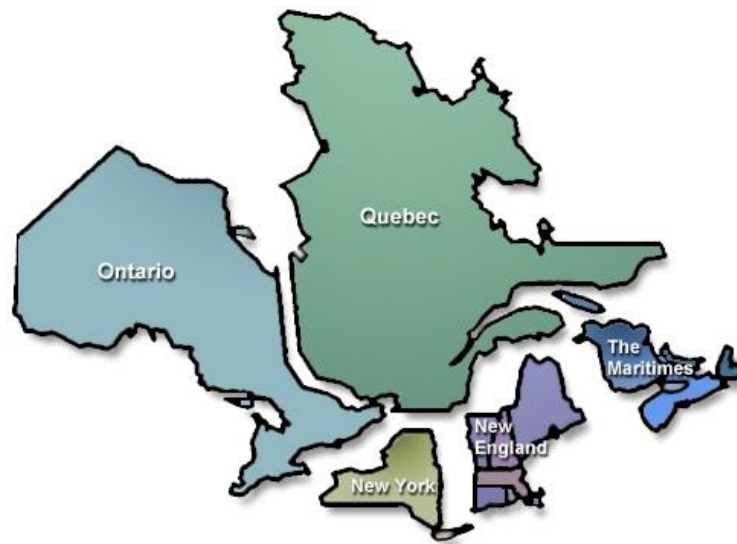




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DRAFT

NPCC Guidance Document, Approaches to Enhance System Resilience and Reliability in a High DER Penetration Future



NPCC Regional Standards Committee
Version 2 Approved XX/XX/2020



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Executive Summary

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

As Distributed Energy Resources (DER), installed on the distribution system, continue to replace traditional industry generation resources, this transformation will change the resource mix and require changes to how the system is planned and operated. Opportunity exists to leverage the operational characteristics of DER to enhance reliability and resilience of the Bulk Power System (BPS). Historically, the North American Electric Reliability Corporation (NERC) Reliability Standards have not been applicable to equipment on distribution systems unless such equipment has a direct impact on the Reliable Operation¹ of the BPS such as 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.

Development of this document was initiated by the NPCC Board of Directors to develop Regional guidance for voluntary use by NPCC Members and stakeholders. The guidance provided herein identifies reliability risks² to the BPS and suggests high level regional approaches NPCC Members could consider to reliably implement DER. Specifically, integration, capability, and operations issues which should be considered during process modification and development in their Area to maintain and continue to achieve reliable operation of the BPS within NPCC.

The previous version of this guidance document did not consider specific rooftop solar or individual installations of wind turbines or other localized behind the revenue meter DER, although a process described in this document was established which allows entities to identify concerns regarding impacts to NPCC so they can be acknowledged and addressed. This document will continue to identify all emerging issues related to DER's deployment, interconnection, planning and operations. NPCC Staff has developed this guidance in conjunction with NPCC Member input, NERC, and other groups through the NPCC open comment process to highlight the importance of interconnection requirements at the distribution level. This document identifies opportunities for DER related process improvement and ensuring no emerging potential reliability risks due to gaps may exist, in order to promote good utility interconnection practices necessary for the reliability of the NPCC Region as a whole. In addition, during the development of this document, a review of existing DER related documents was performed and

¹ 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."

² 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,

NPCC is working with the NY Interconnection Technical Working Group as well as the Joint Utilities group of NY to align processes where possible.

DER for the purpose of this guidance means any non-BPS real or reactive resource (generating unit, multiple generating units at a single location, distributed generation, battery storage, etc.) located within the boundary of any distribution utility but not behind revenue metering, unless specifically indicated.

Detailed guidance provided by some NPCC Members is included in this guidance document for the benefit of Areas where DER interconnections have not yet progressed to high enough levels to warrant action in their Area. Since DER is a growing technology trend, all NPCC Members will benefit from seeing details on reliable DER integration which have been applied elsewhere. Their presence in this document does not indicate application within NPCC as a whole. Also it is important to note that specific NPCC Area or Utility requirements at the local level will supersede any suggested approaches in this document.

NPCC, is not creating new Criteria or Standards through this guidance document. The intent is purely informational and the document will need continual revisions as NERC System Planning Impacts of DER (SPIDER), and other groups develop their respective guidance documents to achieve continued alignment.

In conjunction with the development of NPCC guidance on DER, NPCC has been conducting DER Forums, the purpose of which is to promulgate DER related information, educate and inform. NPCC provides this as a service to entities within the Northeast to allow the sharing of information and provide a platform where best practices may be discussed. NPCC's Regional Standards Committee (RSC) and Reliability Coordinating Committee (RCC) has also developed a joint process and a form to report DER related impacts. These may be found on the NPCC website.

Introduction and Objective

As DERs continue 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 DERs are interconnected, planned, operated and how they interact with the transmission system.

Reliably and securely integrating DER into the electric system requires a comprehensive 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 this Version 1 writing, to help identify opportunities for guidance.

Many, if not most, of the contemporary DERs are theoretically capable of bringing a number of enhancements to reliability, provided that there are sufficient design specifications and interconnection requirements to implement the enhancements. As an example, inverters, which convert direct current to alternating current, have microprocessor based control systems. These microprocessors operate with a very high internal clock speeds (on the order of MHz) and are capable of fine resolution frequency measurement. They are capable of electronically controlling the upward ramping of DER output and downwards ramping of DER output. Additionally settings in the DER inverters are capable of ceasing the injection of current into the electric system at very high speeds depending on control decisions. Inverters are capable of remaining physically connected (breaker closed) and not injecting current well in excess of normal 3-5 cycle breaker clearing times. This type of response can provide significant reliability benefits if control systems are properly configured to reliably implement it. Additionally, for upward ramping, the distribution level connected resource should be available and operate with "headroom." In order to realize the benefits which DER are capable of to enhance reliability, it is important to understand the hosting capacity of the distribution system feeders where they are being located and the DER's expected capabilities, capacity, and operation. In addition to improving system response, DER in certain circumstances may enhance Resilience³ by decentralizing generation and affording flexibility during restoration beyond that of normal system restoration plans but initially will also complicate system restoration plans⁴. Many utilities across North America are not including any DER in their system restoration to their variability and leaving them disconnected until such time as the system has been restored to a stable state. As DER penetration continues to increase and fossil fuel units retire it will create a need to revisit system restoration and Blackstart.

While DER present opportunities to enhance reliability, they also introduce challenges at the transmission/distribution interface. Interoperability with the transmission system is not solely determined at the point of interconnection. System needs such as visibility of generation state is essential for transmission operators to maintain situational awareness for operations purposes, for forecasting and integrated system planning to ensure reliability is maintained. Presently there are no 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.

In recognition of both benefits and challenges, the approach taken with this first Version of the NPCC DER guidance document was to collect interconnection requirements within the NPCC Region as well as in other areas of the NERC Electric Reliability Organization (ERO) Enterprise. There are some specific issues where opportunity exists to ensure better coordination across the NPCC Region. The intent of

³ Resilience as used in the guideline is referring to the 2018 NERC RISC Resilience Report

⁴ Another example of a reliability risk not addressed is use of DER in system restoration. Specific issue as once voltage presence and frequency are returned, DERs will resync to the Grid without contact to the Control Center. Trying to maintain that balance of Generation and load during restoration path execution without integrating DER into the restoration Plan is challenging.

this document is to identify risks and establish guidance, where possible, for interconnection of DER and raise awareness of opportunities. NPCC hopes to leverage any existing Area or distribution owner requirements in the Region. This is a first step to developing a NPCC Region-wide approach to interconnecting DER to distribution systems and reliably operating DER in conjunction with the BPS. It is recognized that DERs may not be placed optimally and in areas where deliverability to load may not be ideal. In this respect any specific recommendations in this document will be subject to the requirements of the interconnecting distribution utility.

Presently there are no study tools in general use that allow utilities to perform fully integrated and simultaneous system studies of both the transmission and distribution systems, although work is underway in this regard. This is a current reliability risk that is not addressed in this guidance document⁵.

NPCC Reliability Principles

Using its membership structure and governance authority to create and apply Regional Criteria⁶, NPCC Member adherence to Regional criteria contributes to a more robust level of reliability beyond NERC ERO reliability “results-based” standards / requirements. For example, NPCC Criteria mandate specific design requirements for NPCC Member facilities. NPCC’s approach to reliability and Resilience can be summarized in Principles that guide NPCC Members in their effort to meet or exceed NERC requirements. NPCC’s core Reliability Principles⁷ 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

⁵ NERC appears to currently suggest that studies modeling a few details at the T-D interface is sufficient. NPCC is considering proposing that more detailed and coordinated studies between transmission and distribution are needed.

⁶ See NERC Rule of Procedure #313 on page 15 of the [NERC Rules of Procedure 3-9-2018](#).

⁷ The Reliability Principles were summarized in the NPCC 2018 Strategic Review Report.

planning and operation of the power delivery assets in the NPCC region⁸. These critical facilities collectively are identified as the NPCC Bulk Power System^{9,10}.

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 operation¹¹ 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."
6. **Resilience has always been an element of NPCC Criteria:** Based on experience, resilience^{12 13} 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:

⁸ 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.

⁹ 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.

¹⁰ 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](#)

¹¹ 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. "

¹² 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.

¹³ 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".

- Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
- Resourcefulness – The ability to detect and manage a crisis as it unfolds.
- Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
- Adaptability – The ability to absorb new lessons from events.

NERC RISC Model of Resilience

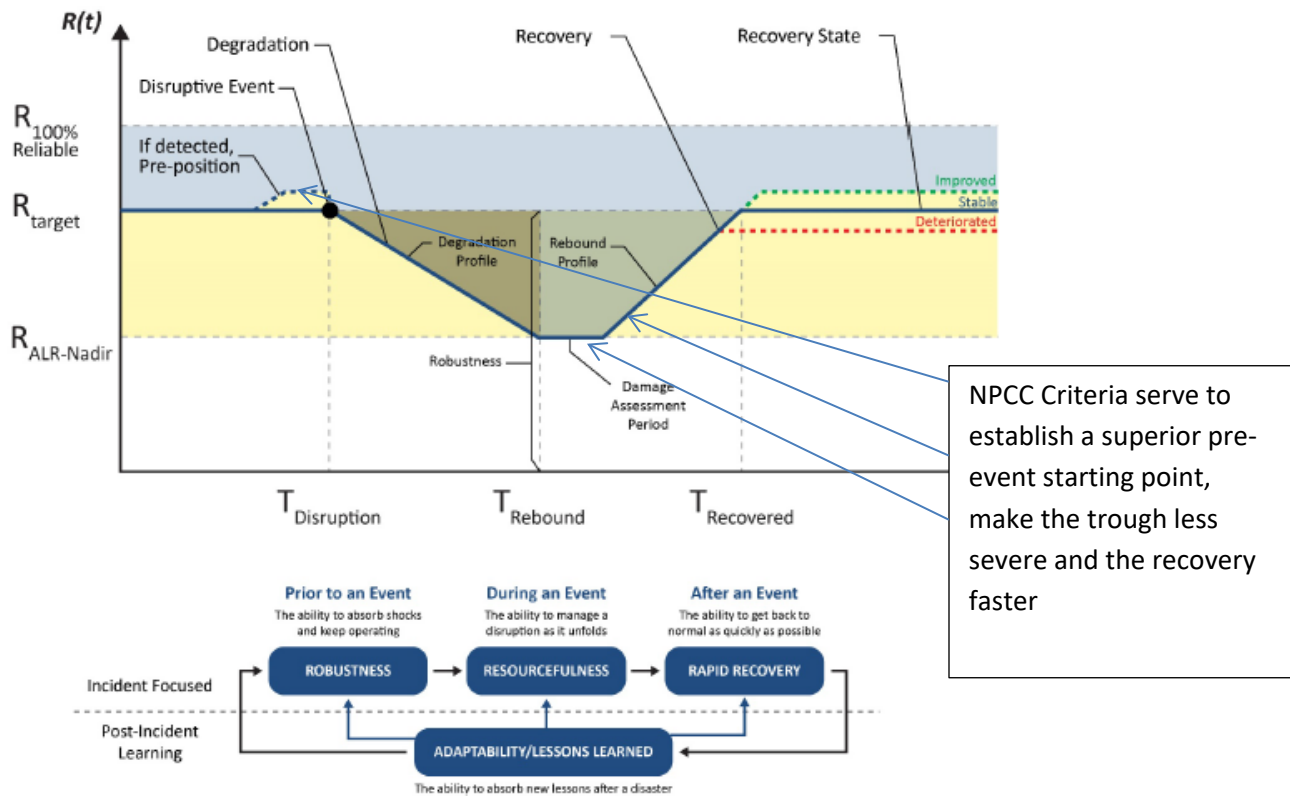


Figure 2.1

Also recognize the critical role that DER will have 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.

NPCC DER Impact Reporting

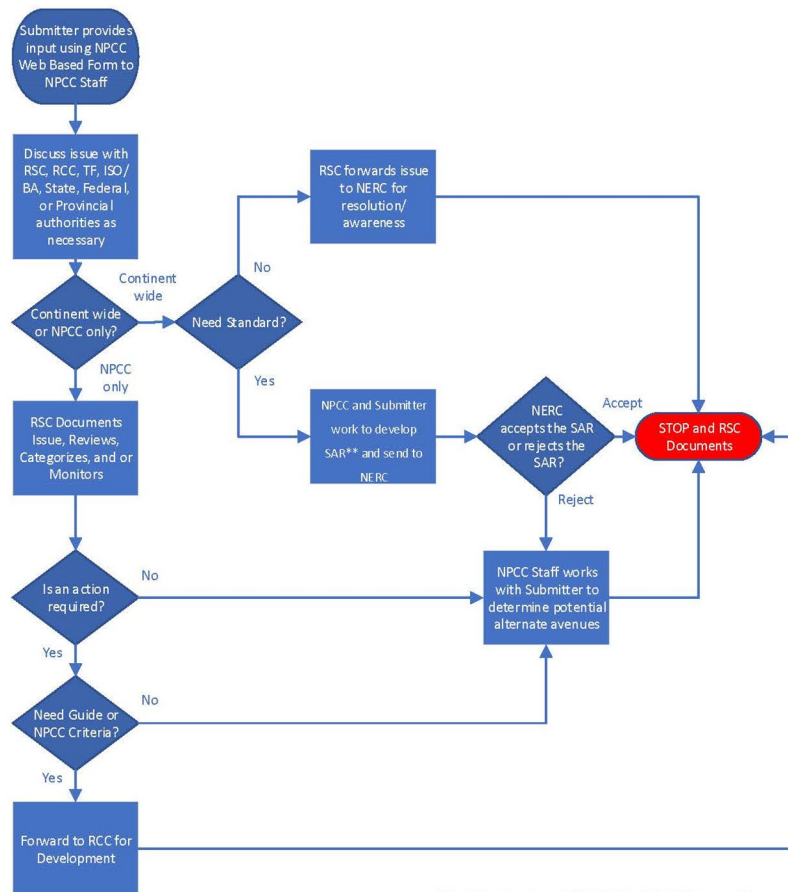
In order to ensure the reliability and Resilience of the interconnected BPS in Northeastern North America as DER continues to proliferate throughout the distribution systems within the NPCC Region, it is important to have a centralized DER impact reporting mechanism. The NPCC Regional Standard Committee (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 the below form resides 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 and will initiate a collaborative review by the Reliability Coordinating Committee and Regional Standards Committee. The process is shown below.

Impacts from Distribution Level* Distributed Energy Resources on the BES



*Distribution Level, Not behind the Meter, utility scale DER

** Standards Authorization Request (SAR)

Regional Standards Committee, Approved 8/22/18 (GVZ)

DER BPS Impact Considerations

NPCC's Regional Standards Committee (RSC) and Task Forces (i.e. Task Force on System Studies and impacts on UFLS) reviews of DER as it pertains to the NPCC Region's BPS performance have identified a number of 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
- DER impacts on Underfrequency Load Shed programs.
- Impacts of DER on System Restoration and Black Start Plans.
- DER Markets: Encouraging identification of Points of Common Coupling transmission nodes affected and injection to where DER is best utilized and the appropriate DER output levels. Some Areas currently allow aggregation across a broad area while others require aggregation to specify at which transmission node the aggregated injection will occur.

NPCC Interconnection Guidance

 (Add in a section here on Authorities Governing Interconnection Requests (AGIR))

This document and any detailed specifications which follow, are intended to be examples of interconnection guidance and do not constitute a Regional Criteria which can only be implemented (if at all) through NPCC Directories. There are numerous efforts underway in many forums and regulatory bodies that are expected to create new, more specific guidance¹⁴. The level of detail and specificity provided is intended to be used as guidance for any NPCC Member Area which may not have yet seen the need to establish detailed operating parameters. Some Members of NPCC 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.

As general considerations, the DER owner should be encouraged to provide appropriate protection and control equipment, including a protective device and communications system that utilizes an automatic disconnecting device which will disconnect the generation under various conditions (for example, in the event that the portion of the utility system that serves the generator is de-energized for any reason, or for a fault in the generator-owner's system). There is also the possibility of over generation as has been demonstrated in CA, 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 therefore System Operator visibility is necessary. In lieu of visibility and operating procedures, some areas of the country

¹⁴ 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), IEEE (IEEE Std 1547-2018, P2800), and various state initiatives such as the New York ITWG, Other Regional initiatives.

are planning to use market mechanisms to address this issue. The DER owner's protection and control equipment also should be capable of automatically disconnecting the generation from the system to which it is connected upon detection of a utility system fault.

The DER owner's protection and control scheme should be designed to ensure that the generation remains in operation when the frequency and voltage of the utility system is within the limits specified by the interconnecting utility and its required operating ranges. Upon request from the interconnecting utility, the DER owner should be prepared to provide documentation detailing conformance with the guidance set forth in the connecting utility requirements.

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

The DER owner should have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection. 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.

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 Process¹⁵.

The guidance set forth in this document are intended to be consistent with those specifications contained in the most current version of IEEE Std. 1547-2018, Standard for Interconnecting Distributed Resources with Electric Power Systems. It is recommended that the requirements in IEEE 1547-2018 above and beyond those contained in this document or the interconnecting utility requirements, are to be followed including any other Standards referenced to in IEEE Std. 1547.

Voltage Response

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. Historically for excursions outside these limits the protective device generally automatically initiates a

¹⁵ 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.

disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547-2018. 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 functionalities may be permitted as agreed upon by the utility and DER owner. The industry is now in the process of changing this approach to promote ride-through via a number of different standards initiatives which NPCC is tracking through its DER Forum.

Example of Alternative Approach to promote ride-through

Ensuring that DERs are able to 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 DERs do not prematurely trip and further deteriorate system conditions. Appropriate tripping for voltages related to temporary fault conditions will also help maintain system reliability.

Quebec Interconnection

Ride through is of primary importance for resources connected to the grid, with the objective of maintaining system reliability. 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. For example, in under frequency, HQ's requirement goes as low as 55.5 Hz (for a short time period) while IEEE-1547-2018 does not require mandatory operation below 57 Hz.

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.



In the Quebec interconnection voltage ranges and regulation requirements vary from the Eastern Interconnection. The requirements of the local authority having jurisdiction should be followed (typically Hydro Quebec).

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 above the curve," not "must trip below the curve. Regarding frequency operating characteristics of Inverters:

The operating range for the DER distribution connected resources should be similar to that of BPS connected resources. The operating band for frequency of a DER resource's operating range should be

at least from 59.3 Hz to 60.5 Hz as required by the latest versions of NPCC's PRC-006 and NERC PRC-024 UFLS standards. If deemed necessary, the utility may request that the generator operate at frequency ranges below 59.3 Hz in coordination with the current under frequency load shedding schemes of NPCC and the local utility system. For excursions outside these limits the protective device should automatically initiate a disconnect sequence from the utility system as 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 PCC and includes detection and intentional time delay. Other static or dynamic frequency functionalities may be permitted as agreed upon by the utility and DER owner. There may be a need to establish a mechanism to formally have TO/DP's provide information as to which DER facilities are connected to feeders that have UFLS protection systems.

In addition, the 59.3 Hz from the UFLS system performance curve within which system frequency should remain (e.g. PRC-006-3). This curve may not be the best source for setting frequency characteristics for generators. There are other standards that have frequency trip curves for generators (e.g. IEEE 1547-2018, PRC-024-2, NPCC-006-NPCC-1 and NPCC D12). Note that the generator frequency trip curves may have a continuous operating range that is lower than 59.3Hz (e.g. 59 Hz in NPCC Directory 12 and PRC-006-NPCC-1).

Quebec Interconnection

Note that in the Quebec Interconnection the frequency operating range is wider than in the Eastern Interconnection. In Quebec, the acceptable frequency range is from 59.4 Hz to 60.6 Hz therefore in Quebec, UFLS systems must operate outside this operating range in accordance with the Quebec variance to the PRC-006-NPCC UFLS-1 regional standard table 4.

Reconnection to the Utility System

If the generation facility is disconnected as a result of the operation of a protective device, the DER owner's equipment should remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits for an acceptable amount of time as specified in the most current version of IEEE Std. 1547-2018. Under IEEE Std. 1547-2018 output is to be restored in 0.4 seconds.

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. 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

Direct current generation can only be installed in parallel with the utility's system using a synchronous inverter. The design should be capable of disconnecting the synchronous inverter upon a utility system event. 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.

Synchronization or re-synchronization of an inverter to the utility system should not result in a voltage deviation that exceeds the local utility or authority having jurisdiction power quality requirements. Only inverters designed to operate in parallel with the utility system should be utilized for parallel operation.

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 functionalities 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.

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

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

Table I: Inverters' Voltage Trip Settings

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

Table II: Inverters' Frequency Trip Settings

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

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

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

$1.10 < V \leq 1.15$	Permissive Operation	1	N/A	Identical
$0.88 \leq V \leq 1.10$	Continuous Operation	infinite	N/A	Identical
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T = 3 \text{ s} + \frac{8.7 \text{ s}}{V - 0.65 \text{ p.u.}}$ 1 p. u.	N/A	Identical
$0.45 \leq V < 0.65$	Permissive Operation ^{a,b}	0.32	N/A	See footnotes a & b
$0.30 \leq V < 0.45$	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:

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

Table IV: Inverters' Frequency Ride-through Capability

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

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF 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

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.

It is not possible to standardize protection requirements according to any single criteria. At a minimum, the protective function guidance in Table VI below should be considered. Function numbers, as detailed in the latest version of ANSI C37.2, are listed with each function. All voltage, frequency, and clearing time set points are should be field adjustable.

Table VI: Grid Support Minimum Protective Functions

Synchronous Generators	Induction Generators	Inverters
Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)
Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)
Anti-Islanding Protection	Anti-Islanding Protection	Anti-Islanding Protection
Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)

For energy storage systems or distributed generation where net export is limited, Reverse Power (Function 32) should be considered.

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. Protective devices should utilize their own current transformers and potential transformers and not share electrical equipment associated with utility revenue metering.

A failure of the DER owner's protective devices, including loss of control power, should open the automatic disconnect device, thus disconnecting the generation from the utility system. For example, if the DER protection is powered off the system AC, and there's a disturbance that drives voltage to go too low and the control/protection loses power which then trips the DER, then the DER wouldn't be meeting the necessary ride-through requirements. A DER owner's 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.

All interface protection and control equipment should operate as specified, independent of the calendar date.

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 and considered in the NPCC region if no other local criteria are available. 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)¹⁶. 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 source feeding the fault is only 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

Add something to this section on Advanced Meter Infrastructure (AMI) pertaining to increasing visibility of DER

Metering requirements for SCADA purposes are 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 is permitted should be installed when a DER has the capability or potential to provide generation back into the utility distribution system, however, the

¹⁶ 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.

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 .

A DER should 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. This information should be available to the system operator as required by the connecting utility. The monitoring equipment should be installed at the time of interconnection and meet the technical requirements of the connecting utility. The DER metering and monitoring communications will allow interoperability and the capability to provide system operators with situational awareness necessary for reliable operation of the interconnecting utility facilities. As more DER is employed and base load generation is replaced with DER resources, it will be important for the Distribution Provider (DP) or interconnecting utility to be able to monitor the availability and production of electricity (power output and energy delivered) from the DER resources.

Power Quality

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

Power Factor

If the output power factor, as measured at terminals of the generator, is less than 0.9 (leading or lagging), 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 the 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

Systems should be designed and operated so that islanding is not sustained on utility distribution circuits or on substation bus and transmission systems. The guidance provided in this document is designed and intended to avoid islanding and is subject to be superseded by local requirements. Special protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

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

Transfer trip is needed in some instances (e.g. on DER connections to non-radial transmission or sub-transmission circuits) in order to protect the utility systems and DER facility from damage during faults

and/or reclosing operations into faults. The decision as to the applicability of direct transfer trip and specific technology to be used for direct transfer trip communications rests with the connecting utility.

Underfrequency Load Shedding Programs

Underfrequency Load Shedding (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 determined, through sensitivity analysis, that increased levels of DER penetration anticipated in the short term will not result in any significant degradation in UFLS performance.

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.

Effective Grounding for DER

With the onset of high penetrations 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 to be voltage sources as they provide constant AC voltages controlled by excitation systems. In contrast, an inverter-based DER plants are considered as current sources, and the DER terminal voltage is dependent on the feeder to which it is connected.

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.

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 and that the amount of energy storage will double from 2018 levels during 2019.

The ESA in conjunction with over 25 vendors and utilities have formed a task force and made a commitment to optimize safety standards. Care should be used in placement of batteries. Suggested placements should avoid proximity to other facilities that may be critical to the reliability of the BPS.

System control and Data Acquisition (SCADA) and Communications

As DER penetration increases and all DERs above a certain MW level, as determined by the interconnecting utility or System Operators, should be required to provide SCADA telemetry data to the control center to monitor their output. 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 situations. Some NPCC Members have encountered difficulty with getting compliance on this need from the DERs. 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 6 second).

DER BPS Recommendations

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

Process and Risk Management Recommendations

- 1) Continue with sensitivity analysis at the Transmission level for various levels of penetration of DER on distribution facilities to determine effects of increased penetration levels of DER on UFLS performance.
- 2) Pursue further opportunities to coordinate distribution and transmission requirements for DER generating resources and promote NPCC Regional consistency where possible.
- 3) Continue to review NPCC Area authorities having jurisdiction and utility interconnection relative to DER requirements documents to identify dissimilarities between Areas which may negatively impact reliability.
- 4) Identify opportunities to share information regarding DER related reliability risk problems and problem solving.
- 5) Continue to solicit and address observable reliability issues of DER initiated BPS impact through the use of NPCC's DER Impact Reporting Forms and its associated process.

- 6) Continue to discuss any changes required for System Restoration and Blackstart Plans, as a result of increased DER.
- 7) Continue to follow DER related ESA ESS safety issues and associated recommendations and share the results with NPCC stakeholders.

Planning Related Recommendations Due to Changing Resource Mix

- 8) Obtain DER modeling and performance data to enable Long-Term Resource, Long-Term Transmission and Operational Planning of the BPS¹⁷
- 9) Clearly identify DER in the NPCC Region's Area DER and particularly PV project queues or forecasts where DER is being proposed for installation and the magnitudes relative to the existing resource base and load projections.
- 10) Address masking of load by DER at the distribution level to ascertain its impact on the assumptions that underpin UFLS programs

Analytics and simulation recommendations to deal with increase system complexity

- 11) Support interconnection wide inertia loss study efforts, to determine potential reliability impacts, as DER increasingly replaces conventional synchronous generation resources.
- 12) 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. Under Frequency Load Shedding,
 - b. Under Voltage Load Shedding,
 - c. Frequency response sharing mechanisms (BAL standards).
 - d. Analysis of system protection systems (both T and D) so that the parameters to set protection systems and other control systems are known so as to permit the most reliability benefits to be garnered from the new resources.

¹⁷ What entities should be responsible for providing DER data to the Planning Coordinator for the purposes of model building?

Appendix A NPCC DER Impact Reporting Form



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 _____

Appendix B, NPCC Areas-Comparisons

Key Inverter based specification extracts

	ISO-NE Inverter Requirements	NG ESB 756 B, C, D	NY SIR ¹⁸	IESO F2 Technical Requirements
Inverter Certification	yes	yes	yes	yes
Voltage and frequency trip settings for inverter based applications	yes	yes	yes	yes
Voltage Response	yes ¹⁹	yes	yes	yes
Frequency Response	yes ²⁰		yes	yes
Abnormal performance capability (ride-through) requirements for inverter based applications	yes	yes		
Other grid support utility interactive inverter functions statuses	yes			
Minimum protection functions		yes	yes	
Monitoring and Control		yes	yes	yes
Reconnection to the System		yes	yes	
Distribution Protection Coordination		yes		yes
Inverter Certification		yes	yes	

¹⁸ NY SIR is the [New York Standardized Interconnection Requirement](#).

¹⁹ 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

²⁰ 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

Power Quality

yes

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

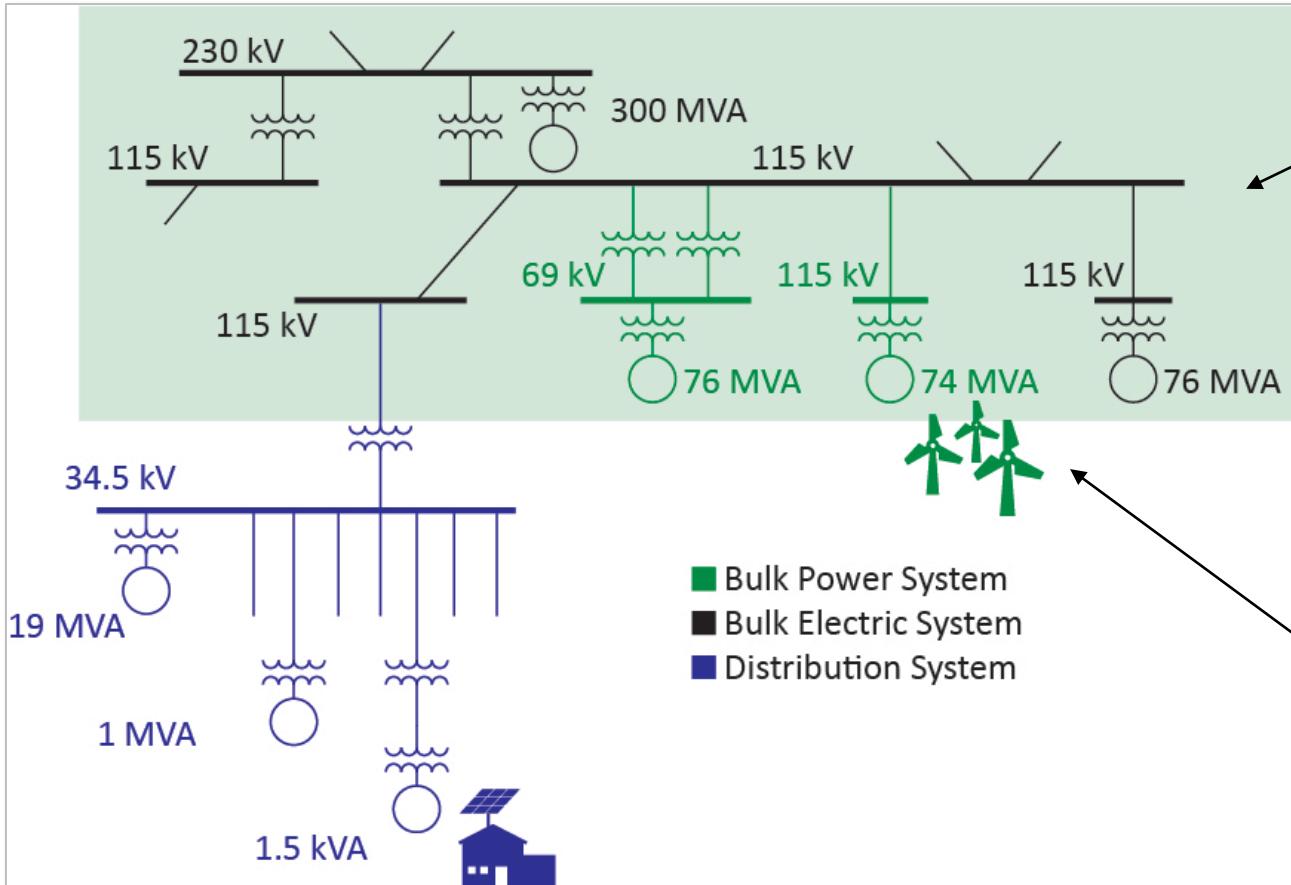
Ensuring BPS Reliability in a Transition towards Inverter-Based Resources

Ryan D. Quint, PhD, PE
Senior Manager, NERC
NPCC DER Forum
February 2020

RELIABILITY | RESILIENCE | SECURITY



Let's Talk the Same Language



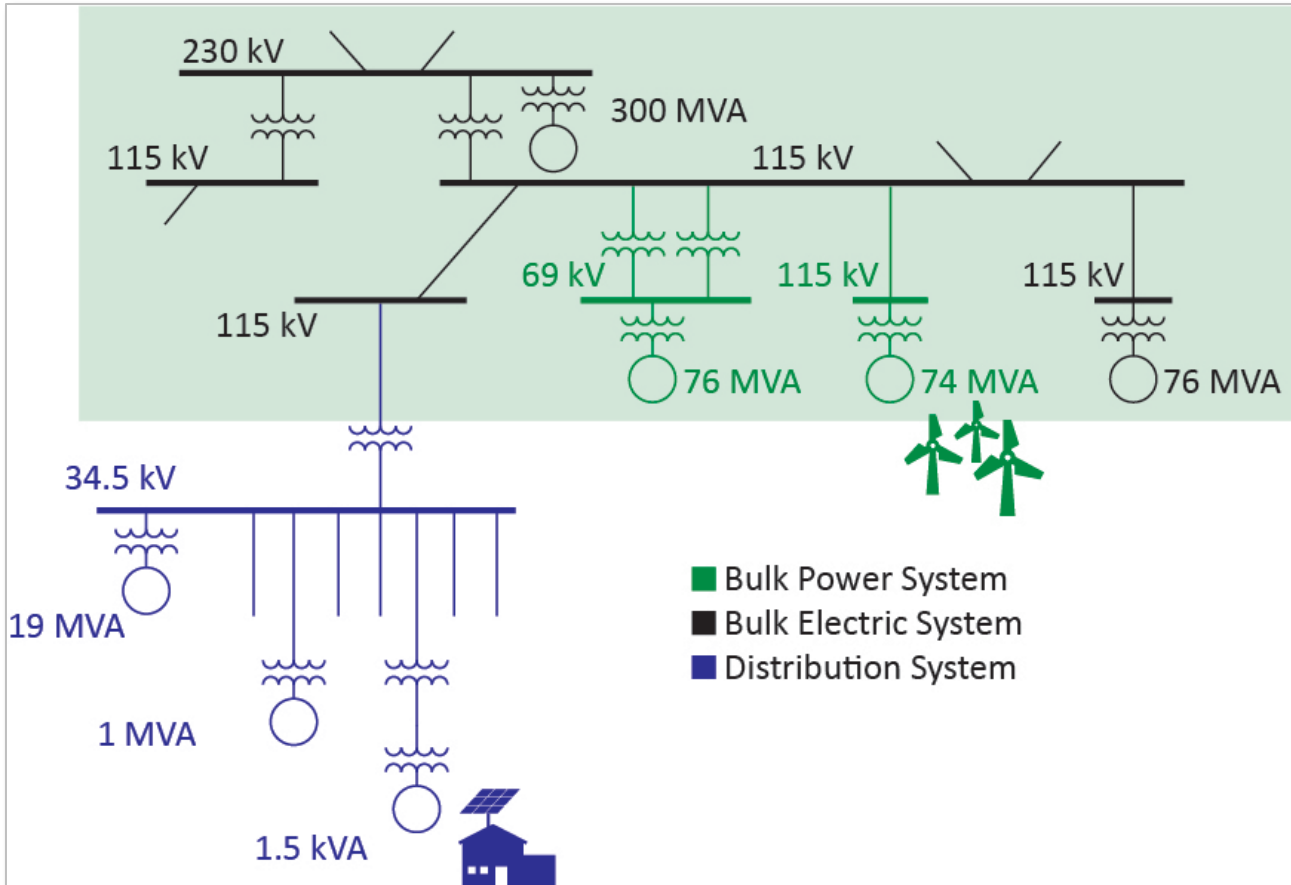
*NERC Reliability Standards
and
FERC LGIA/SGIA*

*Local Utility Interconnection
Requirements
and
FERC LGIA/SGIA*

*States Adoption and Implementation
of IEEE 1547-2018*

Illustrative Purposes Only

Let's Talk the Same Language



Illustrative Purposes Only

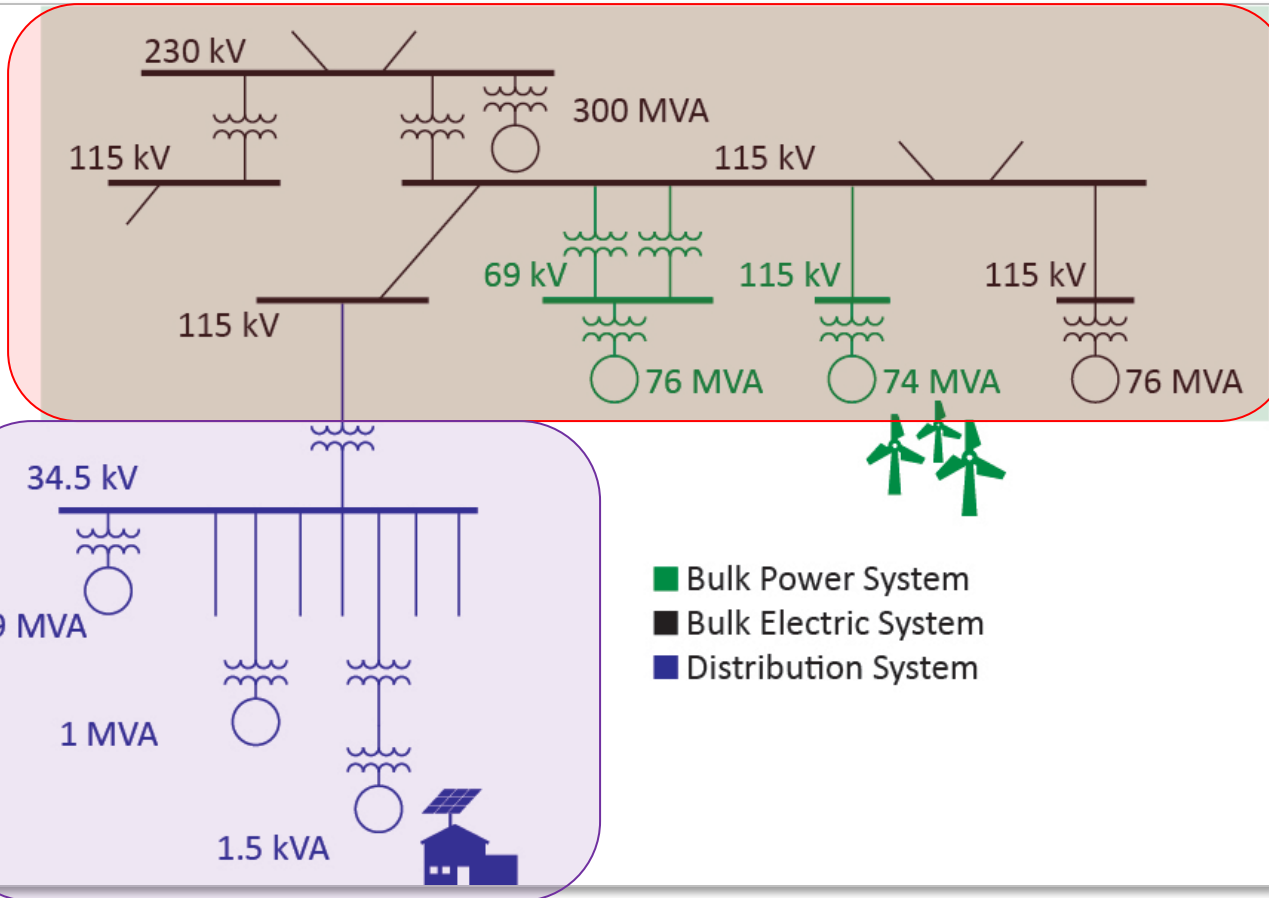
IEEE P2800

- Inverter-based resources
- Covers all BPS and BES
 - Transmission-level
 - Subtransmission-level

IEEE 1547-2018

- All power-producing resources
- Distribution-level

NERC IRPTF



IEEE P2800

- Inverter-based resources
- Covers all BPS and BES
 - Transmission-level
 - Subtransmission-level

IEEE 1547-2018

- All power-producing resources
- Distribution-level

Illustrative Purposes Only

NERC SPIDERWG

NERC Inverter-Based Resource Performance Task Force (IRPTF)

BPS-Connected Inverter-Based Resources



1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report

Southern California 8/16/2016 Event

June 2017



Industry Recommendation

Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Initial Distribution: June 20, 2017

NERC identified a potential characteristic exhibited by some inverter-based resources, particularly utility-scale solar photovoltaic (PV) generating, which reduce power output during fault conditions on the transmission system. An example of this behavior has been observed during recent BPS disturbances, highlighting potential risks to BPS reliability. With the recent and expected increase of utility-scale solar resources, the causes of this reduction in power output from utility-scale power inverters need to be widely communicated and addressed by the industry. The industry should identify reliability preserving actions in the areas of power system planning and operations to reduce the system reliability impact in the event of widespread loss of solar-resources during faults on the power system.

For more information, see the [1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report](#).

[About NERC Alerts](#)

Status: Acknowledgment Required* by Midnight Eastern on June 27, 2017
Reporting Required by Midnight Eastern on August 31, 2017

PUBLIC: No Restrictions
[More on handling](#)

Instructions: This recommendation provides specific actions NERC registered entities should consider taking to respond to a particular issue. Pursuant to Rule 610 of NERC's Rules of Procedure, NERC registered entities shall (1) acknowledge receipt of this advisory within the NERC Alert System, and (2) report to NERC on the status of their activities in relation to this recommendation as provided below. For U.S. entities, NERC will compile the responses and report the results to the Federal Energy Regulatory Commission.

RELIABILITY | ACCOUNTABILITY

900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report

Southern California Event: October 9, 2017
Joint NERC and WECC Staff Report

February 2018



Industry Recommendation

Loss of Solar Resources during Transmission Disturbances due to Inverter Settings - II

Initial Distribution: May 1, 2018

NERC has identified adverse characteristics of inverter-based resource performance during grid faults that could present potential risks to reliability of the BPS. As the penetration of inverter-based resources (particularly solar PV resources) continues to increase in North America, these adverse characteristics need to be widely communicated. This Level 2 Industry Recommendation alerts industry to these adverse characteristics observed with BPS-connected solar PV resources, and provides recommended actions to address fault ride-through and timely restoration of current injection by all inverter-based resources connected to the BPS. (See Background section for more information.)

Although this NERC Alert pertains specifically to BES solar PV resources, the same characteristics may exist for non-BES solar PV resources connected to the BPS regardless of installed generating capacity or interconnection voltage. Owners and operators of these facilities are encouraged to consult their inverter manufacturers, review inverter settings, and implement the recommendations described herein. While this NERC Alert focuses on solar PV, we encourage similar activities for other inverter-based resources such as, but not limited to, battery energy storage and wind resources.

For more information, see the October 9, 2017 Canyon Fire [Disturbance Report](#).

[About NERC Alerts](#)

Status: Acknowledgment Required* by Midnight Eastern on May 8, 2018
Reporting Required by Midnight Eastern on July 31, 2018

PUBLIC: No Restrictions
[More on handling](#)

* These resources do not meet the Bulk Electric System definition, and are generally less than 75 MW and not connected to transmission level voltage.
† To the extent that similar definitions are implemented for or implemented by entities that vary from those of the NERC, NERC requires entities to not participate voluntarily participate in response to this Alert.

RELIABILITY | ACCOUNTABILITY

April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report

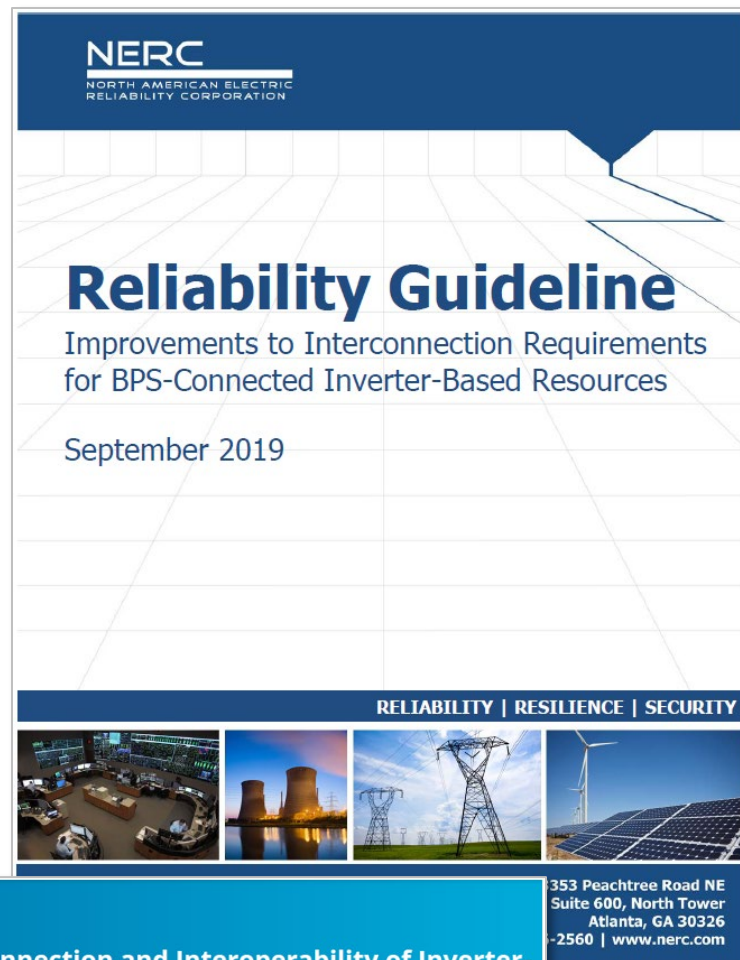
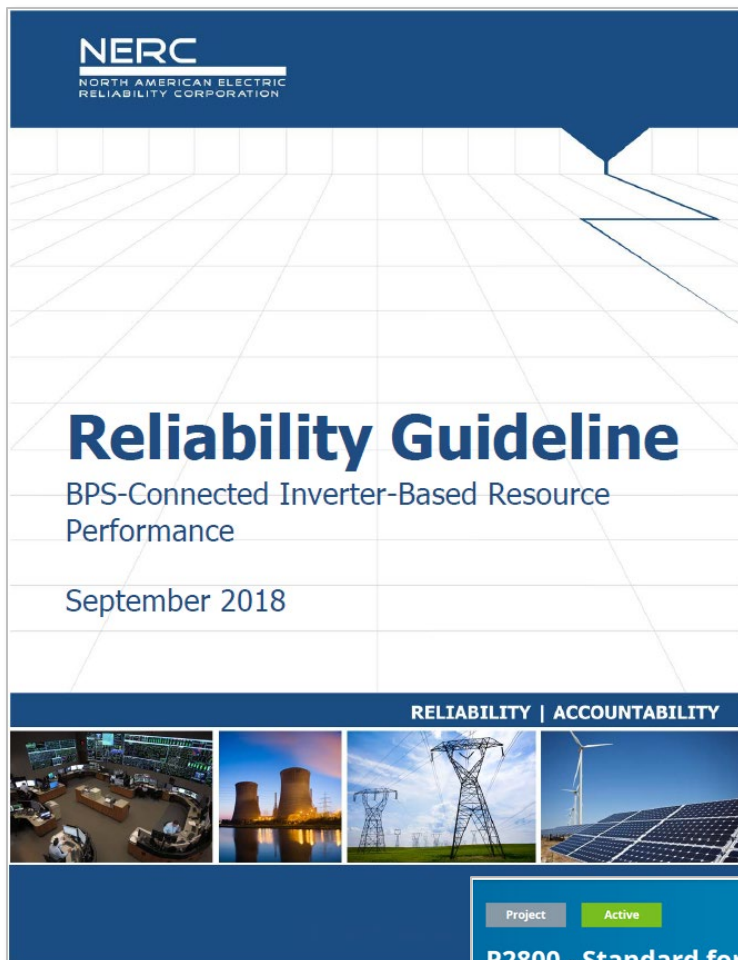
Southern California Events: April 20, 2018 and
May 11, 2018
Joint NERC and WECC Staff Report

January 2019



RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com



Project Active

P2800 - Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems

IEEE STANDARDS ASSOCIATION

353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
-2560 | www.nerc.com

- IBR Modeling and Studies Report (Technical Report)
- Fast Frequency Response Fundamentals (White Paper)
- NERC Reliability Standards Review for IBR (White Paper)
- EMT Modeling and Studies (Reliability Guideline)
- Modeling and Studying BPS-Connected Energy Storage and Hybrid Plants (Reliability Guideline)
- Energy Transition to Increasing Penetrations of BPS-connected Inverter-Based Resources (Technical Report)

NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG)

Aggregate Impacts of Distribution-Connected Energy Resources



- **Aggregate** amounts of DER can and will impact the BPS
 - NERC Goal: provide support where needed in this area; ensure BPS reliability
- Adoption of IEEE 1547-2018
 - Encouraged, from BPS perspective
 - Coordination led by **AGIRs** (e.g., States), engagement from RCs
- Educational materials abound
 - NERC SPIDERWG, NERC Reliability Guideline, EPRI reports, etc.
- Coordination necessary for successful IEEE 1547-2018 implementation (BPS perspectives needed in some areas)
 - DER Category Selection
 - Voltage Tripping
 - Voltage Ride-Through
 - Frequency Tripping
 - Frequency Ride-Through
 - Restore Output
 - Frequency-Droop
 - Phase Angle Change Ride-Through
 - Enter and Return to Service
 - Unintentional Islanding
 - Intentional Islanding
 - Interoperability

IEEE STANDARDS ASSOCIATION



IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Standards Coordinating Committee 21

Sponsored by the
IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed
Generation, and Energy Storage

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std 1547™-2018
(Revision of IEEE Std 1547-2003)

Source: IEEE SA

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Bulk Power System Reliability Perspectives on
the Adoption of IEEE 1547-2018

December 2019

DRAFT

RELIABILITY | RESILIENCE | SECURITY

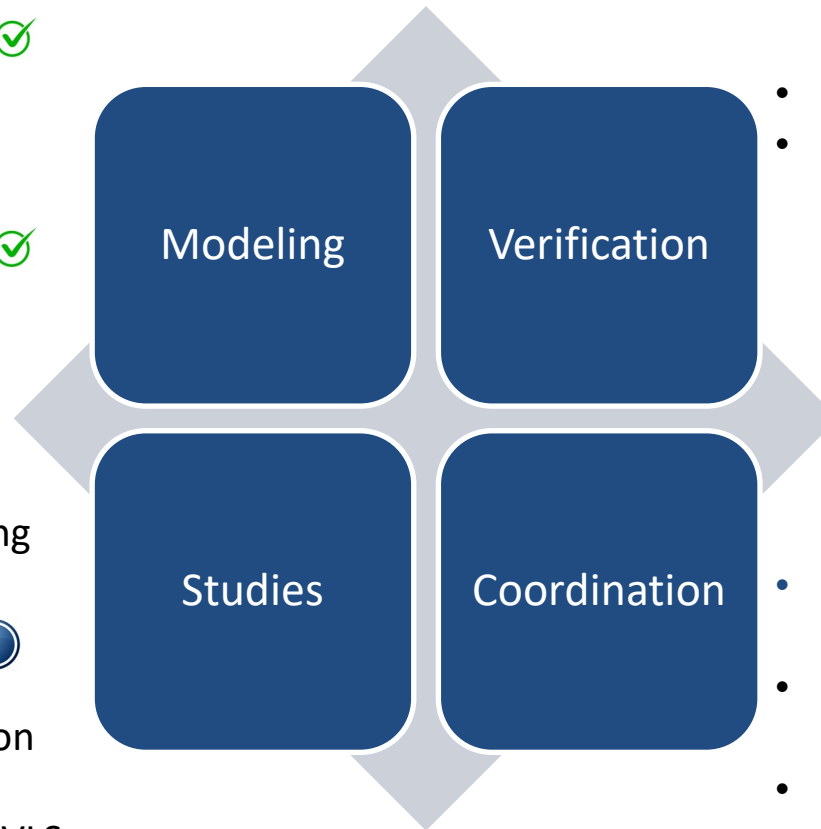


3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

What Else is SPIDERWG Up To?

- DER Modeling Survey
- **DER_A Parameterization** ✓
Guideline
- DER Data Collection
Guideline
- **MOD-032-1 Review/SAR** ✓
- **Modeling Notification** ✓

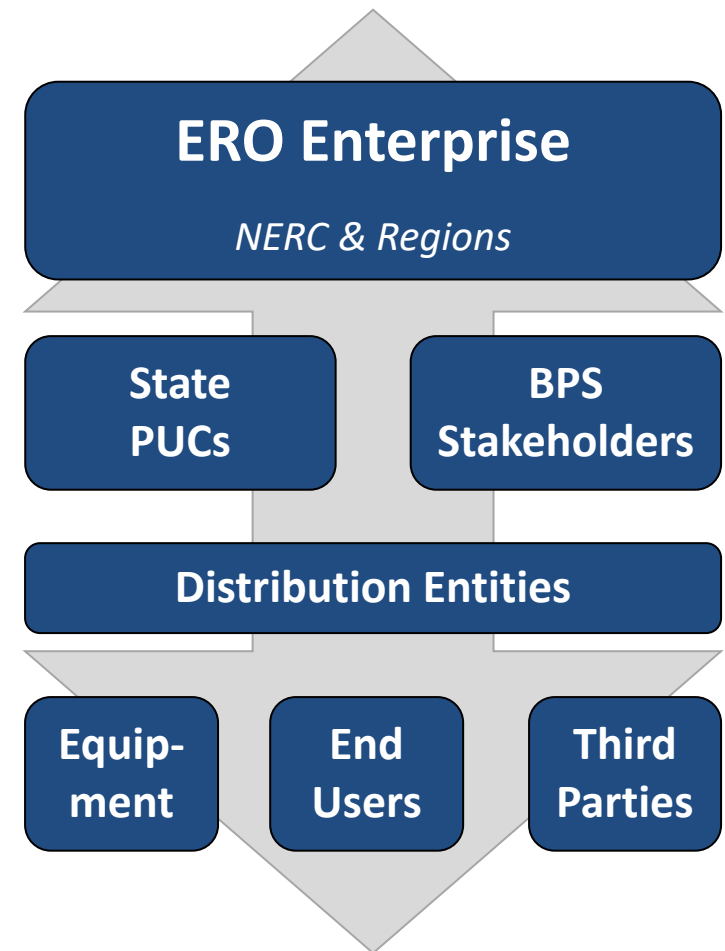
- Guideline on BPS Planning
Practices with DER
- **White Paper: TPL-001** !
Standard Review
- Recommended Simulation
Improvements
- Guidance on UFLS and UVLS
- White Paper: Beyond
Positive Sequence



- DER Verification Guideline
- DER Forecasting Practices
Guideline

- **IEEE Std. 1547-2018 Review** !
and BPS Recommendations
- Guideline on Communicating
across T-D Interface
- Education Materials
- Coordination of Terminology
- NERC Standards Review
- Tracking DER Growth

- **Question:** *How best can we coordinate between NERC, the Regions, and our stakeholders?*
- **My Answer:** “Make It Personal”
 - NERC Guidelines providing clear recommendations for areas where industry will need to *dig in* moving forward
 - Providing unified guidance for industry-wide modeling, simulation, planning, data collection, and other practices
 - HOWEVER ... you all know your system best!
 - What is the highest priority issues in your footprint?
 - What emerging risks could be coming?
 - Have those been articulated to the Region and to NERC?
 - Why? Because we want to help address them together!



Summary of Activities

BPS-Connected Inverter-Based Resources and Distributed Energy Resources September 2019

The electric power grid in North America is undergoing a significant transformation in technology, design, control, planning, and operation, and these changes are occurring more rapidly than ever before. Particularly, technological advances in "inverter-based resources"¹ are having a major impact on generation, transmission, and distribution systems. This document provides a landscape overview of this transformation with its specific changes. This document also provides some recommendations that industry, regulators, and other stakeholders may collaborate upon to ensure the continued reliability of the North American power grid.

Executive Summary

The North American Electric Reliability Corporation (NERC), as the Electric Reliability Organization (ERO), is actively supporting the reliable integration of inverter-based resources across North America by working collaboratively with key industry stakeholders. Some key takeaways from these activities include, but are not limited to, the following:

- At the distribution level, the Institute of Electrical and Electrical Engineering (IEEE) Standard (Std.) 1547-2018 is a significant advancement in ensuring improved capabilities from distributed energy resources (DERs). This standard specifies performance capabilities and addresses interconnection and interoperability. State regulators should encourage collaboration between utilities, regional reliability coordinators, industry stakeholders, and state commissions, and should support the adoption and implementation of IEEE Std. 1547-2018 to ensure consistent performance from DERs on a local, regional, and wide-area basis.
- For Bulk Electric System (BES) generation, the NERC Planning and Operating Committees and their technical working groups are actively developing consistent and clear performance requirements for all connected resources, including inverter-based resources and synchronous generation. While the intent and requirements of the standards are applicable to synchronous and inverter-based (nonsynchronous) resources, the terminology and language around these requirements need to clearly state, when applicable, the differing requirements for each technology.
- Many newly interconnecting inverter-based resources are not subject to NERC Reliability Standards nor relate to IEEE Std. 1547-2018 because these resources are connected to the Bulk Power System (BPS) but are not BES resources. In these cases, NERC is supporting Transmission Operators to

¹ In most cases, inverter-based generating resources refer to Type 3 and Type 4 wind power plants and solar photovoltaic resources. Battery energy storage is also considered an inverter-based resource. Many transmission-connected reactive devices such as STATCOMs and SVCs are also inverter-based. Similarly, HVDC circuits also interface with the ac network through converters. Inverter-based resources are being interconnected at the BPS level as well as at the distribution level, and they are differentiated accordingly throughout this paper.

- Distribution System
 - State regulator and local utility adoption of IEEE 1547-2018
 - Coordinated stakeholder engagement
- Bulk Power System
 - Majority of newly interconnecting IBR
 - Improvements to Transmission Owner interconnection requirements (FAC-001-3)
 - IEEE P2800 standard development
 - Coordination with FERC staff to facilitate changes to pro-forma LGIA and SGIA
 - Mitigation of emerging reliability issues
- Bulk Electric System
 - NERC IRPTF developing guidelines and reviewing NERC Reliability Standards
 - Ensuring clear and consistent requirements

- https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf
- <https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx>
- <https://www.nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-Task-Force.aspx>
- [https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-\(SPIDERWG\).aspx](https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-(SPIDERWG).aspx)
- https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
- https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf
- [https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-\(SPIDERWG\).aspx](https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-(SPIDERWG).aspx)
- https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

*Want to get involved with IRPTF or SPIDERWG?
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Questions and Answers

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NPCC Regional Standards Committee

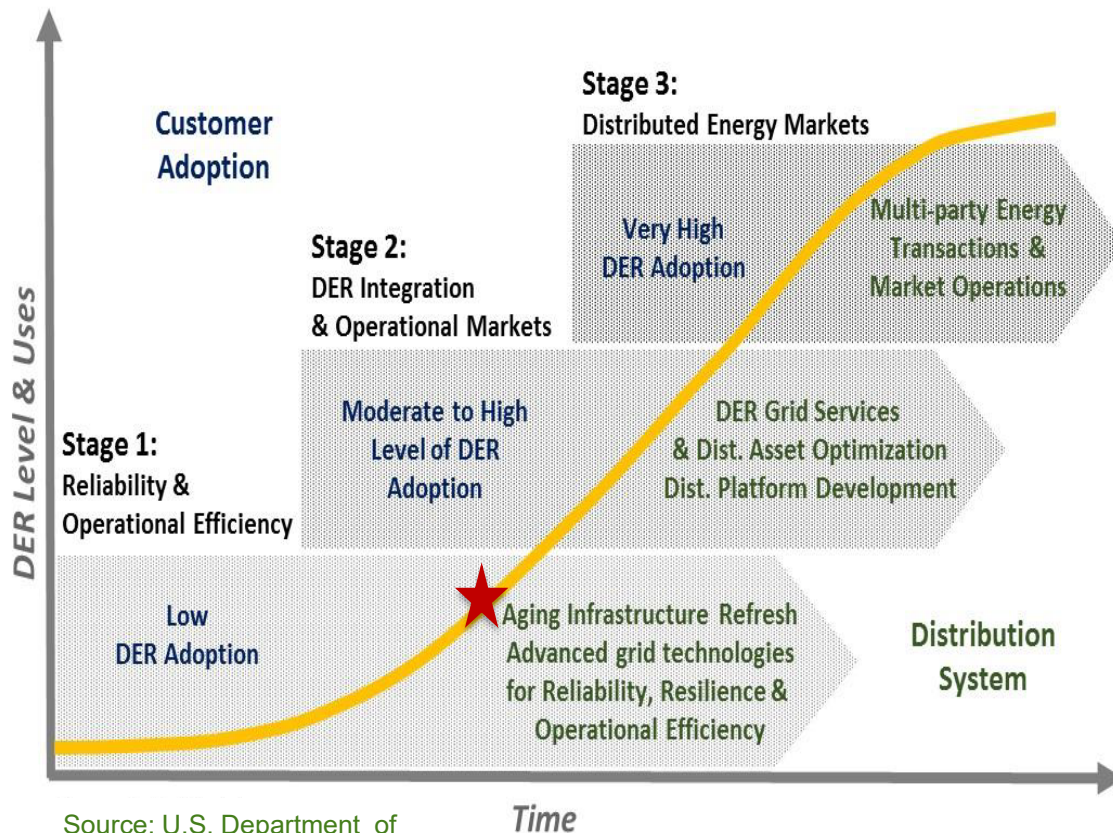
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Overview of UI's Advanced Metering Program

Current State of UI's Distribution Grid Evolution

UI's foundational technologies & applications are customer focused, grid enabling and can be leveraged with enhancements to move the distribution grid to stages 2 and 3

- AMI, OMS, GIS, SAP, SCADA, PI Historian, etc.



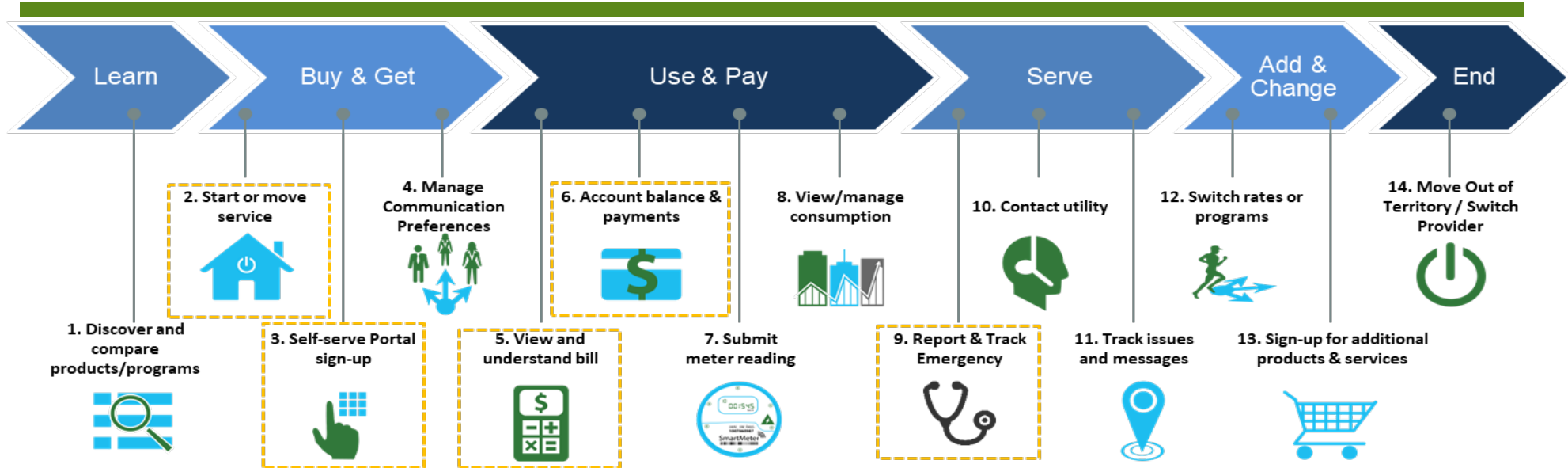
Source: U.S. Department of Energy DSPx

Examples of UI Stage 1 AMI Accomplishments:

- ~345,000 total meters
- AMR fixed network installed in 1999-2002
- AMI upgrade performed 2009
- AMI deployment started 2010
 - ~267,000 AMI meters deployed to date*
 - Meter exchanges based on
 - Frequent customer changes or uncollected bills
 - Meters >30 years old
 - 2 meters per transformer to enhance outage management
 - Build out the mesh network
 - As meters fail or are visited

*Remaining AMR meters planned for exchange by 2024

Long Recognized the Value of Advanced Metering for our Customers

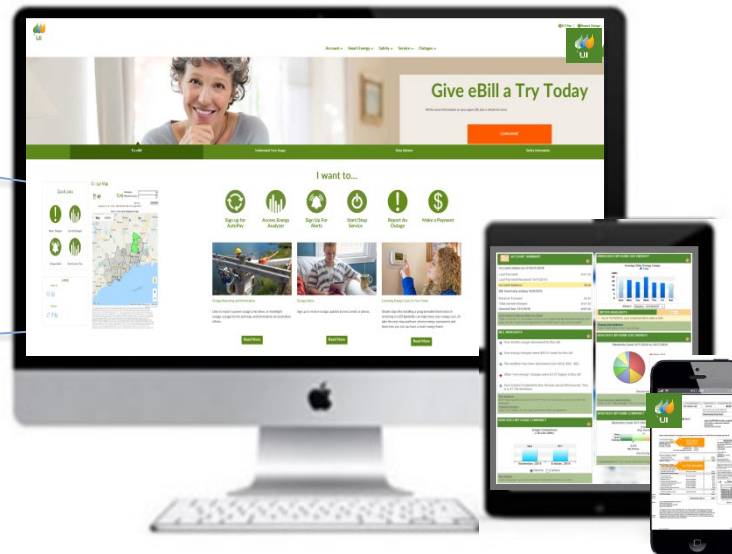


Better Billing & Access to Information

- My usage & My Account
- Bill Analysis & history
- Dynamic Rates available
- Pay on-line
- Sign up for paperless bills

Energy Efficiency & Demand Response

- Energize Connecticut
- Home and Business Solutions



Home Energy Report

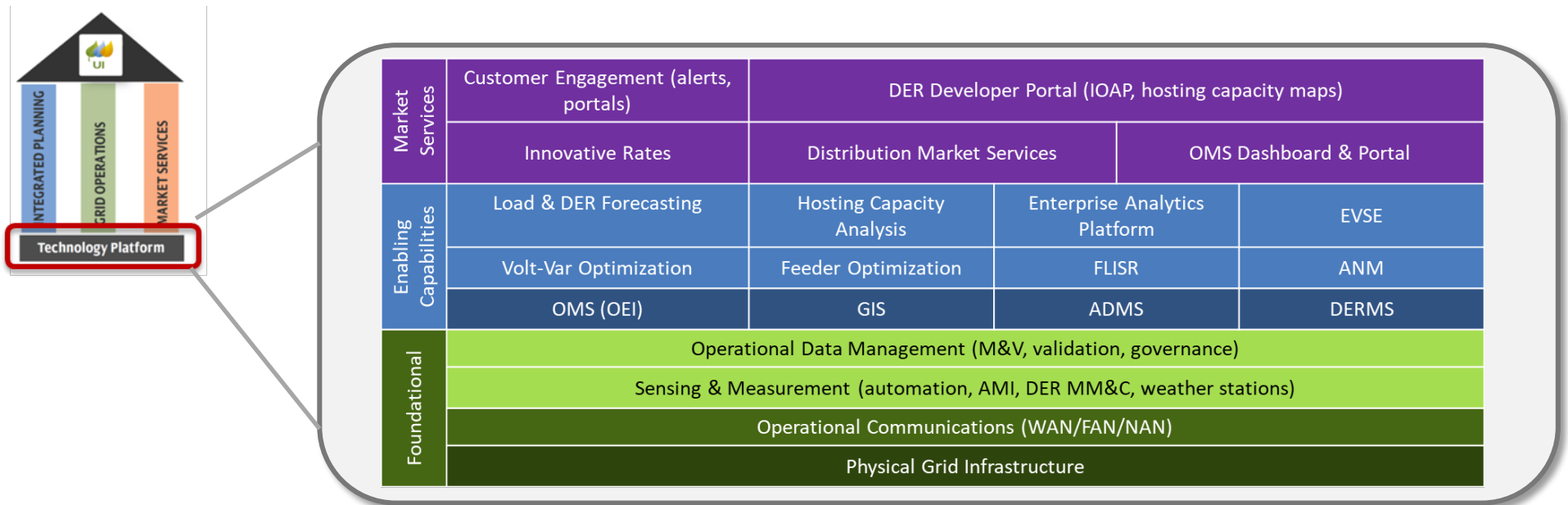
- Customer Analytics
- Behavior changes

Proactive alerts

- Payment & Billing Reminders
- Outage Communications

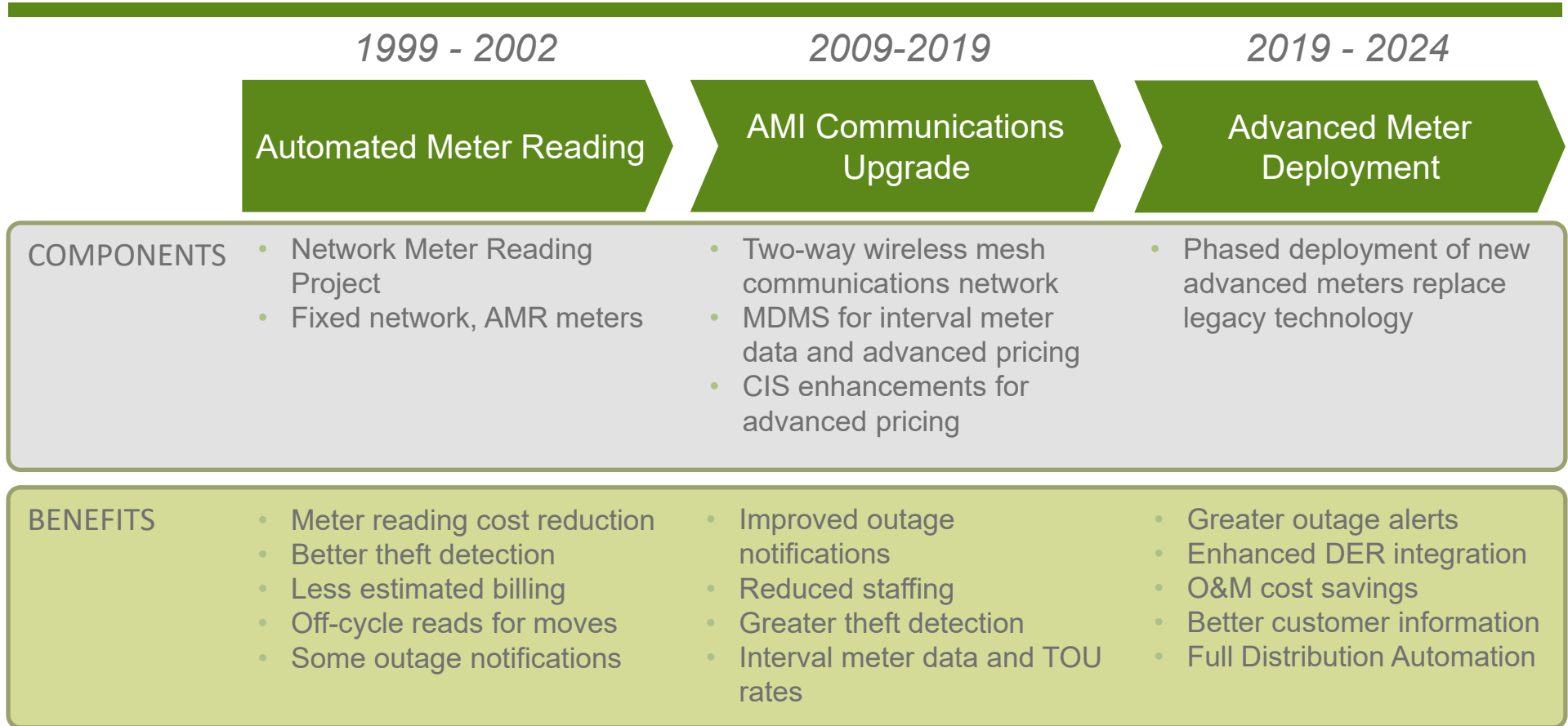
UI's Technology Platform is Critical to Enable the Authority's Objectives

1. Remove barriers to the growth of the burgeoning Connecticut green economy.
2. Enable an economy-wide transition to a renewable future by decarbonization of power generation, transportation and building heating and cooling sectors.
3. Address reliability and resilience standards system-wide, and deploy or enhance the utilization of Advanced Metering Infrastructure (AMI) to provide customers with a more resilient, reliable, and secure commodity.
4. Address energy affordability for all Connecticut ratepayers- - residential, commercial, and industrial customers.



For illustrative purposes; Adapted from DOE/OE DSPx Volume III, Figure 8.

Advanced Metering Infrastructure is Foundational



- UI will leverage Advanced Metering Infrastructure “to provide customers with a more resilient, reliable, and secure commodity.”
- Our AMI network is foundational to the modern grid, and is a critical part of the Company’s technology platform.

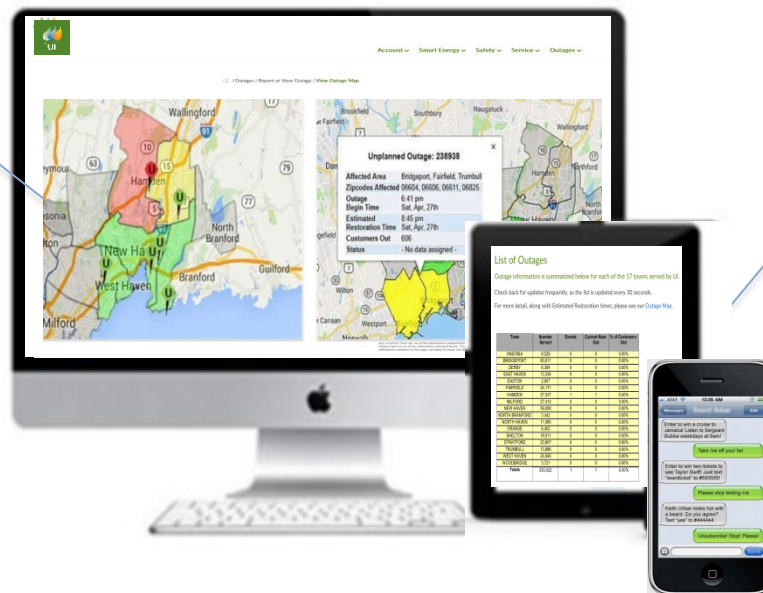
AMI technology translates into Shorter Duration Customer Outages

Outage Detection and Response

- The UI Meter Data Management System uses multiple filters to remove false outages
- UI installed 2 AMI meters per secondary transformer to identify outages, geographically spaced
- Often restore small outages before customers call since October 2016
- Mass Ping application to discover nested outages
- Shorter Outages

Outage Detection

- Outage identification
- Meter pings



Enhanced Outage Response

- Restoration before contact
- Meter pings for nested outages

AMI Benefits Translate to UI Operational Efficiency



Theft Detection Capabilities:

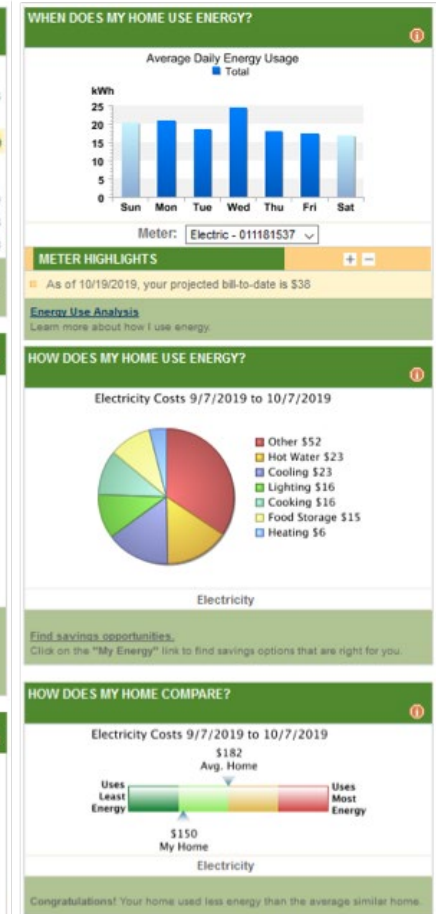
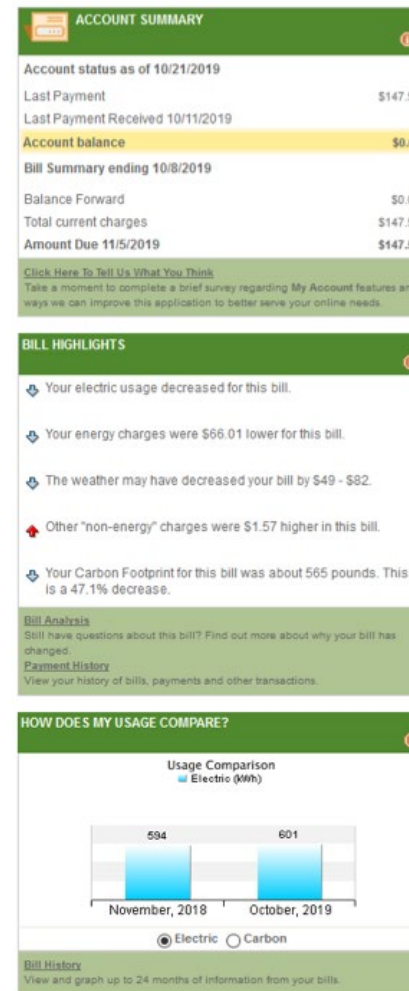
- Interval data and tools helps UI identify theft of service
- Multiple data from smart meters (tamper detection, reverse rotation, meter temperature, high consumption, voltage, magnetic detection) can be used to spot signs of theft

O&M Cost Savings:

- Faster service turns-on within 24 hours, even on weekends
- Move-ins and move-outs can be scheduled
- Automated bill pay allows turn-ons after hours, not on OT staff pay
- Lower meter reading costs
- Fewer truck rolls (127,594 truck rolls saved through September)

AMI Data Provide Customer Convenience

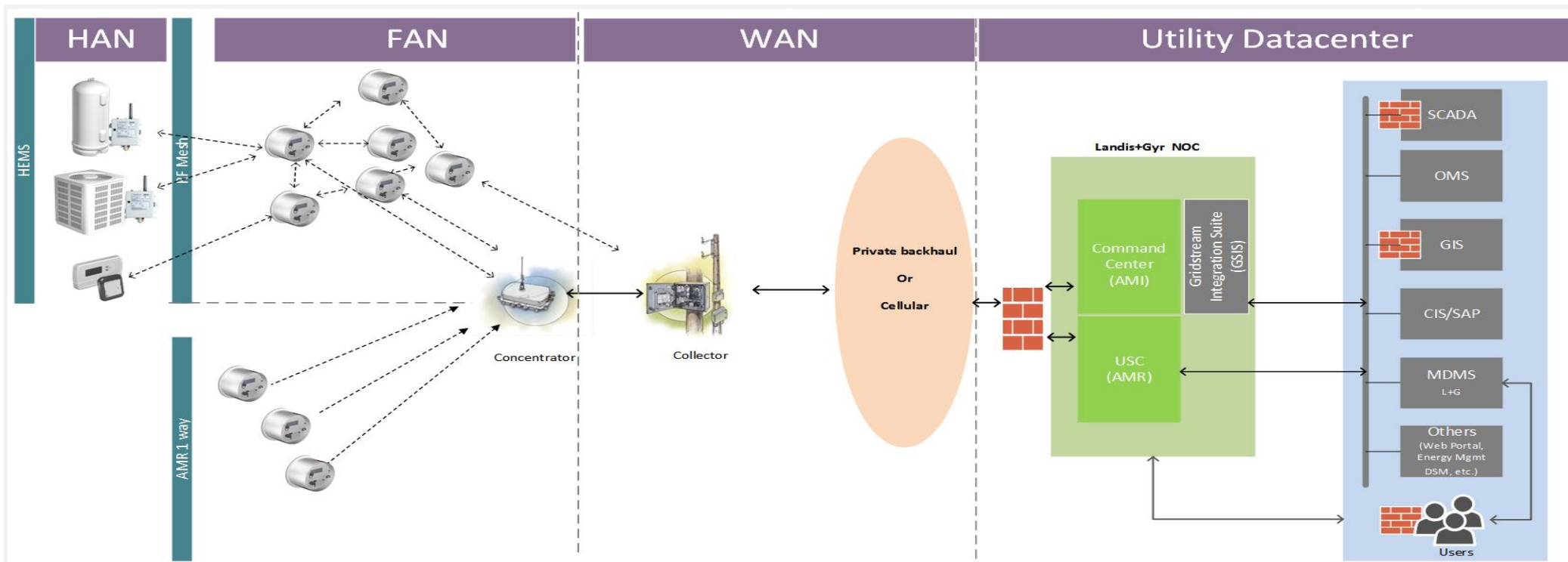
- Customers can view usage and tools via web
- Daily and TOU usage available for all AMI meters
- Supports advanced and dynamic rates
 - Time-of-Day, with or without demand
 - Residential customers can switch between R & RT without delay or meter exchange
 - Can do rate comparisons
 - Usage breakdown shows areas for reduced consumption
 - Identify abnormal usage patterns



Existing Telecommunications Backbone Enhances Cybersecurity

Dual Head End System (HES)

- AMR network devices were upgraded to include AMI
 - Supports legacy AMR system and AMI network
- UI has enabled Advanced Security on AMI meters and network devices
 - All AMI data super encrypted from meter to HES
 - Signals perform frequency hopping over a spread spectrum
 - Ensures secure communications and data privacy

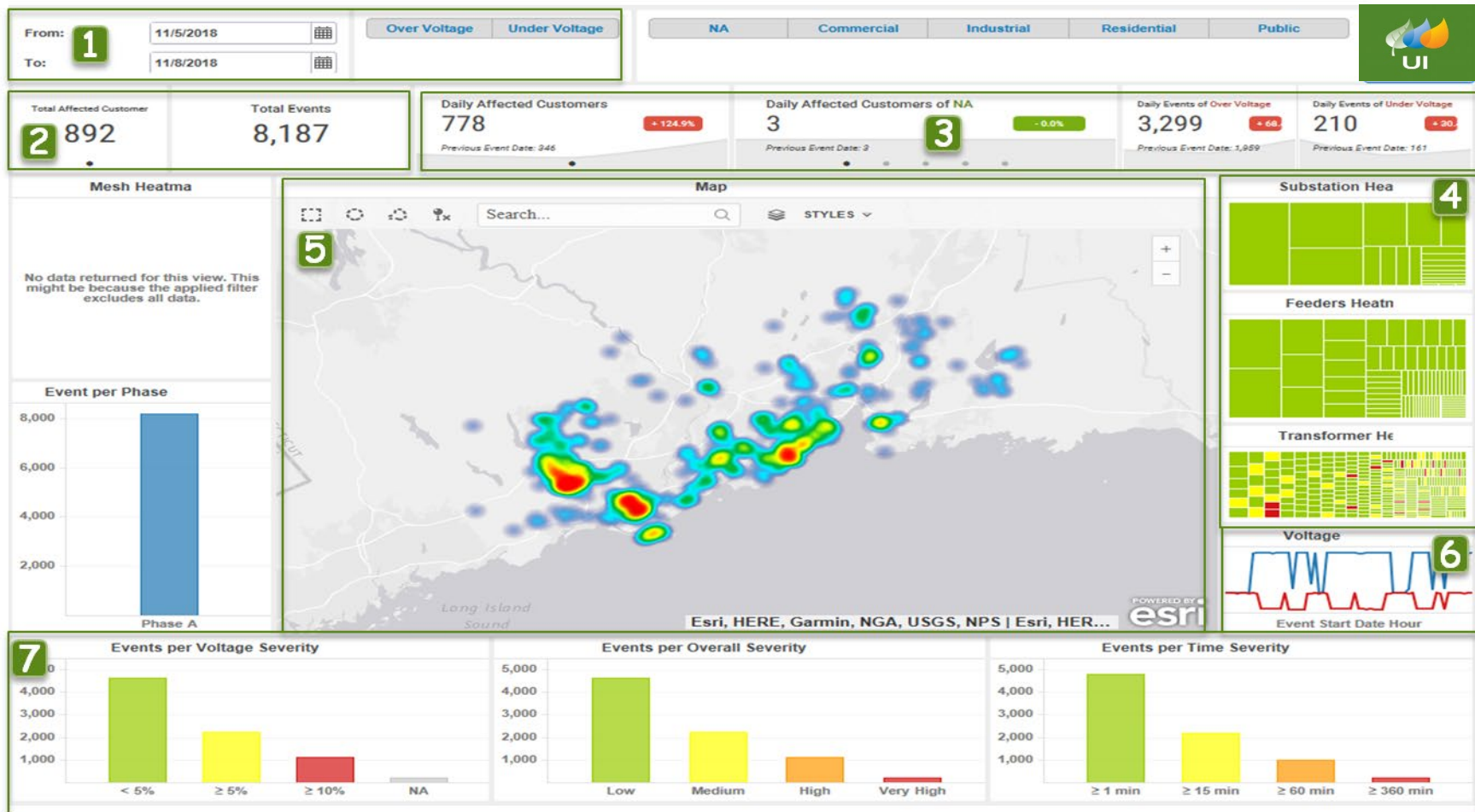


Leveraging AMI

- Big Data analytics
 - Voltage monitoring of customer premises
 - Transformer loading to proactively replace secondary transformer before failure
- UI network upgrade in 2020
 - New Gateway IPv6 (and Wi-Sun capable) network
 - Higher bandwidth for messaging and outage notification capture
 - Better locating of nested outages
- Evaluating next gen meters with Edge sensing
 - Enable customers to have more data about what devices are using power at any time
 - Provide waveform analysis of customer energy
 - Better DER analysis
- More integration between customer meter and web portal to provide increased information to customers

AMI provides access to invaluable Data Analytics that can unlock benefits

- 1 Principal filters: time period, type of voltage events and customer type.
- 2 KPIs showing the total number of events and affected customers in the dashboard.
- 3 Trend KPIs showing the daily evolution of the number of events and affected customers..
- 4 Heat maps with the devices in the network hierarchy which can be navigated.
- 5 Map interface with the geolocation of smart meters and events.
- 6 Voltage curves showing maximums and minimum voltages registered by smart meters in the period.
- 7 Charts with the volume events per voltage severity, time severity and per phase.

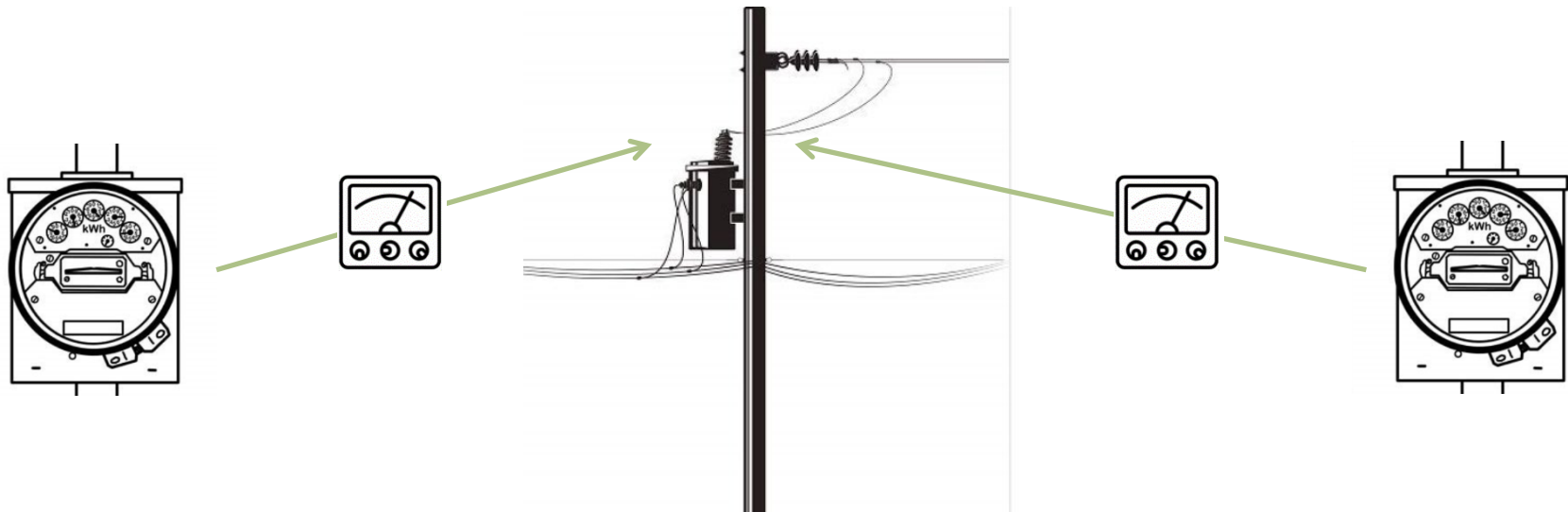


AMI provides access to invaluable Data Analytics that can unlock benefits



Use Case #2 Distribution Transformer Monitoring

Use Case Description	Analytics		Data Sources
Monitor the distribution transformers' performance to predict and anticipate failure • Detect potential conductor issues • Determine potential transformer life deterioration due to overloading exposure • Detect overloaded or underutilized transformers • Detect performance anomalies	Analytic Module 1 Compare voltage of the meters of the customers connected to the same transformer	Analytic Module 2 Compare transformer loadings with that of the manufacture specs (taking into account the ambient temperature)	SAP GIS Manuf actures Specs MDM SCADA 
	Analytic Module 3 Short term voltage profile analysis (Voltage fluctuations)	Analytic Module 4 Long term voltage profile analysis (Voltage Step changes)	



Distribution Automation pilots testing AMI technology deployment

- UI has completed 2 Distribution Automation (DA) pilots to test communications ahead of broader deployment
 - First pilot in Woodbridge to support microgrid and test two different communications methods (GE Orbit radio and L+G AMI mesh).
 - Very hilly and forested terrain
 - Connected 3 reclosers to SCADA
 - Second pilot in East Haven
 - Flatter terrain with suburban neighborhoods
 - Connected 3 reclosers, 3 voltage regulators, and 3 line sensors to SCADA
 - A third pilot is underway now
 - Distant from substation in hilly and forested terrain
 - Connect 12 reclosers, 3 controllable switches
 - Increase reliability to challenged circuits
- UI will continue to explore the ability of the AMI network to support DA devices and provide assured communications for switching.

AMI Technology Required for Grid Modernization in Connecticut

- Increased rates of DER Deployment and/or other electrification technologies (including electric vehicles, energy storage, electric heating loads. etc) will have a large impact on the distribution system and customer load profiles
- The AMI communications network is foundational for UI's modern grid
 - Voltage and VAR optimization, enabled by an Advanced Distribution Management System (ADMS), will improve integration of DERs and ZEVs
 - Enable deployment of smart charging and integration of ZEVs.
- System-wide implementation will measure customers usage by interval, allowing new billing options (peak time, variable peak, alternate supplier rates) via Meter Data Management System (MDMS) data aggregation. Web portal integration will provide increased information to customers (e.g. interval data instead of daily consumption).
- Faster and more detailed analysis for DER Online Hosting Capacity maps for distribution primary lines assists customers and third party developers to find optimal DER locations.

AMI Technology Enables Customer Expectations & Energy Objectives

- Efficient and secure information exchange between Customers and EDCs is crucial
 - AMI supports measurement of energy use by customers and grid information for EDCs
 - Cybersecurity must be maintained to ensure customer privacy and distribution network security
- Full AMI deployment will enhance outage/restoration reporting, service voltage monitoring, behind-the-meter communications, and support volt-var optimization.
- Implementation of interval billing tools allowing for faster implementation of tariffs as well as supplier tariffs different from UI's.
- DER customers will be able to better understand their generation in detail, using customer electricity usage and voltage measurements from advanced meters and obtain consumption patterns, allowing them to maximize their DER benefits.

Questions and Discussion

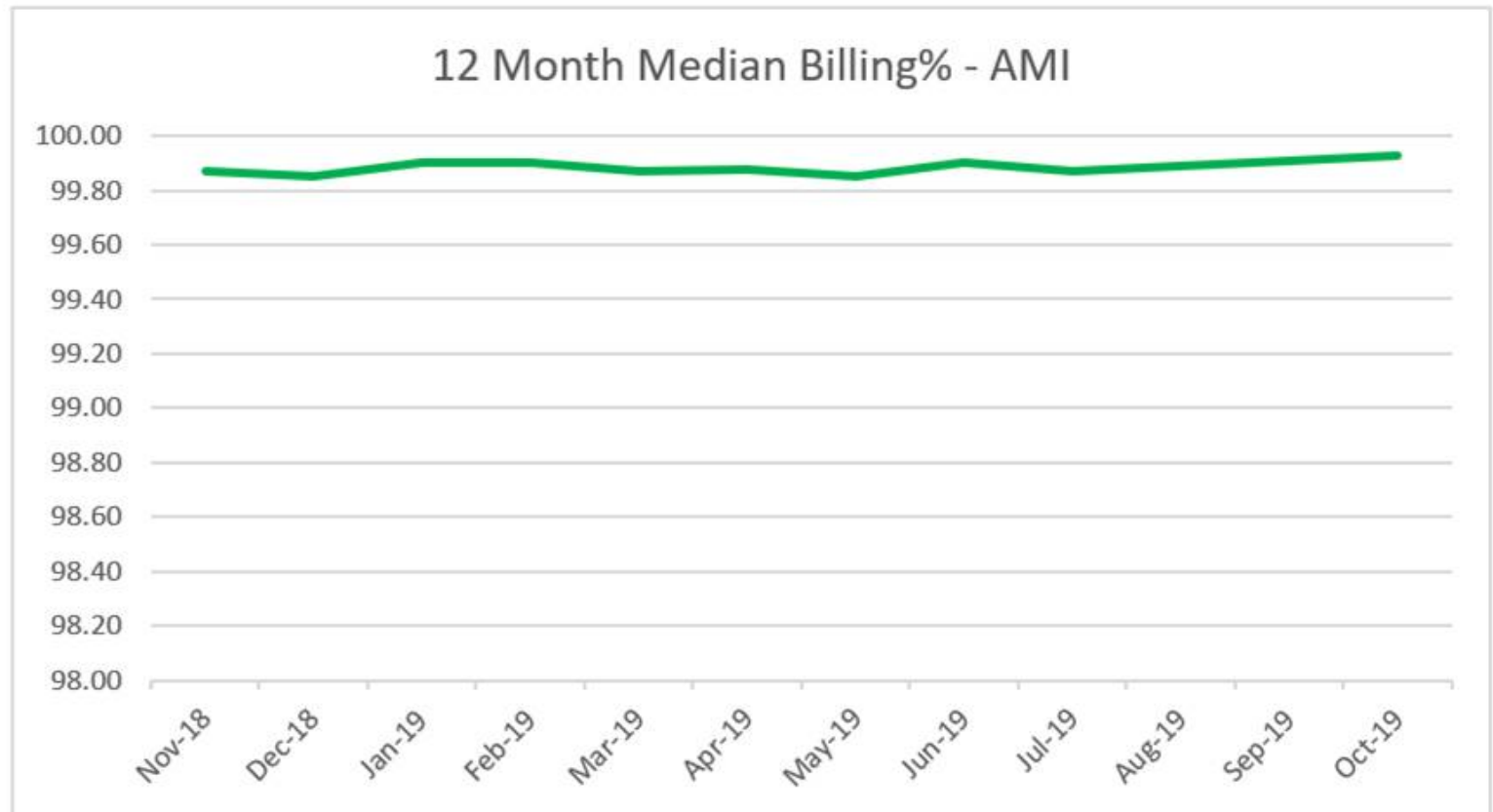


Appendix

AMI Billing Improvements

- The current network has a very high billing rate
 - Walk-up or drive-by billing is often in 80%-85% actual billing
- Reads obtained on day of move, not estimated
- Very low estimated consecutive read rates [~0.6%]

Date	Median Billing%
Nov-18	99.87
Dec-18	99.85
Jan-19	99.90
Feb-19	99.90
Mar-19	99.87
Apr-19	99.88
May-19	99.85
Jun-19	99.90
Jul-19	99.87
Aug-19	99.89
Sep-19	99.91
Oct-19	99.93
Yrl Median	99.89
Yrl Average	99.89



Regional Standards Committee (RSC) and Distributed Energy Resources (DER) Forum

AMI and Smart Meters

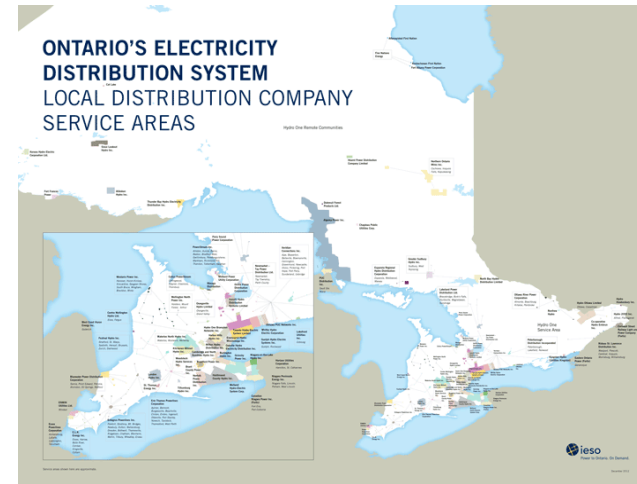
February 13, 2020

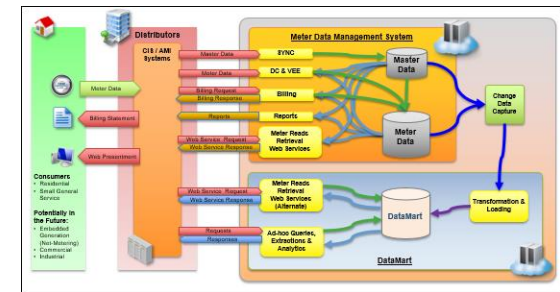
TODAY'S DISCUSSIONS

I. IESO AND THE SME

II. METER DATA MANAGEMENT REPOSITORY (MDM/R)

III. ENHANCING THE VALUE OF THE DATA





I. IESO AND THE SME

The IESO is a Big Data Machine!



... working at the heart of Ontario's power system to ensure that there is enough power to keep the lights on, today and into the future...



Independent Electricity System Operator



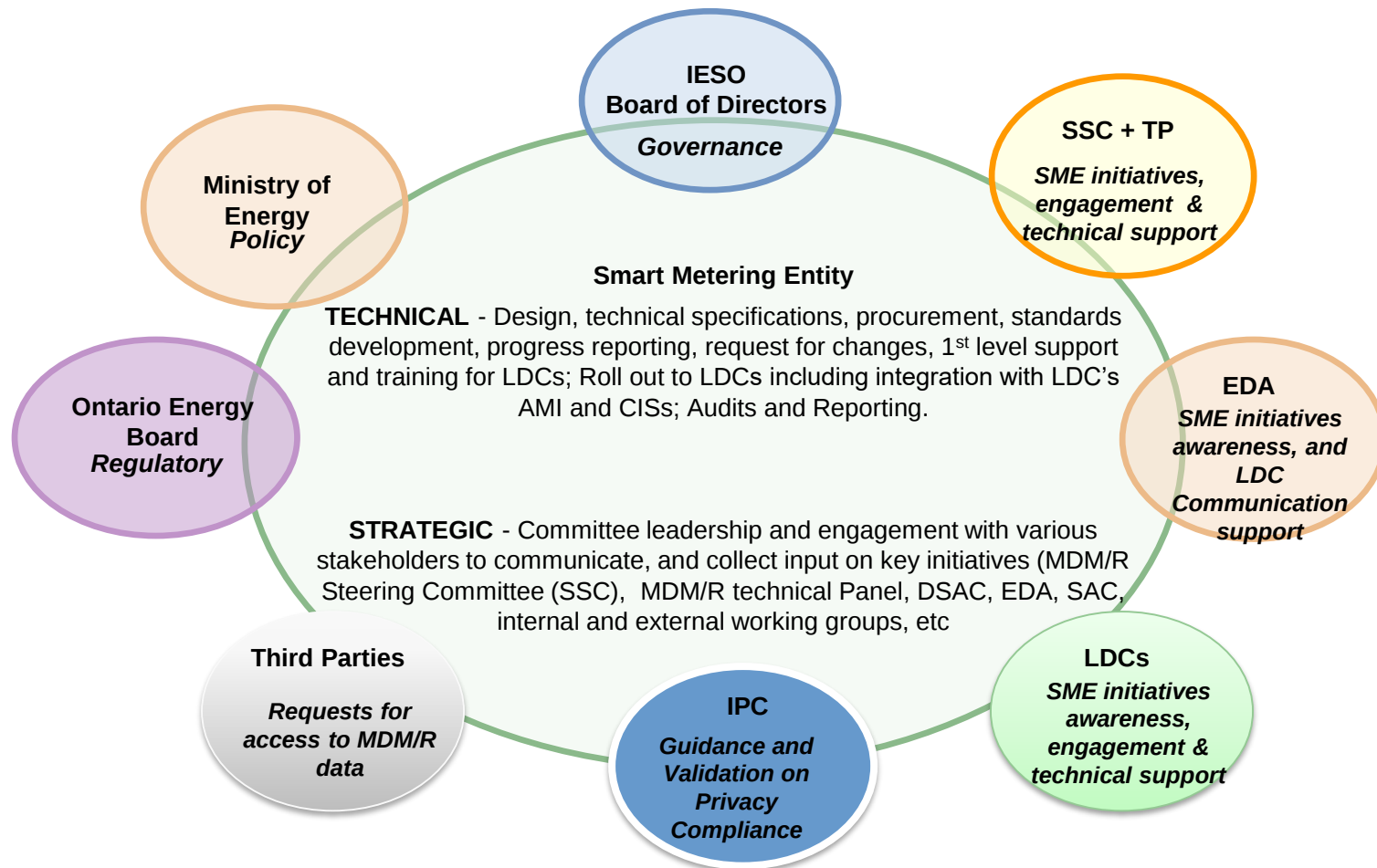
Date	Milestone
April 1999	Privatization. Demerger of Ontario Hydro. Split into Hydro One, Ontario Power Generation (OPG), Independent Market Operator (IMO), Electrical Safety Authority (ESA) and Ontario Electricity Financial Corporation
April 1999	IMO licensed as the Grid Operator
May 2002	Electricity Market opens. IMO licensed as the Market Operator
July 2007	IESO is designated as the Smart Metering Entity
Jan 2015	IESO merged with the Ontario Power Authority. Responsible for Conservation initiatives and long term generation contracts.

Ontario's Smart Metering Initiative



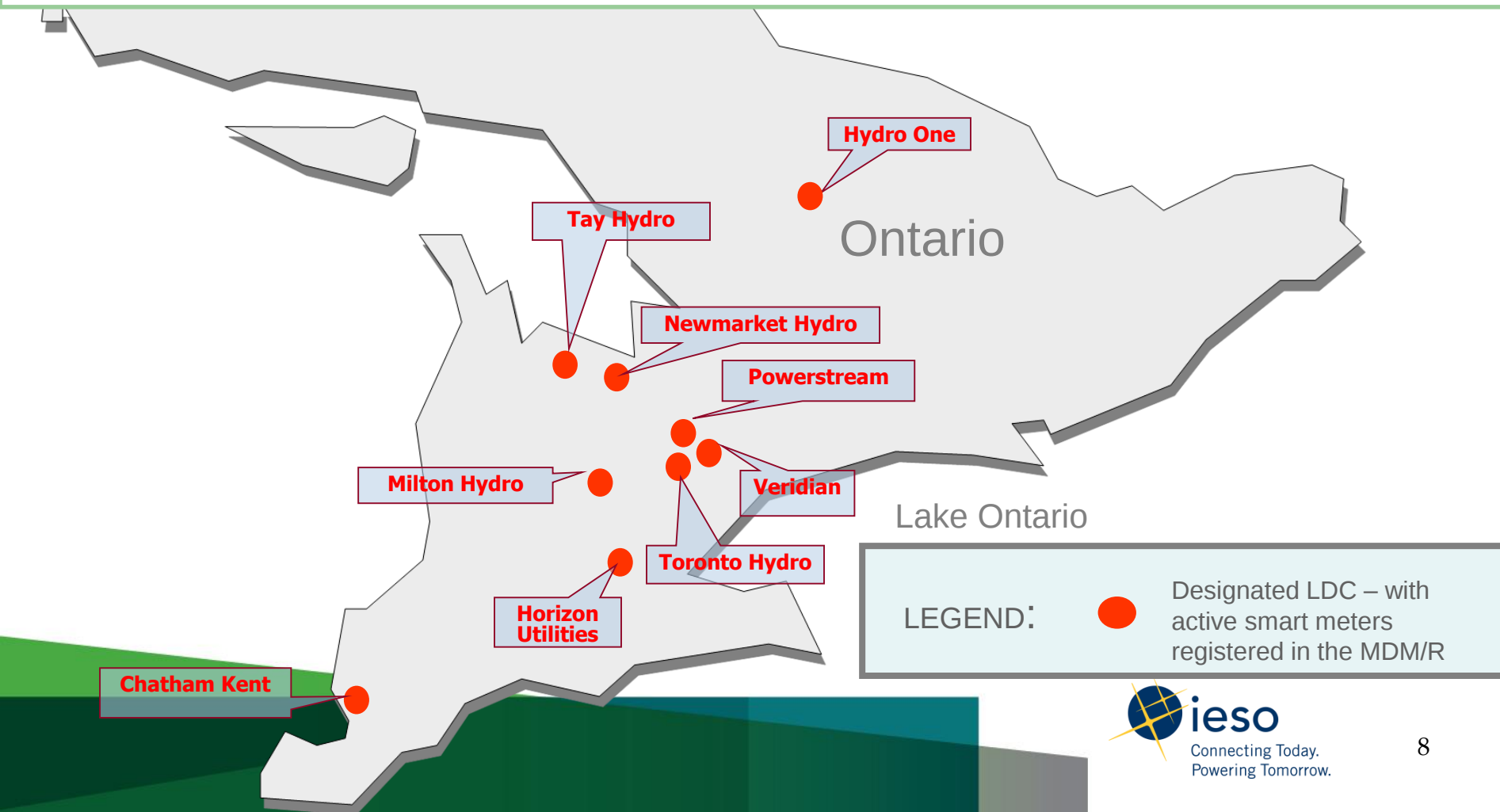
Date	Milestone
2008 - 2012	MDM/R is operational to support LDC customer billing by 2009, and by end of 2012 over 4.7 million smart meters are installed
Jan 2016	OEB Orders that the SME collect more information associated with each meter, and prepare an implementation plan for third party access to this enhanced data.
Nov 2016	OEB renews the SME's licence for a five-year period(2017 – 2021) and endorses the accompanying high level implementation plan filed by the SME
Mar 2018	The OEB approves the SME's new 5 years budget and fee (2018-2022), of \$170.6MM and \$0.57/meter/month respectively (25% lower than previous fee)
July 2019	SME reaches a milestone of over 5,000,000 smart meters installed.

SME's Ecosystem



Smart Meters early deployment...

- 500K+ Smart Meters registered and on Time-Of-Use (TOU) billing in March 2010.
- 9 LDCs were active in the MDM/R by May 2010.
- Remaining 68 LDCs were in various stages of registration and enrolment with the MDM/R.

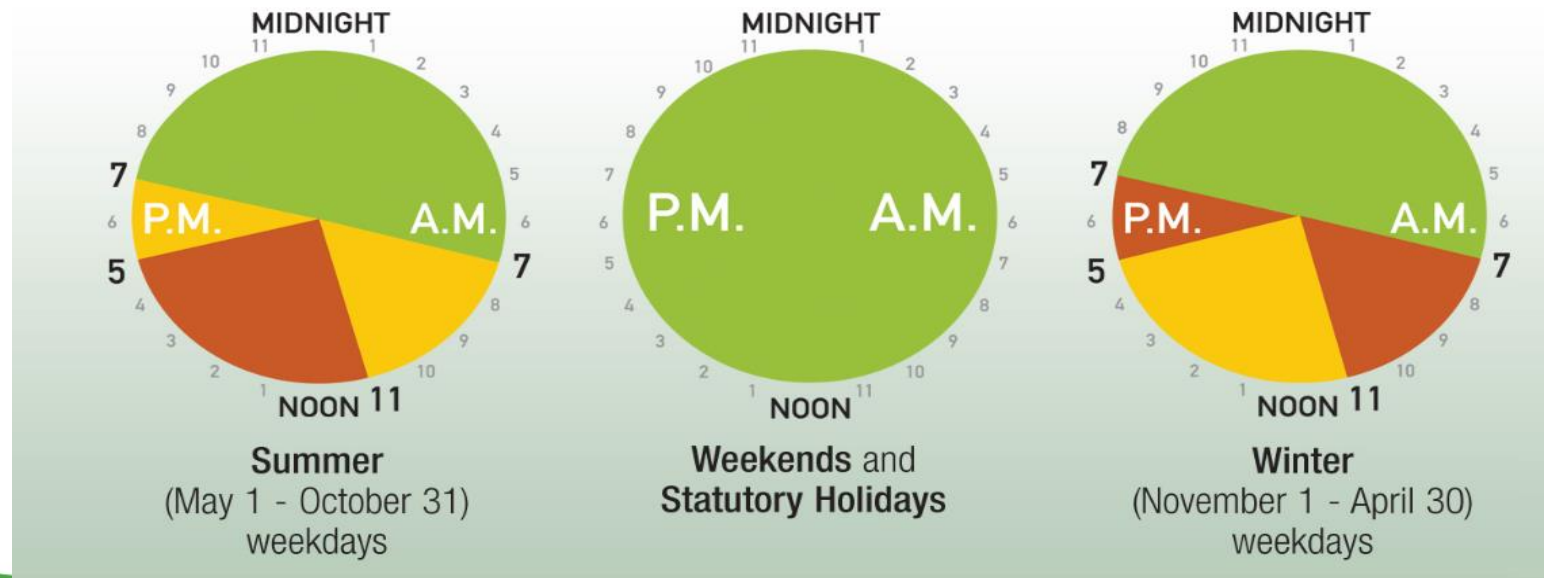


What it took

- Getting from smart meter installation to TOU billing was a significant undertaking that required extensive LDC preparation and activities.
- Preparation
 - Smart meter installation, AMI infrastructure and CIS management
 - Business system and process changes involving the entire company
 - Preparing LDC internal capabilities and pulling together resources
 - Training
- MDM/R Registration and Enrolment
 - Testing and evaluating internal systems and business processes with the MDM/R
 - Cut over into the production system, reviewing reports
- Customer Education and Notification
- TOU Implementation

TOU Structure in Ontario

- **Off-peak, when demand for electricity is lowest** - Ontario households use the majority of their electricity – nearly two thirds of it – during off-peak hours.
- **Mid-peak, when demand for electricity is moderate** - These periods are during the daytime, but not the busiest times of day.
- **On-peak, when demand is highest** - The busiest times of day. Generally when people are cooking, firing up their computers and running heaters or air conditioners.



TOU Pricing in Ontario

TOU Price Periods	May 1, 2019 TOU prices	November 1, 2019 TOU prices
Off-Peak (Weekdays 7 p.m. – 7 a.m., all day weekends and holidays)	6.5 ¢/kWh	10.1 ¢/kWh
Mid-Peak (Weekdays 11 a.m. – 5 p.m.)	9.4 ¢/kWh	14.4 ¢/kWh
On-Peak (Weekdays 7 a.m. – 11 a.m. and 5 p.m. – 7 p.m.)	13.4 ¢/kWh	20.8 ¢/kWh

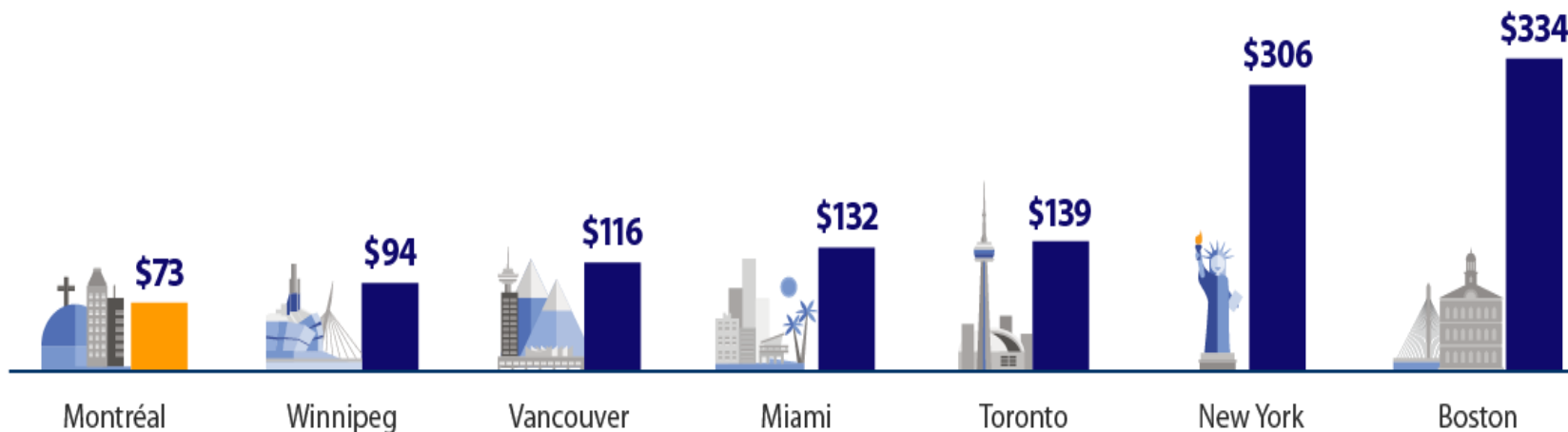
Tiered Pricing in Ontario

Price tiers	Tiered RPP prices	May 1, 2019 tiered prices	November 1, 2019 tiered prices
Tier 1	Residential – first 1,000 kWh/month	7.7 ¢/kWh	11.9 ¢/kWh
	Non-residential – first 750 kWh/month		
Tier 2	Residential – for electricity used above 1,000 kWh/month	8.9 ¢/kWh	13.9 ¢/kWh
	Non-residential – for electricity used above 750 kWh/month		

Lowest Rates in North America

Residential Customers

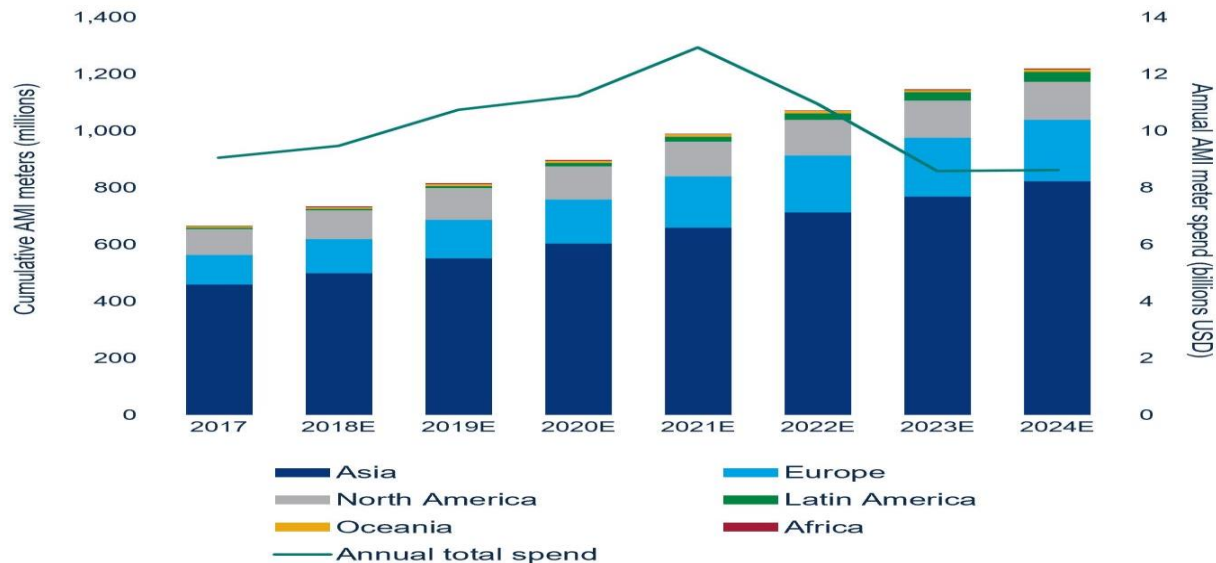
Monthly bills for a consumption of 1,000 kWh/month in CA\$



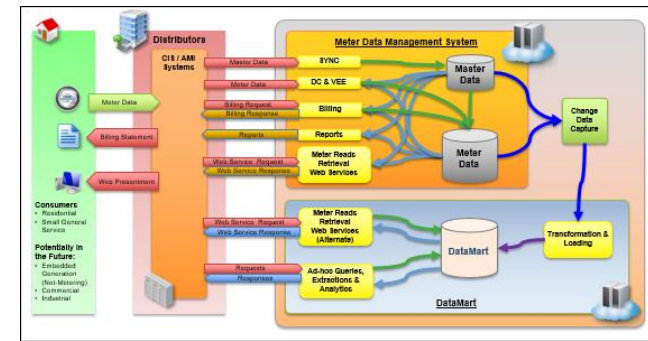
Rates in effect April 1, 2019

Smart Meters - a Mature Technology Worldwide

- The total number of smart meters around the world is expected to almost double over 2017 levels by 2024, opening up new opportunities for customer-side control and analytics.
- The global smart meter total will rise from 665.1 million in 2017 to more than 1.2 billion by the end of 2024



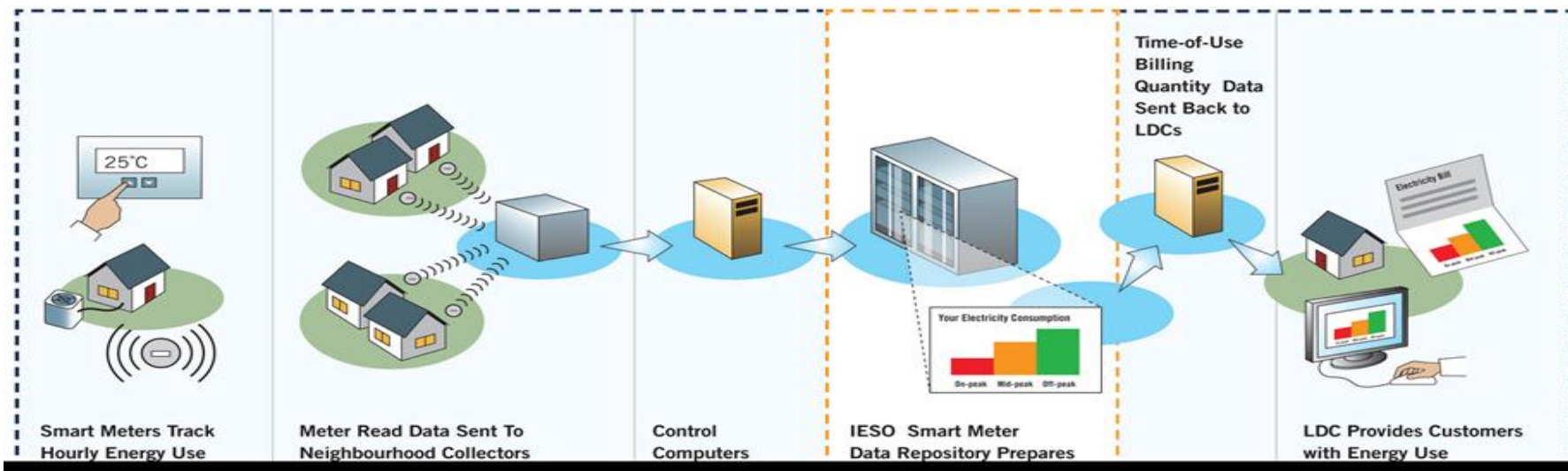
SOURCE: Wood Mackenzie Power & Renewables



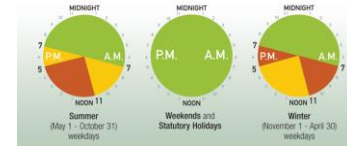
II. METER DATA MANAGEMENT REPOSITORY

Ontario's Smart Metering System

The MDM/R works in conjunction with LDCs metering and billing systems to provide detailed, accurate and timely electricity usage information, and support TOU billing with an exclusive authority mandate for VEE of meter data, in accordance to Measurement Canada requirements



Smart Metering Entity Overview

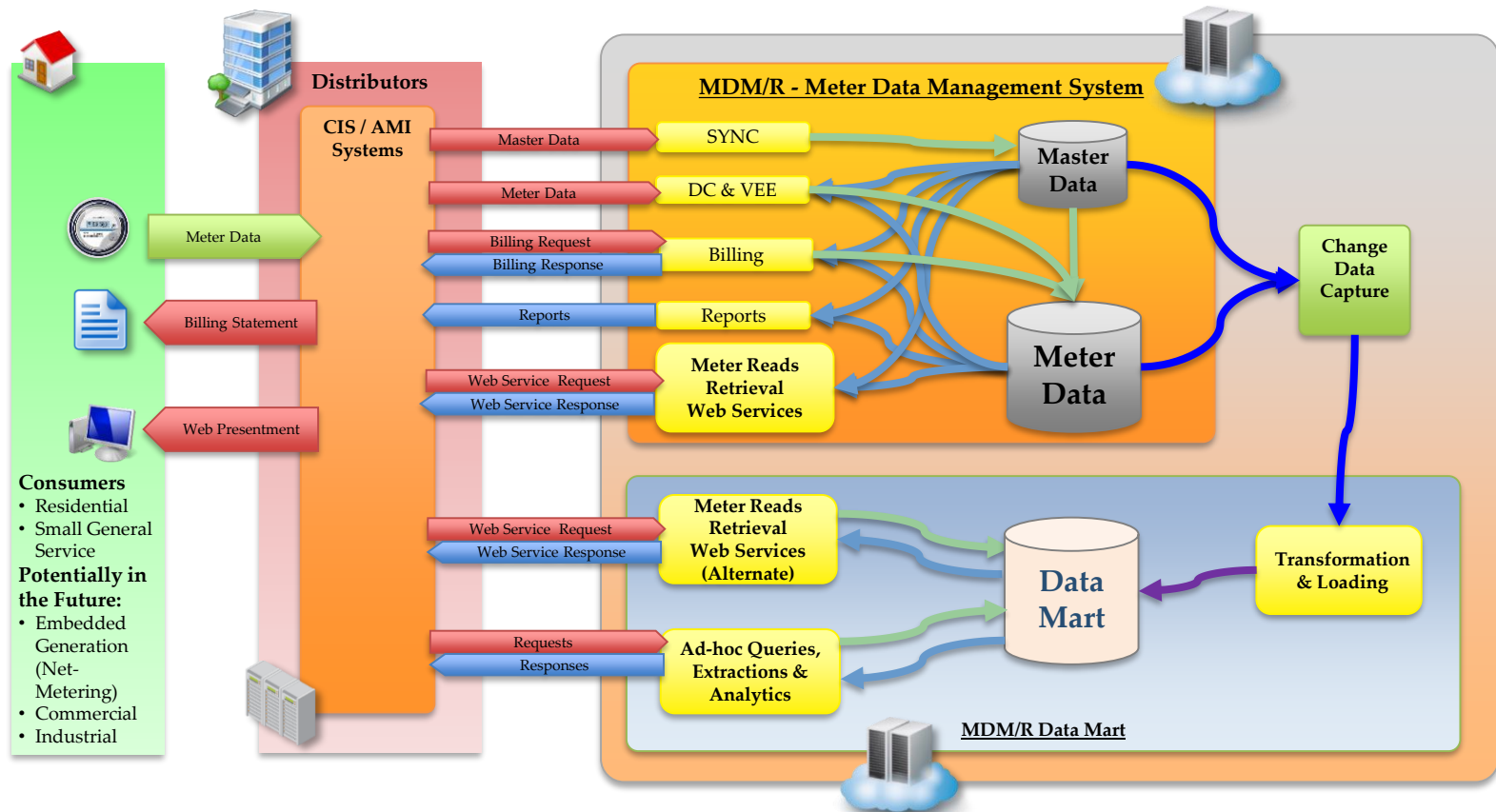


- In its role as *Smart Metering Entity*, the IESO is responsible for the design, operation, and maintenance of the MDM/R. The MDM/R has been operational since March 2008.
- The MDM/R is a central platform for processing, storing and managing all smart meter data in the province, primarily for the operational role of providing consistent and reliable TOU billing services to all LDCs, with an exclusive authority mandate for VEE services of meter data.
- The MDM/R ensures that all Ontario's Residential and Small Business consumers (General Service <50kW), around 5 million smart meters, have access to high and consistent standards for effective and accurate smart meter billing information regardless of where they live.
- The MDM/R has a disaster recovery facility at a separate location that will resume all MDM/R functions should a business interruption occur.

The MDM/R in Numbers

Service Delivery Points	Residential: 4.6m, Small General Service: .4m
AMI Supported	Sensus, Elster, Trilliant, Tantalus, SmartSynch (5, 15, 30, 60 minute intervals; most are 60 minute)
Services	26 Validation, Estimation and Editing Services 28 Framing Structures
Interval Reads	100m – 120m per day (processing 24 to 28 million per hour)
Billing Requests	200K to 300K per day
Data Retrieval Requests	15K to 60K per hour
Reports Delivered	2,300 per day
Data Size	200+ billion rows of data
Meters Installed	Over 5 million Smart Meters

MDM/R Architecture



MDM/R Privacy & Security

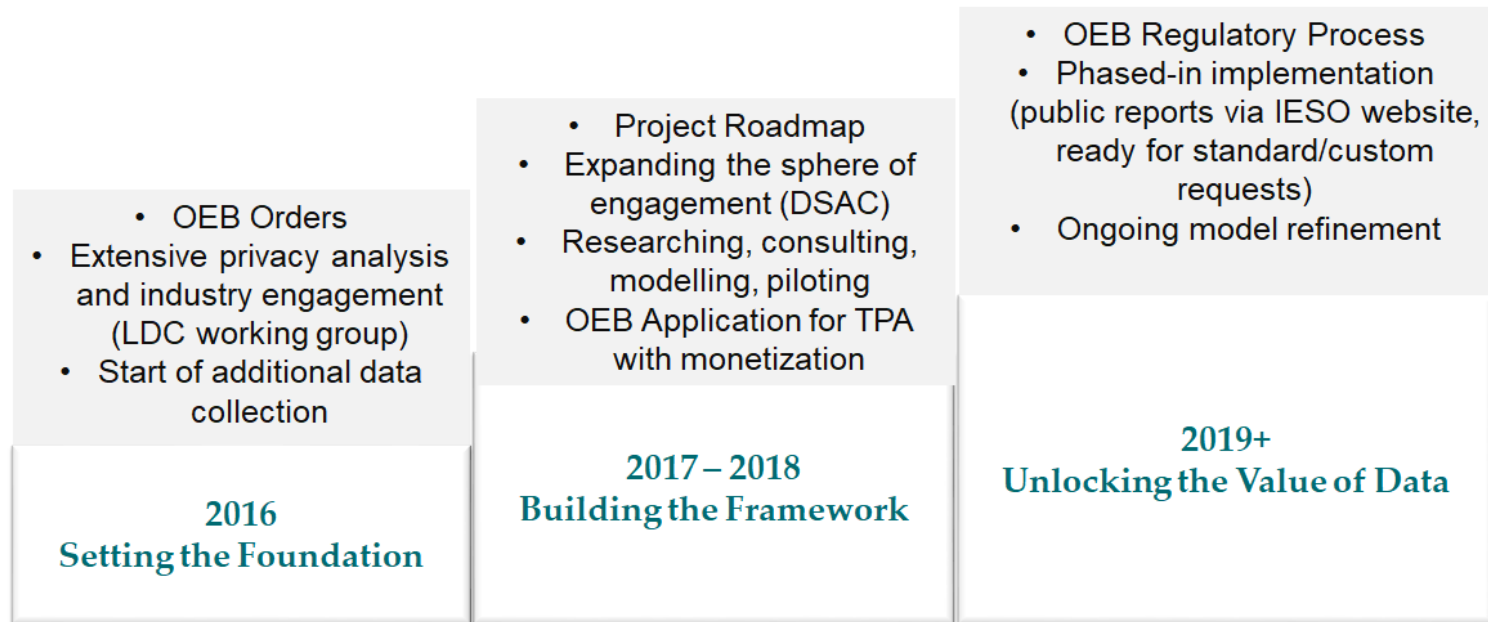
- The core functions of the MDM/R have been originally designed following the best in class principles of Privacy-by-Design (“PbD”), as set by the Information and Privacy Commissioner of Ontario.
- Data transferred to and from the MDM/R complies with the stringent industry protocols that describe how to transmit encrypted data over the internet securely.
- Currently, only LDCs and their authorized agents have the ability to transmit or request information from the MDM/R.
- The MDM/R has a disaster recovery facility at a geographically separate location that will resume all MDM/R functions, should a business interruption occur.
- All MDM/R information and protocols established in support of the 2016 OEB Order implementation (and the related third party access), have been designed in close collaboration with key stakeholders, privacy experts and the IPC to ensure full privacy compliance.



III. ENHANCING THE VALUE OF THE DATA

SME's Data Project

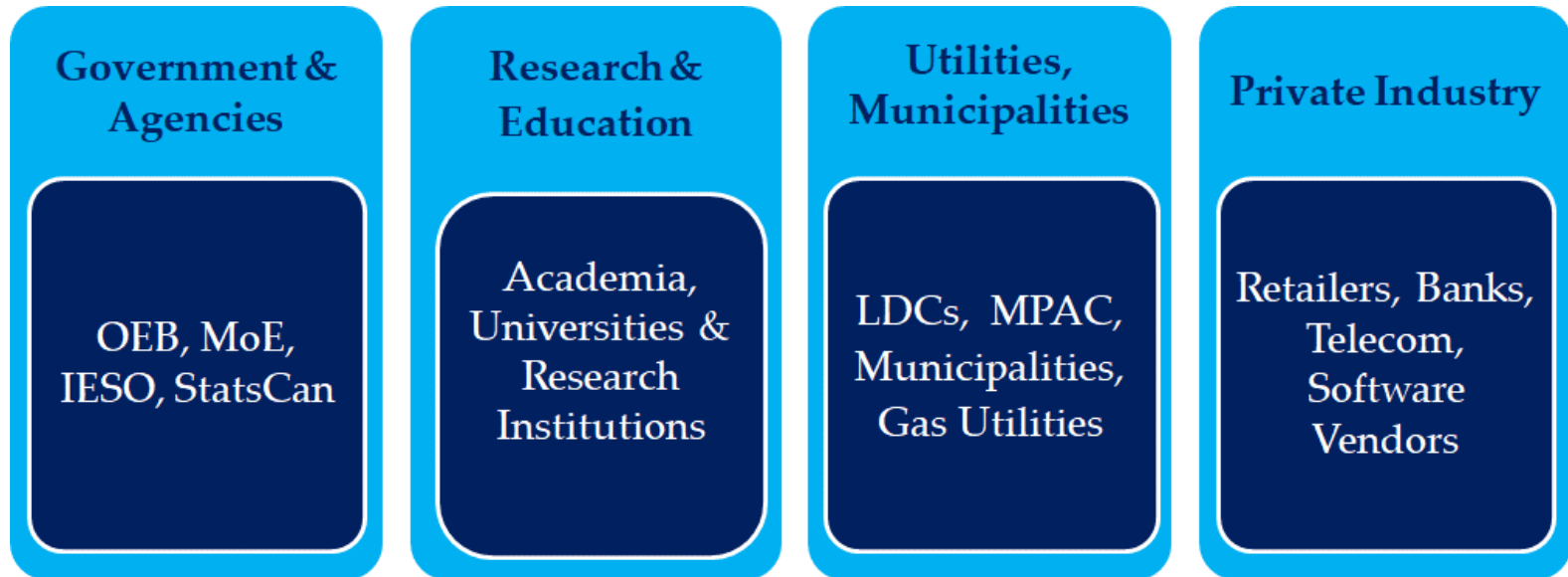
- Following the 2016 OEB orders, the IESO embarked on an effort to unlock the value from the data it collects through the MDM/R to create efficiencies, build new value streams and to reduce costs for electricity consumers.
- This included the collection of certain additional information* from the LDCs, and the development and implementation of a plan for third party access to this enhanced data, in a privacy compliant manner.



* Effective January 1, 2017 the SME started collection of the additional data, sufficiently as rendered non-personal information: 6 digit postal code (unique dwelling postal codes masked under W8W8W8), distributor rate class (DRC), commodity rate class (CRC), occupant change date (yearly level) . Additionally, any potential previous identifiers, such as address information was removed from the MDM/R to ensure max privacy compliance.

Potential Third Party Clients

- Access to the smart meter **big data** can enable advancements in government policy initiatives, research, energy efficiency programs, and industry innovation



- The IESO's de-identification strategy prevents third parties from identifying individual dwellings or individuals, while still enabling access to useful information to drive **public and private good outcomes**

Establishing the Value Proposition

The SME has conducted extensive theoretical, and practical, research and explorations into how other organizations, sectors, jurisdictions are approaching their Big Data questions, with some of the key learnings below:

- Privacy and security of data remain primary concerns.
- Data science is not a discipline that is broadly spread across the energy sector, nor are players seeing the “data as an asset” within their own organizations.
- Current uses are fairly limited to customers’ ability to see their own data, and limited operational uses, with LDCs polarized in recognizing and extracting the value of the data.
- Public organizations follow at least a cost recovery model to cover costs associated with specific product offerings; some organizations have planned surplus targets which are directed back into the organization as a re-spending budget or as an adjustment to their operating budgets.
- Tests / Pilots are a key step in building the understanding of “real-life” aspects of Big Data

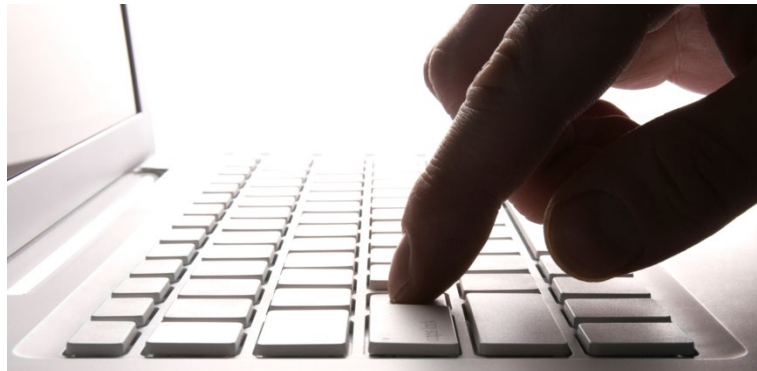
Thank You

Web: www.ieso.ca | Twitter: [IESO Tweets](#) | LinkedIn: [IESO](#) | Smart Metering Entity:
<http://www.ieso.ca/sector-participants/smart-metering-entity/>

AMI and Smart Meters in Ontario

Regional Standards Committee (RCS) and Distributed Energy Resources (DER) Forum

Feb 13/20



Marianne Blasman, Vice President of Information Technology and Chief Information Officer
Burlington Hydro Inc.

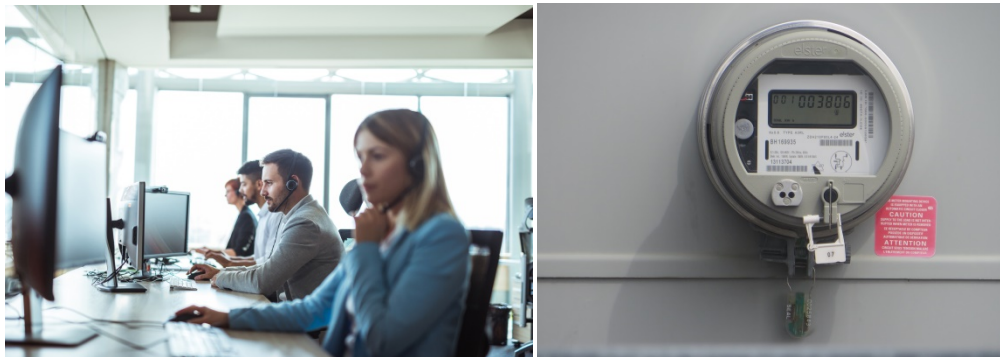


Advanced Meter Infrastructure (AMI)

- Strategy for Transition to AMI Infrastructure
- Goals for Transition to AMI and IESO's Central MDM/R
- Internal Meter Data Management System
 - MDM-ODS
 - What is it?
 - What are the Benefits?
 - What are the Challenges
- Smart Meter Deployment Process
- Smart Meter Deployment Challenges

AMI & Cyber Security

AMI and Smart Meters in Ontario

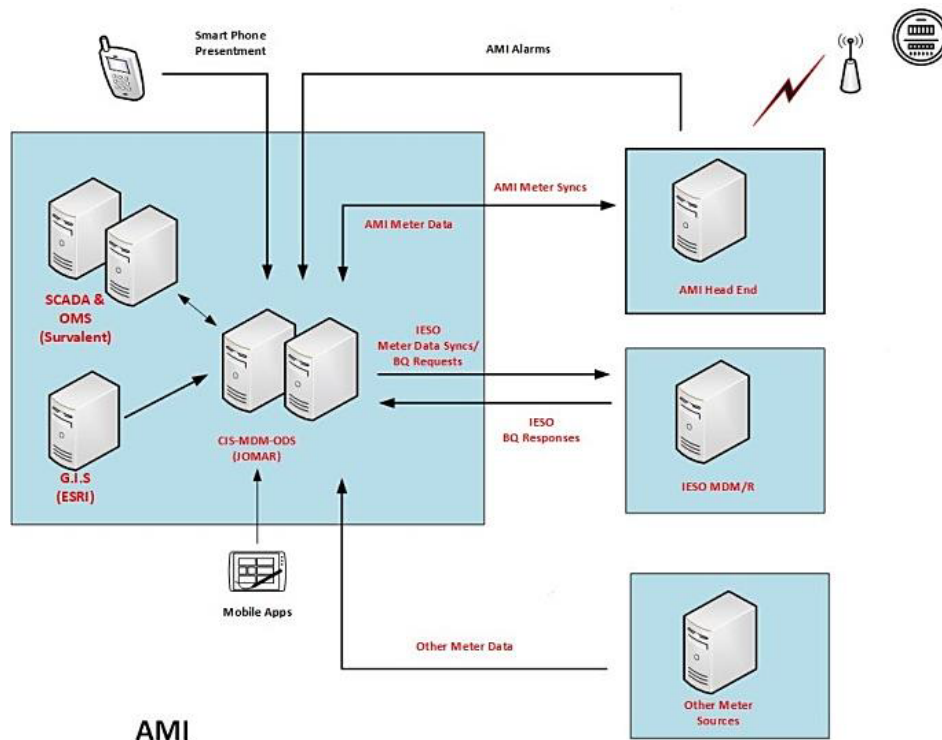


*Its not just about Customer Information Systems
and Billing Anymore*

Strategy for Transition to Smart Meters (and IESO's Central MDM/R)

- Alignment of key information systems
 - Advanced Metering Infrastructure (AMI)
 - Meter Data Management & Operational Data Store Repository (MDM-ODS)
 - Customer Information and Billing Systems (CIS)
 - Geographical Information System (GIS)
 - Outage Management System (OMS)
- Recognize Distinct Roles and Responsibilities of These Systems
- Achieve Streamlined Systems Integration
 - Internally (Integrated CIS-MDM-ODS / GIS / OMS)
 - CIS-MDM-ODS with Ontario IESO's Central MDMR (Very Important!)
- Make sure we have all our AMI & Meter Data
 - Smart Meters / Operational Alarms & Alerts / Suite Metering / Demand / Walk Reads

Alignment of Key Information Systems



**AMI
&
Smart Meters**



Goals for Transition to Smart Meters (and IESO's Central MDM/R)

- Understand our Meter Data
- Know What's Happening within our AMI
- Develop Proactive not Reactive Business Processes
- Streamlined and Timely delivery of Missing intervals and Register Reads back to IESO's MDM/R
- Automatic reconciliation of IESO MDM/R exceptions (Very Important!)

What is an MDM-ODS?

- BIG DATA
- *Valuable* BIG DATA
- Central Repository for large volumes of valuable data that belongs in an *integrated* CIS-MDM-ODS System
 - Electrical Consumption Data (kWh, KW, KVA, KVAR, Walk Reads)
 - Operational Alarms & Events
 - Outage / Restoration / Tamper etc)
 - Voltage Information (Min, Max, Avg)



What are the Benefits of an Integrated MDM-ODS?

➤ Meter & Network Health

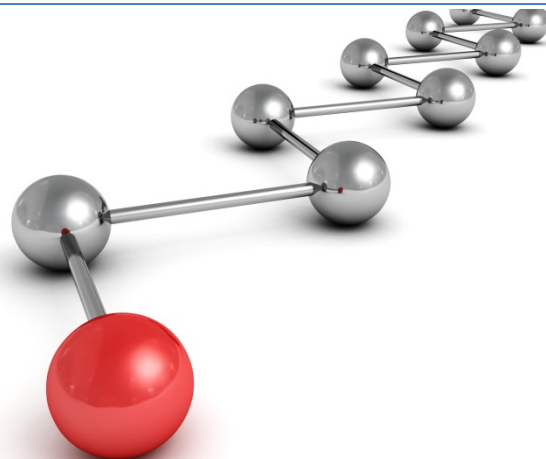
- Provides for Monitoring of AMI Meter/Network Health
- Ability to Verify Network Integrity for Daily Compliance (SLA levels)
- Combination of Meter Data + Operational Data: Tells the Whole Story
- Effective Resolution of Intermittent Meter Events
- Positions You to be Proactive

➤ Seamless Integration with Centralized IESO's MDM/R

- Automated reconciliation processes with MDM/R (Meter Syncing, Meter Data Corrections)
- Streamlined Billing Inquiries by Cycle with MDM/R Meter Data Exceptions

➤ Allows for Integrated Outage Management System

- Timely Resolution of Operational Alarms & Events
- Assists with Infrastructure Planning via Load Analysis & Trending
- Automated 'Watch Lists'



What are the challenges with an MDM-ODS?

- Understanding the True Potential and Role of an integrated MDM-ODS
- Establishing New Proactive Business Processes that are Smart, Efficient and Automated Across Systems
 - Automated Estimation of Missing Intervals
 - Meter Replacement: Automated Interval Estimation for Unavailable 'Off Reads'
 - Dashboard: Combined Billing Schedule / Meter Data / AMI Exceptions / Service Orders
 - GIS Transformer/Service Delivery Point Relationships Resident in MDM-ODS for Transformer Load Analysis
 - GIS Selection of an Area → Dashboard with Transformer/Meter Relationships & Individual Meter Status/Voltage/S.O.'s
 - AMI Operational Alarms delivered to OMS: Know where the outage is before the Customer calls
- Processing Large Volumes of Information in a Timely and Effective Manner to Make Data Useable
- Data Organization / Dashboard Presentation
 - User Configurable Business Rules for Automatic Generation of Exception Events
 - Manage by Exception / Prepare for Estimation

AMI and Smart Meters in Ontario

Integrated CIS-MDM-ODS / AMI Information

Billing Cycle

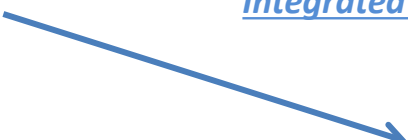
15
28
34
Etc...

Billing Cycle Date

Feb 20
Feb 21
Feb 21
Etc...

48 Hr Stale State

25
15
5
Etc...



<u>Meter Number</u>	<u>Meter Status</u>	<u>AMI Alarm</u>	<u>Service Address</u>	<u>SN Ratio</u>	<u>Voltage Min/Max/Avg</u>	<u>Service Order</u>
12345	Active	NoCom	123 First	3:1	120/140/150	CO 1143
67890	Active	NoCom	453 Second	4:1	120/140/160	CO 2431
77777	InAct	Comm	321 Third	3:1	120/140/150	-----
11111	Active	Tamper	231 Fifth	3:1	125/135/120	CO 3241
Etc.....						

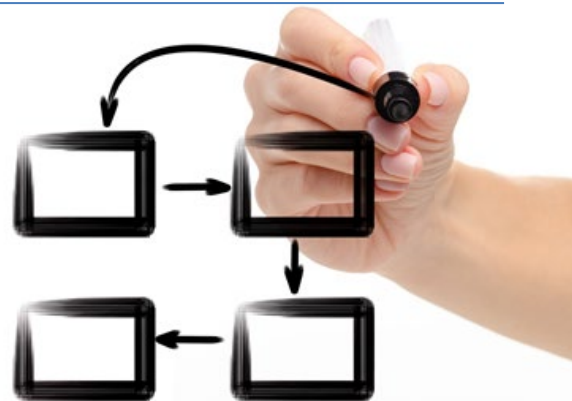
AMI and Smart Meters in Ontario

Integrated Transformer / Meter / AMI / CIS Information

<u>Xformer Number</u>	<u>SDP</u>	<u>Meter Status</u>	<u>AMI Status</u>	<u>Service Address</u>	<u>SN</u>	<u>Voltage Min/Max/Avg</u>	<u>Service Order</u>
12345	2351356	Active	NoCom	123 First	3:1	120/140/150	CO 1143
67890	1122334	Active	NoCom	453 Second	4:1	120/140/160	CO 2431
77777	7676767	InActive	Comm	321 Third	3:1	120/140/150	-----
11111	3826754	Active	Tamper	231 Fifth	3:1	125/135/120	CO 3241
Etc...	Etc....	Etc...	Etc....	Etc....	Etc...	Etc.....	Etc...

Smart Meter Deployment Process

- Cross-Departmental Smart Metering Project Team
 - Billing / Metering / Customer Service / Information Technology
 - Weekly Status Reviews
- Routine Updates with Executive Team
- Business Process Redefinition (Top Down Approach)
 - Metering's Internal AMI Monitoring of SLA's
 - 24 hr Stale / 48 hr Stale / 72 hr Stale / Intermittent Stale State
 - Proactive Monitoring of Operational Alerts (Know when a meter is *starting* to fail)
 - Different Smart Meter Technologies (Noise to Signal Ratio, Repeaters, AMI to Meter Path)
 - Eventually: Achieve 98% 'Read Interval Success' Rates
 - Meter Change Outs / Disconnects / Checks
 - No longer beginning / ending reads
 - New Meter typically talks immediately with intervals flowing
 - Mobile Field Based Processing



Smart Meter Deployment Process (Cont'd)

- Achieve 'Enrollment' with IESO's MDM/R Quickly
 - Allow Meter Data to Flow Well Before Billing Starts
 - Build Historical Production Meter Data to Provision Meaningful Estimation
 - 'Real Life' Experience with New Business Processes (Including IESO's MDM/R)
- Test / Test / Test: Heavy Use of MDM/R 'Sandbox'
- Training: Informal Hands-On & Formal with IESO's MDM/R Staff
- Start Up Smart Meter Billing: Two Pilot Cycles
- Shakedown of Business Processes with Two Pilot Cycles

Smart Meter Deployment Challenges

- Resource Requirement Across All Departments (Despite 'Day Jobs')
- Constant Close Coordination Between Departments and Executive
- Establishing New Business Processes
 - Automate Exceptions
 - Accept Estimation as a Fact of Life
 - Monitor Meter State States
- First Generation MDM-ODS Products
- Test / Test / Test



Four Areas of Dramatic Evolution

- 1. Cyber Capitalization**
- 2. Types of Cyber Attacks**
3. Countermeasures Employed
4. Regulatory Climate



QUESTIONS?



Special Thanks: Kevin Meyers, Elexicon Energy
JOMAR Softcorp Services, Next Generation CIS-MDM-ODS Software

Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB

KEVIN SCHNEIDER

February 13th, 2020

Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (High-Level Project Summary)



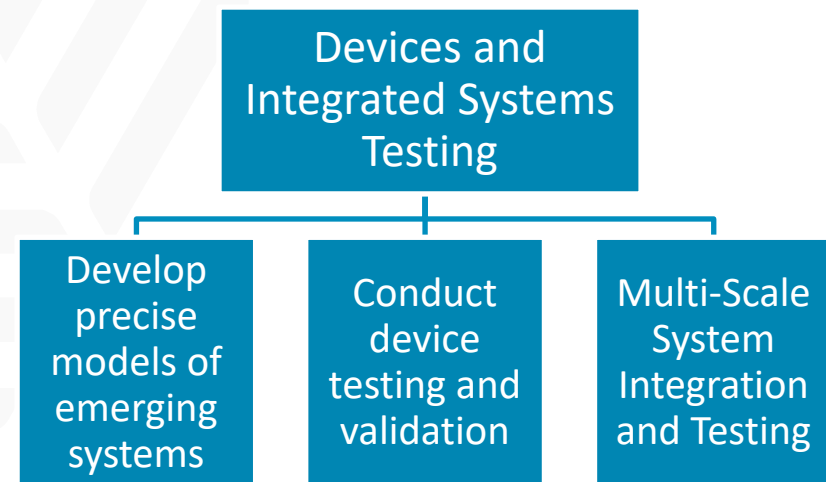
The primary goal of this project is to increase distribution resiliency through flexible operating strategies. This will be accomplished by actively engaging utility and non-utility assets as flexible resources.

Value Proposition

- DER deployments at moderate- to high-penetration levels prevent a “business-as-usual” approach
- Duke Energy has halted some self-healing systems deployments due to moderate/high-penetration PV concerns
- What is needed is a way to coordinate the operation of distributed PV, to make it a resource, and not an obstacle
- This is extensible to other centralized and decentralized system combinations

Project Objectives

- Develop flexible operating strategies that integrate centralized and decentralized control systems (e.g., self-healing/PV)
- Engage utility and non-utility assets to increase the resiliency of critical end-use loads to all hazards events
- Develop, and deploy, a layered control architecture using commercial-off-the-shelf (COTS) equipment and open source code



Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (Project Team)



- **PNNL – Kevin Schneider and Wei Du**
 - Development of architecture, controls, and operations
 - Co-Simulation of distribution and communications
- **ORNL – Josh Hambrick and Mark Buckner**
 - Implementation of the OpenFMB Harness
 - Application of OpenFMB cybersecurity framework and microgrids protection
- **NREL – Kumaraguru Prabakar**
 - Sub-system testing of centralized controls, e.g., GE DMS
 - Cost/Benefit analysis and technical performance analysis
- **Duke Energy – Stuart Laval and Phil Shaw**
 - Host utility which owns and operates all utility assets
 - Execute final field evaluation and cyber red team activities
- **GE Grid Solutions – Avnaesh Jayantilal**
 - Technical support for production DMS and FLISR
- **UNC-Charlotte – Madhav Manjrekar and Somasundaram Essakiappan**
 - Primary HIL performers, using Typhoon, support of controls validation
- **University of Tennessee – Leon Tolbert and Yilu Liu**
 - Integrate VOLTTRON nodes into OpenFMB Harness
- **Smart Electric Power Alliance (SEPA) – Robert Tucker**
 - Outreach agency to ensure that lessons learned are transferred

- **Project Industry Advisory Board (IAB) Members**
 - Entergy – Cat Wong
 - Avista – Curt Kirkeby
 - APS – Jason Delany
 - North America Energy Standards Board (NAESB) – Jonathan Booe & Elizabeth Mallet



Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (Approach)



➤ **Approach:**

- R&D: foundational research in architecture, controls, simulation & emulation, and multi-scale testing
- Market Stimulation: active Industry Advisory Board (IAB), including material developed and distributed by SEPA
- Standards: using OpenFMB, and an open-source, standards-based approach

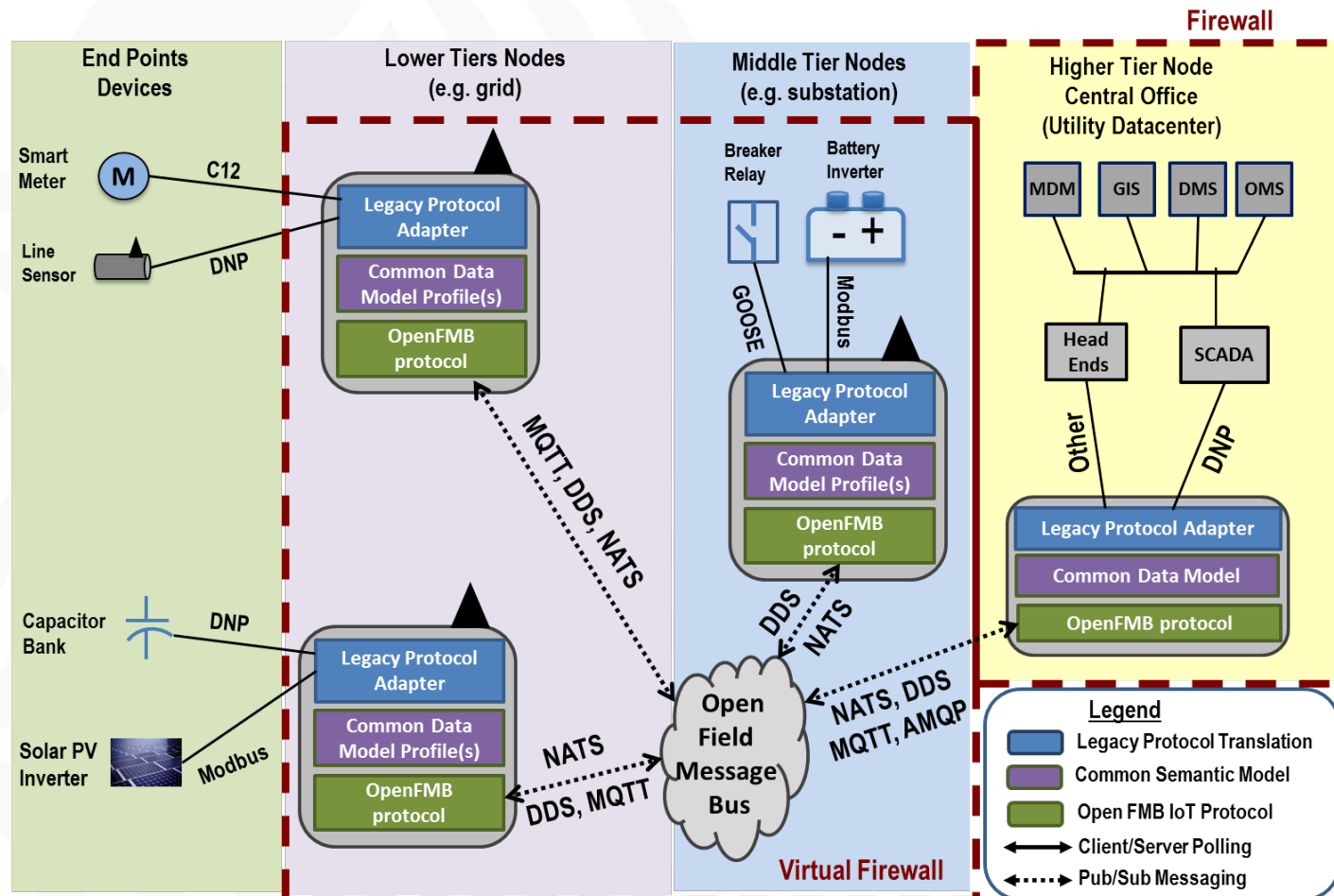
➤ **Key Issues:**

- Increasing flexibility as a resiliency resource, to address uncertainty in planning and operations
- Coordinating centralized and decentralized systems, utility and non-utility owned/operated
- Transforming the perspective of DER from being an obstacle to being a resource

➤ **Distinctive Characteristics:**

- Industry driven: the project is motivated by utility needs, and supported by IAB members with similar classes of operational challenges
- Standards based: all work is being conducted with open platforms to facilitate broad adoption
- Deployable: the final field validation will use COTS equipment running containerized open-source software, further facilitating broad adoption

OpenFMB Overview

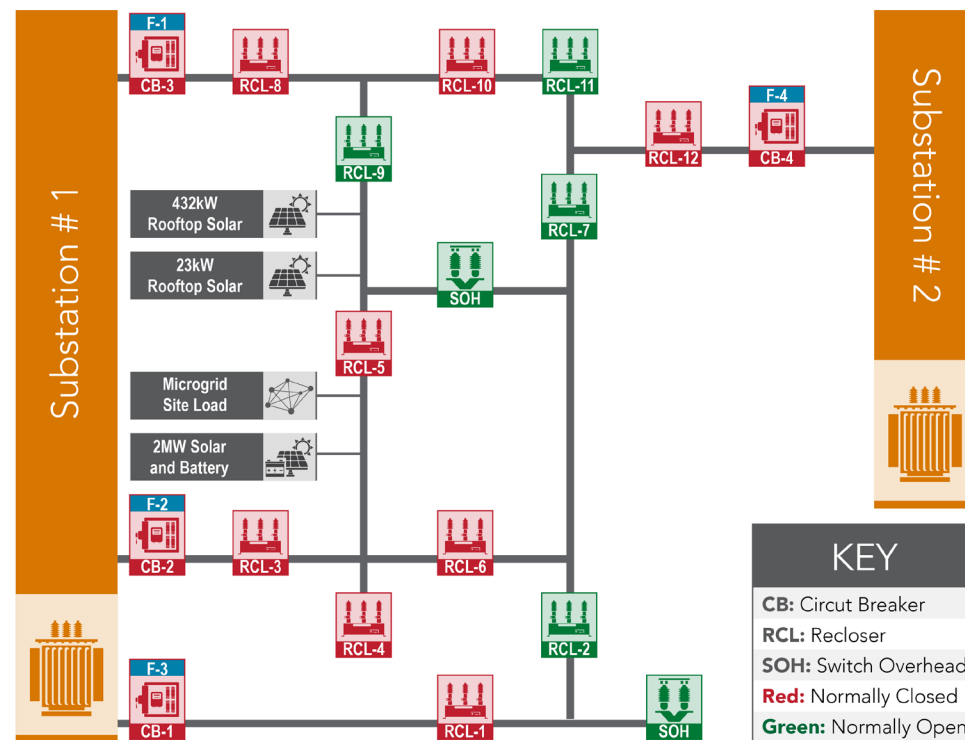


Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (Architecture and Controls)

A layered control structure with elements of a laminar control architecture developed to coordinate self-healing, microgrids, and DERs.

Concept of Operations (CONOPS) has been completed, including 12 use-cases

- Protection operates autonomously at the device level, using local set point groups
- OpenFMB maintains protection coordination after system changes (publish & subscribe)
- Central DMS determines “optimal” topology post event, issues commands
- DMS can engage transactive to incentivize non-utility assets to generate additional switching options
- Operations across layers are coordinated, enabling effective centralized and distributed system operations



Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (Simulation/HIL/Emulation)



Before equipment can be operationally deployed, the architecture, controls, and set points must be developed, simulated, and validated. A multi-stage validation approach has been taken.

- Co-Simulation: HELICS, GridLAB-D, and NS-3
 - Initial electric and communications models complete
 - Results supporting HIL simulations
- HIL Simulation: Typhoon HIL & ADMS Testbed
 - Typhoon running at UNCC and Duke Energy
 - NREL is working on setting up GE DMS
- Emulation: ORNL SI-Grid
 - ORNL and UTK are working with Duke RTUs
 - SI-Grid connected to NREL, working on UNCC
- Field Deployment: Anderson, SC
 - Schedule has been pushed back due to siting issues
 - Equipment selection Q1 CY20
 - Field validation Q2 CY21
- All software and HIL models have been coordinated, so team members are using consistent information

Co-Simulation



HIL Simulation & Emulation



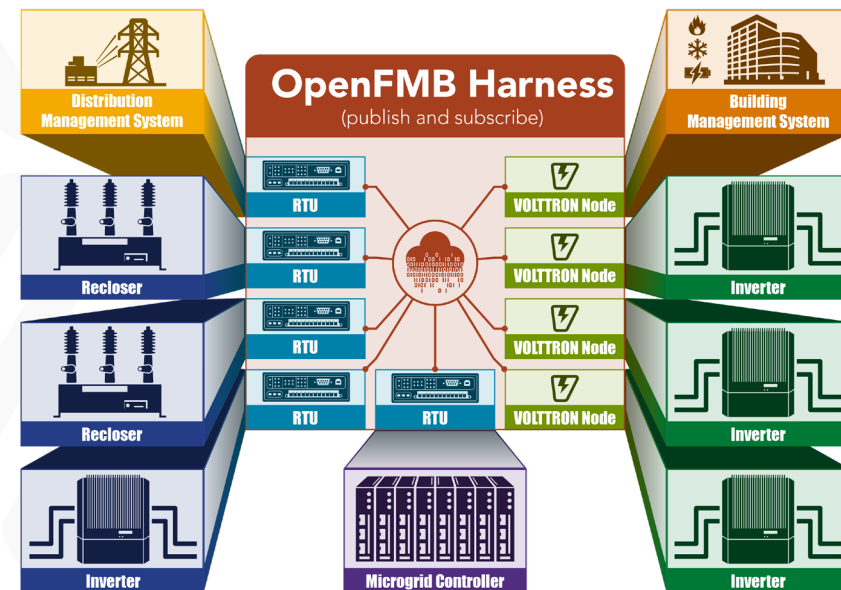
Field Deployment



Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (OpenFMB Harness)

The OpenFMB “Harness” is the physical realization of the reference architecture

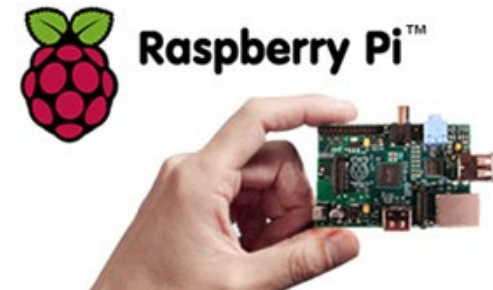
- Built using the standards-based OpenFMB reference implementation: leveraging past work the data structure and models are almost defined
- The harness is scalable for large numbers of DERs, and does not use proprietary adaptors
- Utility assets connected via COTS Remote Terminal Units (RTUs) with containerized applications: RTUs are being tested with initial harness
- Non-Utility asset connections will use VOLLTTRON on commodity platforms: work is continuing on VOLLTTRON integration



Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (Hardware Transitions)

For a resilient control system to be viable, there must be a path to deployment with COTS equipment.

- Early OpenFMB work used commodity Raspberry Pi™ prototype controllers
- The utility assets for this project will use COTS RTUs and/or 4G LTE gateways, with OpenFMB in a containerized environment
- Using open-software containerized applications on COTS equipment enables hardening for industrial applications, while ensuring interoperability and portability
- COTS devices integrates TPM2.0 crypto-chips and X.509 certificates with whitelisted, containerized, OpenFMB applications
- COTS devices are being tested on the initial harness implementation



Substation/Microgrid RTU: SEL 3555



Recloser RTU
SEL 3505



4G LTE Gateway
Sierra Wireless MP70+

Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB (Plug Fest)



- Event hosted by UNC-Charlotte 9/24-9/26
 - Day 1: Plenary Session / Vendor presentations at PORTAL building
 - Day 2: Tutorials / Lab / Utility presentations at UNCC ECE building
 - Day 3 morning: OpenFMB interoperability plugfest demos in UNCC ECE Lab
 - Day 3 afternoon: Microgrid Tour at Mount Holly
- 55 attendees from 25 different companies
- Participants: ABB, Cisco, Eaton, Itron, OES, RTI, SEL, Sierra Wireless, SGS, ORNL, EPRI, UNCC
- Distributed Intelligence Use-cases: Distribution Automation, FLISR, DER Optimization, AMI telemetry, Microgrid State Estimation, Distributed Historian, and Digital Twin.
- 4 utilities in Attendance: Duke, Avista, Entergy, ConEd
- ABB
 - REF615 protection relay (61850 GOOSE native)
 - E-mesh RTU540 / HMI (61850 GOOSE native)
- Cisco Systems
 - IC3000 compute gateway (with OpenFMB Docker container)
 - IE 4010 substation switches
 - IR1101 ruggedized router (Docker capable)
 - Cybervision and Stealthwatch network diagnostics and analytic tools
- Eaton Corporation
 - CL-7 single-phase Voltage regulator (DNP3 native)
- Electric Power Research Institute (EPRI)
 - Photovoltaic (PV) simulator (IEEE 1547 functions, DNP3 native)
- Itron
 - Single-phase Riva Meter (with OpenFMB MQTT adapter)
- Oak Ridge National Laboratory
 - OpenFMB NATS adapter for TyphoonHIL Simulator
 - Digital-twin OpenFMB protobuf profiles for Battery, PV, Switch modules
- Open Energy Solutions
 - Containerized OpenFMB adapter (DNP3/Modbus/GOOSE to NATS/MQTT/ DDS)
 - OpenFMB protobuf message viewers (subscribers on NATS and MQTT message buses)
 - Grafana visualization and displays (via OpenFMB time-series database adapter)
- Real Time Innovations (RTI)
 - DDS publish-subscribe licenses
 - Battery simulator (OpenFMB DDS native)
 - DDS Viewer and HMI
- Schweitzer Engineering Laboratories (SEL)
 - 651R recloser controller (DNP3 native)
 - 735 Revenue Grade meter (MMS native)
 - 700G generator protective relay (MMS native)
 - 3355 industrial computer (with multi-tenant container orchestration and Docker)
 - 3555 RTAC (with OpenFMB NATS adapter and FLISR demo)
- Sierra Wireless
 - MP70+ 4G LTE cellular gateway (with multi-tenant container orchestration and Docker)
- Smarter Grid Solutions
 - DERMS with HMI application (OpenFMB NATS native)
- UNC Charlotte
 - OpenFMB users group plugfest venue host
 - Typhoon HIL 604 real-time grid simulator

Increasing Distribution System Resiliency using Flexible DER and Microgrid Assets Enabled by OpenFMB

