation of the **VDER Value Stack**

Developed an EV Readiness Framework to outline the Joint Utilities' plans to facilitate wider adoption of **electric vehicles** and charging infrastructure deployment

Produced statewide **privacy standards** for sharing of customer data

Defined **operational requirements** for coordination among the DSP, NYISO, and DER aggregators

Distributed System Platform (DSP) Enablement Efforts

Developed individual and central **utility data portals** (e.g., system data, large-scale renewables value, non-wires alternatives RFP opportunities, hosting capacity, EVs)

Expanded deployment and demonstration of **foundational communications and operations infrastructure**: AMI, sensors, DSCADA, Distribution Automation, ADMS

Released **advanced hosting capacity displays** which added sub-feeder level granularity and existing distributed energy resources

Implementation of **Green Button Connect** (or similar) for increased data access through easier and more granular mechanisms

Created **online application portal** for greater automation and ease of interconnection process for DER (e.g., PV, storage, CHP)

Integrating **energy storage** through procurement and formation of safety agreements with local authorities

Enabled **dual participation** for DER and energy storage resources to access value for both distribution-level services and wholesale markets

Formalized dispatch and communication protocols and roles and functions between the DSP, NYISO, aggregator, and DER owner

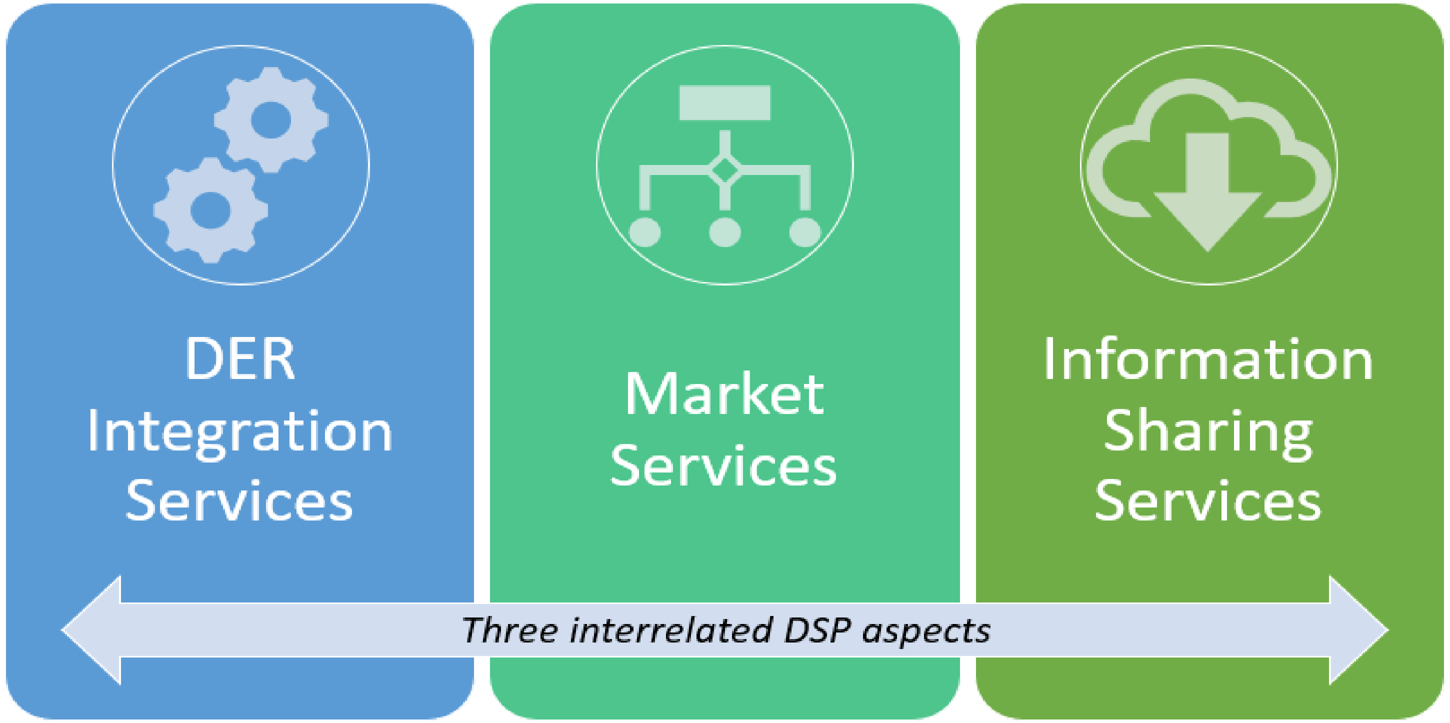
Facilitating wider adoption of **electric vehicles** and charging infrastructure deployment

Our 5-Year Distributed System Platform (DSP) Vision

Growing emphasis on large-scale renewables

DSP becomes even more flexible and adaptable

Opening new sources of value for customers and market participants



DSP delivers safe, reliable, efficient, and clean electricity to customers

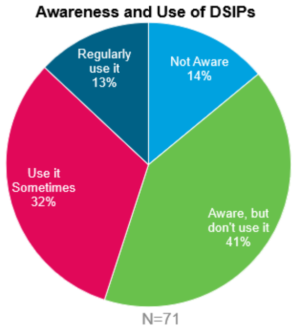
Expanded customer choice, greater use of distributed energy resources as system resources, and enhanced access to value streams

DSP investments in operational systems support grid and market operations

Remaining responsive to evolving state objectives (REV, Climate Leadership and Community Protection Act) and market dynamics

JU Stakeholder Engagement in Advance of 2020 DSIPs

Stakeholder Survey released to help inform the 2020 DSIPs



51%
of respondents are using the JU website:
www.jointutilitiesofny.org

Quarterly DSP Enablement Newsletter published with updated structure based on October survey

Next quarterly newsletter posted to JU Website

Company-specific stakeholder meetings on DSIPs (*dates TBA*)

Oct ... Dec | Jan | Feb | March | April | May | June – September

JU Stakeholder Webinar on Distributed System Implementation Plans (DSIPs)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Distributed System Implementation Plans (DSIPs) Stakeholder Webinar

December 11, 2019

JU Stakeholder Webinar on updates for several topics: System Data, Customer Data, EVs, Hosting Capacity, Coordination

June 30, 2020

Individual DSIPs are filed

Sharing Up-to-Date Information

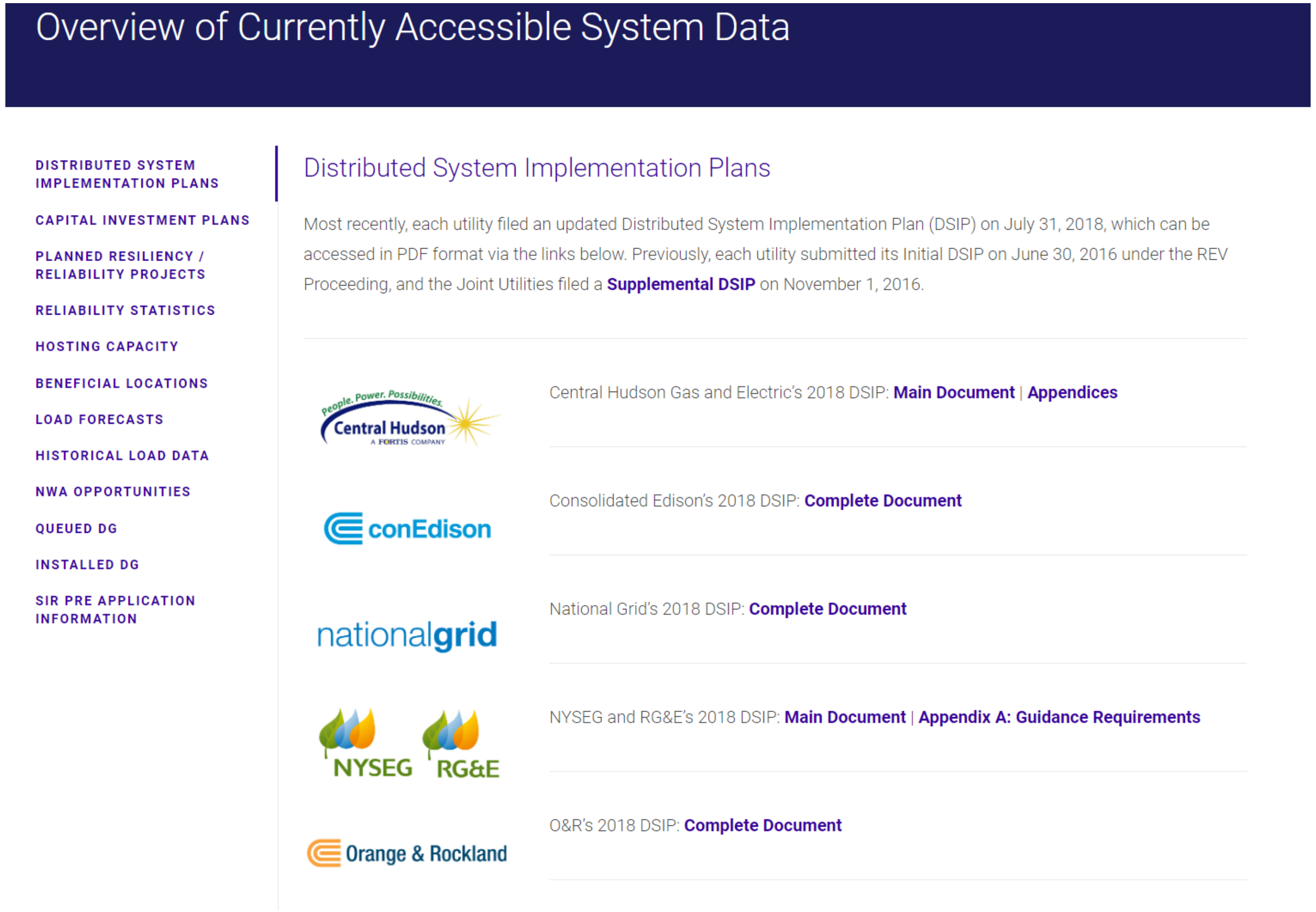
Please visit our website: www.jointutilitiesofny.org

Links to utility-specific information:

- NWA Opportunities
- System Data
- Hosting Capacity
- Electric Vehicles

Recent Commission Orders, Whitepapers, and Filings

Stakeholder engagement opportunities



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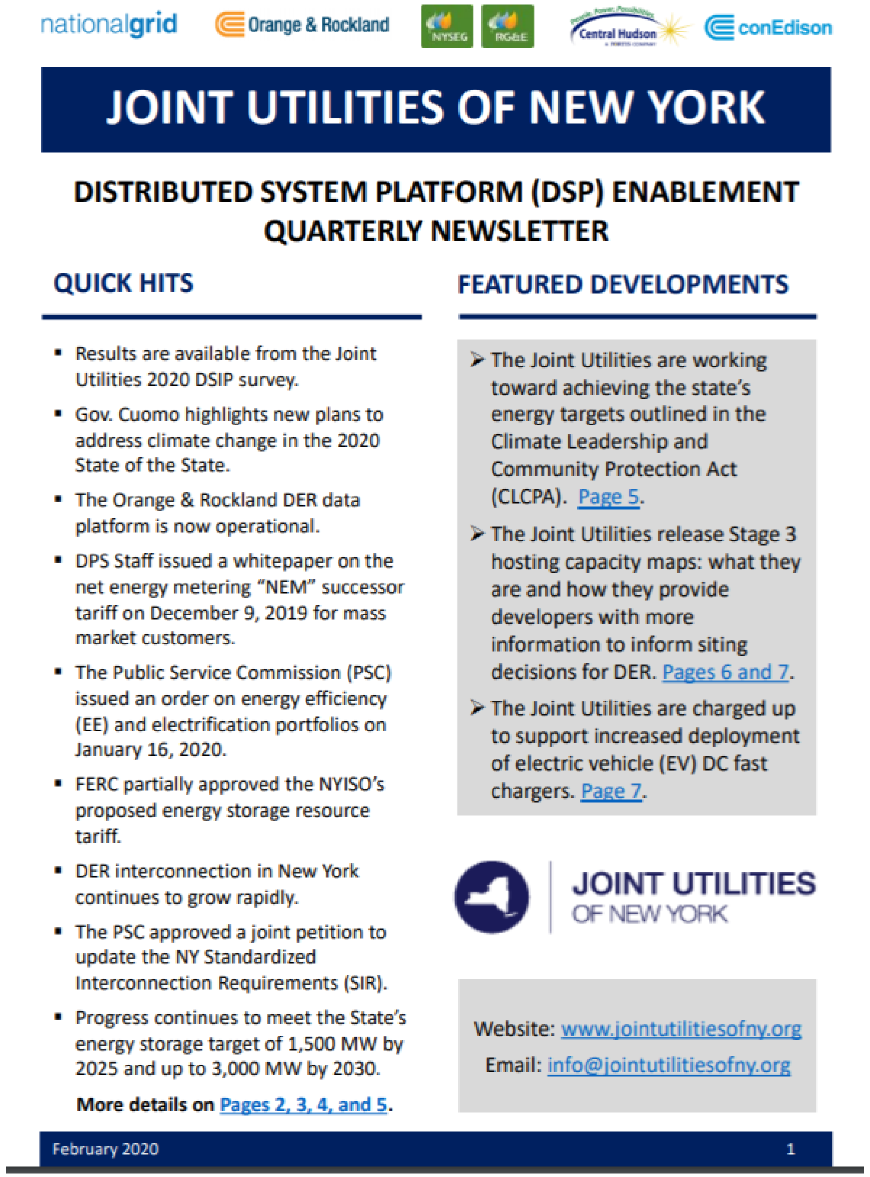
Quarterly DSP Enablement Newsletters

- Check out our quarterly newsletter with meaningful, substantive updates related to the DSIPs
- Succinct snapshot of how the utilities are making progress on the DSP
- Readily accessible information sources that are updated more frequently than the two-year DSIP cycle
- Regulatory updates with a focus on the potential impact to the DSPs and the attainment of state goals
- Available on the Joint Utilities website (tab: Stakeholder Engagement)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DISTRIBUTED SYSTEM PLATFORM (DSP) ENABLEMENT QUARTERLY NEWSLETTER

QUICK HITS

- Results are available from the Joint Utilities 2020 DSIP survey.
- Gov. Cuomo highlights new plans to address climate change in the 2020 State of the State.
- The Orange & Rockland DER data platform is now operational.
- DPS Staff issued a whitepaper on the net energy metering "NEM" successor tariff on December 9, 2019 for mass market customers.
- The Public Service Commission (PSC) issued an order on energy efficiency (EE) and electrification portfolios on January 16, 2020.
- FERC partially approved the NYISO's proposed energy storage resource tariff.
- DER interconnection in New York continues to grow rapidly.
- The PSC approved a joint petition to update the NY Standardized Interconnection Requirements (SIR).
- Progress continues to meet the State's energy storage target of 1,500 MW by 2025 and up to 3,000 MW by 2030.

More details on Pages 2, 3, 4, and 5.

FEATURED DEVELOPMENTS

- The Joint Utilities are working toward achieving the state's energy targets outlined in the Climate Leadership and Community Protection Act (CLCPA). Page 5.
- The Joint Utilities release Stage 3 hosting capacity maps: what they are and how they provide developers with more information to inform siting decisions for DER. Pages 6 and 7.
- The Joint Utilities are charged up to support increased deployment of electric vehicle (EV) DC fast chargers. Page 7.

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Website: www.jointutilitiesofny.org

Email: info@jointutilitiesofny.org

February 2020 1

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Thank you!

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NPCC Regional Standards Committee Meeting #20-2

DER Forum
Agenda Item 16.4

May 13-14, 2020

DERs Prompting More EDC and TO Coordination

EVERSOURCE ENERGY

- DERs are blurring the line between Transmission Interconnections and Distribution Interconnections
  - Significant increase in DER Transmission System Impact Studies
  - Numerous Eversource stations expected to experience Reverse Power Flow
- An increasingly relevant way for EDCs and TOs to facilitate DER development is to assist developers with making informed decisions
  - Regarding the regulatory jurisdiction of their proposed projects
  - Developing customer facing technology solutions such as Hosting Capacity Maps
  - Implementing expedited study processes for projects that have minimal impact to reliability or operations.
- Increasing amount of DERs intend to participate in wholesale markets
  - Improved coordination with ISO NE when performing capacity market qualification reviews

Eversource Quick Stats

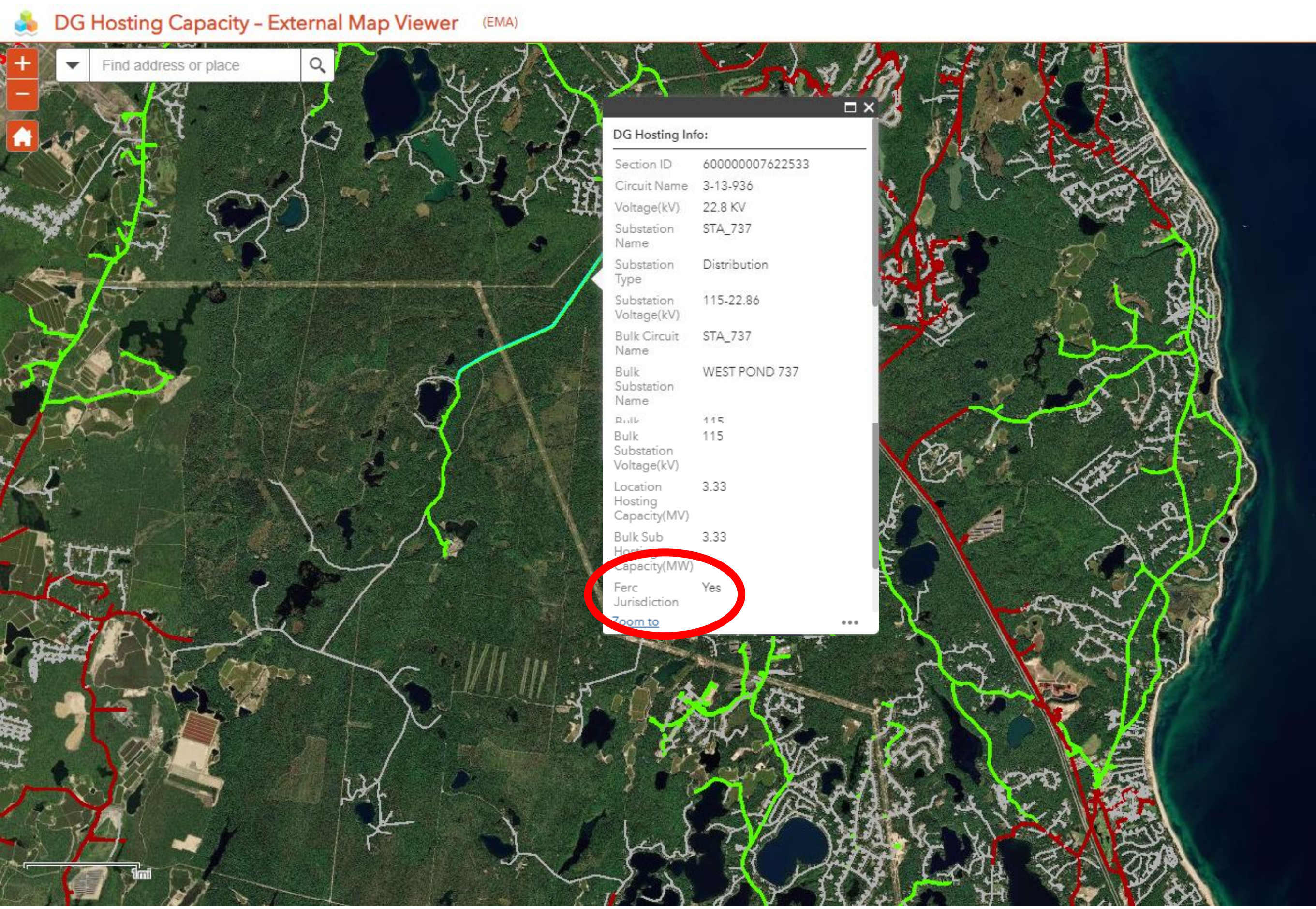
EVERSOURCE ENERGY

- Eversource strives to promote DER growth and implemented internal D and T coordination 5 years ago
- **2,101:** Eversource owns approximately 2,010 distribution facilities
- **310:** Of which, roughly 310 are dual-use facilities (i.e., used for wholesale and retail sales)
- **50%:** The number of dual-use facilities is expected to increase by 50 percent year-over-year
- When a DER is proposing to interconnect to a dual-use distribution facility and make wholesale sales itself, it needs to submit an interconnection request to ISONE

Hosting Capacity Maps 2.0

EVERSOURCE ENERGY

- Eversource's DER Hosting Capacity Maps now include distribution facility regulatory jurisdiction



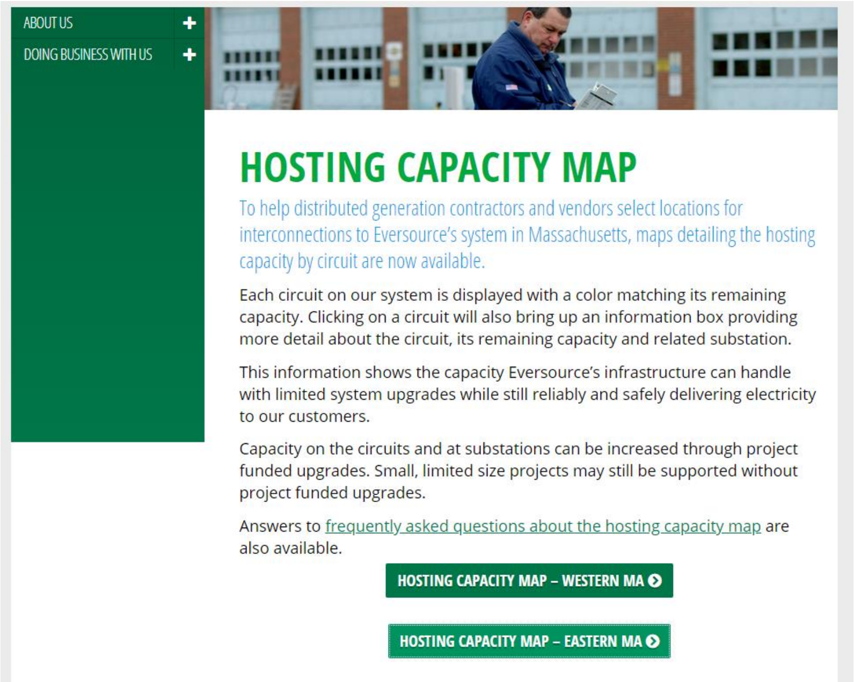
Maps show customers where it is likely to be easier to locate medium and larger scale solar facilities

Information is expected to improve the interconnection experience for customers

We continue to enhance these to provide more granular information e.g. regulatory jurisdiction.

Website Links

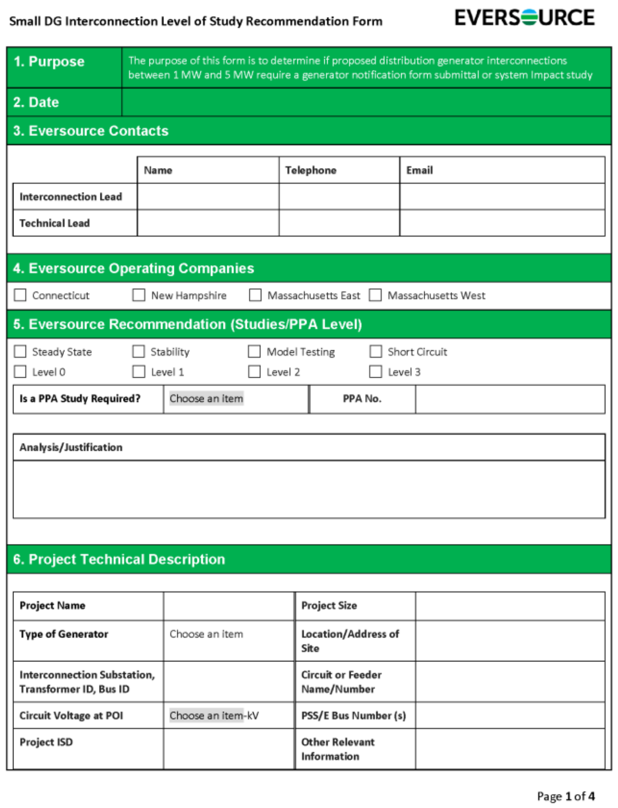
- Eversource's Hosting Capacity Maps publicly available here: https://www.eversource.com/content/ct-c/about/about-us/doing-business-with-us/builders-contractors/interconnections/massachusetts-application-to-connect/hosting-capacity-map



ISONE I.3.9 Level 0 Screening

- The Proposed Plan Application requirements for DERs sized >1MW and < 5 MW are subject to ISONE discretion (per Planning Procedure 5-1)

- To expedite the process and facilitate ISONE's determination, Eversource developed and uses a screening document to provide more information to help justify a Level 0 Notification Form



Small DG Interconnection Level of Study Recommendation Form

EVERSOURCE

1. Purpose The purpose of this form is to determine if proposed distribution generator interconnections between 1 MW and 5 MW require a generator notification form submittal or system impact study

2. Date

3. Eversource Contacts

	Name	Telephone	Email
Interconnection Lead			
Technical Lead			

4. Eversource Operating Companies

☐ Connecticut ☐ New Hampshire ☐ Massachusetts East ☐ Massachusetts West

5. Eversource Recommendation (Studies/PPA Level)

☐ Steady State ☐ Stability ☐ Model Testing ☐ Short Circuit
☐ Level 0 ☐ Level 1 ☐ Level 2 ☐ Level 3

Is a PPA Study Required?	Choose an item	PPA No.	

Analysis/Justification

6. Project Technical Description

Project Name		Project Size	
Type of Generator	Choose an item	Location/Address of Site	
Interconnection Substation, Transformer ID, Bus ID		Circuit or Feeder Name/Number	
Circuit Voltage at POI	Choose an item-kV	PSS/E Bus Number (s)	
Project ISD		Other Relevant Information	

Page 1 of 4

Automatic Underfrequency Load Shedding and Distributed Energy Resources

Northeast Power Coordinating Council
Regional Standards Committee DER Forum

Dan Kopin
Utility Services

May 2020

Agenda

- Premise
- “Friendly Neighborhood Utility” – *Hypothetical*
  - NERC Standard PRC-006
  - SPIDER Working Group Reliability Guideline
  - Hosting Capacity Analysis
- ERCOT Market Notice & Proposal

Premise

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

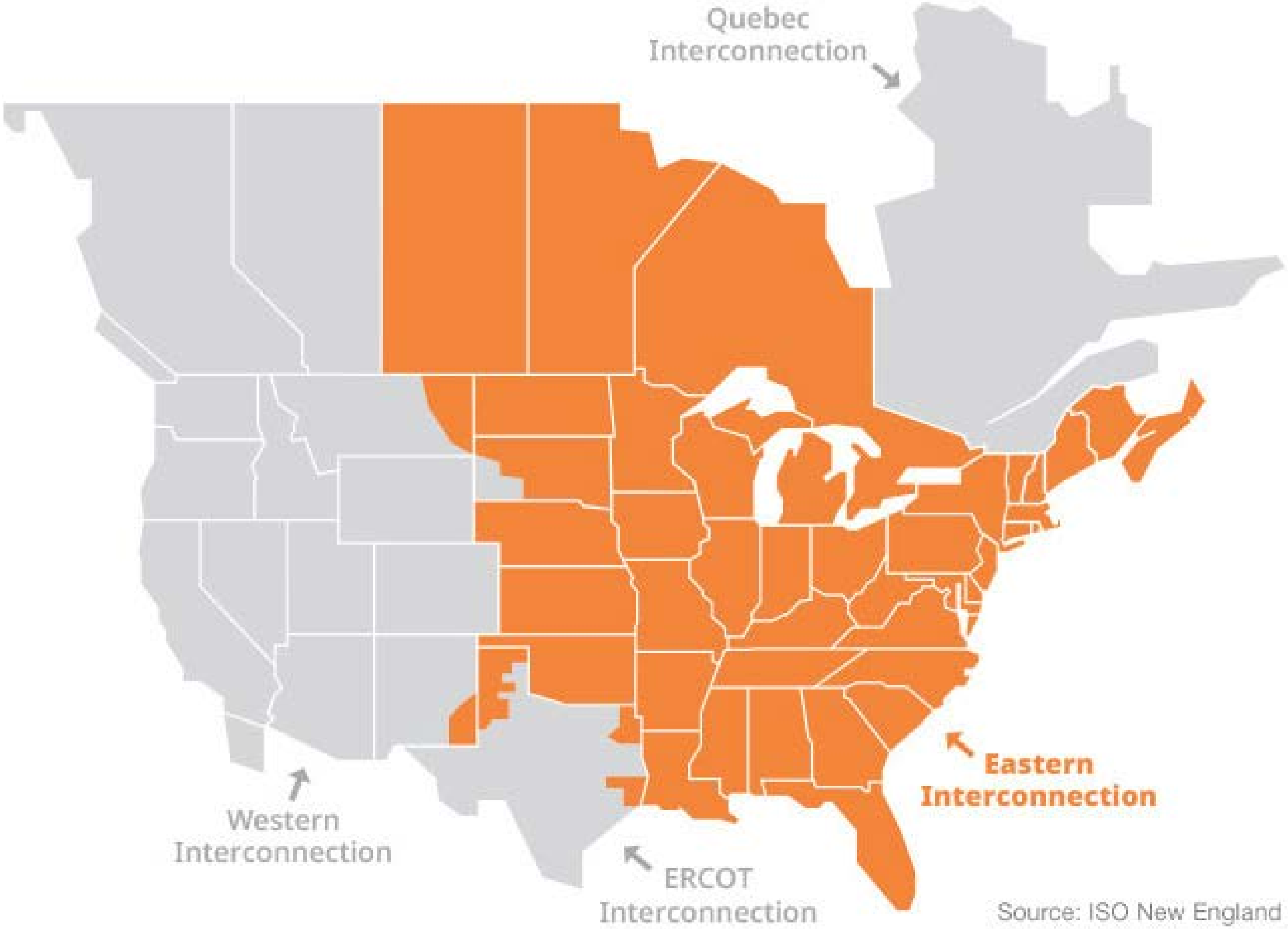
Guideline Key Takeaways

- ***Aggregate*** amounts of DER can and will impact the BPS
  - NERC Goal: provide support where needed in this area; ensure BPS reliability

Source: NERC (2020)

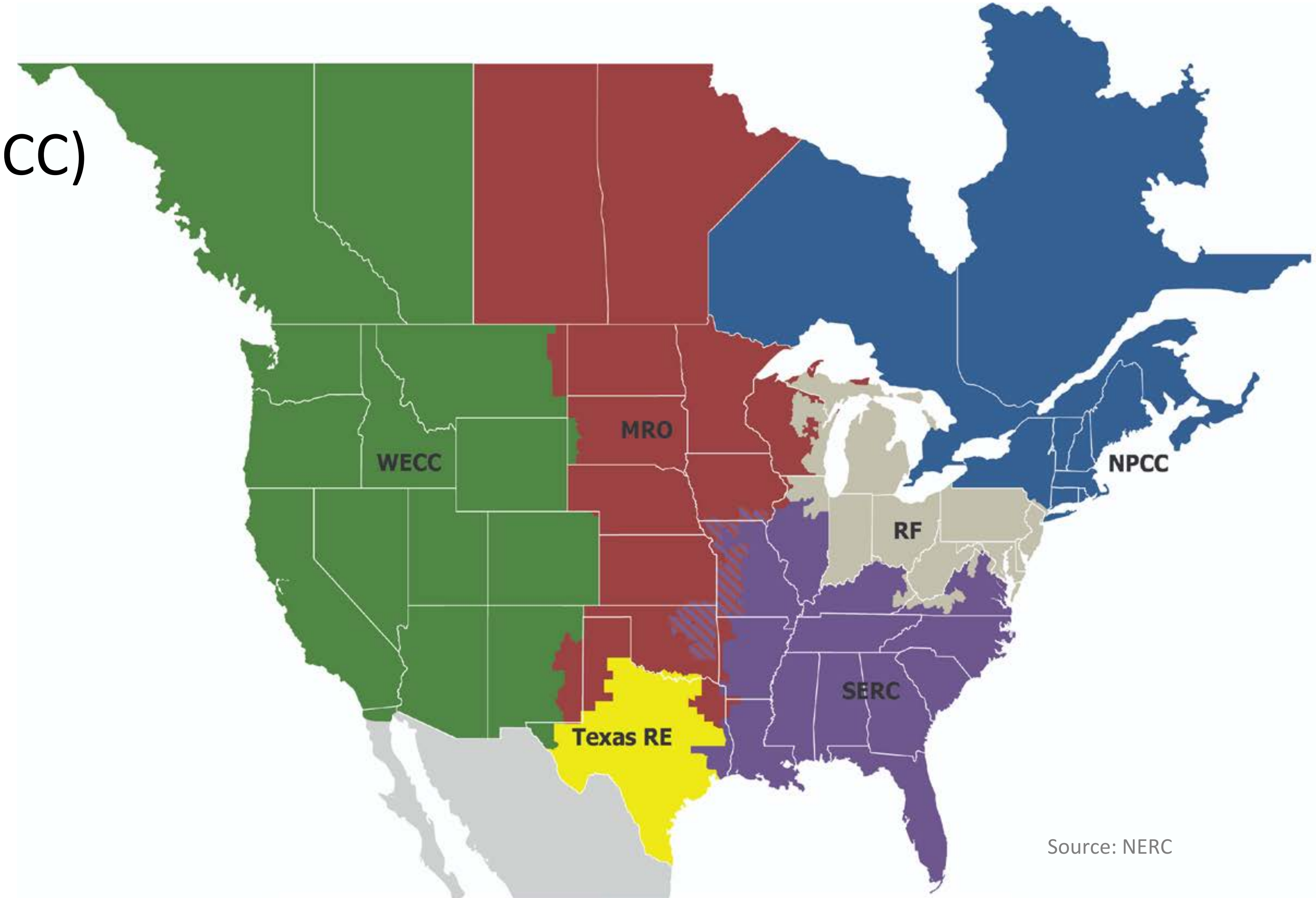
“Friendly Neighborhood Utility”

- Eastern Interconnection



“Friendly Neighborhood Utility”

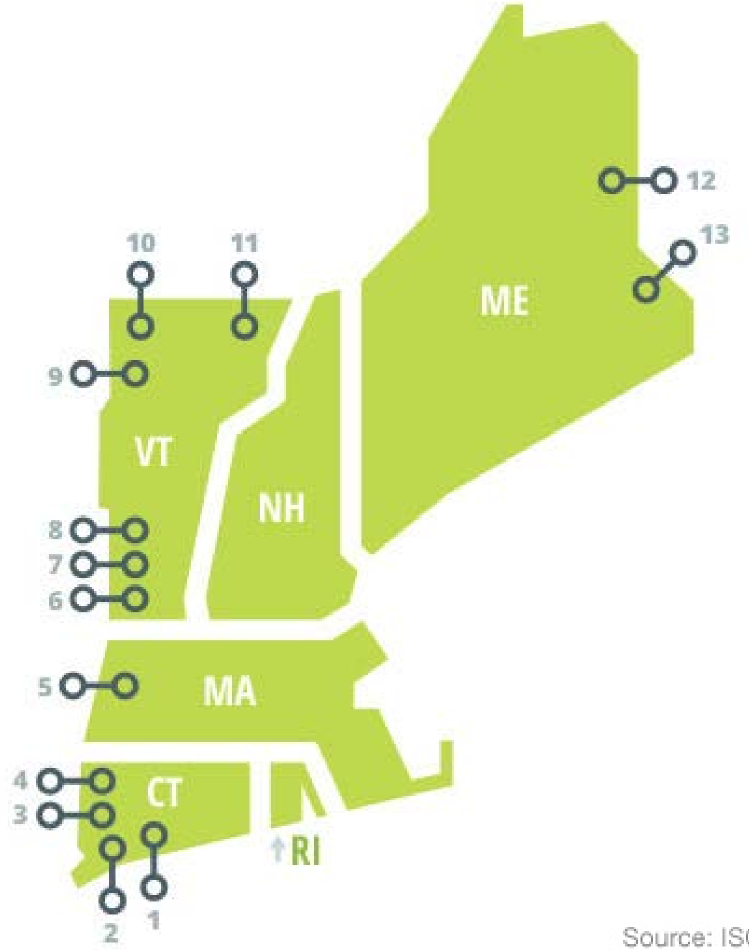
- Eastern Interconnection
- Northeast Power Coordinating Council (NPCC)



Source: NERC

"Friendly Neighborhood Utility"

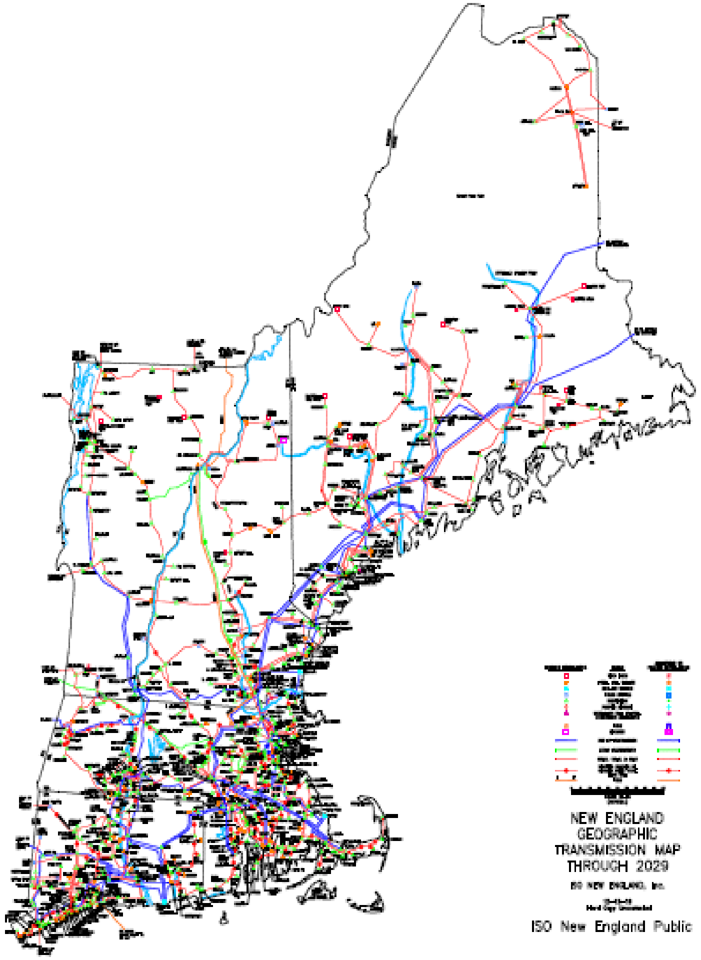
- Eastern Interconnection
- Northeast Power Coordinating Council (NPCC)
- ISO New England Balancing Authority Area



Source: ISO New England

“Friendly Neighborhood Utility”

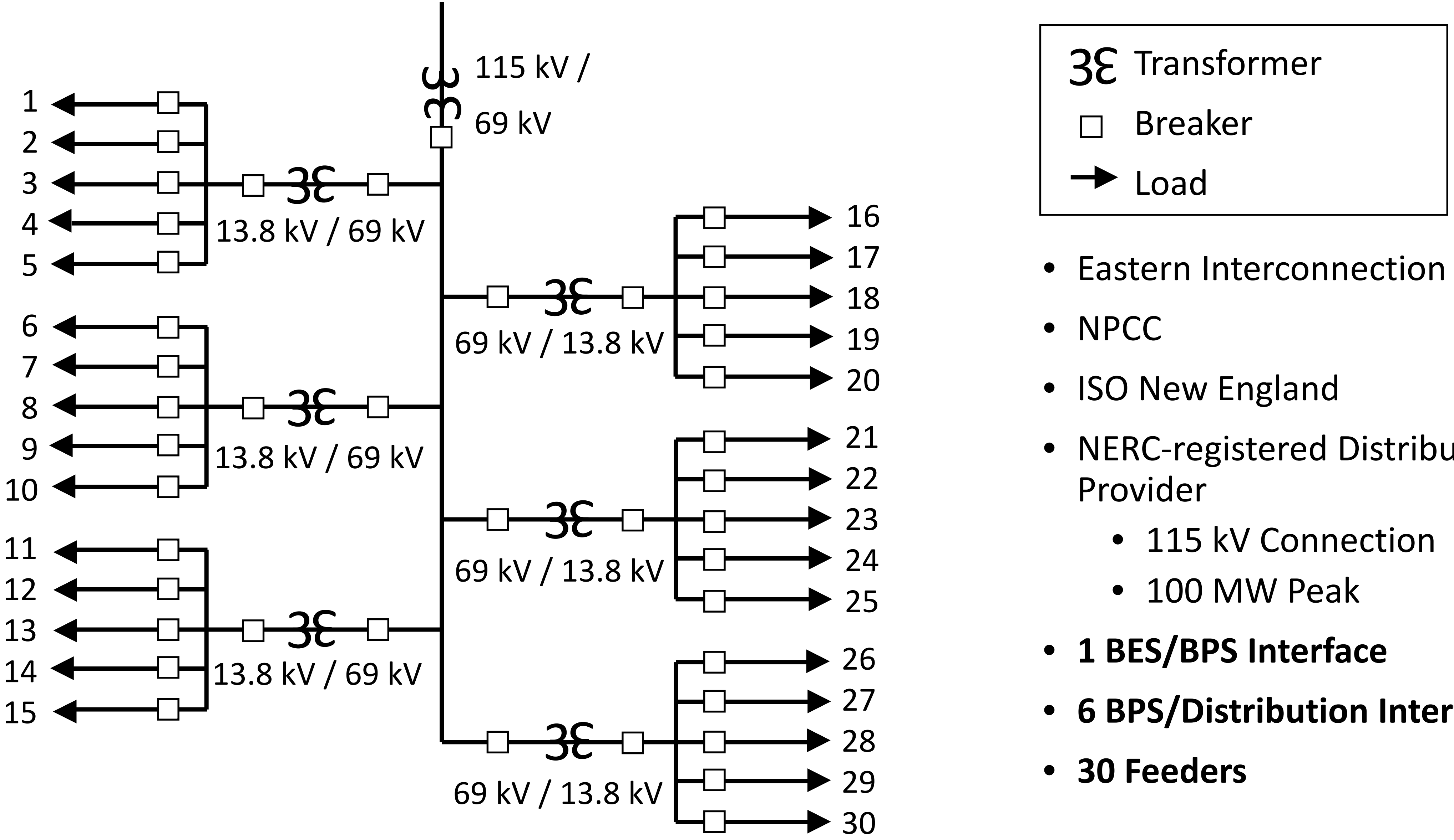
- Eastern Interconnection
- Northeast Power Coordinating Council (NPCC)
- ISO New England Balancing Authority Area
- NERC-registered Distribution Provider (DP)
    - Connected at 115 kilovolts (kV)
    - Peak of 100 megawatts (MW)



"Friendly Neighborhood Utility"

- Eastern Interconnection
- Northeast Power Coordinating Council (NPCC)
- ISO New England Balancing Authority Area
- NERC-registered Distribution Provider (DP)
  - Connected at 115 kilovolts (kV)
  - Peak of 100 megawatts (MW)
- Applicable to NERC Standards
  - [FERC Order No. 693](#) (2007)
  - [FERC Order No. 773](#) (2012)

“Friendly Neighborhood Utility”



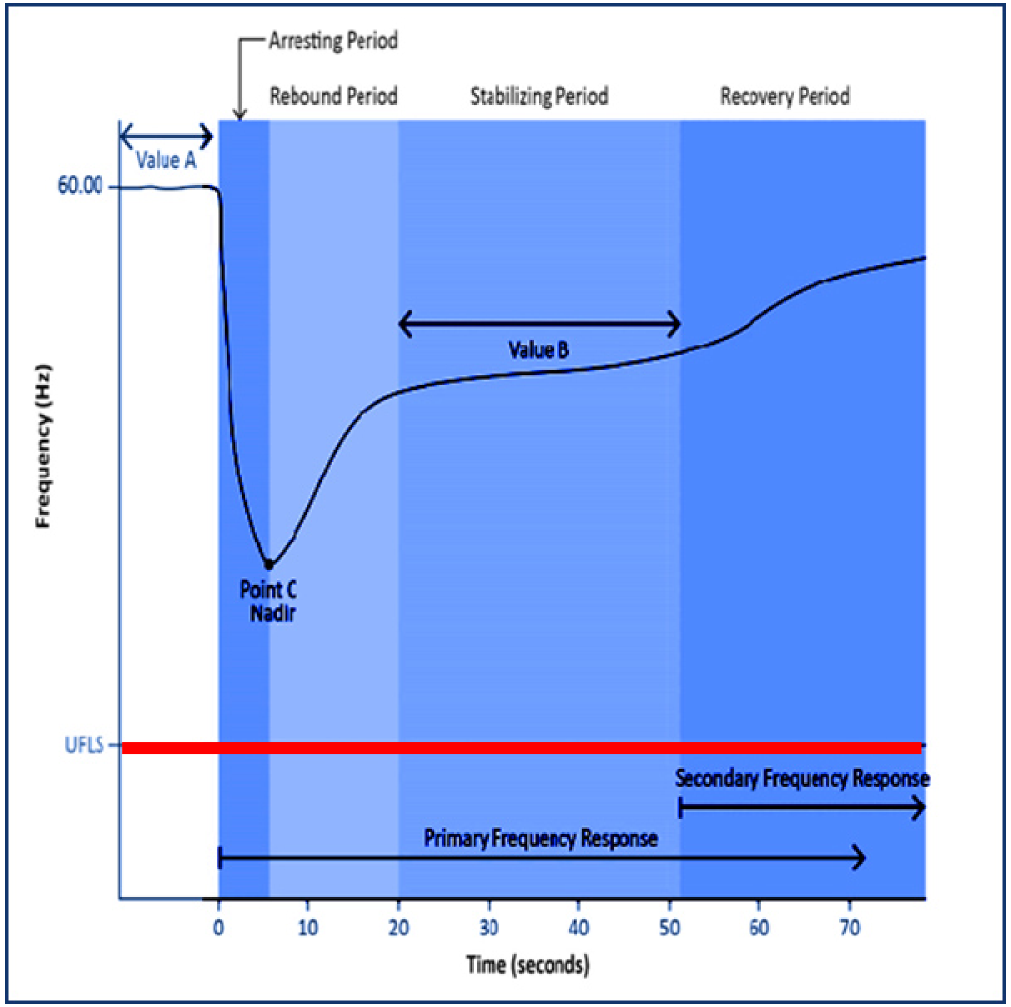
- Eastern Interconnection
- NPCC
- ISO New England
- NERC-registered Distribution Provider
  - 115 kV Connection
  - 100 MW Peak
- **1 BES/BPS Interface**
- **6 BPS/Distribution Interfaces**
- **30 Feeders**

PRC-006

- As a DP, “Friendly Neighborhood Utility” is applicable to PRC-006 *Automatic Underfrequency Load Shedding*.
  - Given that this “Friendly Neighborhood Utility” hypothetical is in NPCC, specifically PRC-006-NPCC-1. Otherwise, DPs and DP-UFLS Only Entities are applicable to either PRC-006-3 or PRC-006-SERC-02.
- What is Underfrequency Load Shedding (UFLS)?

PRC-006

"Reliability is threatened when a large electric generator(s) disconnects from the power system because the loss of generation causes an immediate decline in power system frequency. If the loss of generation is large enough and the remaining, still-connected generators do not respond and rapidly arrest the decline in frequency, power system frequency may decline below established, safe operating bounds and trigger automatic, emergency load shedding to avoid a cascading blackout" – [LBNL (2018)]



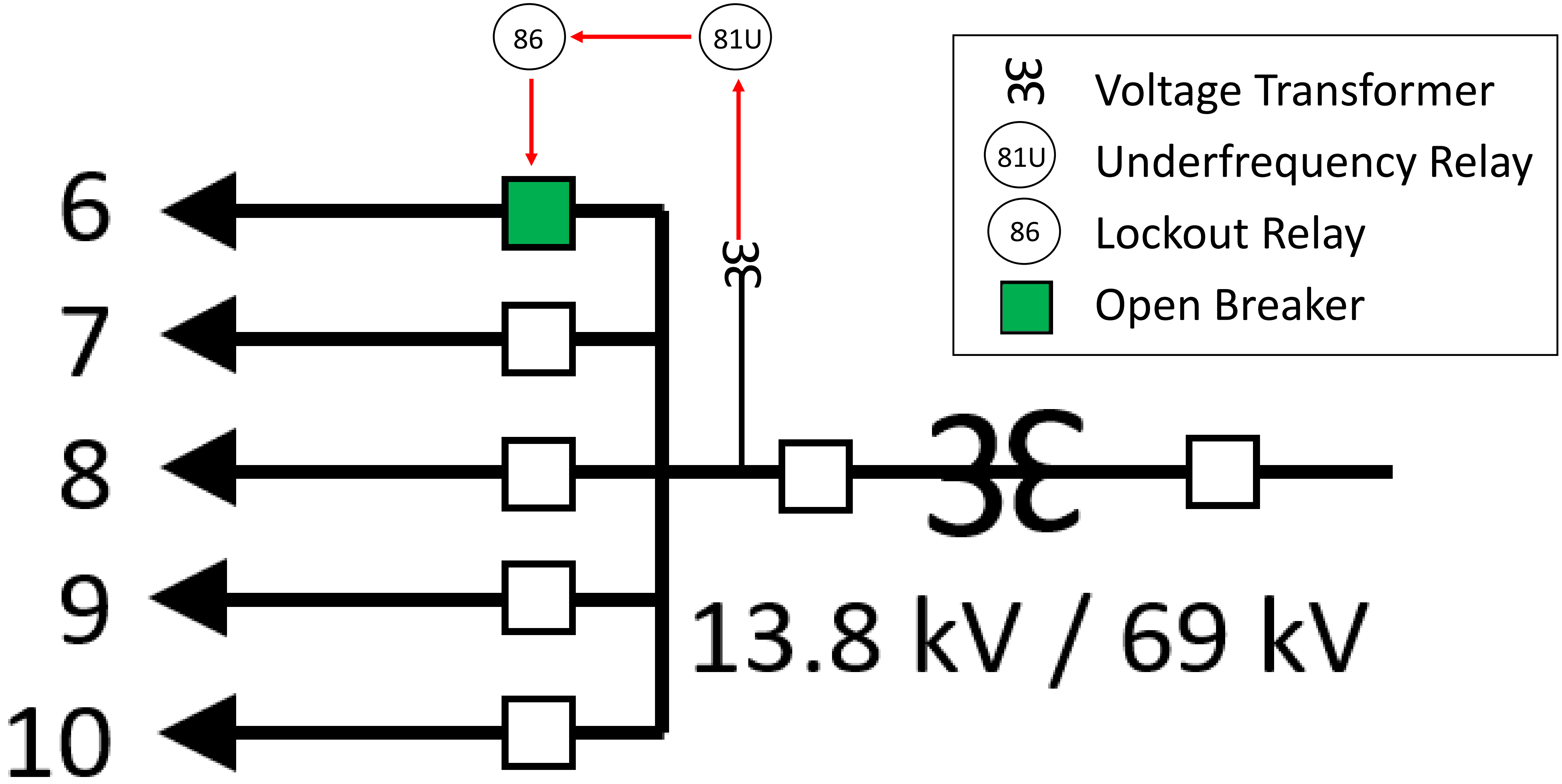
= Automatic Underfrequency Load Shedding

PRC-006

- FERC Order No. 763

  "The UFLS program addressed in Reliability Standard [PRC-006] is important to arresting declining frequency and assisting recovery of frequency following system events that lead to system instability, which can result in a blackout. Accordingly, the Reliability Standard is necessary for reliability because UFLS is used in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island."

PRC-006



86
81U
Voltage Transformer
81U
Underfrequency Relay
86
Lockout Relay
Open Breaker
6
7
8
9
10
13.8 kV / 69 kV

PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

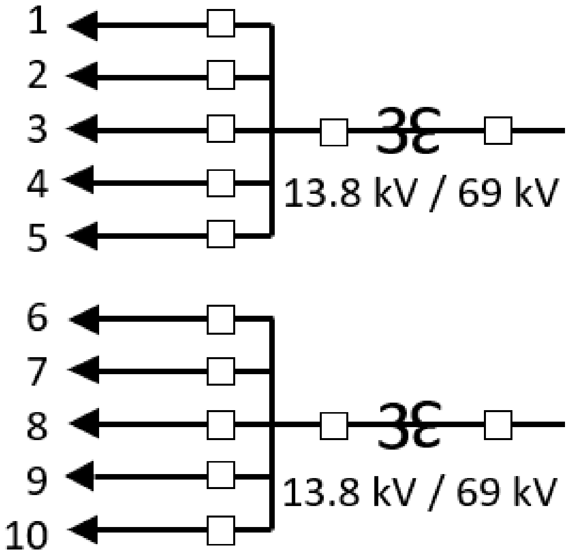
	Peak ≥ 100 MW		***50 MW ≤ Peak < 100 MW***		***25 MW ≤ Peak < 50 MW***	
Trip Setting (Hz)	Load Shed	Cumulative Load Shed	Load Shed	Cumulative Load Shed	Load Shed	Cumulative Load Shed
59.5	6.5-7.5%	6.5-7.5%	14-25%	14-25%	28-50%	**28-50%**
59.3	6.5-7.5%	13.5-14.5%				
59.1	6.5-7.5%	20.5-21.5%	14-25%	**28-50%**		
58.9	6.5-7.5%	27.5-28.5%				
59.5 (10s)	2-3%	**29.5-31.5%**				

PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

Entity Name:	Projected DP 2025 Peak Load (MW)	UFLS Feeder ID	Trip Setting	Feeder Load Tripped (MW)	% of Peak
"Friendly Neighborhood Utility"	100	1	59.5	3.5	3.5
		2	59.5	3.5	3.5
		3	59.3	3.5	3.5
		4	59.3	3.5	3.5
		5	59.1	3.5	3.5
		6	59.1	3.5	3.5
		7	58.9	3.5	3.5
		8	58.9	3.5	3.5
		9	59.5 (10s)	1	1
		10	59.5 (10s)	1	1
				30	30

PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

Entity Name:	Projected DP 2025 Peak Load (MW)	UFLS Feeder ID	Trip Setting	Feeder Load Tripped (MW)	% of Peak
"Friendly Neighborhood Utility"	100	1	59.5	3.5	
		2	59.5	3.5	
		3	59.3	3.5	
		4	59.3	3.5	
		5	59.1	3.5	
		6	59.1	3.5	
		7	58.9	3.5	
		8	58.9	3.5	
		9	59.5 (10s)	1	
		10	59.5 (10s)	1	
				30	30



PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

Entity Name:	Projected DP 2025 Peak Load (MW)	UFLS Feeder ID	Trip Setting	Feeder Load Tripped (MW)	% of Peak	DER (MW)
"Friendly Neighborhood Utility"	100	1	59.5	3.5	3.5	0
		2	59.5	3.5	3.5	0
		3	59.3	3.5	3.5	0
		4	59.3	3.5	3.5	0
		5	59.1	3.5	3.5	0
		6	59.1	3.5	3.5	0
		7	58.9	3.5	3.5	0
		8	58.9	3.5	3.5	0
		9	59.5 (10s)	1	1	0
		10	59.5 (10s)	1	1	0
				30	30	0

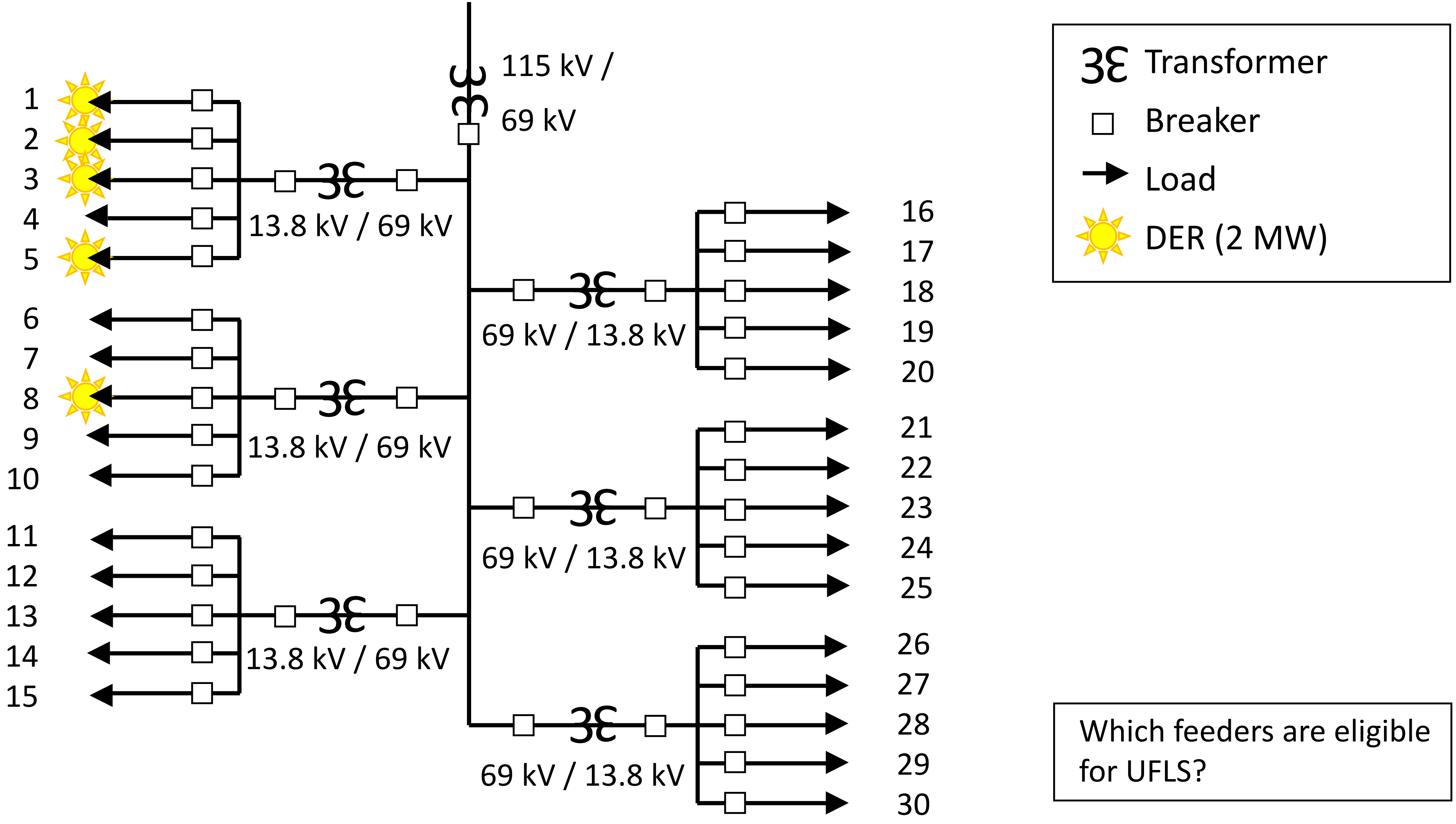
PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

Entity Name:	Projected DP 2025 Peak Load (MW)	UFLS Feeder ID	Trip Setting	Feeder Load Tripped (MW)	% of Peak	DER (MW)
“Friendly Neighborhood Utility”	95	1	59.5	2.5	2.6	1
		2	59.5	2.5	2.6	1
		3	59.3	2.5	2.6	1
		4	59.3	3.5	3.7	0
		5	59.1	2.5	2.6	1
		6	59.1	3.5	3.7	0
		7	58.9	3.5	3.7	0
		8	58.9	2.5	2.6	1
		9	59.5 (10s)	1	1.1	0
		10	59.5 (10s)	1	1.1	0
				25	26.3	5

PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

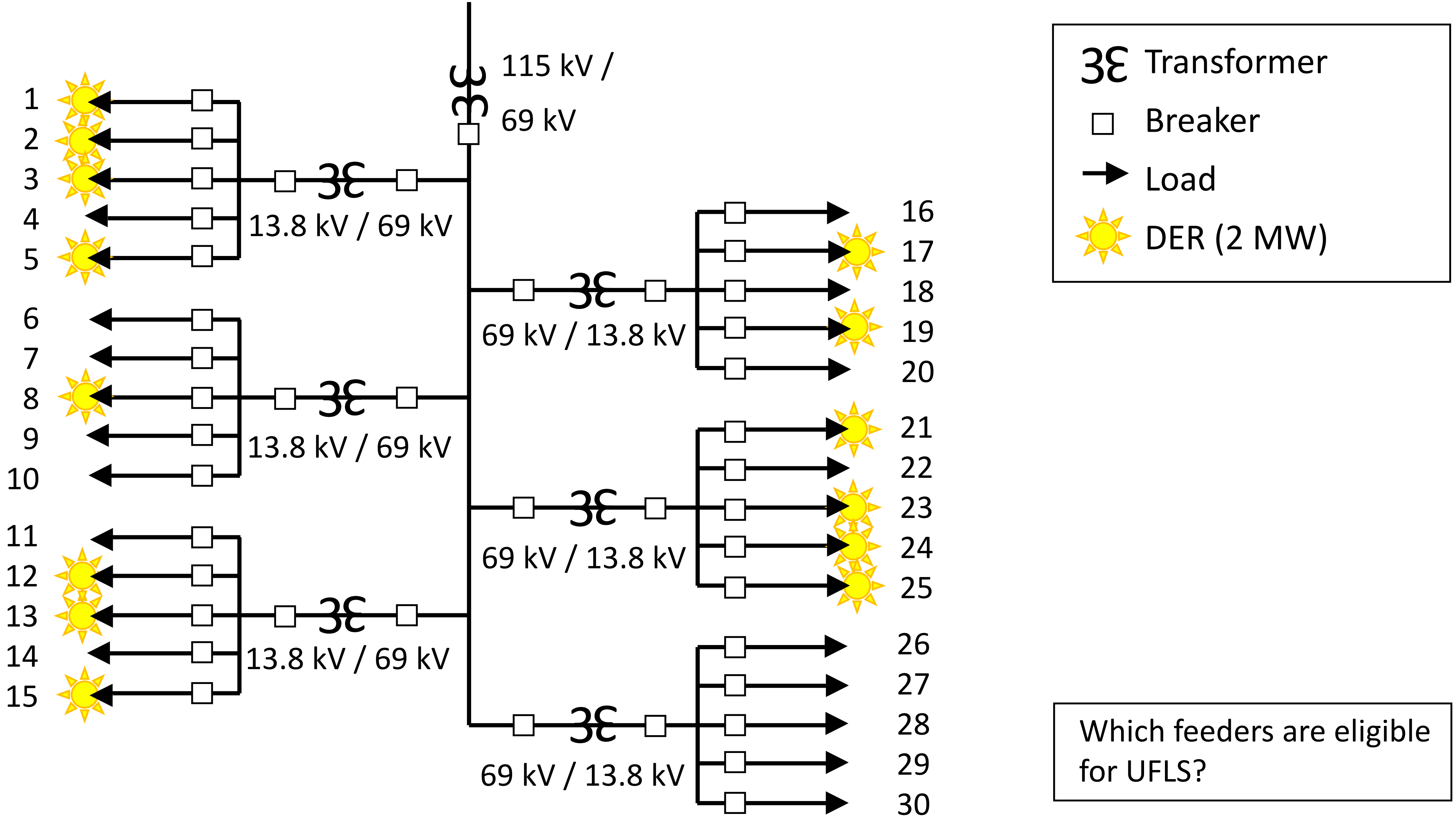
Entity Name:	Projected DP 2025 Peak Load (MW)	UFLS Feeder ID	Trip Setting	Feeder Load Tripped (MW)	% of Peak	DER (MW)
"Friendly Neighborhood Utility"	90	1	59.5	1.5	1.7	2
		2	59.5	1.5	1.7	2
		3	59.3	1.5	1.7	2
		4	59.3	3.5	3.9	0
		5	59.1	1.5	1.7	2
		6	59.1	3.5	3.9	0
		7	58.9	3.5	3.9	0
		8	58.9	1.5	1.7	2
		9	59.5 (10s)	1	1.1	0
		10	59.5 (10s)	1	1.1	0
				20	22.2	10

PRC-006



Which feeders are eligible for UFLS?

PRC-006



Which feeders are eligible for UFLS?

PRC-006
NPCC DER Guidance Document (August 2019)

"The importance of an effective automatic UFLS program cannot be overemphasized. UFLS is considered a "safety net" for the [Bulk Electric System] and a last resort."

"UFLS is primarily armed on distribution feeders, where DER is increasingly being deployed."

"As DER penetrates in the longer term it may be necessary to adopt a more flexible approach to UFLS" with real-time monitoring of feeder load.

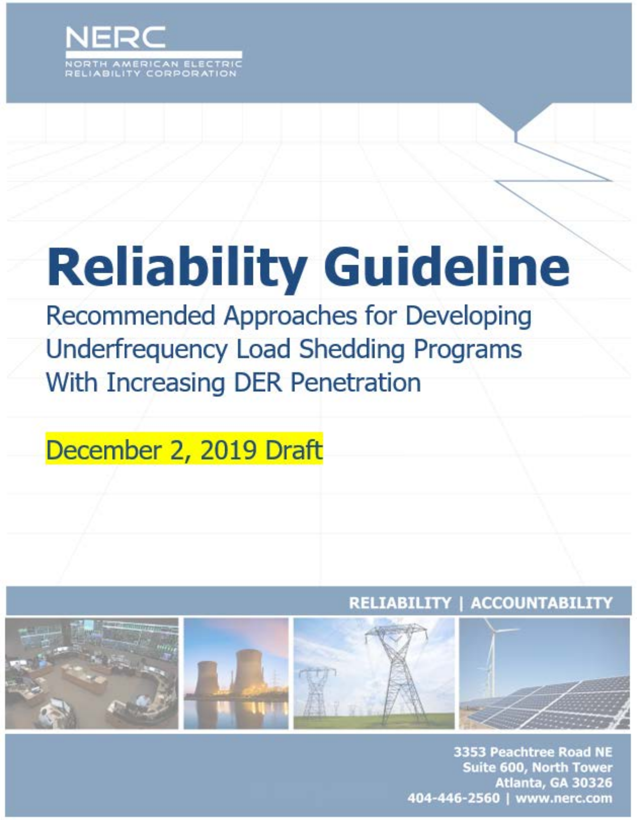
[NPCC (2019)]

SPIDER Working Group Reliability Guideline

Reliability Guideline: Recommended Approaches for Developing UFLS Programs with Increasing DER Penetration

Guidance on how to study UFLS programs and ensure their effectiveness with increasing penetration of DER represented.

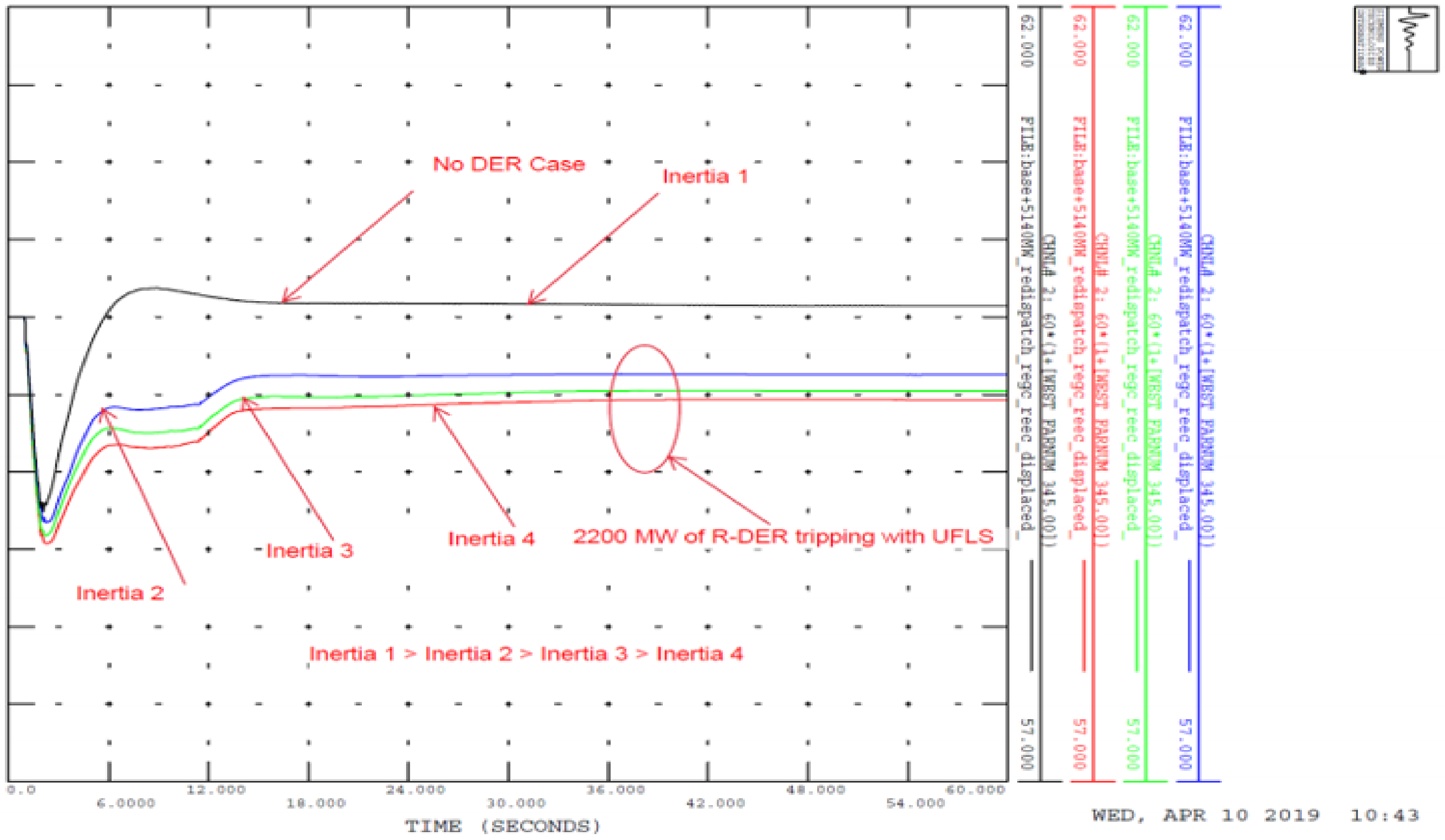
- Background
- Impacts of DER on Island-Level Frequency
- Impacts of DER on UFLS Program Design
- Recommendations



SPIDER Working Group Reliability Guideline

Impact of DER on Island-Level Frequency: Available Load Shed

ISO New England's Islanding Study – Impact of DER



ISO New England Island Frequency Performance – 60 Seconds

SPIDER Working Group Reliability Guideline

Impact of DER on UFLS Program Design: Load Selection

Hawai'i Electric Light's Adaptive UFLS

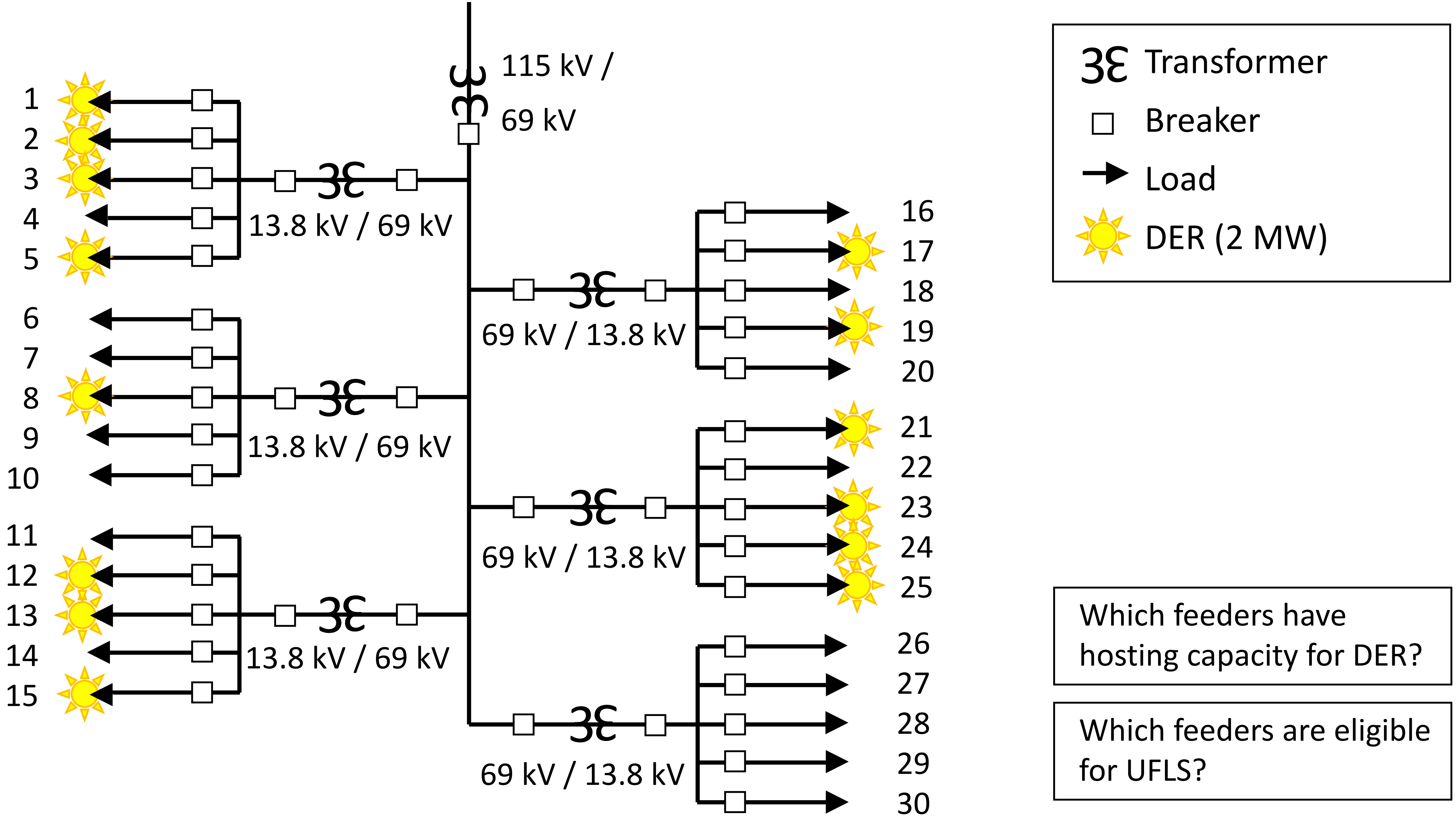
UFLS STAGE DATA

System Load:	141.853
Total Target:	112.185
Total Available:	114.292

Stage	Frequency	Percent	Target MW	Avail MW	Tol %	Tolerance	Delta MW
STAGE1	59.100	5.00	7.01154	6.82032	5.000	0.351	0.191
STAGE2	58.800	10.00	14.02308	13.83560	5.000	0.701	0.187
STAGE3	58.500	10.00	14.02308	13.34422	5.000	0.701	0.679
STAGE4	58.200	15.00	21.03462	22.24468	8.000	1.683	-1.210
STAGE5	57.900	10.00	14.02308	14.21575	8.000	1.122	-0.193
STAGE6	57.600	20.00	28.04617	25.46988	25.000	7.012	2.576
KICKER1	59.500	5.00	7.01154	6.79824	8.000	0.561	0.213
KICKER2	59.300	5.00	7.01154	6.54598	8.000	0.561	0.466

Summary Display of Hawaii Electric Light Adaptative UFLS Scheme EMS

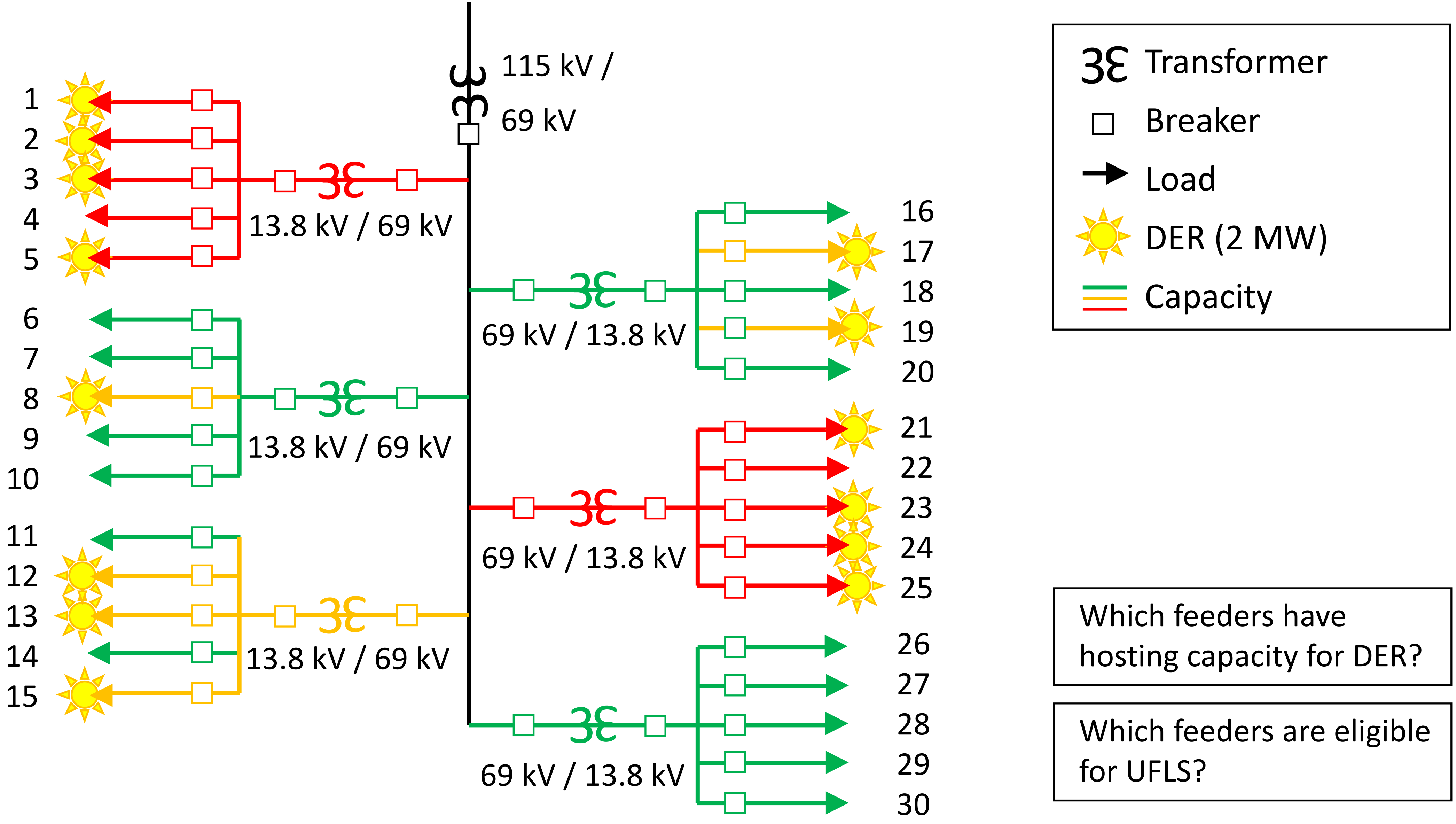
Hosting Capacity Analysis



Which feeders have hosting capacity for DER?

Which feeders are eligible for UFLS?

Hosting Capacity Analysis



Which feeders have hosting capacity for DER?

Which feeders are eligible for UFLS?

ERCOT Market Notice & Proposal

"ERCOT rules do not address how Transmission and/or Distribution Service Provider (TDSP) Load-shed obligations may be impacted by DGRs. If feeders that connect DGRs to the ERCOT System are disconnected during an Energy Emergency Alert (EEA), Under-Frequency Load Shed (UFLS), or Under-Voltage Load Shed (UVLS) event, the resulting unavailability of the generation can worsen an already severe reliability condition. This regulatory gap will need to be addressed by changes to ERCOT rules and possibly Public Utility Commission (PUC) rules."

ERCOT (2019)

ERCOT Market Notice & Proposal

3.8.7 Distribution Generation Resources (DGR)

(1) As a condition for the interconnection of a DGR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall provide documentation from the DSP to ERCOT stating that the interconnecting distribution circuit will not be disconnected as part of a manual or automatic Load-shed system during a Load shed event, including without limitation an Energy Emergency Alert (EEA) Level 3 event, an under-frequency Load shedding event, or an under voltage Load shedding event. DSPs shall ensure that Generation Resources are not connected to Load circuits subject to disconnection. If a DSP determines that the circuit to which a DGR is interconnected must be designated for Load-shed, then the DSP shall provide at least 120 days' notice of the change in designation to the Resource Entity for the DGR. The Resource Entity shall deregister the DGR by submitting an appropriate modeling change to ERCOT to be effective prior to the date on which the Load-shed designation will be effective.

ERCOT (2019)

Takeaways

- DPs are required to comply with PRC-006, regardless of DER integration levels.
- Hosting capacity analysis encourages DER integration on the same feeders that are used for UFLS, diminishing effectiveness.
- DPs require flexibility to implement UFLS programs, especially in areas with high levels of DER.
- Wholesale markets for DER are just beginning to account for UFLS requirements.
- State-level transmission/distribution planning venues are ideal for discussing and addressing these issues with stakeholders.

Thank You!
Questions?
dan.kopin@utilitysvcs.com

Autonomous Energy Systems

A vision of the future grid integrating massive amounts of distributed energy resources

Ben Kroposki, PhD, PE, FIEEE

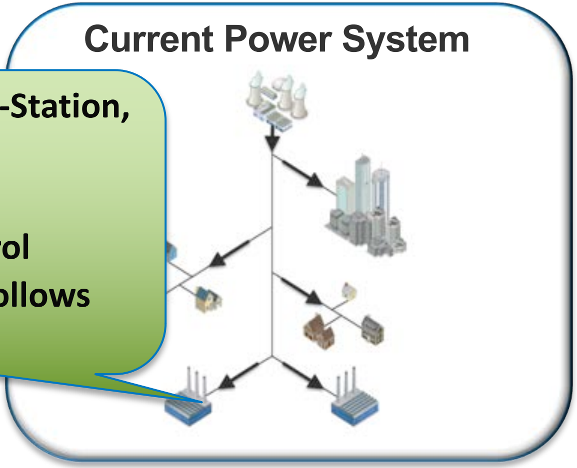
Director – Power Systems Engineering Center

National Renewable Energy Laboratory

May 2020

Disclaimer

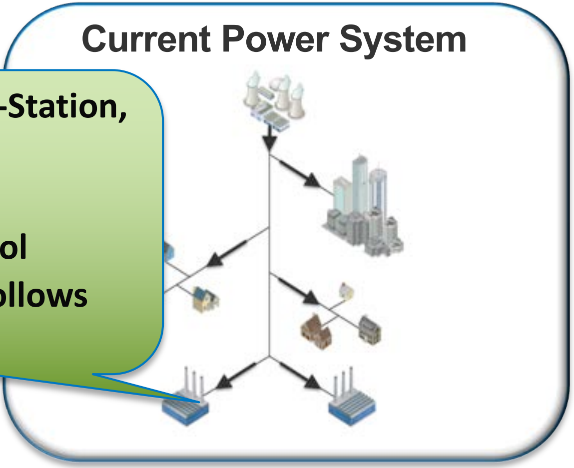
Transformation of the Power System



- Large Central-Station, Synchronous Generation
- Central Control
- Generation follows Demand

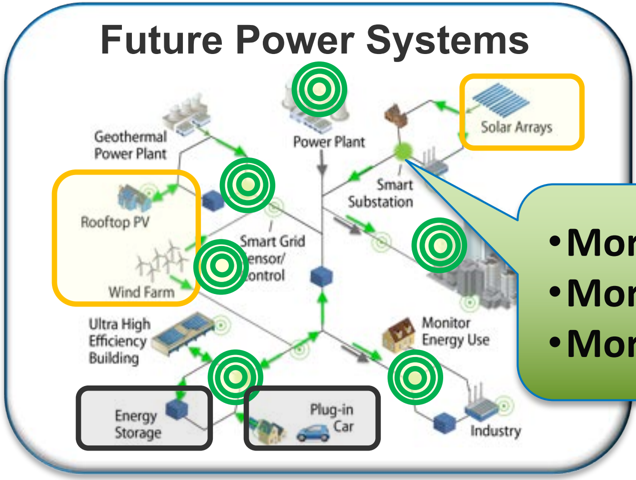
Transformation of the Power System

Current Power System



- **Large Central-Station, Synchronous Generation**
- **Central Control**
- **Generation follows Demand**

Future Power Systems



- **More VRE**
- **More Information**
- **More Distributed**

- Increasing levels of wind and solar – variable and power electronics based
- More use of Communications, Controls, Data, and Information (e.g. Smart Grids) – can have interoperability and cybersecurity issues
- Other new distributed technologies: EVs, Distributed storage, Flexible Loads
- Increasing interdependencies between electricity grids and other infrastructures
- Becoming highly distributed and more complex to operate

Is the Grid getting too complex to control?

Current Grid

Central Control
10^4 Bulk Generators

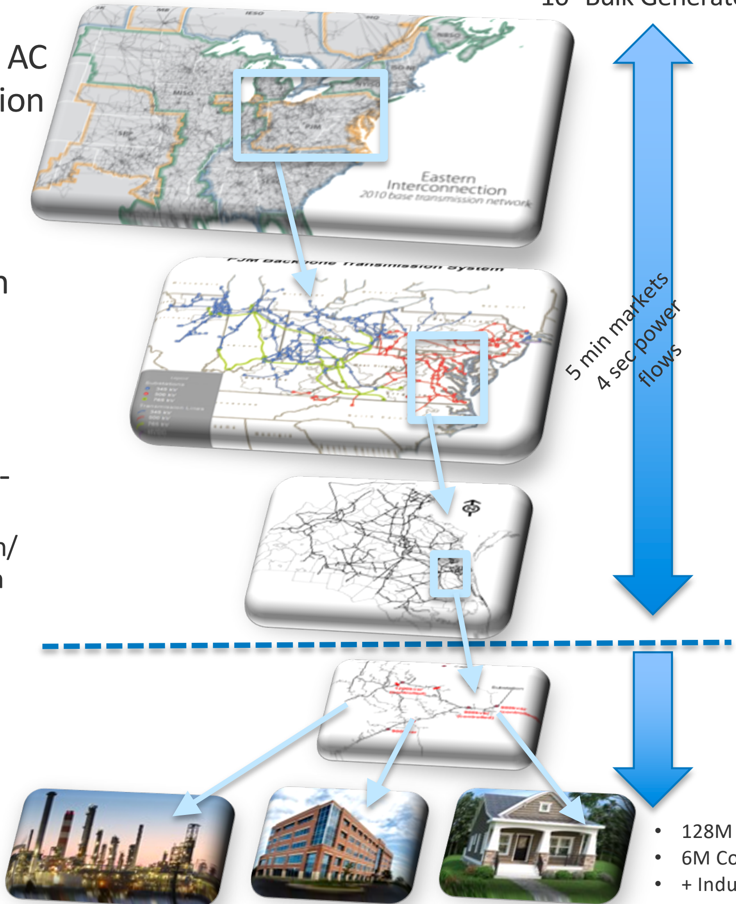
Synchronous AC Interconnection

Regional Transmission Operator - Market/ Reliability Coordinator

Local Utility - Transmission/ Subtransmission/ Bulk Generation

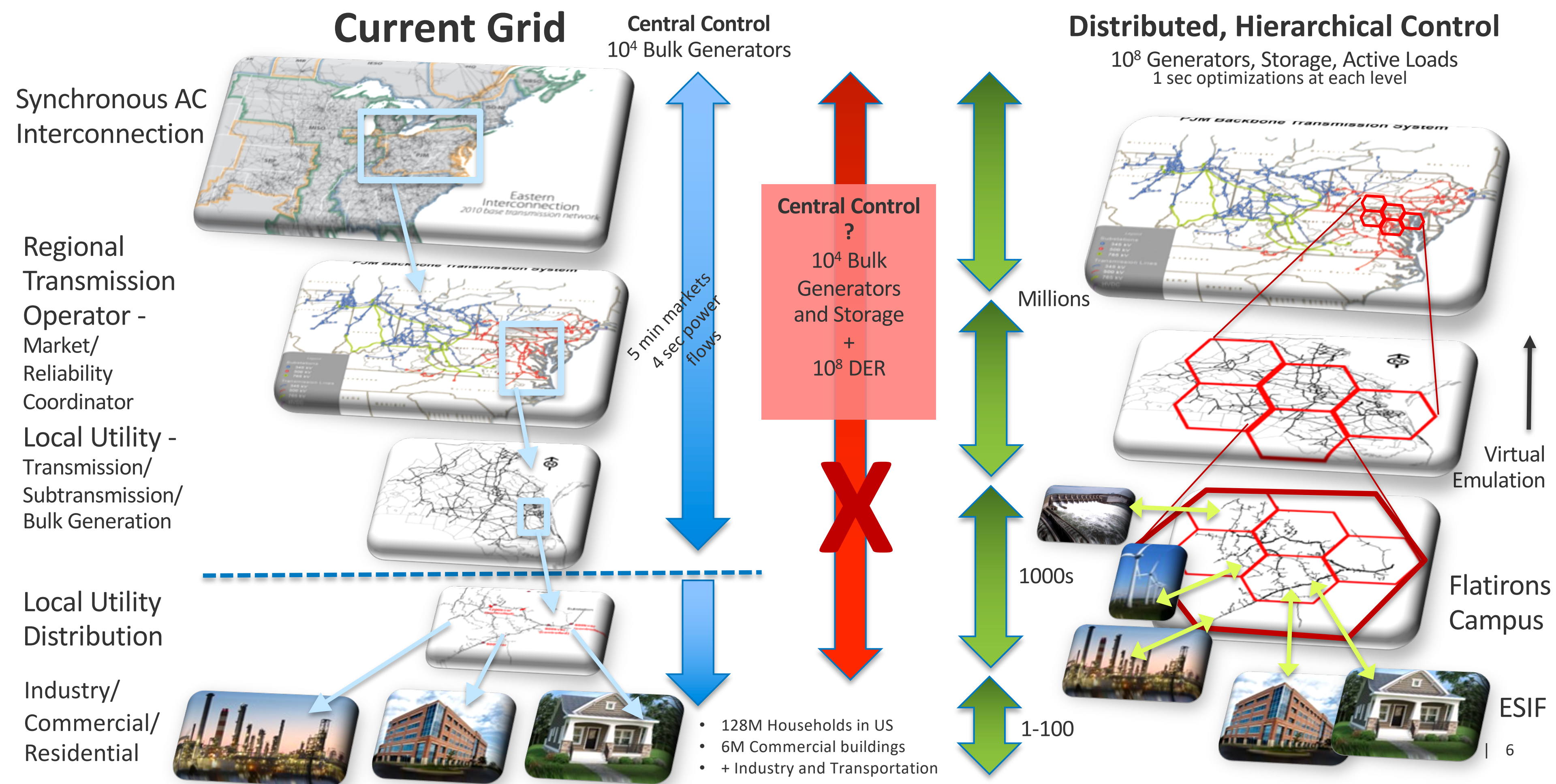
Local Utility Distribution

Industry/ Commercial/ Residential

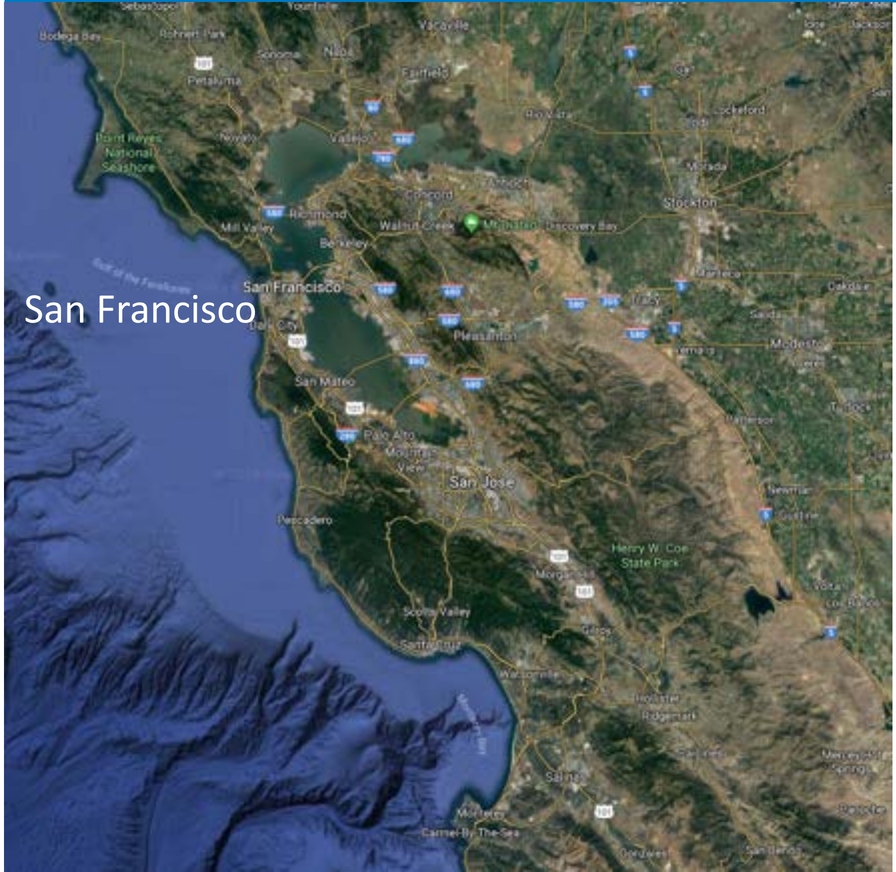


- 128M Households in US
- 6M Commercial buildings
- + Industry and Transportation

Is the Grid getting too complex to control?



What are we trying to achieve in the Autonomous Energy Systems Project?

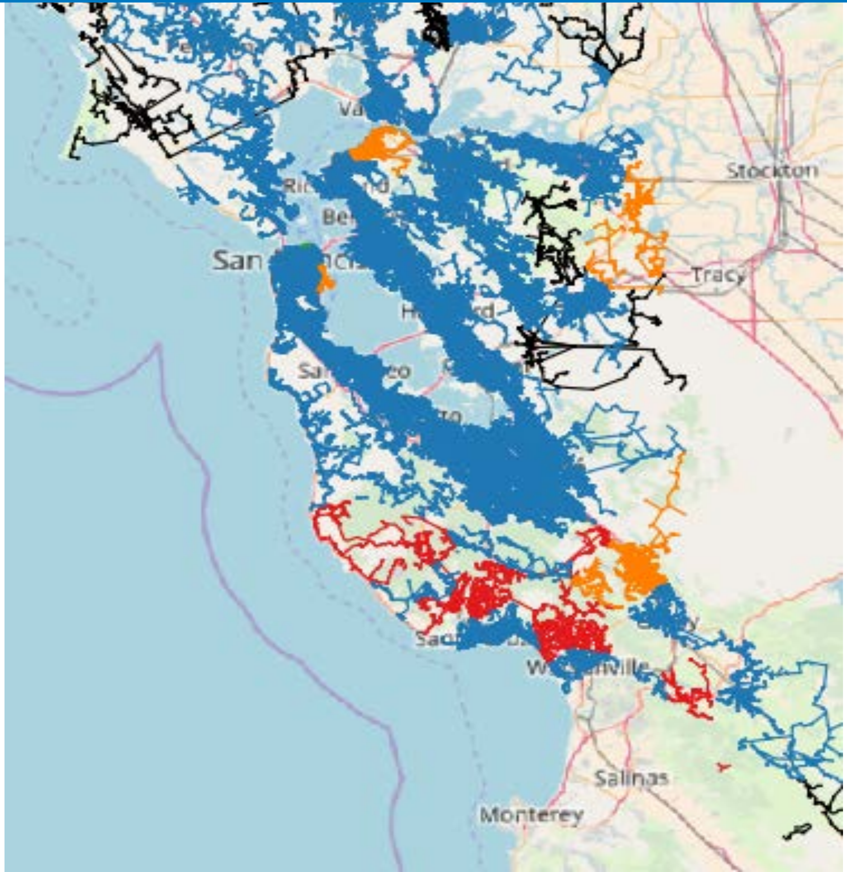


Distributed Energy Resources (DER) =

- Generation (solar, wind, fuel cells, generators)
- Storage = Batteries, Ice storage
- Loads = Buildings, Homes
- Mobility = EVs, Chargers

Optimize and control massively deployed DER in real-time.

What are we trying to achieve in the Autonomous Energy Systems Project?



Distributed Energy Resources (DER) =

- **Generation (solar, wind, fuel cells, generators)**
- **Storage = Batteries, Ice storage**
- **Loads = Buildings, Homes**
- **Mobility = EVs, Chargers**

Optimize and control massively deployed DER in real-time.

Example: SF Bay Area

- Grid has more than 10 million electric nodes at distribution level
- 4.3 million Customers – each with PV, storage, smart homes, plug-in EVs = 10-20 million controllable devices

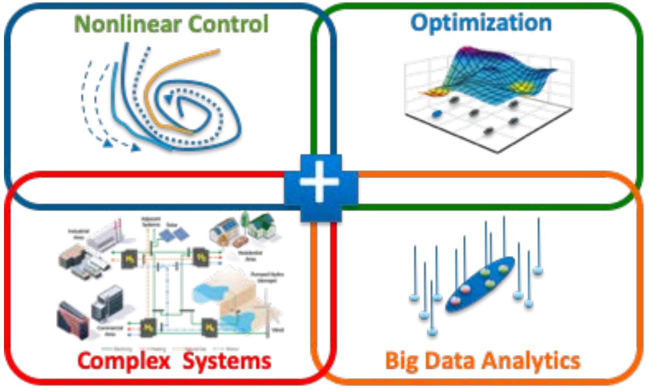
Nobody knows how to do this!

Transforming ENERGY through Autonomous Energy Systems

Home | Neighborhood | Community/Town | Large City

Develop framework to enable scalable control and optimization of all energy resources across several domains (grids, buildings, transport, renewables) and scales

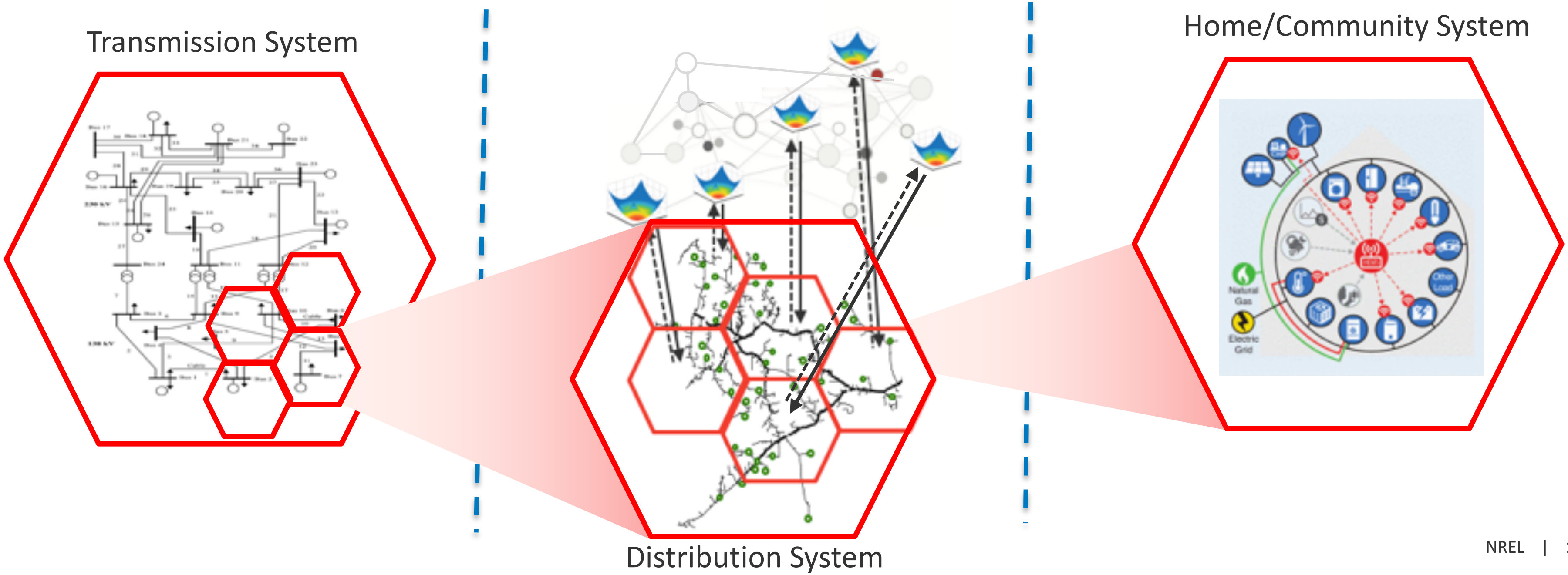
- **Bridge the gap between control theory and optimization theory** and **propose a unified theoretical approach** that builds on contemporary advances in control, optimization, and parallel computing
- Develop distributed optimization **algorithms that can run in real-time** (1s) across full system
- **Ensure a computationally affordable, optimal, resilient, and reliable distributed operation** with the objective to enable flexible operation and maintain stability and optimality
- **Validate the results in relevant real-world applications**



Formulating new math to address challenges

Challenges that are being addressed:

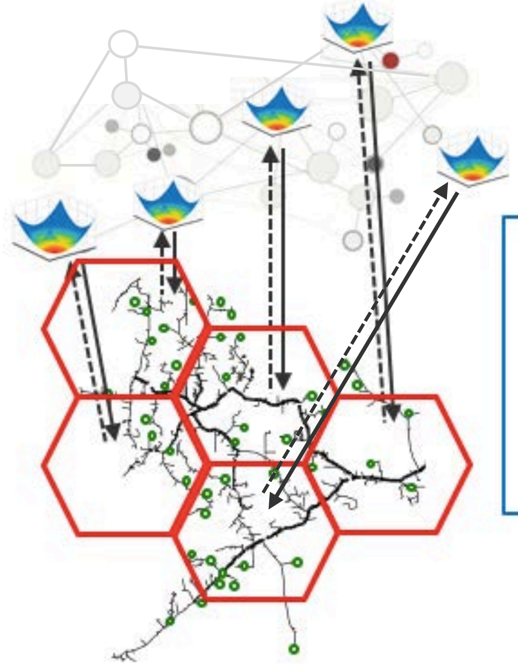
1. **Distributed** – Needs to be fast enough to operate in real-time (On-line)
2. **Scalable** – Needs to be able to control millions of devices (Hierarchical)
3. **Data Aware** – Make best use of time-varying asynchronous measurements



Distributed Control and Optimization

Real-time optimization with missing model parameters

- *"Online Optimization with Feedback",* A. Bernstein, E. Dall'Anese, and A. Simonetto accepted to ***IEEE Transactions on Signal Processing***
- *"Online Optimization as a Feedback Controller: Stability and Tracking",* M. Colombino, E. Dall'Anese and A. Bernstein, submitted to ***IEEE Transactions on Control of Network Systems***

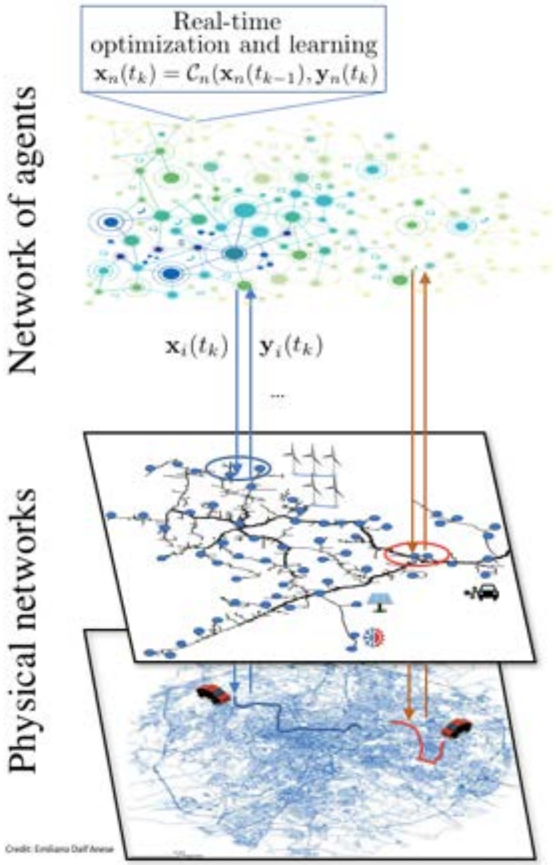


$$
\begin{aligned}
\min_{\mathbf{x},\mathbf{p}_i,\mathbf{q}_i} \quad & f_{net}(\mathbf{x}) + \sum_{DERs} f_i(\mathbf{p}_i,\mathbf{q}_i) \\
\text{subject to} \quad & \mathbf{p}_i,\mathbf{q}_i \in \mathcal{Y}_i \ \forall i, \\
& \mathbf{h}_i(\mathbf{p}_i,\mathbf{q}_i) = \mathbf{0} \ \forall i, \\
& \mathbf{g}_i(\mathbf{p}_i,\mathbf{q}_i) \leq \mathbf{0} \ \forall i, \\
& \mathbf{h}_{net}(\mathbf{x},\mathbf{p},\mathbf{q}) = \mathbf{0} \\
& \mathbf{g}_{net}(\mathbf{x},\mathbf{p},\mathbf{q}) \leq \mathbf{0}
\end{aligned}
$$

Unique Impactful Results

- Unique results in terms of convergence/stability of the algorithms for **real-time/ closed-loop optimization** algorithms that utilize measurements
- New mathematical framework for driving dynamic system to **optimal time-varying solutions**

Integration of Data Analytics - Formulating new math (ADMM-RL)



Combining Distributed Optimization and Learning (data-driven optimization)

- *"Distributed Reinforcement Learning with ADMM-RL"*, Peter Graf, Jennifer Annoni, Christopher Bay, Dave Biagioni, Devon Sigler, Monte Lunacek, Wesley Jones submitted to the ***ACC Conference***

Alternating Direction Method of Multipliers (ADMM)

Decomposition-coordination procedure in which the solutions to small local subproblems (optimization) are coordinated to find a solution to a large global problem.

$$\begin{aligned} \text{minimize} \;\; & f(x) + g(z) \\ \text{s.t.} \;\; & Ax + Bz = c \end{aligned}$$

$$\begin{aligned} \text{minimize} \;\; & \sum_i f_i(x_i) \\ \text{s.t.} \;\; & x_i = z. \end{aligned}$$

+

Reinforcement Learning (RL)

Learner discovers what action yields maximum reward.

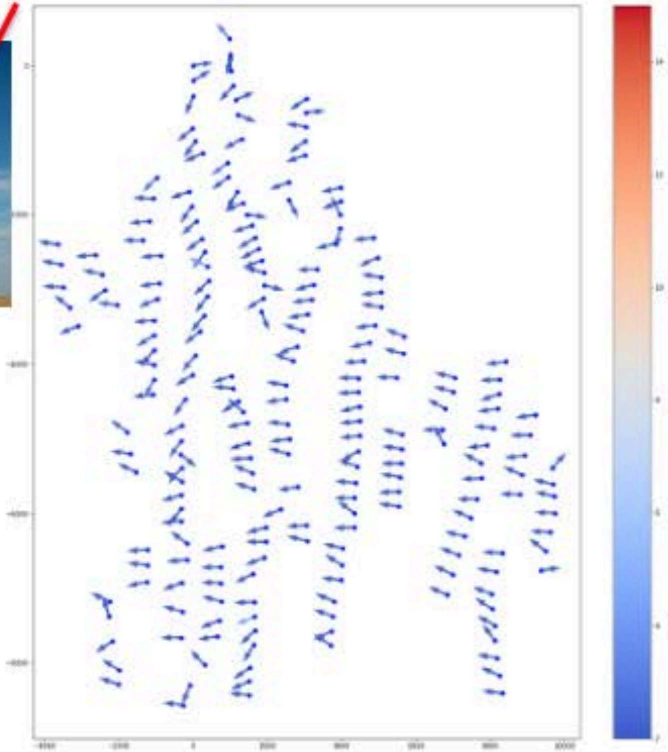
$$\begin{aligned} x_i^{k+1} &= \underset{x_{p(i)}}{\text{argmin-RL(n)}}\, f_i(x_i) + y_k^{k,T}(x_i - \bar{x}^k) + \\ &\quad \frac{\rho}{2}\|x_i - \bar{x}^k\|^2 \\ y^{k+1} &= y^k + \rho(x_i^{k+1} - \bar{x}^{k+1}), \end{aligned}$$

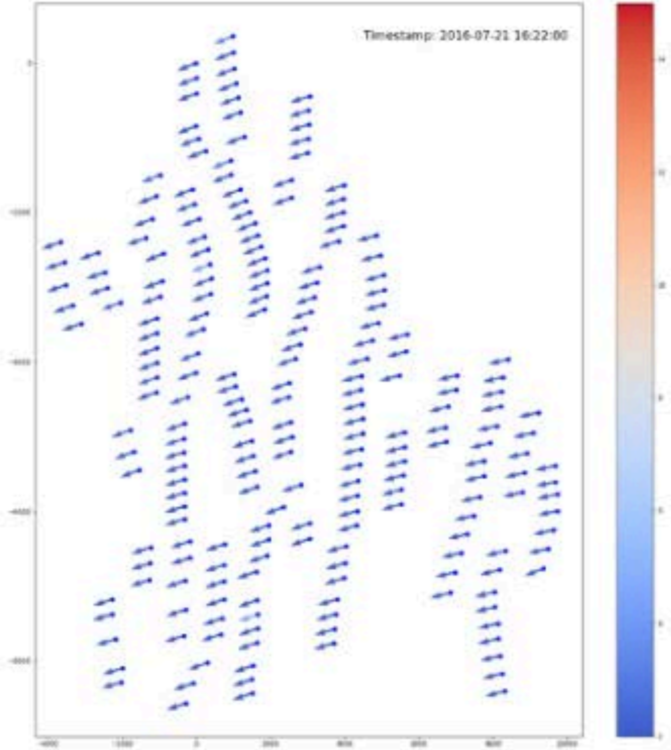
This Paper introduced a ADMM-RL controller to train wind turbines and water heater controls

Application – Distributed Control of Wind Farms

Typical Wind Farm Control

(Each turbine moves based on local wind measurements)



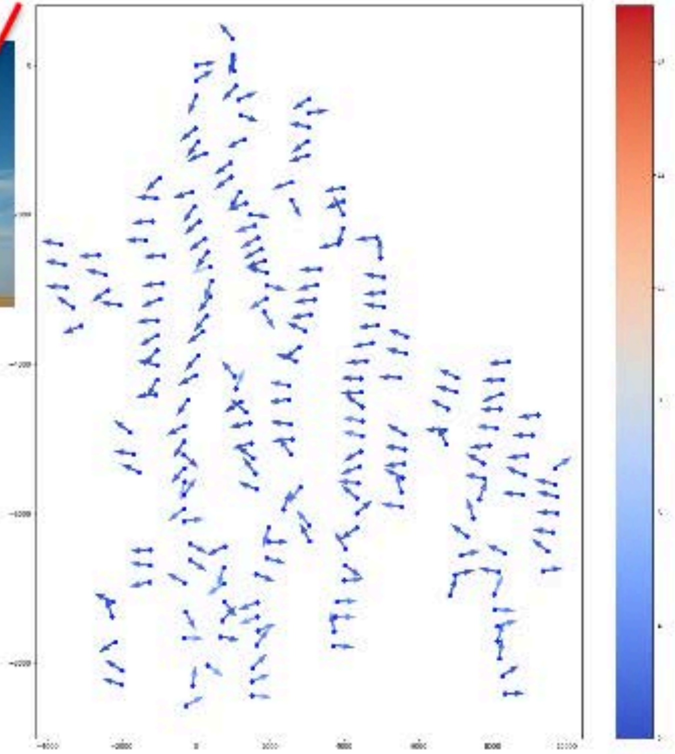


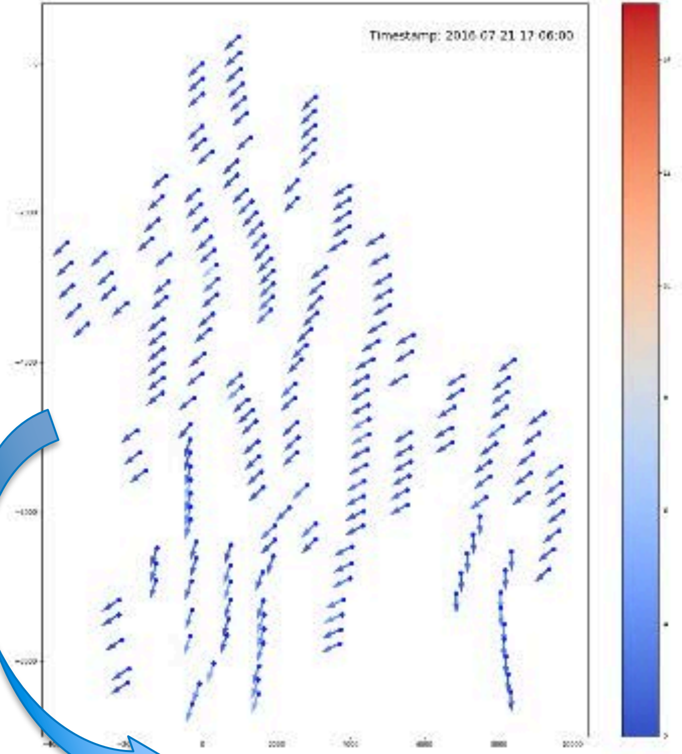
https://www.youtube.com/watch?v=nYV_LH46ZOU

Application – Distributed Control of Wind Farms

Typical Wind Farm Control

(Each turbine moves based on local wind measurements)



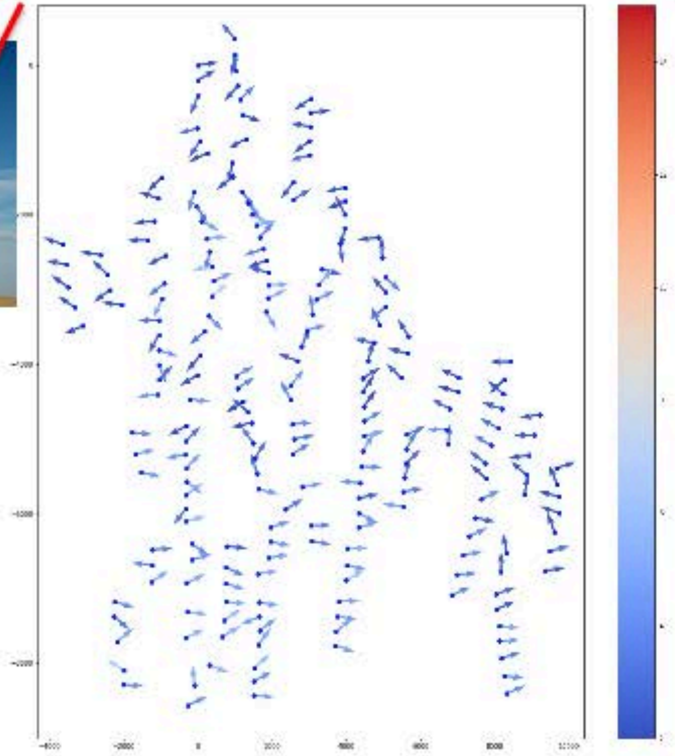


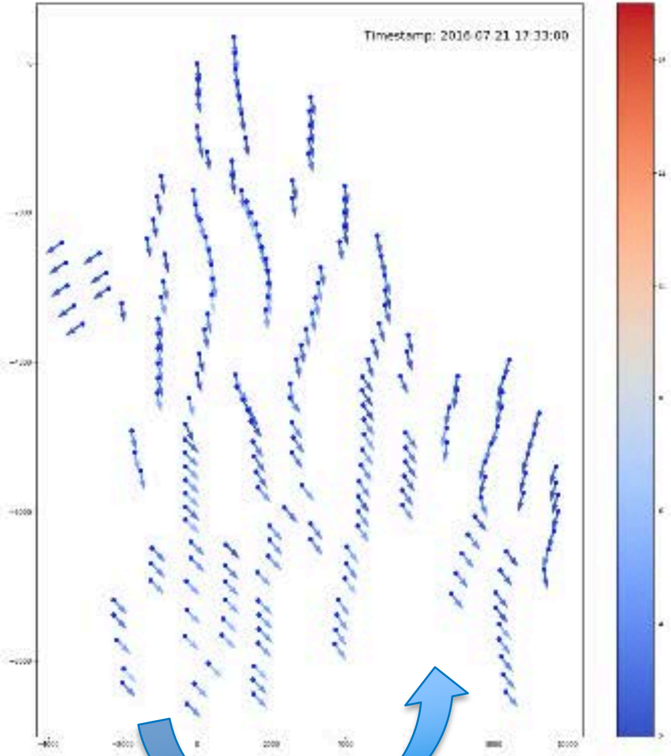
Wind Direction Shift

Application – Distributed Control of Wind Farms

Typical Wind Farm Control

(Each turbine moves based on local wind measurements)





Wind Direction Shift

Application – Distributed Control of Wind Farms

Typical Wind Farm Control

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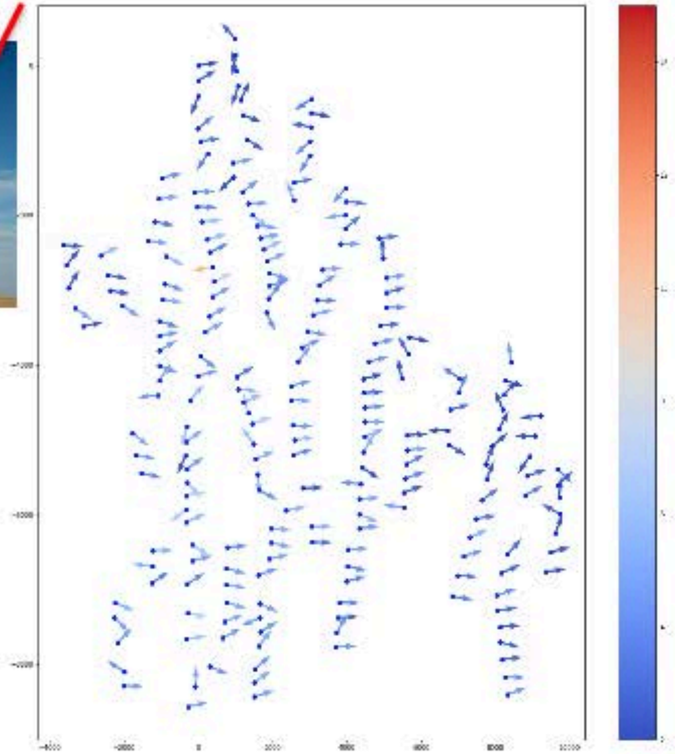
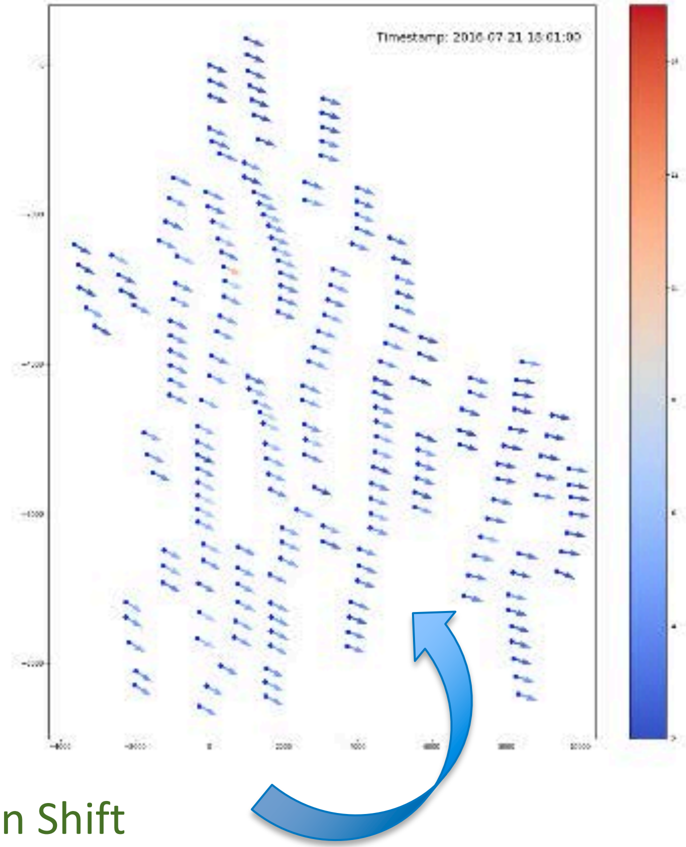


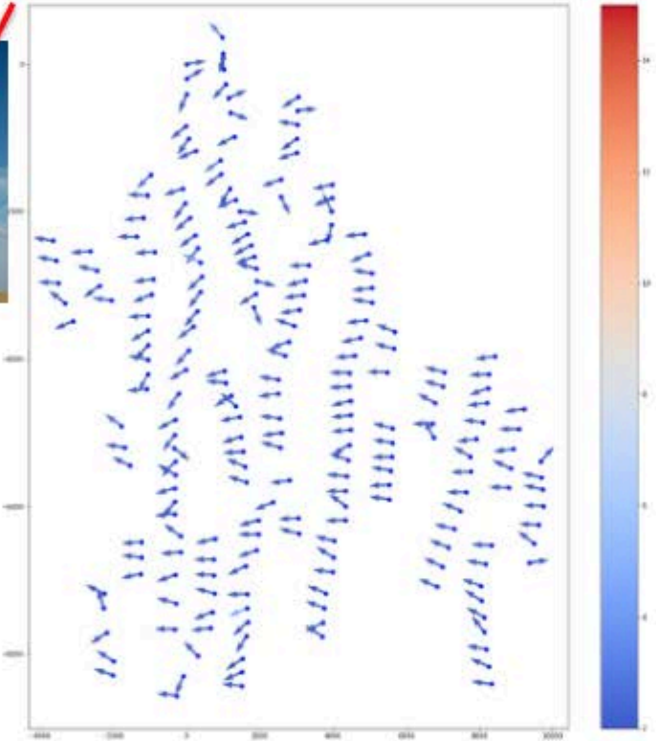


Wind Direction Shift

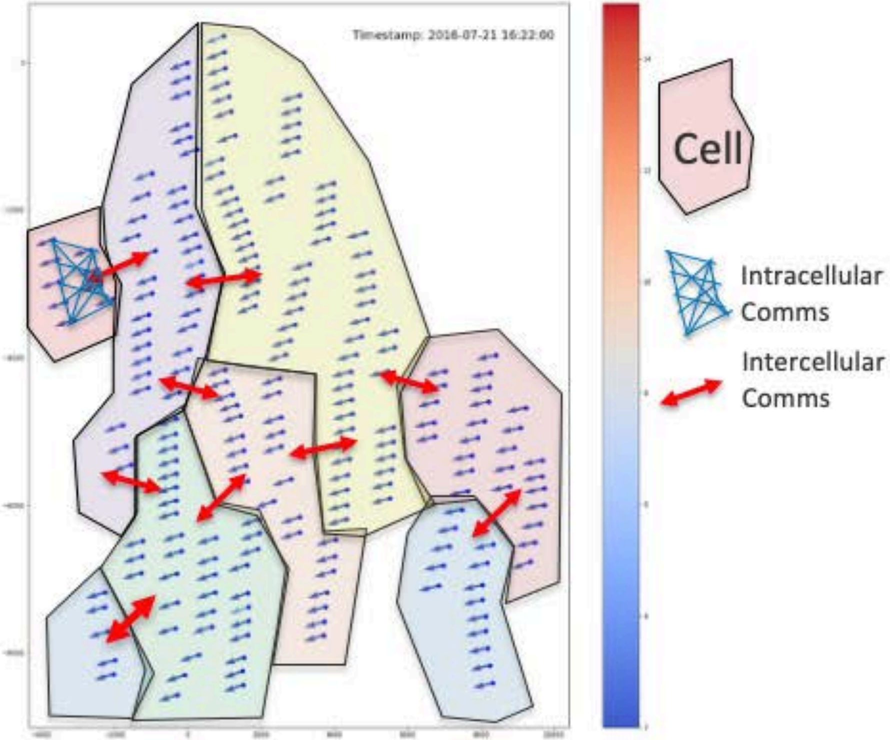
Application – Distributed Control of Wind Farms

Typical Wind Farm Control

(Each turbine moves based on local wind measurements)

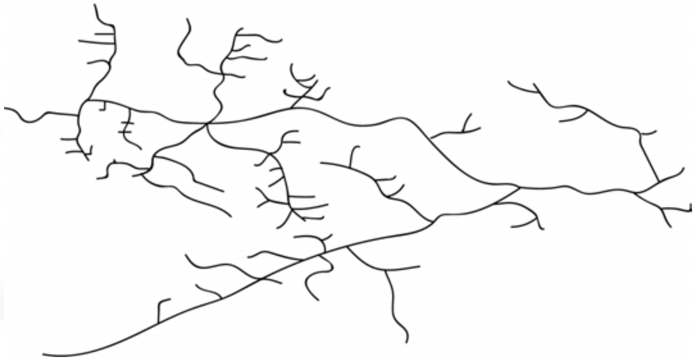


Distributed Wind Farm Control

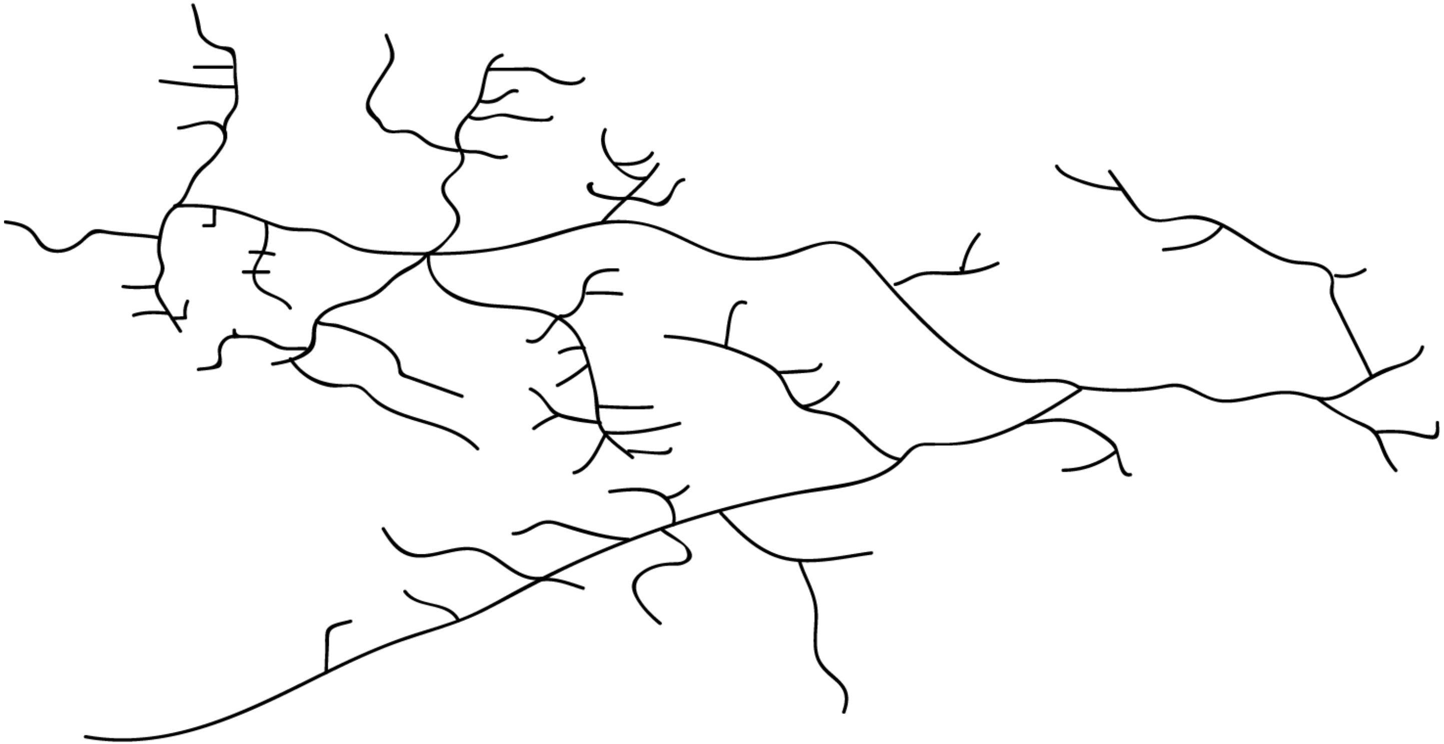


- Solution from Central Control of **13.75min** to Distributed Control of **2s**
- **Allowing ~2% more energy production annually**

Let’s look a little closer – a single distribution circuit

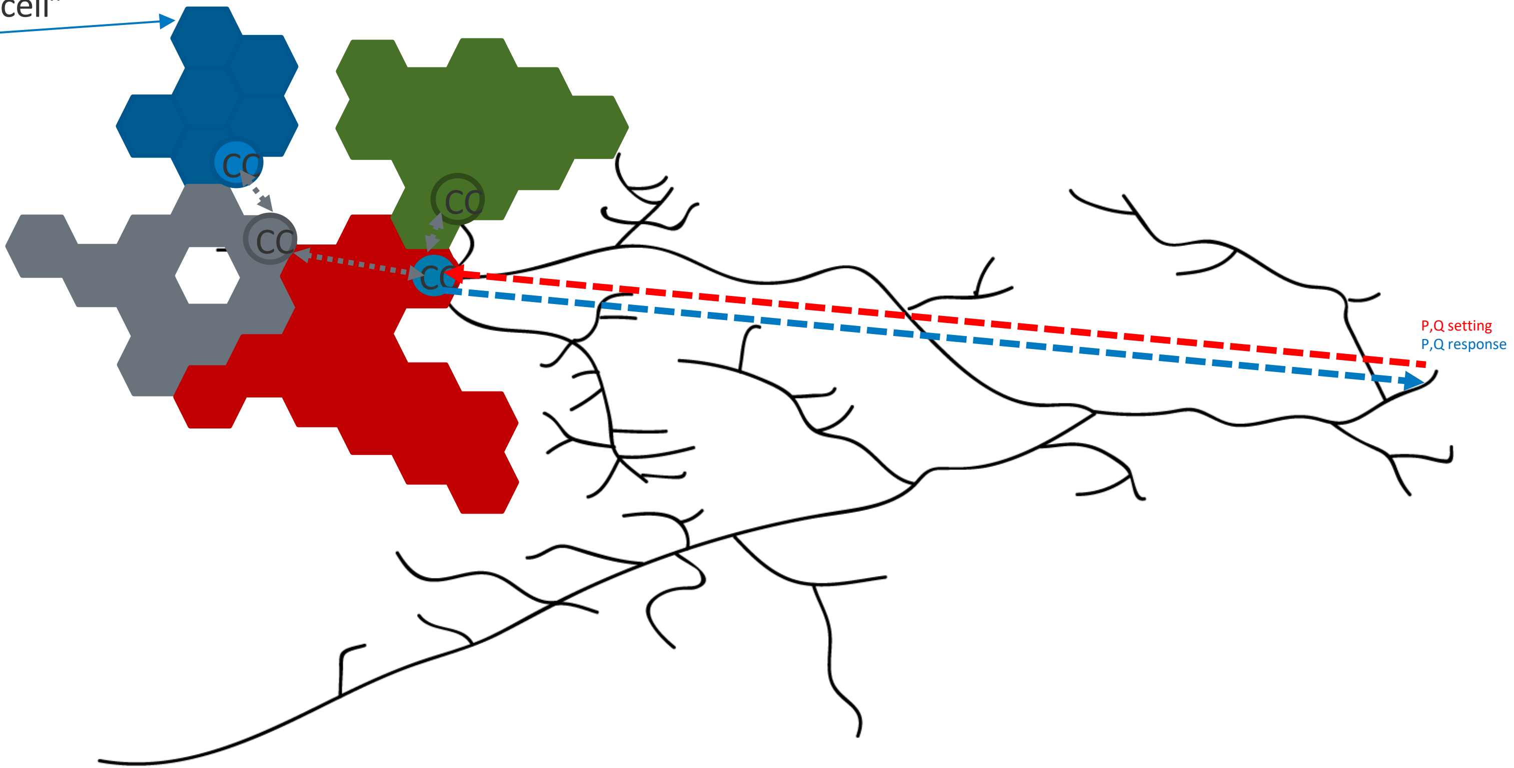


Complex system simulation with new optimization and controls

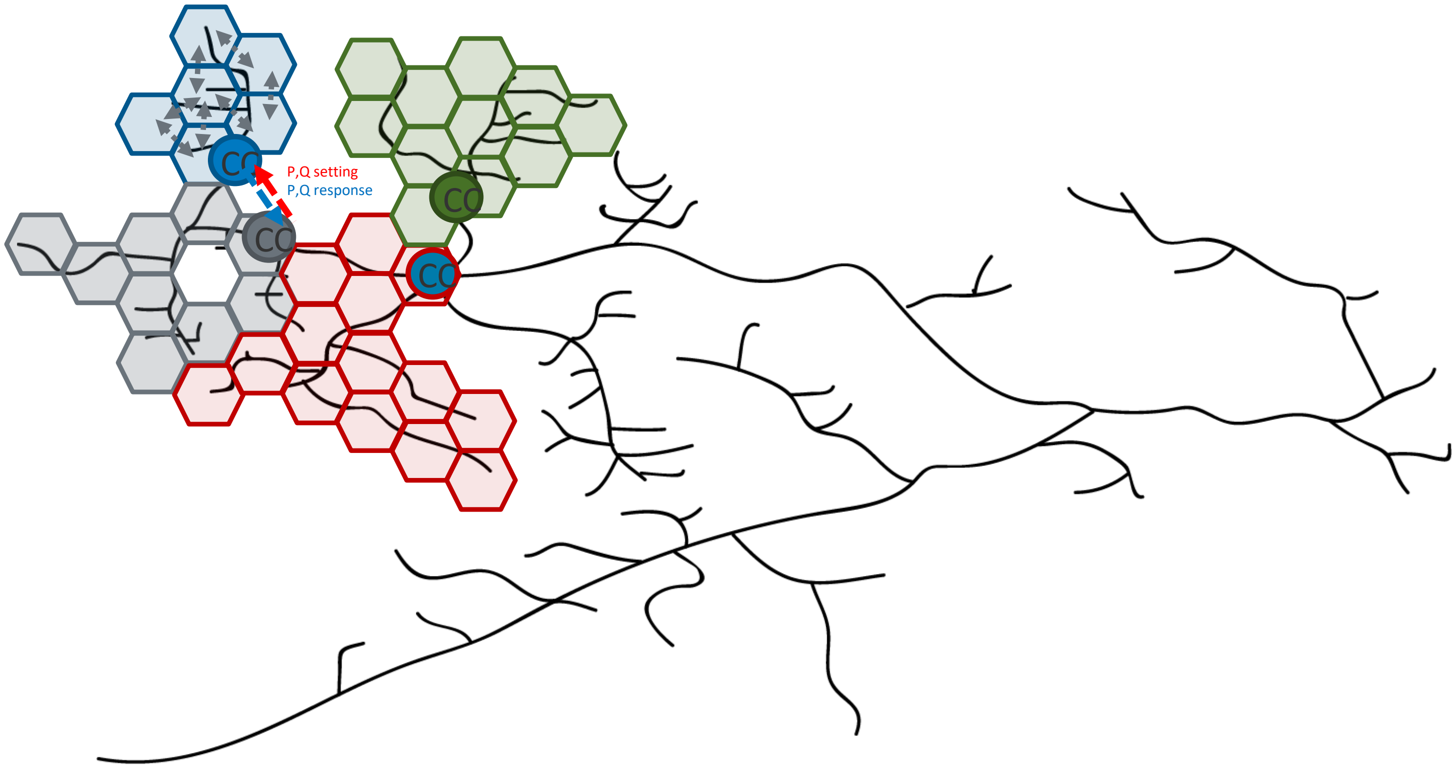


Complex system simulation with new optimization and controls

Color coding represent the next higher "cell"

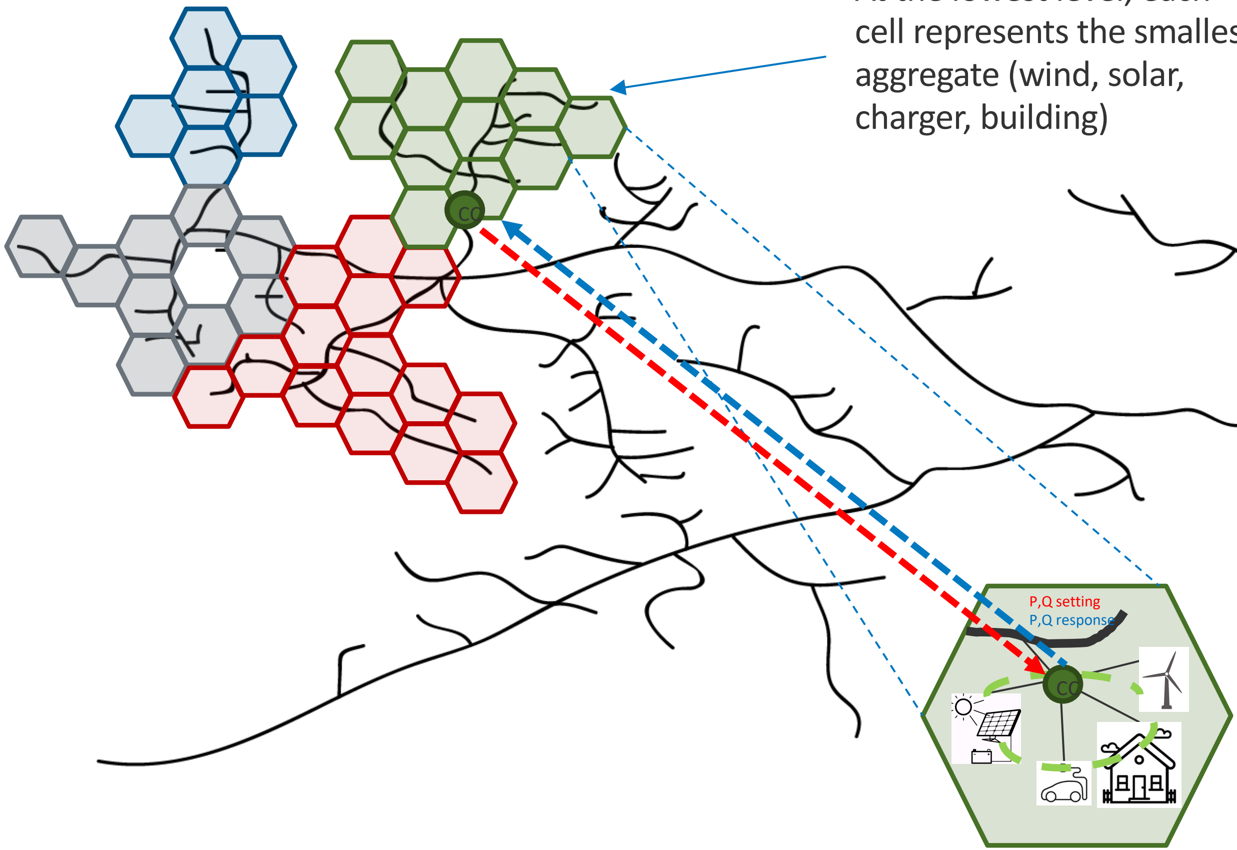


Complex system simulation with new optimization and controls



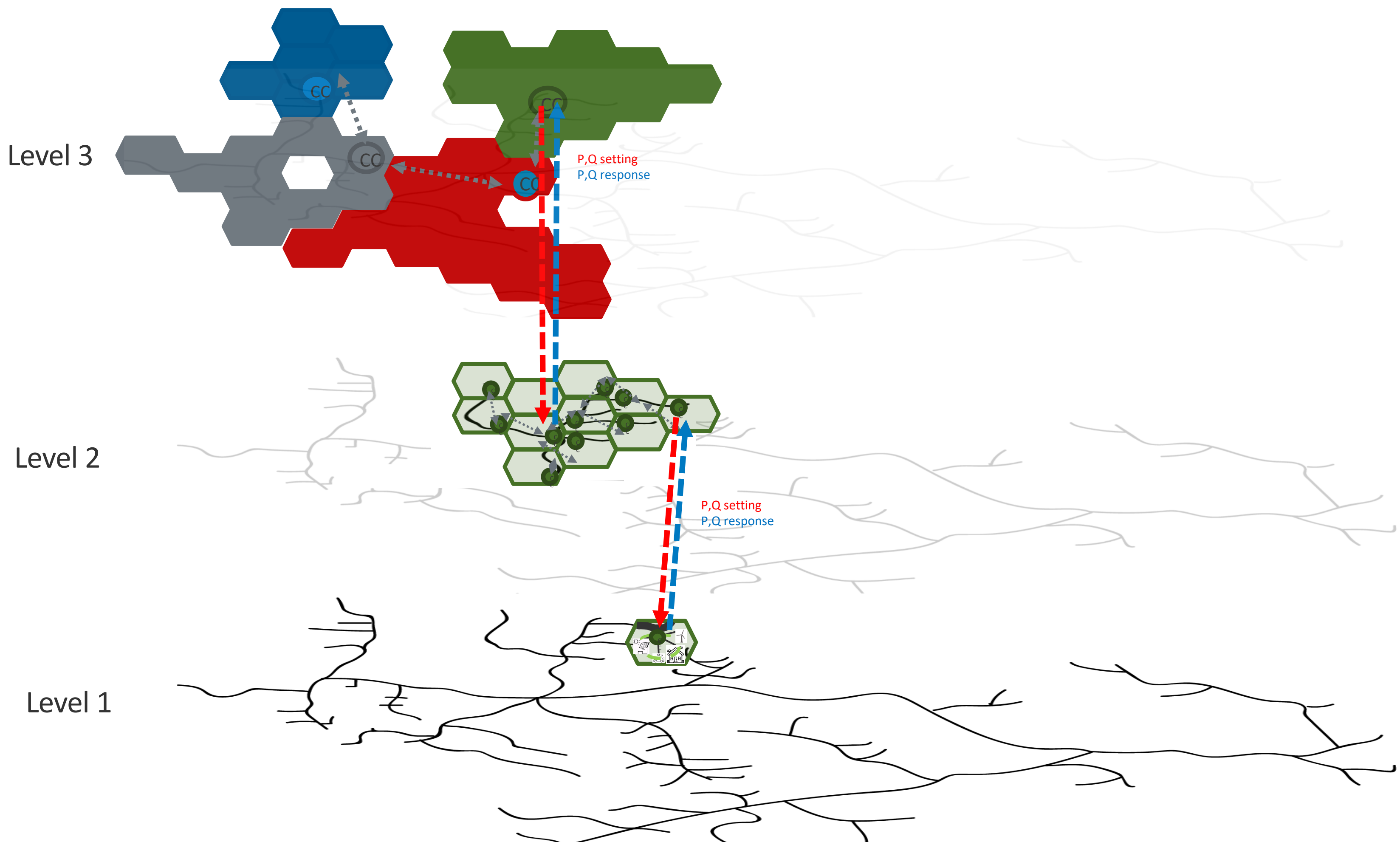
Complex system simulation with new optimization and controls

At the lowest level, each cell represents the smallest aggregate (wind, solar, charger, building)



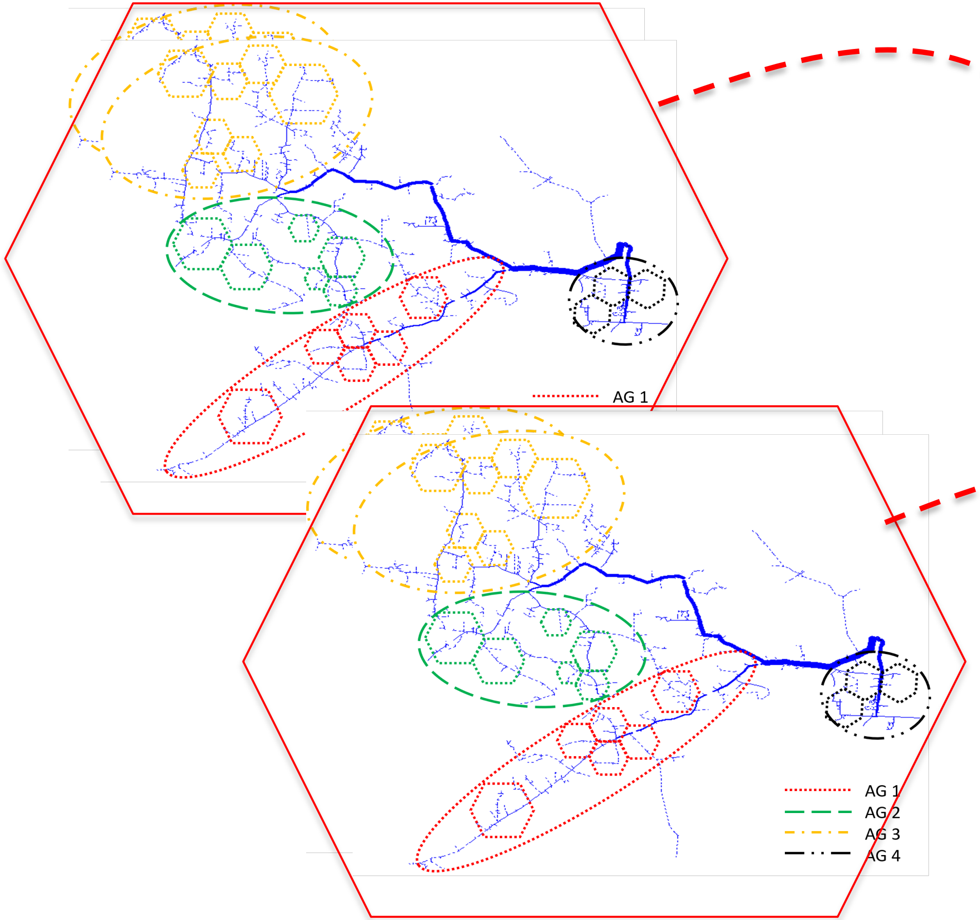
At this level, devices inside the cell communicate with each other (green line) to reach a P,Q set point passed from the next higher level cell coordinator (CC) (red line)

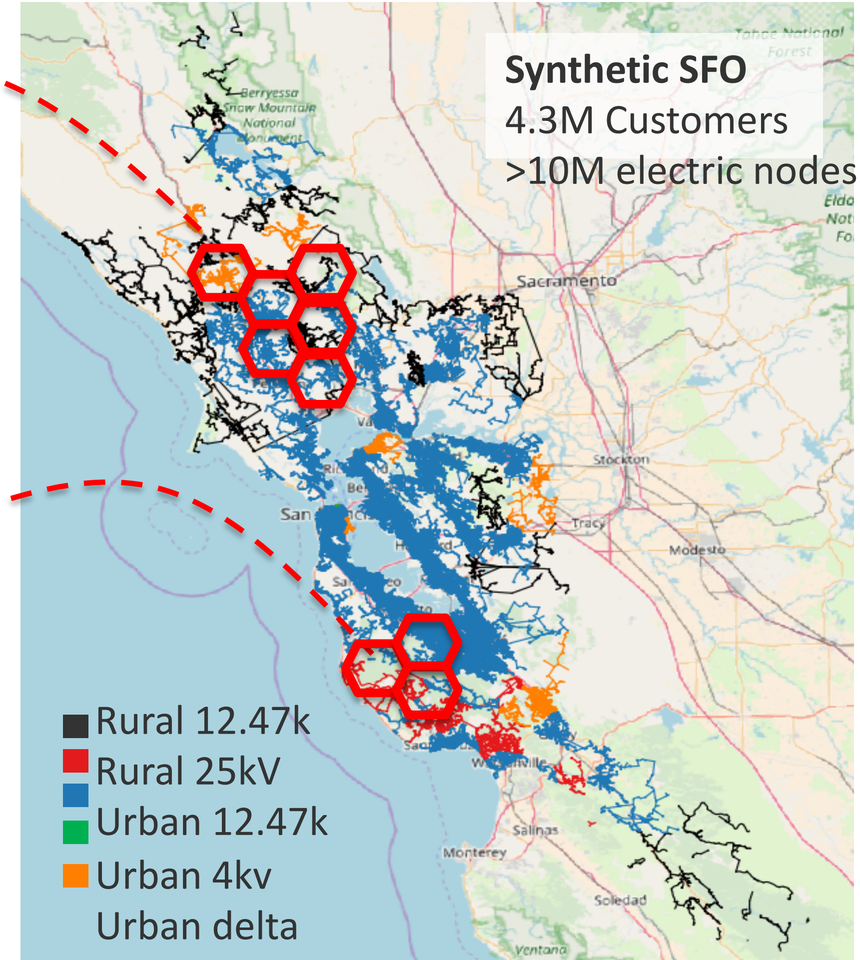
In 3D



Level 3
CC
CC
CC
CC
P,Q setting
P,Q response
Level 2
P,Q setting
P,Q response
Level 1

Moving Back to the Metropolitan Scale





All that Simulation was nice, but can you show me it really works?


Energy Systems Integration Facility (ESIF)

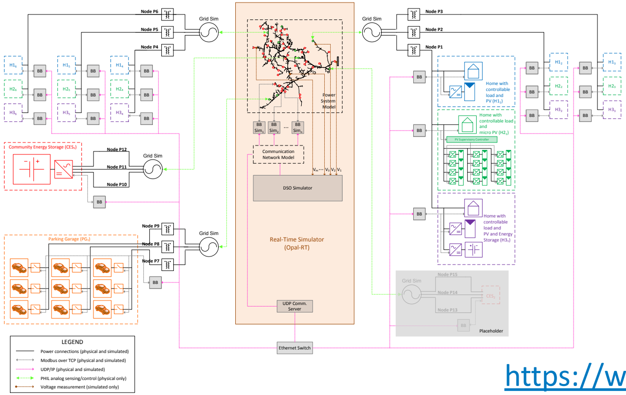
Shortening the time between innovation and practice

ESIF Unique Capabilities

- Multiple parallel AC and DC experimental busses (MW power level) with grid simulation and loads
- Flexible interconnection points for electricity, thermal, and fuels
- Medium voltage (15kV) microgrid test bed
- Virtual utility operations center and visualization rooms
- Smart grid testing lab for advanced communications and control
- Interconnectivity to external field sites for data feeds and model validation
- Petascale HPC and data mgmt system in showcase energy efficient data center
- **MW-scale Power hardware-in-the-loop (PHIL) simulation capability to test grid scenarios with high penetrations of clean energy technologies**

ARPA-E NODES: Large-Scale PHIL Experiment

The largest ever number of connection points in a single PHIL experiment!



Network Optimized Distributed Energy Systems (NODES)

arpa·e
CHANGING WHAT'S POSSIBLE

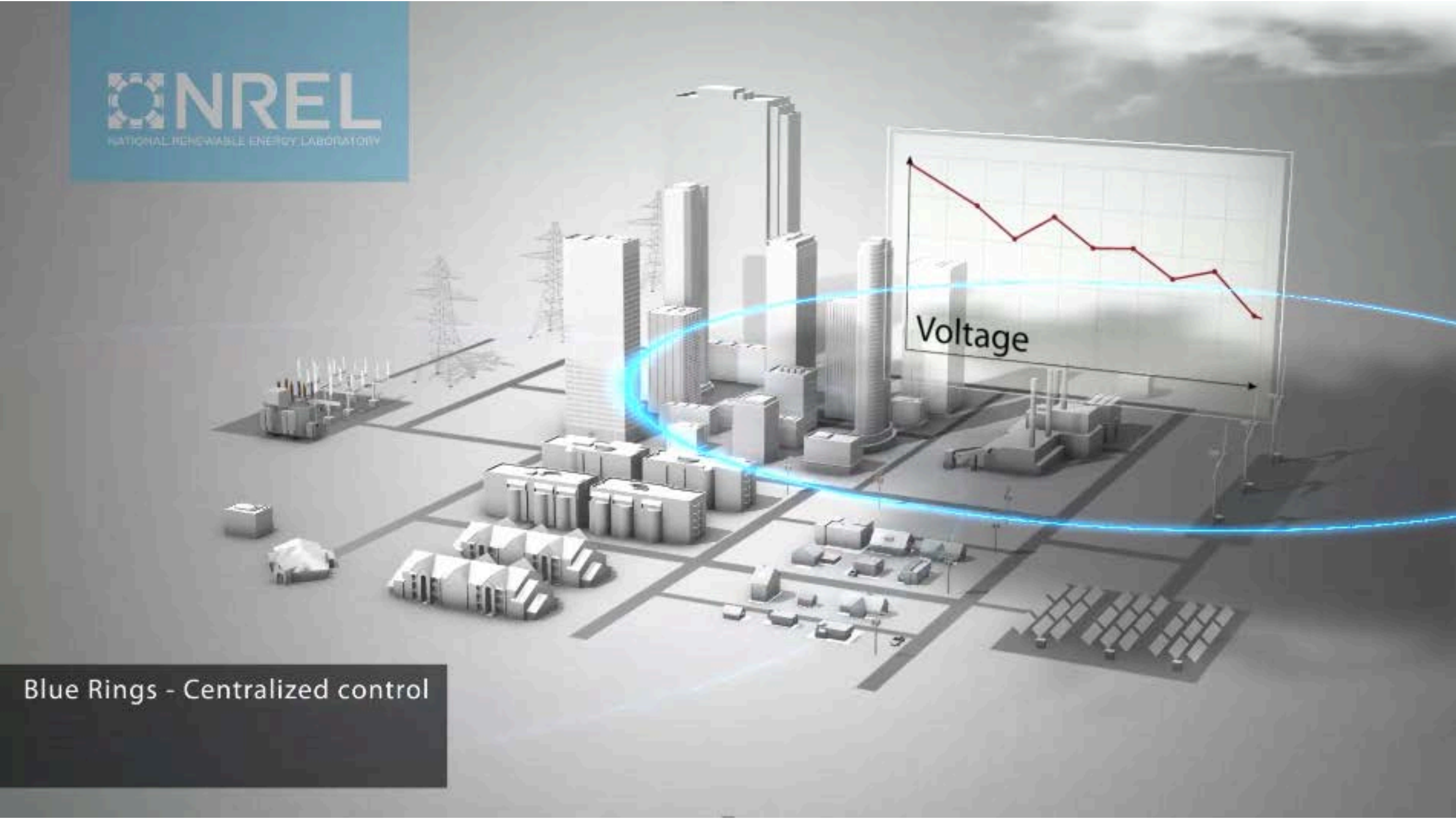
https://www.youtube.com/watch?v=In4HtG6XypU

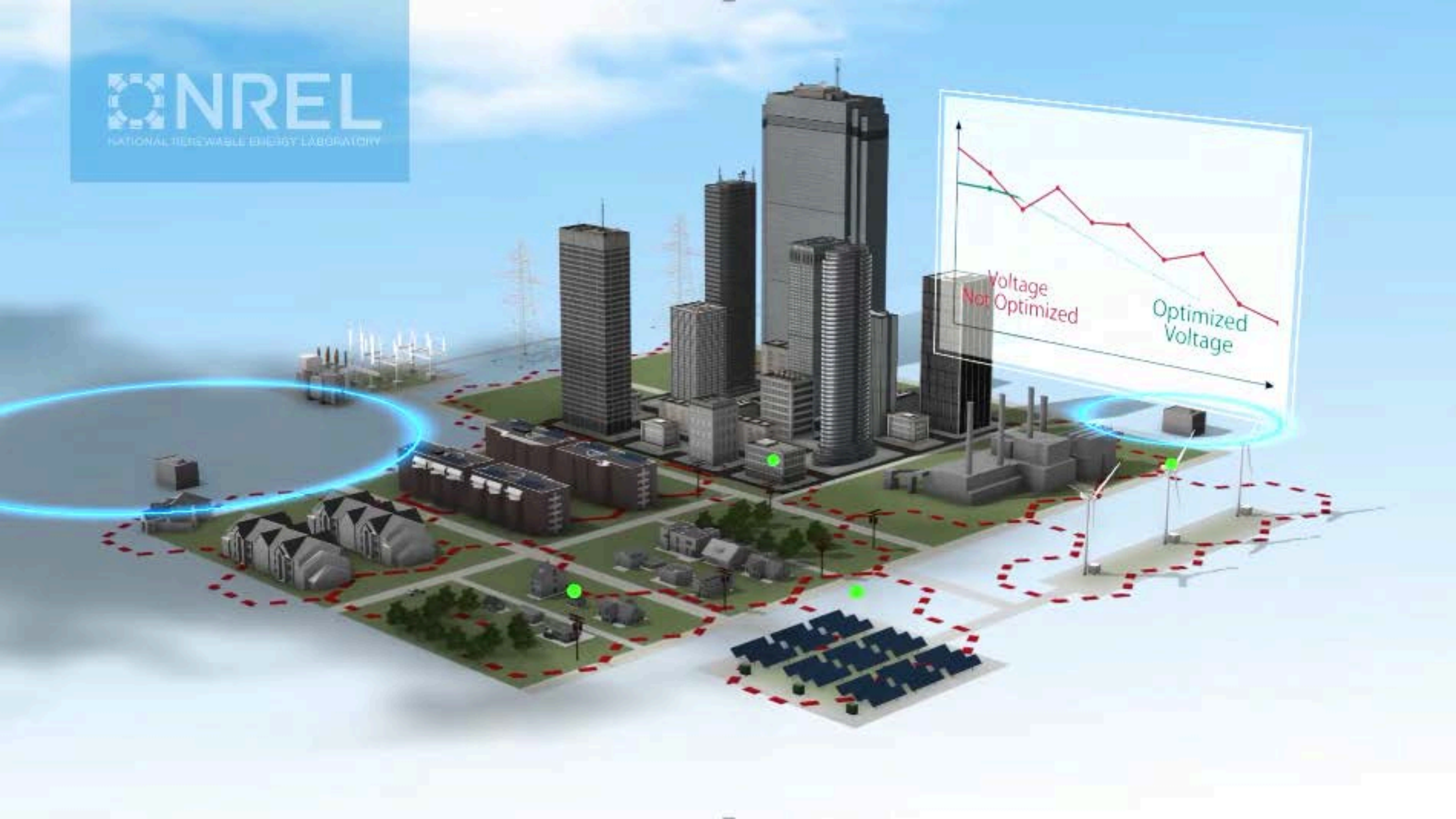
Let’s Look to the Future

Autonomous Energy Grids

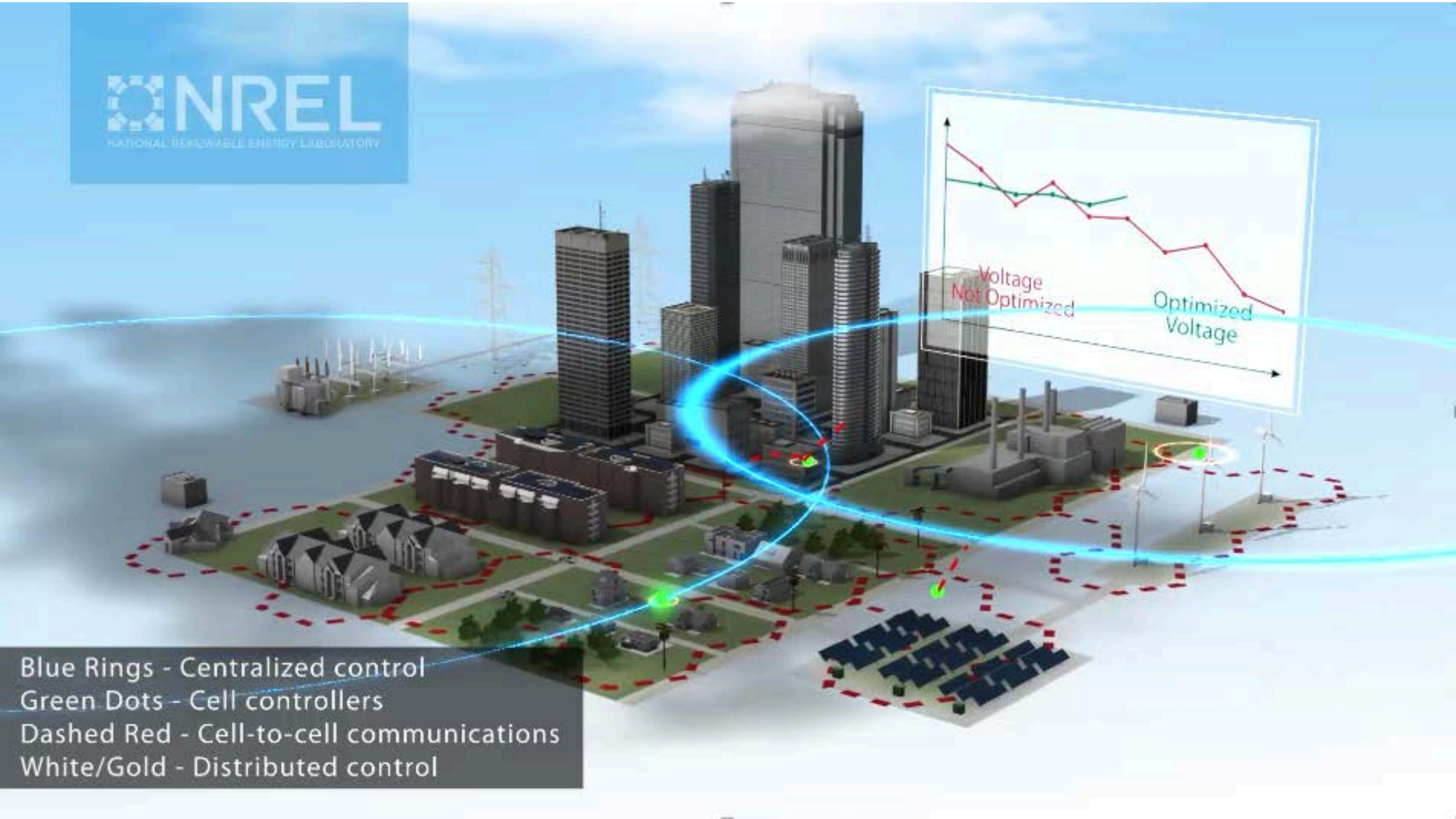
NREL is a national laboratory of the U.S. Department of Energy,
Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.


NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Voltage


NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Voltage
Blue Rings - Centralized control



NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Voltage Not Optimized
Optimized Voltage


NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Voltage Not Optimized
Optimized Voltage
Blue Rings - Centralized control
Green Dots - Cell controllers
Dashed Red - Cell-to-cell communications
White/Gold - Distributed control


NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Voltage
Not Optimized
Optimized
Voltage
Blue Rings - Centralized control
Green Dots - Cell controllers
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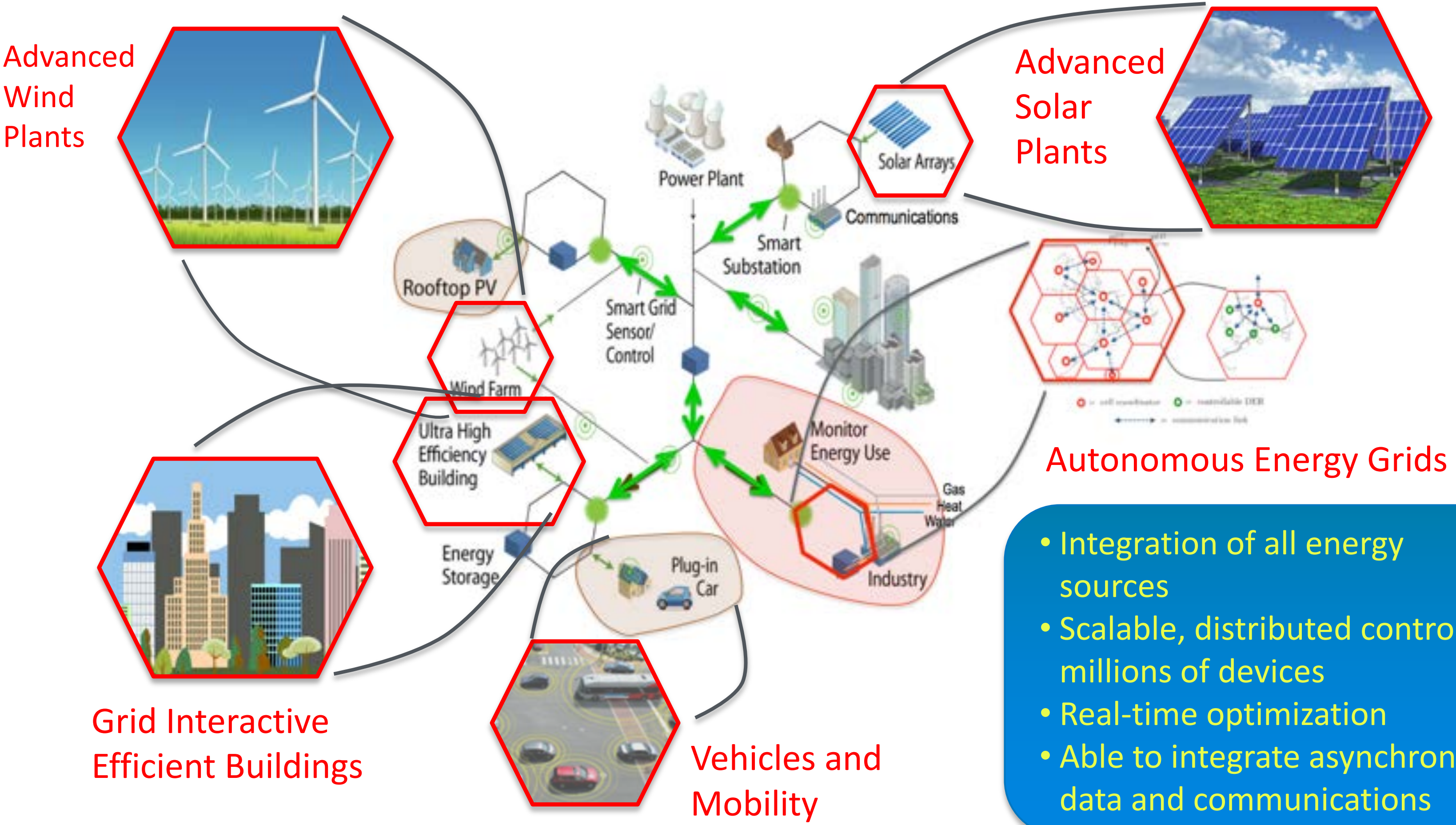
Transforming ENERGY through Autonomous Energy Systems



- Integration of all energy sources
- Scalable, distributed control of millions of devices
- Real-time optimization
- Able to integrate asynchronous data and communications

Thank you

www.nrel.gov/grid/autonomous-energy.html