The cost of waiting: Why utilities need to proactively guide standard DER bulk system responses

By Patrick Dalton and Bob Mack, ICF

Industry standards

IEEE technical standards are formal documents establishing uniform engineering or technical criteria, processes, methods, and practices developed through an accredited consensus process. Standards are:

- Developed based on guiding principles of openness, consensus, balance, and due process
- Established to meet technical, safety, societal, and regulatory needs for technological innovation and global market competition

Abstract

A lack of coordination between utilities and system operators in efforts to standardize regional distributed energy resource (DER) responses can result in inadequate responses for bulk system reliability, create distribution protection and control issues, or drive a need for more complex modeling to account for a range of responses and uncertainties. To support bulk power system (BPS) reliability, DER must stay connected and produce power over a wider range of system disturbance conditions than historically was the case. At the same time, DER responses must coordinate with distribution system protection and control schemes. Further, since modeling DER for BPS reliability studies can be complicated if there are different response types (for example, if a region initially uses standard default responses and later makes changes), regional stakeholders can establish a regional DER response profile prior to the availability of the next generation of certified equipment to proactively mitigate the range of potential issues.

The DER interconnection and interoperability standard IEEE 1547-2018 is garnering significant attention in the industry. Take, for instance, the National Association of Regulatory Utility Commissionsí (NARUC) recently approved resolution recommending that states convene stakeholder processes to adopt the standard.[1,2] NARUC's resolution recognizes the opportunity to take a deliberate approach to implementing advanced DER features, prior to the availability of equipment for these new standard features. The next generation of DER technology, expected to become widely available in the next couple of years, is highly configurable. Adopting new configurable DER functions requires utilities to make important technical implementation decisions. The DER bulk system response aspects of IEEE 1547-2018 involve particularly complex considerations, which contributed to a fast-tracked amendment of the standard in early 2020 (less than two years after the standard was published), a development that came as a surprise to many in the industry.

Recently, some select Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) have taken actions to guide the implementation of IEEE 1547-2018 to support the BPS.[3] These guidelines specify DER ride through responses to stay connected during system disturbances and help to avoid cascading BPS generator-tripping events that could threaten grid reliability. To date, three ISOs have initiated or completed processes to provide guidelines for IEEE 1547-2018 adoption. Some state regulators have already ordered utilities to adopt ISO/RTO guidelines,[4] while more states are expected to start proceedings, especially in light of NARUC's resolution. Since distribution and BPS needs have inherent tension and tradeoffs related to the types of DER responses allowed by the standard, utilities greatly benefit from taking an active role in shaping the implementation of standardized regional DER responses for bulk system disturbances, avoiding operational and planning issues that might otherwise result.

Why should utilities engage with IEEE 1547-2018 implementation?

Proactive utility engagement is key to coordinating DER responses that support the BPS while balancing distribution system needs and urgent objectives as DER becomes more prevalent. In fact, it was a sense of urgency around DER BPS responses that, in part, drove the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2018 revision, but that is not apparent from the industry chatter today. While much of the current discussion focuses on "smart inverter" functions like volt-var and volt-watt, standard DER ride through capabilities critical to electric system reliability and resiliency often receive less attention. In contrast, the North American Electric Reliability Corporation (NERC) published a report for recent BPS events in California showing significant levels of DER tripping—tangible evidence of the potential for DER to impact system reliability if utilities do not implement new BPS support functions.[5]

Approaches not well formed when advanced DER functions become available may lead to multiple versions of DER response profiles (some of which do not meet operational needs and all of which must be accounted for in planning studies), increasing the complexity of an already complex evolving grid. Utilities and system operators with low levels of DER penetration have an important opportunity to shape implementation requirements so that future DER in their service territory has a predictable and desirable response for many

Standard DER bulk system reponses

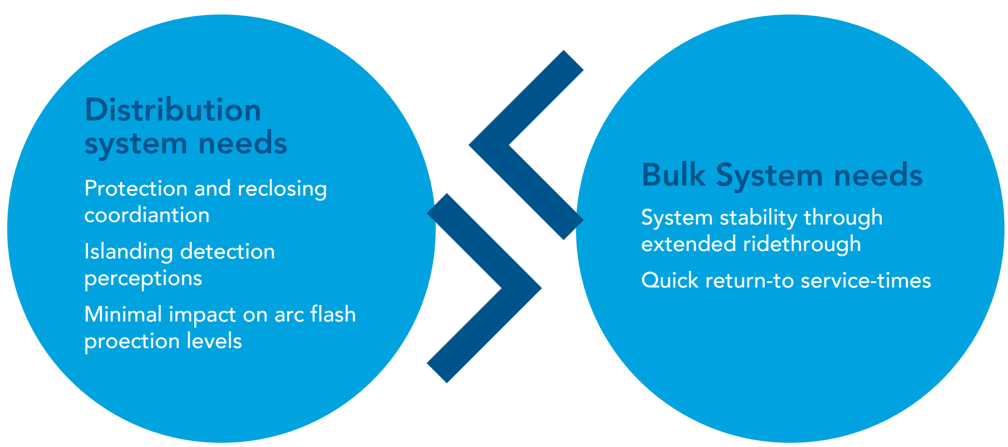
Interconnection and interoperability standard IEEE 1547-2018 defines capabilities, functions, and ranges of allowable settings for DER responses in support of bulk system reliability. Implementing IEEE 1547-2018 requires deciding how DER should respond to bulk system disturbances which might come about from a transmission line fault or generator tripping. Events on the bulk system propagate abnormal voltage or frequency conditions downstream onto distribution systems. DER have historically tripped quickly during system disturbances to simplify system operator troubleshooting and restoration processes. However, an increase in DER penetration in some regions is causing bulk system operators to request DER performance characteristics, such as voltage and frequency ridethrough, that resemble bulk system generator responses.

years to come. As more ISOs/RTOs and state regulatory commissions look to address BPS concerns by implementing IEEE 1547-2018 standard responses, stakeholders may lose the opportunity to take an active role in shaping outcomes that are also preferable to their own operating requirements.

Why does implementing the standard require stakeholder discussions?

While standard DER capabilities surrounding response to abnormal voltage and frequency grid conditions may closely resemble those found in the BPS standard NERC PRC-24-2,[6] the interconnection point of DER on the distribution system leads to unique considerations and tradeoffs. For example, bulk system operators typically prefer ride through regions and mandatory trip times be extended to protect grid reliability, whereas distribution utilities often prefer faster trip times in order to reduce the potential to interfere with distribution reclosing practices or to minimize arc flash concerns. Figure 1 illustrates key aspects of balancing distribution and bulk system needs. This tension between BPS and distribution objectives has been the focal point of recent stakeholder discussions among utilities, regulators, and ISOs/RTOs.[7] The stakeholders involved in striking a balance of BPS and distribution system needs may not historically have communicated regularly and often do not have a shared understanding of power system terminology, as various stakeholders use common terms for different purposes. Establishing lines of communication and an understanding across domains will help utilities continue to operate a safe and reliable system as interactions across transmission and distribution necessarily increase. The implementation of IEEE 1547-2018 in several jurisdictions provides an illustration of potential approaches and outcomes. It is notable that these discussions have led to the fast-tracking of an amendment to the interconnection standard IEEE 1547-2018, which speaks to the complexity of balancing transmission and distribution system objectives.

Figure 1. Balancing Tension between Distribution and Bulk System Needs



Bulk system reliability needs drive changes to DER performance

Recent bulk power system events in California have shown the importance of DER responses to maintaining BPS reliability. In the case of the Angeles Forest disturbance, a failed splice on a 500 kV transmission line caused the tripping of 130 MW of distributed solar PV in the California Independent System Operator (CAISO).[8] The drop in solar PV output came as a result of the inverter controls and protection response to the event. Due to the amount of DER tripping for this event, it was the first disturbance NERC has analyzed where a discernible response of DER was observed through a significant increase in net load. While no conventional bulk system generating resources tripped because of this event, the aggregate solar was the size of some bulk system generators. It provides an example of inverter responses to bulk system events and how the proliferation of DER can impact BPS reliability if support functions are not used or properly configured. NERC goes on to recommend implementing changes to the momentary cessation and voltage and frequency ride through settings that ensure continued reliability on the BPS, further highlighting the importance of coordinated generator responses for bulk system operations. Acting early before DER penetrations are high can help to avoid bad outcomes like the expensive inverter retrofits in Germany needed to manage a system over-frequency issue (i.e. the "50.2 Hz problem").

Striking a balance for DER responses to address distribution and bulk system needs

While distribution and bulk system operators have the same operating objectives of a safe and reliable system, the preferred response from DER may differ significantly between these groups. Bulk system operators often prefer DER to stay connected and output power for a wider range of abnormal conditions, whereas distribution system operators usually prefer the DER to disconnect quickly for system disturbances. This inherent tension requires stakeholders to discuss the options, to weigh tradeoffs, and to strike a balance that is acceptable to system operators across the electric power system supply, delivery, and distribution chain. There are at least four types of considerations to account for when determining an appropriate balance of DER responses to meet distribution and bulk system needs.

- **Reclosing coordination.** Distribution protection engineers may be concerned with out-of-phase reclosing for a circuit energized by DER during low-voltage ride through, especially for circuits with fast reclosing.
- **Protection coordination.** Basic protection coordination for high-impedance faults is a potential issue associated with extended ride through times. Relatively high levels of DER short circuit current may lead to miscoordinated utility protective devices.
- **Worker safety and arc flash.** Extended DER tripping times during ride through events can contribute to higher levels of arc flash incident energy. To a lesser degree, due to the prevalence of inverter-based DER, increased levels of fault current can also impact arc flash.

- **Anti-islanding protection.** DER anti-islanding protection is a concern for some distribution utilities, given the potential for ride through times to extend beyond the standard requirement for DER to quickly detect islands and trip. However, IEEE 1547-2018 states that ride through shall not interfere with DER anti-islanding requirements.

Implementing IEEE 1547-2018 standard involves key decision points

The publication of IEEE 1547-2018 triggered a chain of additional standards and certification development activity that will lead to DER equipment with certified capabilities entering the market in the coming years. IEEE 1547-2018 requires all DER to have capabilities and functions to support bulk system stability during disturbances or abnormal conditions. However, the new standard DER functionality creates several key decision points for utilities. Utilities with clearly defined outcomes for each decision point are better positioned to secure favorable outcomes in stakeholder proceedings (discussed in greater detail below). Table 1 summarizes these key decision points related to adopting DER bulk system responses.[9]

Table 1: Summary of Decision Points and Key Considerations

Decision Point	Key Considerations	Industry Trends
Performance Category Assignment	▪ Current and anticipated levels of DER penetration ▪ Types of DER expected	Category II or III for inverters Category I for synchronous machines
Voltage Mandatory Ride Through and Tripping Settings	▪ Bulk system reliability ▪ Distribution reclosing schemes ▪ Impact on fault current level	Modifying undervoltage trip settings and otherwise using IEEE 1547
Frequency Mandatory Ride through and Tripping Settings	▪ Bulk system reliability ▪ Coordination with underfrequency load shedding schemes	Using IEEE 1547-2018 defaults
Return-to-Service Response Settings	▪ Bulk system capacity needs ▪ Distribution voltage regulation	Not addressing and/or accepting IEEE 1547-2018 defaults
Frequency Droop Settings	▪ Bulk system reliability	Not addressing and/or accepting IEEE 1547-2018 defaults
Optional Dynamic Voltage Support Function and Settings	▪ Bulk system reliability ▪ Lack of standards functions definition	Not implementing at this time.
Optional Inertial Response Function and Settings	▪ Bulk system reliability ▪ Lack of standards function definition	Not implementing at this time.

Decision point: Specifying performance Category I, II, or III for response to abnormal grid conditions

IEEE 1547-2018 introduces the concept of DER performance categories. Utilities, with the guidance of state regulators, select from standardized groups of DER performance characteristics. Performance categories are defined for DER response to normal (i.e., steady-state voltage) and abnormal (i.e., transient voltage disturbance) conditions. Abnormal condition performance categories are particularly important in the context of bulk system responses because each category has its own recommended default voltage, frequency ride through settings, and range of allowable settings. Selecting a performance category based on expected conditions over the lifetime of the DER is a critical first step in implementing IEEE 1547-2018. In other words, the expected level of DER deployment in a region is the most significant factor in selecting a performance category, which is fixed over the lifetime of the DER. While the standard requires DER from all performance categories to ride through voltage and frequency disturbances (and the function cannot be disabled), the degree of ride through capability is adjustable within defined setting limits based on the performance category of the DER. Performance category selection also affects the options for frequency droop performance, impacting how DER responds to deviations in system frequency. Table 2 shows the general characteristics and supporting basis of ride through performance for each performance category.

Table 2: Description of IEEE 1547-2018 Performance Categories

Requirement	Performance Category	Characteristics	Basis
Voltage Ride Through and Mandatory Tripping	Category I	▪ Meets essential bulk system needs ▪ Suited for rotating machine DER	Synchronous machine requirements in German grid code
Frequency Ride Through and Mandatory Tripping	Category II	▪ Meets all bulk system needs ▪ Suited for Inverter-based DER in moderate DER penetration to avoid tripping for wider range of disturbances	NERC PRC-24-2 with adjustments for delayed voltage recovery
	Category III	▪ Meets all bulk system needs ▪ Suited for Inverter-based DER in high DER penetration and includes distribution system reliability/power quality needs	California Rule 21 and Hawaii 14-H with modifications requirements for high DER penetration
	All Categories (harmonized)	▪ Meets all bulk system needs ▪ Suitable for low inertia grids	California Rule 21 and Hawaii 14-H

Decision point: Specifying voltage and frequency ride through performance and mandatory trip settings

IEEE 1547-2018 provides default ride through performance and trip settings that practitioners can choose to adopt or modify (within defined limits) as required by their jurisdiction. Trip settings are provided as two sets of values, over and under, for both voltage and frequency criteria. For example, voltage trip settings are provided as OV2, OV1, UV1, and UV2. Each parameter defines a voltage and frequency trip setting and corresponding clearing time. Similarly, ride through regions are defined through time and magnitude parameters. Figure 2 illustrates an example implementation of voltage ride through regions and trip settings.

Figure 2: Example of new ride through and mandatory tripping created by IEEE 1547-2018

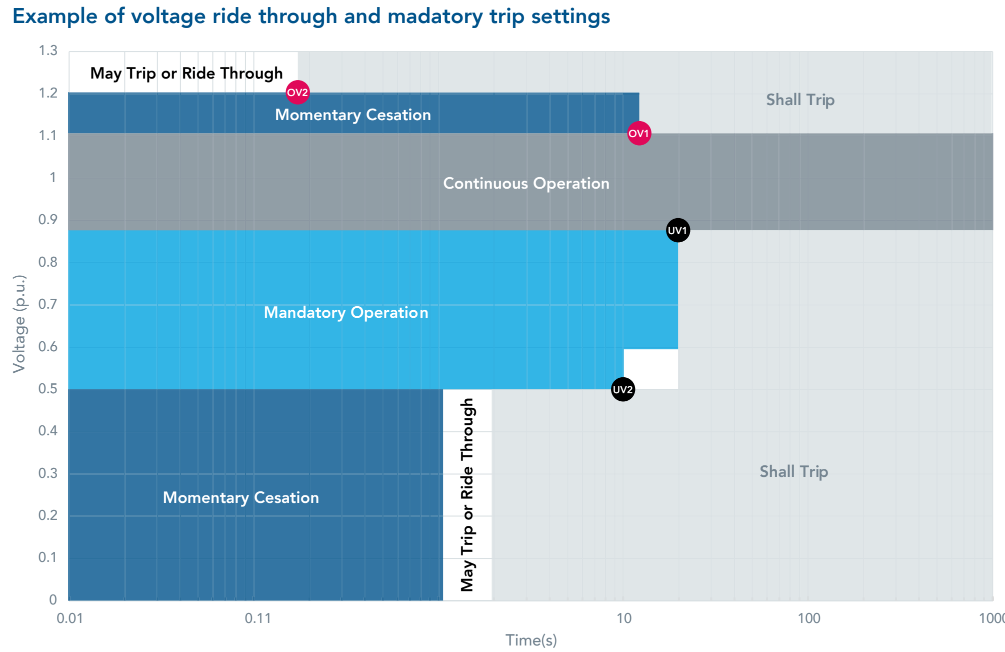
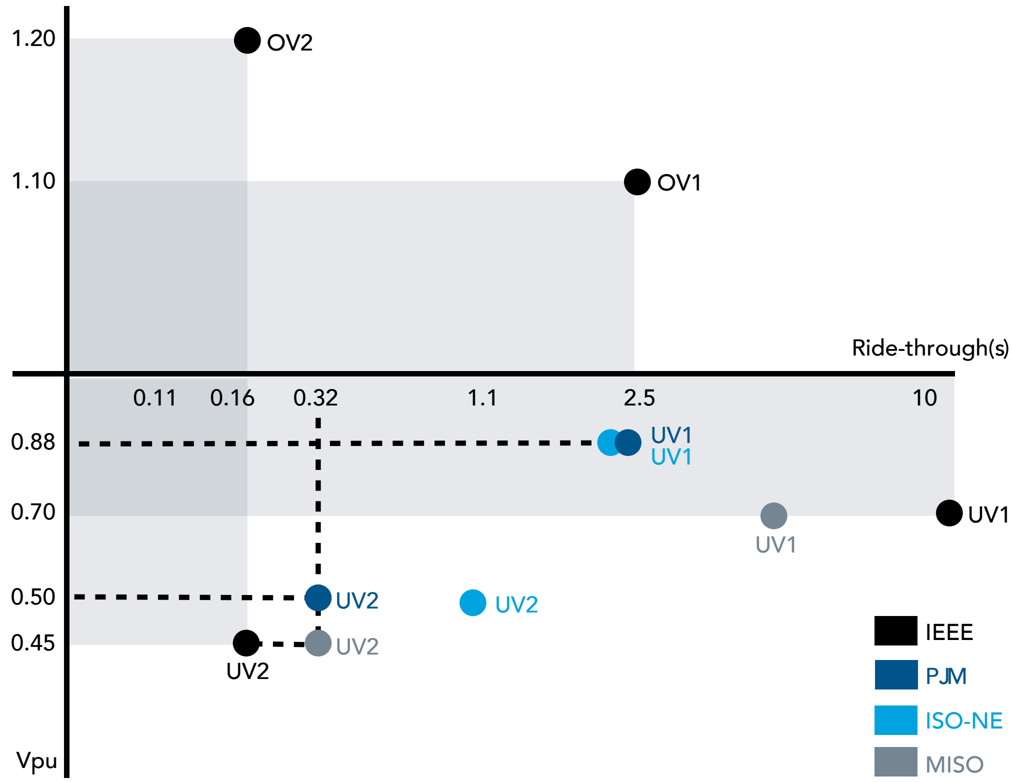


Figure 3 shows ISO/RTO guidelines for voltage ride through and trip settings as compared to the IEEE 1547-2018 default settings. For example, PJM, MISO, and ISO-NE have all adopted the default over-voltage trip settings as-is. However, each of them has applied unique under-voltage trip settings. In MISO's case, while it recommended a UV1 trip time half the length of the default trip setting, it also recommended a UV2 trip time setting doubling the default value. This illustrates that jurisdictions are moving away from default settings, demonstrating the potential for more complex modeling if the first wave of advanced inverter DER uses default settings and subsequent DER uses different settings. Although each ISO/RTO may select ride through and trip settings specific to their jurisdiction, in consultation with local distribution utilities, there are common concerns with the potential for wide area low-voltage conditions and the impacts of fault-induced delayed voltage recovery compounding the severity of low-voltage events. Balancing ISO/RTO and local distribution utility needs is the main driver for deviating from default settings in IEEE 1547-2018.

Figure 3: Comparison of ISO/RTO recommended settings

Cat II exceptions to IEEE 1547 voltage ride through and trip default settings



Decision point: Specifying return-to-service performance including intentional delay and ramp period

After a system disturbance causes the DER to trip, the DER will delay resuming power production for a set period of time before ramping up output over another set time period. Both the delay time and ramp time are adjustable, within defined limits. According to IEEE 1547-2018, return to service shall follow the requirements anytime a DER is entering service. Table 2 shows the default and adjustable ranges for return-to-service and enter service.

Table 3: Return to service and enter service settings

	Default Setting	Range of allowable settings
Intentional delay	300 seconds	0 second to 600 seconds
Ramp time	300 seconds	1 second to 1000 seconds

Transmission system operators may prefer shorter DER ramp times to bring supply resources back online as quickly as possible, while distribution system operators may prefer longer ramp times if they need to coordinate with voltage regulation schemes. Transmission and distribution system operators must strike an acceptable balance when recommending settings.

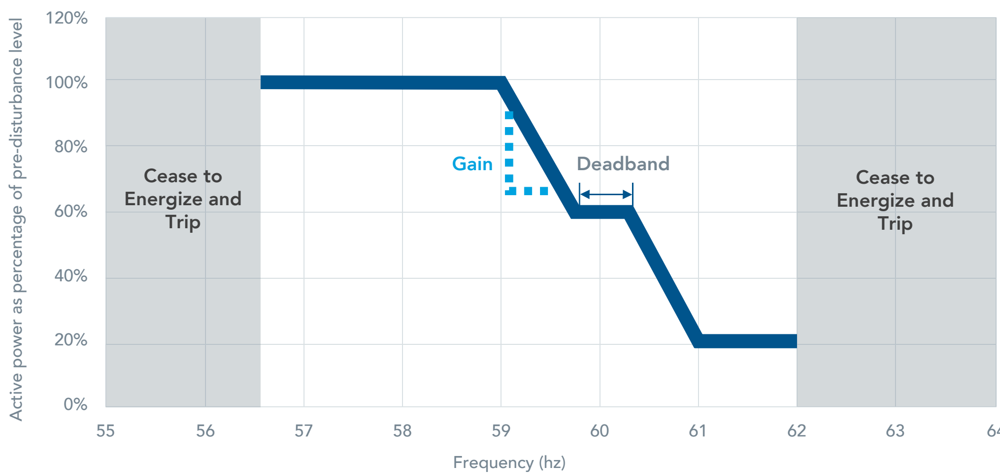
Decision point: Modifying frequency droop default settings

Rotating-machine generators have traditionally varied active power output based on the system frequency to rapidly compensate for slight differences in power supply and demand. This "frequency droop" function is required by IEEE 1547-2018 for all DER. The standard default settings are the same for all three performance categories. However, Category II and Category III must respond to high- and low-frequency conditions, whereas Category I must respond to high-frequency conditions and has the option to respond to low-frequency conditions. Three standard parameters are adjustable:

- Deadband above and below 60 hertz (db_{OF}, db_{UF})
- Gain for under and over frequency events (k_{OF}, k_{UF})
- Open Loop response time for small signal events ($T_{response}$)

Figure 4 shows an example of a frequency droop curve with a pre-disturbance power level of 60% of DER nameplate. The pre-disturbance power level is a key variable in the function defining frequency-droop response as it defines the starting point of the functional response.[10]

Figure 4: Frequency droop example with pre-disturbance power level of 60% of nameplate



Decision point: Including dynamic voltage support requirements

Standard IEEE 1547-2018 permits dynamic voltage support functions for DER, but these functions are not defined or required. Since no standard-defined function exists, the industry has been slow to adopt dynamic voltage support functions. These functions inject reactive power into the power system to prop up voltage during a system fault. Supporting voltage contributes to other DER generating resources maintaining production instead of tripping—and potentially worsening—the severity of a low-voltage event. The standard allows for the use of dynamic voltage support only in the *mandatory operation or permissive operation* regions. The DER *restore output* response differs depending on whether dynamic voltage support is active.

Decision point: Including inertial response requirements

The standard allows DER to mimic a generator inertial response where it varies active power proportionally to the frequency rate of change. While the standard permits this function, no standardized definition or parameterization exists. Like the dynamic voltage support function, industry uptake has been slow due to these standardization barriers. Since fast-acting frequency support from inverter-based resources is an important aspect of the evolving grid, these functions are ripe for further development and definition in future standards development efforts.

Stakeholder processes offer an opportunity for utilities

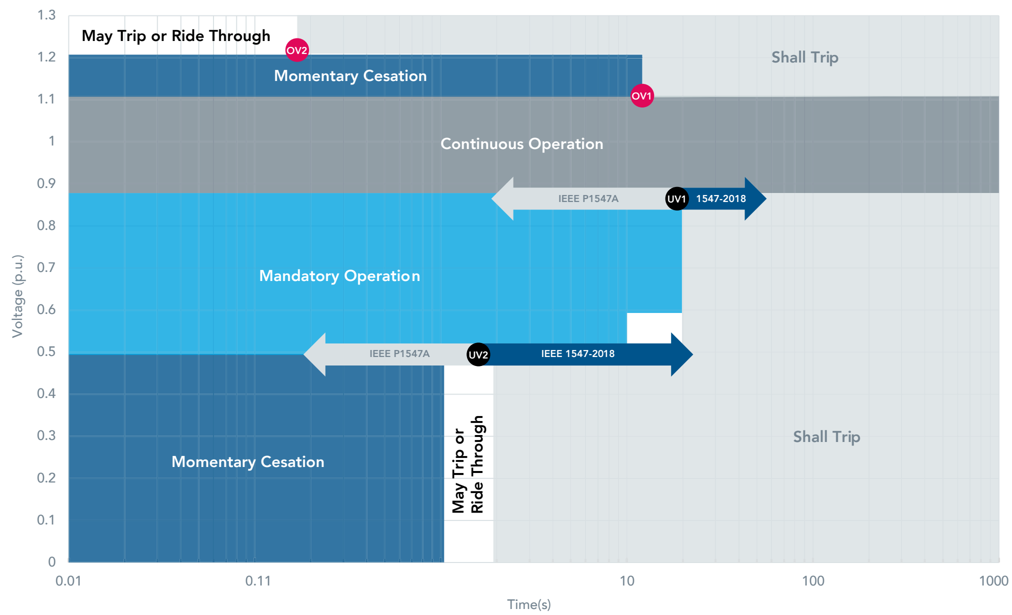
Stakeholder processes held by ISOs/RTOs or state regulators offer an opportunity for utilities to advocate for standardized DER settings compatible with their BPS and distribution system operations. The tension between BPS and distribution utility preferences for DER responses means that it is essential for utility engineers to be actively engaged in processes aimed at developing DER setting guidelines. While three of the major ISOs/RTOs have developed initial guidelines, other ISOs/RTOs have not started the process. Just like standards changing over time, established ISO/RTO guidelines will change as the industry gains additional experience with high DER penetration responding to bulk system disturbances. Regardless of whether a utility is operating in a region with guidelines established, it is important for utilities to understand the inherent tradeoffs created when balancing system objectives. This allows utilities to more meaningfully engage in stakeholder processes when the opportunity arises. Informed engagement by utilities in these processes will contribute to utility core objectives of protecting safety, reliability, and resiliency, all while integrating higher levels of DER.

We are still in the early days of specifying DER responses to support local and bulk systems

The development of IEEE 1547-2018 attempted to anticipate the range of ways in which utilities and system operators would need DER to respond. These expected needs translated into a “range of allowable settings” for many standard DER functions. What stakeholders did not anticipate was how quickly system implementers would find the standard options to be deficient for their application. Stakeholder processes that included distribution utilities and ISOs/RTOs led to a fast track amendment of IEEE 1547-2018 ride through capabilities for Category III to better balance the needs of BPS and distribution system objectives. Most notably, the PJM and MISO processes drew on lessons from the ISO-NE process and started coalescing industry thinking around the need for a standards amendment that allows for a greater range of set points. Figure 5 illustrates the amendment changes to UV1 and UV2 ranges of adjustability for time delay. The upper time range remains the same, but the lower time range extends to allow for shorter tripping times. The amendment will allow for the selection of the Category III performance category while maintaining flexibility for greater inclusion of the distribution operator perspective.

Figure 5: Illustration of IEEE 1547 Amendment Changes

IEEE 1547-2018 Ammendment to category III range of allowable settings



The time to act is now

While the key decisions present a complex landscape of technical and stakeholder challenges, it is important that utilities start engaging in the implementation of IEEE 1547-2018 early. Some utilities may even suggest regulators proactively open proceedings to adopt and implement the standard. Completing this process soon, before certified DER equipment is available, will position utilities to plan and operate the evolving electric system. Approaches that are not well-formed when advanced inverter functions become available may lead to bulk system reliability issues, conflicts with distribution protection or controls, and multiple versions of DER settings and functionality that must be accounted for in planning and operations.

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[1] National Association of Regulatory Utility Commissions (NARUC), Resolutions Proposed for Consideration at the 2020 Winter Policy Summit, 1/28/2020. https://pubs.naruc.org/pub/49A6A319-155D-0A36-3140-EFAD21E48B50

[2] The NARUC resolution also recommended to align implementation on IEEE 1547-2018 with the availability of certified equipment.

[3] Although the conversations may occur in a different context for vertically integrated utilities not in an organized wholesale market, effectively articulating the tradeoffs in DER impacts at the transmission and distribution level enables utilities to protect bulk system reliability.

[4] On November 14, 2019, Minnesota was the first state to adopt new interconnection standards that include IEEE 1547-2018. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={9047416E-0000-C03A-85BA-8002F2E9154D}&documentTitle=201911-157269-02

[5] April and May 2018 Fault Induced Solar Photovoltaic Resource Interruptions Disturbances Report. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

[6] NERC Standard PRC 24-2 is a reliability standard guiding bulk system generator frequency and

voltage protective relay settings. https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-2.pdf

[7] ISO-NE Planning Advisory Committee Meeting Minutes, February 14, 2018. https://www.iso-ne.com/static-assets/documents/2018/05/021418_final_pac_minutes.pdf

[8] April and May 2018 Fault Induced Solar Photovoltaic Resource Interruptions Disturbances Report. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

[9] Implementing IEEE 1547-2018 also involves many other decisions surrounding real and reactive control functions and use of the interoperability interface (both of which are out of scope for this paper).

[10] Details of the formula defining this function are beyond the scope of this paper.

About the Author

Patrick Dalton is a manager on ICF's Distributed Grid Strategy team. In this role he focuses on supporting clients in developing solutions to address DER impacts on utility planning and operations across the U.S. Patrick has eleven years of distribution engineering experience at major U.S. electric and natural gas utility where he most recently led a team responsible for DER integration. He supported drafting of the recently approved Minnesota statewide interconnection process and technical standards. He is an active member of industry standard working groups related to DER interconnection, interoperability, and energy storage including IEEE 1547-2018, IEEE P1547.1, IEEE P1547.2 and IEEE P1547.9. Patrick participated in efforts to address impacts of DER on the bulk electric system, including the NERC System Planning Impacts from DER (SPIDER) working group and the development of MISO guidelines for DER IEEE 1547 implementation. Patrick is a licensed professional engineer in Minnesota. Patrick recently joined the University of St. Thomas in an adjunct faculty role.

Bob Mack is an analyst on ICF's Distributed Grid Strategy team. He brings experience in distribution planning, system hardening, distribution system reliability, load forecasting, distribution operations and interconnection of both solar photovoltaic (PV) and energy storage systems to the grid. Bob's expertise stems from his utility experience working in Distribution Planning and Distributed Generation, and in working closely with the Joint Utilities of New York. His expertise includes advising best practices to updating interconnection requirements to deal with high penetrations of DER, modeling and analyzing power distribution systems, hosting capacity criteria and methodologies, analyzing historical and real time data in context of both load and distributed energy resources (DER) forecasts and evolving traditional distribution planning and operations best practices to account for higher penetrations of DER. Bob has led the technical analysis to study the impacts of energy storage technologies on the distribution system, specifically in the context of non-wires solutions. Bob has also worked closely with ICF's Independent Engineering group to support the technical due diligence of utility solar and wind scale interconnections for project financiers.

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Visit us at icf.com/work/energy

For more information, contact:

Patrick Dalton
Patrick.Dalton@icf.com +1.612.336.7501

Bob Mack
Bob.Mack@icf.com +1.212.656.9151

twitter.com/ICF
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