It's Time for States to Get Smart About Smart Inverters

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About Center for Renewables Integration (CRI):

www.center4ri.org

Our team of energy experts advise and help develop policies that enable a high percentage of variable renewable energy to connect to the electricity grid, without impacting reliability, and while maintaining a focus on costs. We contract directly with state agencies that are working to implement a high percentage of renewable generation, or we are funded by foundations that are working to implement a clean energy future and occasionally by private companies operating in the clean energy sector.

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Executive Summary

Written for state electricity regulators and their staffs, this paper outlines a set of recommendations to implement smart inverters and to help states reach clean energy goals. Smart inverters are a solution which increases the amount of clean, distributed energy that can be cost effectively and safely hosted on the distribution system. Additionally, this paper provides:

- a layman's explanation of the opportunities and challenges presented by significant percentage of clean generation interconnected to the distribution grid;
- an overview of smart inverter technology and how it enables high penetration renewables cost effectively;
- an introduction of the new standards governing the rollout of smart inverters,[1] specifically IEEE 1547-2018™ and correlating documents; and
- lessons learned from states leading the deployment of smart inverters.

State electricity regulators should expect distributed energy resources (DER) such as solar, energy storage, combined heat and power, fuel cells, and electric vehicle fleets to comprise a significant portion of the state's electricity generation at some point in the future, either because the state has set a clean energy mandate, consumers choose clean power, businesses require increased levels of reliability, or the economics of distributed generation become so favorable it becomes an obvious choice for consumers.

State regulators can either enable high levels of DER in their state, or make it difficult, by controlling a number of "regulatory levers" such as interconnection, net metering, and others. This paper is written for states that want to enable DER. One of the most cost effective solutions to do so, and the focus of this paper, is the adoption of "smart inverters" a new generation of inverters that can enable the benefits, and solve many of the challenges, of high penetration DER. Smart inverters convert "dumb" DER, that passively generate electricity with limited communication and no control, into "smart" DER that can react to conditions on the distribution grid to improve power quality, use encryption to communicate securely, and be aggregated and controlled remotely if desired.

High levels of DER present both an opportunity and a challenge. The opportunities are clear – increasing levels of clean generation, improving resiliency, effectively using of resources such as mobile batteries (e.g. EV fleets), enabling new business models, increasing competition in electricity generation as well as consumer choices. The challenges are less well documented, but real, and need to be addressed. For example, variable generation such as distributed solar can create undesirable voltage fluctuations on a distribution line that can negatively impact all electrical equipment connected to the line. Collectively, all inverter-based generation has the potential to exacerbate small faults on the grid into larger events. Even though it provides many benefits, clean distributed generation cannot be allowed to degrade the reliability of electricity infrastructure. Technology must be deployed to ensure ongoing performance with high penetration renewables on a distribution grid.

Aware of these challenges, the Institute of Electrical and Electronics Engineers (IEEE), the standards body that oversees rules governing the interconnection of generators to the distribution grid, worked for many years to update an existing standard to both eliminates the potential threat of DER contributing to grid

[1] For a more detailed discussion of the content included in IEEE 1547-2018™, CRI suggests the Interstate Renewable Energy Council's paper *Making the Grid Smarter*, written by Byran Lydic and Sara Baldwin, published January, 2019.

faults, and allow smart inverters to mitigate voltage fluctuation. The update to IEEE's applicable standard, IEEE 1547, was published in 2018.

Known as IEEE 1547-2018™ this standard presents unique challenges to state electricity regulators. First, it is voluntary. Action must be taken by state regulators to update interconnection regulations to reference the 2018 version of IEEE-1547. Second, it is not prescriptive. In order to accommodate all of the various scenarios and types of DER, IEEE did not issue one single set of rules, but instead provided a menu for regulators to choose from. To implement the standard state regulators must make choices.

As the sole entity that regulates electricity distribution companies, there is no option but for state regulators to find a way to navigate the decisions associated with implementing this standard. Failing to implement IEEE 1547-2018™ means that DER remain "dumb" and the challenges introduced by interconnecting a high volume of DER impose an overly restrictive limit on the amount of DER that can be interconnected. Any state that wants to enable clean generation or customer choice must update their interconnection regulations to include IEEE 1547-2018™ and navigate the implementation choices.

A number of states and utilities have been forced to lead on this issue, working to test technology solutions and develop new regulations in advance of IEEE finalizing on the 2018 update. An examination of the lessons learned from these states and experience gathered participating in commission-led smart inverter workgroups allows CRI to distill a set of recommendations:

1. **Start now and develop implementation plans:** Launch stakeholder processes now in order to be ready for new inverter capabilities in late 2021. While states with lower DER penetration levels may be tempted to delay implementation, DER adoption within a state can occur very quickly.
2. **Plan for high penetration:** Regulators in Germany and Hawaii found themselves in the unenviable position of having to require upgrades to installed inverters. There is no additional cost to enable functionality that will be built into inverters starting in 2021. It is better to enable functionality before it is needed than to require retrofits.
3. **Allow stakeholder participation:** While it may be tempting to allow the distribution utilities to select from the menu of options included in IEEE 1547-2018,™ the impact of the decisions will be felt across the state. Stakeholders such as DER providers, DER Management System (DERMS) companies, DER aggregators, customer advocates, and others should be allowed to participate in setting new standards.
4. **Provide guidance:** Commissions launching processes to incorporate the 2018 version if IEEE 1547 should consider providing stakeholders with guidance. If Commissioners can articulate objectives and a timeline, it will provide stakeholders with direction.
5. **Maintain standardization:** The majority of interconnection applications should continue to fall under quick, low cost, standard, state-wide processes and not require expensive studies, new communication solutions, or bespoke inverter settings. There will always be scenarios where customized inverter settings, communication solutions, and extensive interconnection studies are required, but those should remain limited. Determining how to set those thresholds between applications that should be standardized, versus those that should be custom, and applications in between will be an important aspect of a commission's implementation.
6. **Collaborate with bulk power system operators:** State commissions may need to collaborate with operators of transmission and bulk power systems (e.g. ISO/RTOs where applicable) to implement ride-through capability.

Understanding the Opportunities and Challenges of High Penetration Distributed Energy Resources

Aggressive goals for clean energy are being established in states across the U.S. Clean energy goals that started modestly a decade ago have been increased in many states, as all parties become more comfortable with the cost effectiveness of renewable energy and as concerns with climate change grow. To achieve these goals, inverter-based generation connected to the distribution system can and should make a significant contribution. This may include variable generation such as solar (ranging from residential to community), dispatchable generation such as energy storage (home storage up to commercial EV fleets) and everything in between (e.g. combined heat and power, solar + storage hybrids, fuel cells, etc.).

Jurisdictions with 100% Clean, or Renewable, Energy Goals

- **California**
- **District of Columbia**
- **Hawaii**
- **Maine**
- **Minnesota**
- **Nevada**
- **New Jersey**
- **New Mexico**
- **New York**
- **Puerto Rico**
- **Washington**
- **Wisconsin**

In 2018, additional states elected governors that ran on significant clean energy platforms – Colorado, Illinois, Oregon.

Source: https://news.energysage.com/states-with-100-renewable-targets/

Numerous studies have documented the benefits distributed generation can provide[2], including:

- Avoided generation – Distribution connected generation can avoid the need for centralized generation and may allow older, frequently dirtier, and more expensive peaking centralized generation to be ramped back.
- Greater customer engagement and lower energy use – Customers installing distributed generation frequently also take additional measures to manage energy use, from smart thermostats to energy efficiency and everything in between.
- Avoided transmission and distribution upgrades – Appropriately sited distributed generation can reduce the need for planned upgrades to transmission and distribution.
- Cleaner generation – Solar generation is one of the most common distributed assets selected by ratepayers.
- Increased resiliency – Distributed generation, particularly when combined with storage, or newer generation inverters, can allow customers to access emergency power in case of a power outage and provide a cleaner solution than diesel generators for those that do not have uninterruptable power requirements.
- Better asset utilization enabling faster transition to clean generation – Energy storage, both stationary, grid connected storage as well as mobile, remains a key enabler for high levels of variable generation. More uses and associated revenue from energy storage will accelerate the

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[2] United States Department of Energy, The Potential Benefits of Distributed Generation and the Rate-Related Issues That May Impede Their Expansion. February, 2007.
ICF, The Hunt for the Value of Distributed Solar. February, 2019.
A. Zibelman, REVing up the energy vision in New York: Seizing the opportunity to create a cleaner, more resilient, and affordable energy system, IEEE Power Energy Mag., vol. 14, no. 3, pp. 18–24, May–June 2016
S. Burger, et al, Why Distributed?. IEEE Power & Energy Magazine. March/April, 2019.

deployment of storage as well as variable generation. For example, commercial fleets of electric vehicles charging at night may be able to mitigate renewable energy curtailment, potentially enabling the economics of the EV fleet via low cost charging and improving the economics of wind generators that might otherwise be curtailed.

However, injecting large amounts of variable generation onto distribution systems has the potential to push line voltage outside acceptable limits. Uncorrected, this can cause power quality problems for others connected the distribution line and can accelerate wear on utility voltage management hardware.

Additionally, greater deployment of inverter-based generation also can cause concerns for transmission grid operators. If inverter-based solar systems are set to trip off line in response to minor voltage or frequency disturbances, a momentary grid problem can cause a large-scale loss of generation, greatly amplifying the original problem.

In the face of these concerns, historically distribution companies and electricity regulators have only had the options of either limiting the amount of DER that can be interconnected or requiring expensive upgrades to distribution lines and equipment as DER penetration rises. This strategy is at odds with increasing clean energy mandates and achieving those mandates at the lowest cost. While concerns have been most acute in leading solar states such as California and Hawaii, CRI has observed solar siting restrictions and/or costly upgrade requirements occurring in pockets in many states.

Smart Inverters allow more variable generation to be connected to the distribution system without triggering expensive upgrades or jeopardizing grid reliability.

There is a new solution on the horizon. Specifically activating and utilizing the capabilities that will be built into all DER inverters starting in late 2021, which include:

- automatically correcting voltage fluctuations introduced by variable generation, or doing so in response to signals from remote operators;
- eliminating the risk of DER automatically shutting down in anomalous grid system operating conditions, thereby potentially cascading small issues into larger ones; and
- providing secure two way communications to enable greater visibility and control of DER performance for both distribution or bulk electricity system operators.

What is a Smart Inverter?

An inverter converts electricity from direct current (DC) to alternating current (AC), connecting a direct current device, such as solar PV, to a building or to the grid. Smart inverters employ advanced electronics to monitor grid frequency and voltage in real time and adjust their output characteristics in response. Adjustments can be made autonomously based on pre-programmed settings, or in response to an external signal or command.

To support greater deployment of inverter-based distributed generation, three types of advanced features are most important:

1. Low/high voltage ride through and low/high frequency ride through

Within a designated range, a smart inverter will "ride through" a momentary abnormality in grid voltage or frequency without disconnecting. This autonomous function helps ensure a momentary fault on the grid doesn't cascade into a widespread loss of distributed generation, making a minor problem potentially much more severe. Ride through capabilities are currently a common requirement for larger, transmission-connected generators. Smart inverters extend those capabilities to distribution connected systems.

2. Voltage management

These capabilities adjust the real (Watts) or reactive (VAR) power output of the inverter in order to limit impact of variable generation on distribution line voltage. This allows the distribution circuit to operate within acceptable voltage limits at higher levels of interconnected DER. Voltage management can be either autonomous or controlled.

In some cases, smart inverters can be used to improve distribution circuit voltage beyond the capabilities of standard utility voltage management equipment by virtue of their continuous and autonomous sensing of and adjustments to line voltage. This capability may be the basis of additional grid services provided by DERs.

3. Communications interface

Smart inverters have interface capabilities that allow for external control. With a combination of encrypted, two-way communications and control systems such as Distributed Energy Resource Management Systems (DERMS) put into place, distribution utilities, ISOs, DER owners, and third-party resource aggregators can obtain visibility into DER operation, or control inverter behavior.

The use of secure communication solutions is best suited to applications where it is necessary or enables a service. Examples of the former might include very large DER assets, or unique and complex combinations of DER technologies. Examples of the later might include non-wires alternative applications where the DER are deferring an upgrade to the distribution system, or large DER aggregations participating in bulk system markets.

IEEE 1547-2018™ Overview

The national engineering standard that defines the functionality required to connect generators to the distribution grid is published by the Institute of Electrical and Electronics Engineers (IEEE). IEEE standard 1547 was first issued in 2003, and a significant revision was published in April 2018. IEEE 1547-2018™ includes detailed requirements for a variety of smart inverter features.

Given the broad range of distributed generation technologies that may connect to distribution lines (e.g. solar, CHP, EV fleets, small wind, energy storage), together with the fact that distribution and transmission system characteristics vary from place to place, IEEE 1547-2018™ requires inverters to be capable of a number of specified categories, modes and settings. It is up to state commissions to select the capabilities that will be enabled in the state. For this reason, this standard is unique in that it provides a menu of options and requires states to select what they wish to implement.

It is important to note that action is required to benefit from some of the capabilities that will be standard in smart inverters. For example, the default, no action, mode does not allow voltage control,[3] one of the key benefits and reasons to deploy smart inverters.

It is easy to get lost within the categories, modes and settings included in the new standard, and summarized in Appendix A. It is easier to understand IEEE 1547-2018™ by focusing on the core functionality that will be built into all smart inverters and by highlighting the perspectives and concerns stakeholders may bring to a stakeholder process.

- **Voltage management versus none** – IEEE 1547-2018™ requires smart inverters to either be able to either correct voltage or not. Since voltage management increases hosting capacity, it should be expected that DER providers may support enabling voltage control. Distribution utilities, concerned with the potential interaction with their voltage management systems, may not.
- **Real versus reactive voltage management** – The new standard specifies the ability to manage voltage either by modulating real power (Watts) or reactive power (VAR). Using real power to adjust voltage may have a some financial impact on DER providers since it has the effect of curtailing electricity produced. For that reason, DER companies may support using reactive power settings as preferred settings. There is also the option of using real power setting as a "backstop" if reactive power settings cannot maintain voltage within desired limits.[4]
- **Autonomous versus remotely controlled** – The new standard requires smart inverters to be able to operate autonomously, or to follow remotely provided instructions for voltage control. In autonomous mode, the inverter automatically reacts to changes in voltage on the distribution grid and adjusts its output in order to correct the voltage. It is possible that DER companies will want to see autonomous mode enabled in almost all applications. It is also possible that distribution utilities may prefer to see smart inverters remotely controlled by themselves, via periodic adjustments, or in some limited cases, real-time. To maintain standardization for the majority of interconnection applications, Commissions may want to allow both autonomous and

[3] Default mode for voltage control is constant power factor mode (at unity power factor), which does not allow the inverter to adjust output in order to provide voltage control. Voltage control is one of the key functionalities that allows higher hosting capacity of variable generation assets such as solar on distribution lines.
[4] For a more detailed discussion and recommendations on voltage management settings see: *Ric O'Connell, Curt Volkmann, Paul Brucke. Regulating Voltage: Recommendations for Smart Inverters. GridLab, 2019, http://gridlab.org/publications/*

controlled voltage management, and the decision will focus on where and how to set the thresholds applications accordingly.

- **The amount of ride through** – The new standard provides three increasing levels of voltage and frequency ride-through capability to ensure distribution connected inverter-based generation does not negatively impact grid performance when a fault has occurred. States located within an ISO/RTO may find the effort to select the right settings being led by their ISO/RTO, and it will primarily fall to the distribution companies to participate in that stakeholder process. Still state commissions will have to adopt the ISO/RTO recommendations.
- **Utilizing secure communication capability** - IEEE 1547-2018™ requires smart inverters to support at least one of three standard communication protocols, and be compliant with IEEE 2030.5 cyber security requirements. The development and use of DER management systems (DERMS) to aggregate and control DER is still fairly new, but the security standards are tighter than they are for online banking.[5] Companies that provide DER aggregation will be advocating for enabling this capability, while others may want to take a more cautious approach.

IEEE 1547-2018™ compliant inverters will reach the market in late 2021. In order for compliant hardware to reach the marketplace, however, two additional standards must be developed:

- An update to IEEE 1547.1 must be finalized to detail the type and production testing needed to certify equipment compliance with IEEE 1547-2018™ as well as the commissioning test requirements at the time of installation.
- An update to UL-1741 must be finalized to detail the protocols used by UL laboratories to certify equipment for compliance with the IEEE standard and to earn the UL "stamp."

This work is ongoing and happening independent of any state commission implementation decisions. When all standards work is complete, each manufacturer must have its equipment tested to the new IEEE and UL standards.

The revised version of IEEE 1547.1 is scheduled for publication in the fourth calendar quarter of 2019 or the first calendar quarter of 2020. UL is scheduled to update its 1741 standard by the end of 2020, presuming no delays in the IEEE 1547.1 release.

Manufacturers will be able to submit their equipment for UL testing in 2021, with some hardware becoming fully certified in 2021, and a significant amount of hardware becoming fully certified in 2022. It should be anticipated that by the end of 2022, most new inverter equipment will be compliant with IEEE 1547-2018™.

[5] See discussion of California's lessons learned in DERMS and cyber security later in this paper for a more detailed explanation.

Learning from Smart Inverter Deployment Efforts Across the Nation

While the update to IEEE 1547 was published in 2018, the functionality that smart inverters can provide and that will become standard across the US starting in 2021, is not new. Domestically, smart inverters are already required in California and Hawaii, where Commissions took action in advance of IEEE's update. Internationally, Germany was the first country to adopt new requirements for ride-through that have now become standard in the European Union and Mexico. This section summarizes how various U.S. states have approached the transition to smart inverters, summarizes some of the key lessons learned, and provides a quick look at a few pilots and ongoing regulatory work in other states. A more detailed discussion of state activity and lessons learned is included in Appendix B.

Countries and states have been mandating smart inverter functionality for years:

- 2013: Germany performs retrofits to include ride through capability and mandates it going forward
- 2015: Hawaii mandates all inverters include ride through capability
- 2017: California requires all DER inverters to provide autonomous voltage control and ride through capability
- 2019: California is expected to mandate secure communication protocols for inverters

California and Hawaii took very different approaches to implementing smart inverters. As one of the first U.S. states to embark down the path, California was required to bootstrap their effort and proceed cautiously. California commissioners launched the Smart Inverter Working Group (SWIG) in 2013 and developed their own update to interconnection regulations, Rule 21. The state adopted a three phase approach, and spent the first year planning the multiple phases. Phase 1 focused on deployment of autonomous voltage management. Phase 2 focused on communication protocols, in part to enable Phase 3, which includes the development of DER Management System standards and remote operation of DER. California is not requiring retrofits or remotely performed firmware upgrades to incorporate increased functionality.

Hawaii commissioners turned to experts at Department of Energy National Renewable Energy Lab to model the HI grid and develop recommendations which the commission codified. Hawaii commissioners focused first on enhancing the ride-through capabilities of inverters and, like Germany, required a retrofit of inverters (done via a remote firmware update) installed in the field to improve ride-through performance. After tackling ride-through, Hawaii commissioners turned to voltage management. Hawaii's updated interconnection requirements are reflected in Rule 14.

Both California and Hawaii standardized on autonomous voltage control using reactive power. During the pilot phase, California evaluated voltage management using real power, but concluded reactive power provided enough benefit without the downside of curtailing production.

Additionally, regulators in other states have authorized a number of demonstration projects, including those conducted by Arizona Public Service, Salt River Project, and Duke.[6] NREL and EPRI have also working in collaboration with several utilities including Pepco, DTE Energy, and National Grid[7] which have all been conducting pilots. Arizona has conducted some of the larger demonstrations, with 1600 residential DER

[6] Palmintier, B., et al. Feeder Voltage Regulation with High-Penetration PV Using Advanced Inverters and a Distribution Management System. National Renewable Energy Lab, November 2016.

[7] Seal, B, et al. Smart Grid Ready Inverters with Utility Communication. DOE report # DOE-EPRI-5337. March 30, 2016.

systems controlled directly by the utility. To date the Arizona utilities, have only tested voltage control using remotely provided instructions via secure communications and have not tested autonomous modes.

Maryland, Illinois and Minnesota are three other states that have started down the regulatory path to determine how to approach updating their interconnection regulations to include IEEE 1547-2018.™ After a year-long stakeholder process, the Maryland commission issued a rulemaking that, in essence, provides high level implementation guidance. The commission also directed the distribution utilities to provide detailed recommendations within a year, which will not be finalized without stakeholder review. CRI co-led the smart inverter workgroup and the final comments submitted summarize the key provisions of the proposed regulations.[8]

Smart Inverters Increase Hosting Capacity

States interested in achieving high penetration renewable energy goals will be curious to see where smart inverters successfully increase hosting capacity. Hosting capacity is defined as the amount of DERs that can be accommodated on the distribution system at a given time, and at a given location, under existing grid conditions and operations without compromising safety, power quality, reliability or other operational criteria and without requiring significant infrastructure upgrades.[9]

The most notable example is Hawaii where, in 2013, HECO placed a moratorium on new solar interconnections on line segments where solar exceeded 120% of minimum daily load. With the addition of smart inverters, that limit was raised to 250% of minimum daily load, which allowed 2500 solar projects that were waiting in the interconnection queue to proceed.[10]

With the addition of smart inverters, Hawaii was able to raise solar interconnection limits from 120% of minimum daily load to 250%.

Results from the APS study show adding PV with smart inverters increase the hosting capacity of a distribution line versus PV with "dumb" inverters. In one example, a feeder could support an additional 700 kW of solar without triggering hosting capacity limitations.[11]

Numerous models and analyses have also investigated and shown the ability of smart inverters to increase hosting capacity. In 2015, IEEE published an analysis which studied the PV hosting capacity of several real, unbalanced, three-phase distribution feeders both with and without the application of a local voltage regulating reactive power control on the PV grid-tied inverter. The results of the simulations indicate that the overall feeder hosting capacity improved by an average of 84% with the implementation of the Volt/VAR control.[12]

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[8] Read CRI's comments summarizing the smart inverter provisions of the proposed regulations here: https://www.psc.state.md.us/search-results/?q=RM68&x.x=0&x.y=0&search=all&search=rulemaking#

[9] Stanfield, S. et al. Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources. IREC, 2017.

[10] NREL, NREL and Hawaiian Electric Navigate Unchartered Waters of Energy Transformation Part 1. April 23, 2018

[11] EPRI, Arizona Public Service Solar Power Partner Program, Advanced Inverter Demonstration Results, 2017 Technical Report. May, 2017.

[12] Seuss, J. et al. Improving distribution network PV hosting capacity via smart inverter reactive power support, July 2015.

Recommendations:

Based on experience gathered from participating in smart inverter workgroups, as well as extensive research looking across the U.S. and gathering lessons learned, CRI offers the following recommendations for state electricity commissioners to consider as they work to update their interconnection regulations to include 2018 publication of IEEE 1547-2018™:

1. **Start now and develop implementation plans:** Launch stakeholder processes now in order to be ready for new inverter capabilities in late 2021. While states with lower DER penetration levels will be tempted to delay implementation, DER adoption within a state can occur very quickly.
2. **Plan for high penetration:** Regulators in Germany and Hawaii found themselves in the unenviable position of having to require upgrades to installed inverters. There is no additional cost to enable functionality that will be built into inverters starting in 2021. It is better to enable functionality before it is needed than to require retrofits.
3. **Allow stakeholder participation:** While it may be tempting to allow the distribution utilities to select from the menu of options included in IEEE 1547-2018™ ,the impact of the decisions will be felt across the state. DER providers, DERMS companies, and others should be allowed to participate in setting new standards.
4. **Provide guidance:** Commissions launching processes to incorporate 2018 version if IEEE 1547 should consider providing stakeholders with guidance. If Commissioners can articulate objectives and a timeline, it will provide stakeholders will direction.
5. **Maintain standardization:** The majority of interconnection applications should continue to fall under quick, low cost, standard, state-wide processes and not require expensive studies, new communication solutions, or bespoke inverter settings. There will always be scenarios where customized inverter settings, communication solutions, and extensive interconnection studies are required, but those should remain limited. Determining how to set those thresholds between applications that should be standardized, versus those that should be custom, and applications in between will be an important aspect of a commission's implementation.
6. **Collaborate with bulk power system operators:** State commissions may need to collaborate with operators of transmission and bulk power systems (e.g. ISO/RTOs where applicable) to implement ride-through capability.

Each recommendation is discussed in greater detail below.

Start Now to Develop Implementation Plans:

The table below provides a sample timeline for assuring that smart inverter ride through and voltage management features can be activated as soon as IEEE 1547-2018™ compliant hardware is available.

	2018	2019	2020	2021
Status of standards development	IEEE 1547-2018 adopted; IEEE 1547-2018.1 under development	IEEE 1547-2018.1 under development	IEEE 1547-2018.1 and UL 1741 updates adopted	IEEE 1547-2018 compliant hardware becomes available
Ride-through – autonomous operation		Determine appropriate modes and settings through collaborative process ***(ISO, RTO or state regulators)***	Incorporate into state regulations, tariffs, policies and practices	Require all new solar generators to use properly configured smart inverters
Voltage control, active/reactive power – autonomous operation	Permit use of smart inverter features compliant with interim standards	Determine appropriate modes and settings through collaborative process ***(state regulators)***	Incorporate into state regulations, tariffs, policies and practices	Require all new solar generators to use properly configured smart inverters

Most ISOs/RTOs across the nation have now specified, or are in the process of specifying, the ride through settings recommended for their systems. Due to these efforts, most state regulators will not need to undertake complex technical proceedings of their own on this subject. It is important to note, however, that ISOs/RTOs have no formal authority to establish requirements for systems interconnected to distribution systems. State regulators must incorporate the ISO/RTO recommendations into state regulations, utility tariffs and/or other appropriate policy documents. States should complete the needed actions (e.g. hearings, rulemakings, tariff proceedings) by the end of 2021 to assure that all IEEE 1547-2018™ compliant inverters are properly configured when they are being installed.

Deciding on approaches to voltage management is the area where state regulators, in collaboration with all stakeholders, need to do the most work. In order to assure that standards are in place as soon as IEEE 1547-2018™ compliant inverters are available for installation in 2021, efforts should begin as soon as possible.

A first step, which several states have already taken, is to permit inverters compliant with "interim" smart inverter standards to be used in selected cases. This can allow utilities to gain experience with smart inverter operation and allow interconnecting customers to avoid expensive distribution system upgrades. Standards that can be cited include:

- IEEE 1547-2003 Amendment 1 – 2014,
- IEEE 1547.1-2005 Amendment 1 – 2015,
- UL 1741 January 28, 2010 edition
- California Rule 21
- Hawaii Rule 14h

States may want to layer in levels of increased functionality in their implementation approach. For example, active control of assets requires implementing cybersecurity standards, and therefore may not be the first priority. Distribution connected assets that participate in ISO/RTO markets, such as energy storage under FERC Order 841, may also be a later priority for states to implement.

Implementing active voltage control requires adoption of standards outside of IEEE 1547-2018™, specifically those that encompass communication security protocol IEEE 2030.5. The organization leading grid cybersecurity is the National Institute of Standards and Technology (NIST) which was mandated by Congress, via the Energy Independence and Security Act of 2007, to coordinate standards for the development of the smart grid. IEEE 2030.5 was developed using foundational documents, including NIST's Guidelines for Smart Grid Cybersecurity (NISTIR 7628 Rev 1), and has been evaluated and found to be compliant with NISTIR 7628. An update to IEEE 2030.5 was published in May 2018 to synch the communications standard with IEEE 1547.

A sample timeline for implementing active, remote, control of smart inverters is provided in the table below. The development and operation of utility-owned Distributed Resource Management System platform will be borne by ratepayers. Commissions and consumer advocates will want to ensure remote operation of DER provides a value to ratepayers. It is also possible that state regulators may want to consider whether it is appropriate to provide compensation structures to encourage the active control or communication with smart inverters, either by utilities or third parties, particularly if doing so results in improved power quality on the distribution grid, lower outages, or more rapid recovery from outages.

<table>
<tr><th></th><th>2019</th><th>2020</th><th>2021</th><th>TBD</th></tr>
<tr><td>Low-cost, secure communications</td><td>Evaluate options</td><td>Select approach</td><td rowspan="2">Pilot (if desired)</td><td rowspan="2">Initiate active control of smart inverters</td></tr>
<tr><td>Distributed Resource Management System</td><td>Evaluate options</td><td>Select approach</td></tr>
</table>

The operation of battery storage systems also involves controls and control protocols that lie outside of IEEE 1547-2018. Batteries can be installed to operate in a variety of modes (e.g. backup power, non-export, grid services), and the impact of those modes on interconnection requirements requires additional evaluation. FERC Order 841 requires ISO/RTOs to allow distribution connected electric storage, located either behind or in front of the meter, to be able to participate in markets. Regulators will want to consider the interaction between IEEE 1547-2018™ implementation choices and decisions made to comply with Order 841.

	2018	2019	2020	2021
Battery Storage Controller Requirements		Incorporate controller use cases into interconnection policies	FERC Order 841 compliance	

Plan for High Penetration:

In smart inverter planning, regulators should consider the potential *future* levels of DER penetration. This will help assure that advanced functionality is available to address pockets of high penetration in the near term, and broader deployment in the future.

DER adoption rates, particularly for solar, are highly non-linear. Vast portions of a state may find they have little to no DER adoption, while small pockets will have already hit limits on distribution hosting capacity. DER adoption is largely correlated to local utility tariffs. For example, in 2018 solar adoption in New York state was in the low single digit percentages of power generation. Yet, in portions of Long Island and other suburban areas near New York city, such as Staten Island, distribution systems had already reached hosting capacity limits. Electricity rates in Zones J and K (NY city and Long Island) are significantly higher than the rest of the state, hence the higher adoption rates downstate.

Similarly, price declines in DER, or changes in legislation, can dramatically change the economic viability of DER within a state faster than regulators can respond. For example, in 2017 Florida was not even on the list of Top 10 solar states in the United States. Two short years later, in 2019 Florida jumped all the way to #5 on the Top 10 list with 3.2 GW of solar. While much of the installed solar in Florida was large-scale, it is an example of how quickly conditions can change in a state.

Allow Stakeholder Participation:

While it is cumbersome to use a stakeholder process to determine categories, modes and settings of smart inverters, various stakeholders will be impacted by decisions made and should be allowed to provide input.

Commissions may want to consider other forums, other than a full open stakeholder process, such as an invited, multidisciplinary team with representative experts from the distribution utilities, DER aggregators, DER providers, National Labs, or other engineering experts, to develop recommendations that may be reviewed and commented upon by a broader stakeholder group, prior to commission review.

Provide Guidance:

Depending upon the process selected by a commission to update interconnection regulations, commissioners may want to consider outlining guidance for stakeholders to follow to help structure the process. For example, the commission could specify:

1. Vision for clean energy and DER in the state, particularly if the state has a goal to achieve a significant clean energy target;
2. Implementation timeline to ensure interconnection regulations reflect the 2018 standard when smart inverters become available in 2021;
3. Guidelines that encourage the majority of smart inverter applications to fall under a statewide standard, and streamlined interconnection process that limits the number of custom settings; and
4. Process for collaborating with the appropriate bulk electric market operator, possibility and ISO/RTO, and adopting their recommendations for specific ride-through settings.

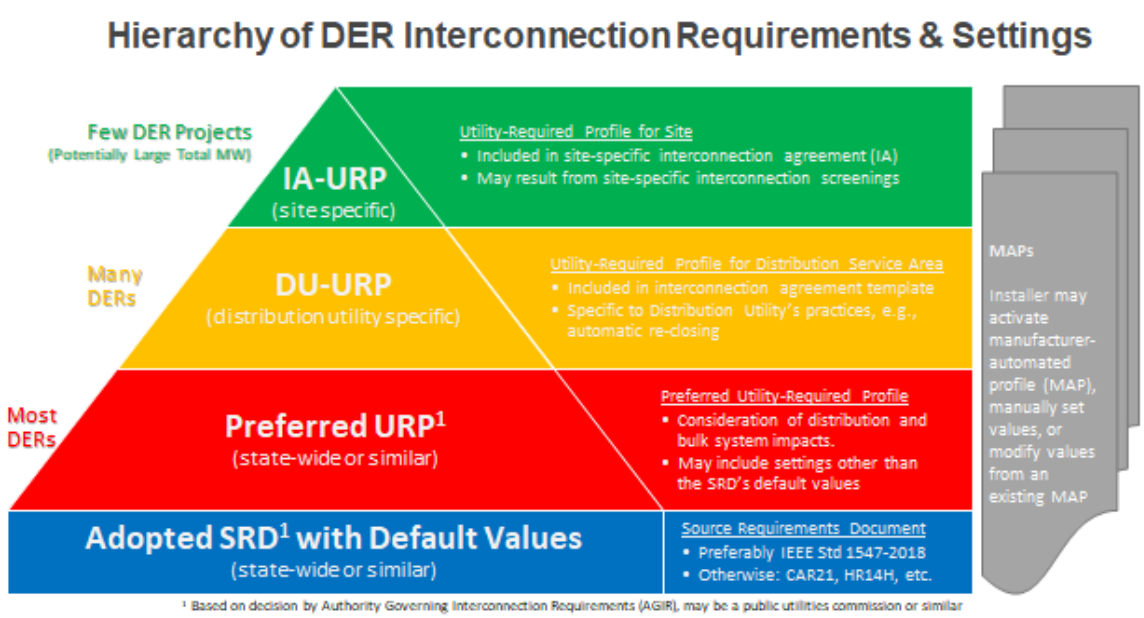
Maintain Standardization:

States that want to enable DER should set a goal of ensuring the majority of DER interconnections fall under a default, state-wide specification, which includes the simplest, lowest cost interconnection process. The graphic below, created by Electric Power Research Institute (EPRI)[13] and included with permission,[14] provides an excellent depiction of this approach.

The blue base of the pyramid shows that the applicable standard for most states, other than CA & HI, will be IEEE 1547-2018.™ The red layer, most DER, suggests that most DERs should be installed to a state-wide standard. For example, state-wide standard settings might be applicable to all residential and small commercial DER. To keep costs low, autonomous voltage control would allow deployment of voltage management technology, without increasing interconnection costs by requiring deployment of communication solution.

The yellow layer of the pyramid, many DER, illustrates that standard approaches to specialized situations might also be established. EPRI envisions distribution utility specific settings in their diagram. However, other parameters could be used as thresholds, such as DER size (e.g. > MW), configuration (e.g. solar + storage hybrids), or specifics of the distribution system (e.g. non-radial circuits).

The green layer of the pyramid, few DER, acknowledges that there will be a limited number of situations that may require site-specific customized settings. These would typically be larger systems, unique systems such as micro-grids, or projects that are designed to defer an upgrade to the distribution system (aka a non-wires alternative project).



Source: Boemer & Walling, Electric Power Research Institute, DER Ride-Through Performance Categories and Trip Settings. October, 2018

[13] Dr Jens Boemer & Reigh Walling, DER Ride-Through Performance Categories and Trip Settings: Presentation at PJM Ride-Through Workshop, October 1 – 2, 2018.

[14] EPRI makes no warranty or representations, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in the Material. Additionally, EPRI assumes no liability with respect to the use of, or for damages resulting from the use of the Material.

Collaborate with Bulk Power System Operators:

The selection of ride-through categories and settings is of primary importance to the stability of the transmission or “bulk power” system. Where state regulators oversee the operation of the transmission system, they will need initiate the decision-making process. They will also need to coordinate with other state commissions, interconnected RTOs and/or NERC to assure that their standards are in appropriate harmony with decisions made in neighboring jurisdictions. In states where transmission operation is overseen by regional RTOs (e.g. PJM, MISO, ISO-NE), state regulators may be able review and adopt their recommendations for ride-through settings.

The process underway at PJM is an example of an organized stakeholder engagement process on bulk power system implications. PJM launched a “DER Ride Through Task Force” process soon after the publishing of IEEE 1547-2018™. The Task Force deliverables include a policy document that state regulators can use to incorporate Task Force recommendations into state regulations, tariffs and policies in advance of compliant hardware arriving on shelves.

Appendix A: IEEE 1547-2018™ Details

Understanding Categories, Modes and Settings

As mentioned, IEEE 1547-2018™ provides a menu of categories, modes and settings to choose from. The decisions quickly become highly technical and should be evaluated by multi-disciplinary technical experts. Below is a summary of the categories and modes included in the new standard.[15]

Categories

IEEE 1547-2018™ defines two categories of voltage control capabilities for "normal" grid operation – Categories A and B. In simple terms, Category A capabilities are sufficient for situations where DER penetration is low, and DER output variability is also low. Category B capabilities cover situations of higher DER penetration and variability.

Note, however, that IEEE 1547-2018™ covers all generation technologies interconnecting with the distribution system, some of which will not be capable of meeting the performance requirements associated with Category B (e.g. DER with rotating generators such as combined heat and power systems). Regulators may need to determine how to accommodate exceptions. In assigning either Category A or B requirements to various situations and applications, IEEE 1547-2018™ provides guidance in Annex B to the standard.

Category Recommendations for NORMAL Grid Operations

DER Output Variability	Expected DER Penetration: Low	Expected DER Penetration: High
High	Category B	Category B
Low	Category A	Category B AND/OR Category A for some technologies unable to meet B performance requirements, and/or for some distribution feeders

Category Recommendations for ABNORMAL Grid Operations

DER Output Variability	Expected DER Penetration: Low	Expected DER Penetration: High
High	Category II	Category II or III Category III may be required for some very high penetration applications on feeders, and/or for specific technologies
Low	Category I	Category II

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[15] For a more detailed discussion of the content included in IEEE 1547-2018™, CRI suggests the Interstate Renewable Energy Council's paper *Making the Grid Smarter*, written by Byran Lydic and Sara Baldwin, published January, 2019.

IEEE 1547-2018™ defines three categories of voltage and frequency ride-through capabilities for "abnormal" grid operation – Categories I, II, and III. Category I capabilities are sufficient to support the essential stability and reliability needs of the transmission grid, Category II capabilities can assure all stability and reliability needs of the transmission grid by avoiding tripping over a range of voltage and frequency disturbances, and Category III capabilities address the needs of both the transmission and the distribution systems under very high DER penetration conditions.

The choice between Categories I, II and III depends on the broader needs of the power grid. In states with RTOs or ISOs, those entities generally have made, or are in the process of making, category determinations. It appears that Category II may be needed in many areas, though it is worthwhile to note that Category III is generally modeled after requirements established in California to address their high level of renewables penetration.

Modes (Voltage Control)

Once normal operating Categories (A or B) are assigned, the optimal modes of voltage control can be established. IEEE 1547-2018™ provides for five different voltage control modes: four that modulate the reactive power output of the inverter, and one that modulates the real power output. The mode of voltage control can be configured at the time of installation, continuing to operate under that mode indefinitely – so called "autonomous" operation. Modes can also be activated by external control signals using the smart inverter communications interface capabilities.

Ideally, standard modes will be specified that accommodate most DER interconnections. There will be situations where either the large size of a solar system or specific characteristics of a distribution circuit require deviating from state-wide standard mode selection. Interconnection regulations, utility tariffs or other policies can clarify when a more detailed review of the interconnection is advisable or needed.

The selection of voltage control modes is important to utilities, DER owners and operators, and other stakeholders, and their respective interests may need to be balanced in making those selections. Of particular concern to DER owners is the fact that certain voltage control modes in certain circumstances can cause curtailment of solar system output. Selecting modes that minimize curtailment while simultaneously assuring adequate voltage control is an important product of the mode selection effort.

With respect to ride-through capabilities, there are no operating modes to be chosen. Inverters will be configured to autonomously ride through certain grid voltage and grid frequency disturbances, as discussed below, with a possibility of override in selected circumstances.

Settings

IEEE 1547-2018™ prescribes a number of detailed default electrical parameter settings for each voltage control mode but allows certain parameters to be adjusted within defined ranges. The default settings are likely to be acceptable and appropriate for most all situations. If there are specific requirements to select settings other than the defaults for state-wide standards, this can be surfaced in a stakeholder process. If setting adjustments are needed in specific cases, that can be established where more detailed interconnection reviews are performed for large systems or for special grid circumstances.

IEEE 1547-2018™ also prescribes default parameter settings and acceptable ranges for ride through capabilities. ISOs/RTOs have established or are establishing recommendations on those settings as part of their processes.

Appendix B: Lessons Learned from States That Have Already Implemented Smart Inverters

Hawaii and California started rolling out smart inverters prior to release of IEEE 1547-2018™

Internationally, Germany has been the leader in deploying smart inverter capabilities. German utilities and regulators recognized in 2011 their high solar penetration levels required inverters to become smarter, in order to ensure a single fault on the grid didn't cascade into something larger. Since that time, the EU and Mexico have adopted similar standards. In the U.S., with very rapid adoption of renewable generation, both California and Hawaii found they needed to take action to ensure grid reliability at high penetration levels and to increase hosting capacity. The California Public Utilities Commission created the Smart Inverter Work Group (SIWG) in 2013 to develop an implementation approach to determine the updates required to IEEE 1547-2003™ and to develop a structured approach to transition the state to new requirements. IEEE leveraged the work done by SIWG in developing IEEE 1547-2018™. Comprised of commission staff, distribution utilities, clean energy companies, NGOs, and the ISO, the workgroup developed a phased implementation plan for rolling out smart inverter functionality, with the end of each phase culminating in updates to CA's interconnection regulations, Rule 21.

Summary of California's Transition to Smart Inverters

After a four-year process, the CPUC mandated the use of smart inverters that can autonomously provide voltage control and ride-through disturbances on the grid starting in 2017.

In 2019, all new smart inverters will be required to comply with the standard communication protocols selected by the state.

Each distribution company is responsible for ensuring compliance in their service territory.

As the first state undertaking the process of rolling out smart inverters, California proceeded cautiously. A year-long stakeholder process was required to develop a three-phased, multi-year plan, which the state has been following since 2014. Phase 1 focused on implementing autonomous functions built into smart inverters. Phase 2 was focused on developing the communication protocols. Phase 3 was dedicated to advanced functionality including determining how to best use the communication protocols established in Phase 2. The SIWG issued final recommendations for Phase 3 in March, 2017.[16]

The California joint utilities summarized years of smart inverter learning in six key recommendations to ensure that smart inverter DER become an effective and reliable distribution resource.[17] Findings range from ensuring the timing of DER response aligns with the grid need, to prioritizing the need for coordination between the utility and DERs, or DER aggregators.

Hawaii also had to take action prior to the approval of IEEE 1547-2018™. With a series of isolated island grids and very high renewable generation penetration, in 2011 Hawaii started first by widening the frequency trip limits, and by 2014 Hawaii had made ride-through capabilities mandatory for all distributed

[16] SIWG Phase 3 DER Functions: Recommendations to the CPUC for Rule 21, Phase 3 Functional Key Requirements, and Additional Discussion Issues. March 31, 2017

[17] CA Joint IOUs, Enabling Smart Inverters for Distribution Grid Services. October 2018

solar installed after 2015.[18] Action to standardize on voltage control settings came later, and Hawaii teamed with the National Renewable Energy Lab (NREL) to provide technical assistance required to understand the implications of high penetration renewables and develop solutions. While NREL was performing the analysis, Hawaii Commissioners had to take the extreme action of temporarily halting the interconnection of new exporting solar systems. Since then, voltage control has been rolled out and codified in Hawaii's interconnection standard, Rule 14H, Hawaii has been able to increase the amount of solar allowed on distribution lines.[19]

Ongoing projects to demonstrate and improve smart inverter functions

Below is a selection of projects designed to test smart inverter functionality and interaction with the grid.

1. Voltage control: If allowed, smart inverters can detect and correct the voltage on the distribution line in order to maintain it between optimal ranges. This can be done either through autonomous capability built into the inverter, or via active control via a distributed energy management system communicating either directly with the distribution utility, or via third party aggregators.

As part of Phase 1, California chose to test autonomous voltage control, initially selecting real power priority settings on inverters as the distribution utilities performed a series of field demonstrations. In 2017, after gathering significant data, commissioning studies, and gathering extensive feedback from stakeholders, the Commission refined its recommendation on autonomous voltage control settings and standardized on reactive power priority.[20] California determined that it did not need to retrofit existing systems already in the field. Since July, 2017, regulations require all inverters installed in the field to autonomously provide voltage control using reactive power settings. The objective of Phase 2 was the development of communication protocols, in part to enable Phase 3, which focused on advanced smart inverter functions, including active control of voltage control modes.

Hawaii commissioners turned to NREL to develop recommended autonomous voltage control settings for inverters. NREL started by developing a simulation of Oahu's grid at NREL's testing facility. NREL used its simulation tools to test four emerging smart inverter protocols under various transient over-voltage scenarios. As a result, Hawaii now requires all inverters to operate in autonomous "volt/VAR control" mode (a reactive power setting) for all new solar inverters installed. NREL is now working with a small group of solar customers in HI who allow NREL to control their inverter settings remotely to determine if different settings can yield better results.

In addition to settings that have been codified in interconnection regulations in both these states, sizable demonstration projects are ongoing in other states. Projects in Arizona are summarized in the following table.

[18] St John, J. Greentech Media. A State by State Snapshot of Utility Smart Solar Inverter Plans. November 6, 2015

[19] NREL(https://www.nrel.gov/news/features/2018/nrel-and-hawaiian-electric-navigate-uncharted-waters-of-energy-transformation-part-1.html)

[20] CPUC, Staff Proposal on Reactive Power Priority Settings of Smart Inverters. July 2017.

Region	Project Objective	Description	Results & Next Steps
Arizona	Arizona Public Service & EPRI - pilot project from 2015-2017[21] designed to determine the optimum technologies to enable high penetration distributed PV.	• 1600 utility owned, smart inverter-controlled rooftop solar systems were deployed, concentrated on specific testing feeders. • In addition to tracking voltage using the 1600 smart inverters, APS also tracked voltage fluctuation on an additional 14,000 customers located on the test feeders using advanced meter infrastructure (AMI).[22] • APS developed a platform to connect the rooftop systems to the utility's control center and to allow for real-time data transfer between the utility and smart inverters, allowing APS to operate the rooftop systems like any other power plant, ramping or curtailing as required.	• APS is testing multiple technologies – including smart inverters and energy storage, to ensure power quality. The work performed from 2015 – 2017 demonstrated that smart inverters correctly tracked commands, effectively maintained power quality, and increased hosting capacity on the feeder.[23]
Arizona	Salt River Project (SRP) & EPRI launched Advanced Inverter Pilot and includes approximately 700 residential solar participants and a commercial system.	• SRP is testing three voltage control modes simultaneously: 1) fixed inverter setting; 2) a mix of fixed and seasonally changed settings; 3) actively controlled settings.	• SRP found smart inverters are effective at controlling power quality. • SRP also found that inverters generally have a very low error and follow instructions closely.[24]

2. Ride through: Smart Inverters have the capability of "riding through" minor disturbances to frequency or voltage instead of tripping off line. Voltage ride-through is used to keep large amounts of DER from disconnecting from the grid during a short-duration voltage event. Transmission and distribution faults (e.g. ground faults) can cause voltage to dip or swell before fault-clearing devices on the power system act to restore normal power flow. If DER makes up a significant part of the total generation serving an area, loss of the generators could delay voltage recovery or cause further frequency instability.

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[21] EPRI Quarterly Update Q3 2017, Integrated Grid Pilot Projects
[22] APS & ERPI, Solar Power Program: Research Highlights, January 31, 2017.
[23] EPRI, Arizona Public Service Solar Power Partner Program, Advanced Inverter Demonstration Results, 2017 Technical Report. May, 2017.
[24] EPRI, Quarterly Update: Integrated Grid Pilot Projects. Q3, 2017.

Traditionally, interconnection requirements have mandated that inverters must shut down during grid issues to prevent back-feeding current onto the grid, which could jeopardize safety. But when inverters shut down, solar projects can't generate power, and sometimes the lost generation is significant, potentially creating problems for grid operators. For example, a fault on the transmission system caused by a wild fire drove about 1,200 MW of transmission-connected solar generation in Southern California (three assets of approximately 400 MW each) to "trip" offline and cease generating power. The NERC report on that event highlighted the need to change the conditions under which inverters trip, requiring inverters to ride-through short faults. This has since been addressed transmission-connected systems.[25]

The objective of all US utilities and their regulators should be to avoid the hard lesson learned in Germany which was forced to retrofit 30,000 inverters in the field in 2013.

In the US, California and Hawaii have again led the effort to specify standards for ride-through capability in which are now codified in Rule 21 and Rule 14, respectively. FERC considered issuing an Order on ride-through in 2006, but after receiving feedback declined to include ride-through in FERC's Small Generator Interconnection Agreement at that time, confident that standards organizations such as IEEE was addressing the issue.[26]

Because of the rapid growth of solar PV in New England and the timeline for full implementation of the revision to IEEE 1547, ISO-NE also sought out an interim solution for obtaining ride-through for voltage and frequency variations. ISO-NE worked with the Massachusetts Technical Standards Review Group (TSRG) to get input from distribution engineers, solar PV developers and inverter manufacturers. ISO-NE created default settings for ride through capabilities by setting a frequency range which is within the allowable range in Category II of IEEE-1547-2018™.

3. Communication controls: Historically, communication between grid operators, distribution companies and generators was limited to expensive SCADA systems and was only economic on large facilities. Leveraging the fact that costs for communication systems have decreased significantly and there are increasingly economic solutions available for DER, particularly for larger commercial and industrial DER, IEEE 1547-2018™ requires smart inverters to support at least one of three standard communication protocols, allowing various parties to communicate with and receive updates from smaller DER such as a residential solar system.

The primary objective of Phase 2 of California's smart inverter rollout was the development of communication protocols. California standardized on IEEE 2030.5 for communication protocols, which

[25] NERC, 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report, Southern California 8/6/2016 Event. June, 2017.
[26] FERC, Order 792, paragraph 220. November 22, 2013.

includes cybersecurity requirements. An update to IEEE 2030.5 was published in May 2018 to synch the communications standard with IEEE 1547-2018™.

IEEE 2030.5 Specifies Secure Communication Protocols for Smart Inverters

Congress charged National Institute of Standards and Technology in 2007 to coordinate standards for the development of the smart grid, including cybersecurity.

IEEE 2030.5 outlines secure communication protocols, and has been evaluated and found to comply with NIST requirements.

IEEE 2030.5 was recently updated to synch with IEEE 1547.

The National Institute of Standards and Technology (NIST) has been mandated by Congress, via the Energy Independence and Security Act of 2007, to coordinate standards for the development of the smart grid. NIST in turn created the Smart Grid Interoperability Panel (SGIP) which was established as a public/private partnership to develop communication and cybersecurity protocols. In 2017, SGIP merged with Smart Electric Power Association (SEPA).

In short, standards organizations have been carefully planning for and developing rules to ensure the security of the smart grid. IEEE 2030.5 was developed using foundational documents, including NIST's Guidelines for Smart Grid Cybersecurity (NISTIR 7628 Rev 1), and has been evaluated by the SGIP and found to be compliant with NISTIR 7628.

Ensuring cybersecurity has been an important aspect of CA's Smart Inverter Working Group in Phase 2. It's worth highlighting that IEEE 2030.5 and Open ADR requires both the client (e.g. the utility) and the device (e.g. the DER or DER Aggregator) to send a security certificate to each other for authentication. This is above and beyond online banking, which only requires one certificate, just from the client to the device.

Numerous companies are actively working to develop or deploy software platforms that provide cost effective encryption solutions over public lines, versus private. APS successfully used a virtual private network (VPN) as part of its Solar Power Partners Program where it deployed 1600 solar systems connected to APS' operations center. In 2017, CAISO interconnected a generation facility using critical infrastructure software defined network (CISDN) developed by Dispersive Technologies.

IEEE 2030.5 requires two-way authentication for DER, which is more secure than on-line banking.

Beyond security, each of the California Distribution Companies has conducted its own pilot programs to test communication protocols, latency and security. These companies are also working to develop their strategy for communicating with DER. Anticipating that DERMS will be interfacing with hundreds of thousands of DER, millions if EVs are included, the California distribution companies are considering they will interface with DERMS, which will in turn provide information, and potentially control, of all smart inverter connected devices. In short, the DERMS will act as an interface between the utility and DER. DERMS will recruit, compensate, and operate aggregated DER in response to signals provided by distribution utilities.

EPRI has also been leading several demonstration projects focused on smart inverter communication. The key elements of the projects include end to end communications at the utility operations center through integration of distributed energy resource distribution management system, back-end DER plant master controller and functionality built into smart inverters. The benefits include that standard communication protocols will enable PV inverters from different manufacturers to support the same feeder and also, responsive and controllable PV inverters can be coordinated with existing devices like load tap changers, voltage regulators, and capacitor banks.

APS' Solar Power Partners Program also tested communications speed and volume. APS tested both cellular network connection as well as AMI radio. The cellular connection included a virtual private network (VPN) connection between the modem and APS operations center. APS successfully communicated with smart inverters daily, sending both commands to change configuration and receiving a data set every five minutes.