Revision of IEEE Standard 1547™

Additional Topics

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This TechSurveillance *article is the last in a series of four articles that describe the changes proposed for IEEE 1547, provide the rationale for these changes, and describe how they will affect the planning, design, protection, and operation of rural electric cooperative distribution systems into the future. All of the articles in this series are available to members on* ***cooperative.com****.*

The ***first article*** *of the series provided the background of IEEE 1547 and the drivers behind the present revision effort. The* ***second article*** *focused on DER reactive power and voltage regulation performance requirements that will be mandated. The* ***third article*** *focused on voltage and frequency disturbance behavior, including new ride-through performance requirements.*[1] *This final article addresses a number of remaining topics not covered in the preceding articles. Although it is now in the final draft stage, cooperative engineers are encouraged to become involved in the review and balloting of this proposed standard revision to ensure that it sufficiently addresses their system circumstances. Details on how to participate in the balloting process are defined at the end of this article:* ***Balloting Process for IEEE 1547: How to become a member of the balloting pool for IEEE Standards****.*

[1] After the third article was published, a new report from NERC became available that provides much additional information on the potential impacts of DER on the bulk power system. Although it does not directly pertain to the array of topics covered in this article, a link to this NERC report is included in the list of references at the end of this article for the convenience of readers of this *TechSurveillance* series.

ARTICLE SNAPSHOT

What has changed?

IEEE Standard 1547, which defines interconnection requirements for distributed energy resources (DER), is presently undergoing a major revision. The standard is greatly increased in complexity and detail, and introduces concepts and terminology that may be unfamiliar. A number of requirements have been made more definitive, such as quantitative flicker and overvoltage limits, and clarification of the requirements for DER to coordinate with feeder reclosing practices. Although the details of DER testing will be covered in a separate standard (revised IEEE 1547.1), the revision of the base IEEE 1547 standard addresses the stage where each requirement of the standard will be tested or verified, such as at the factory, by analysis and design review, or at commissioning of the DER facility.

What is the impact on cooperatives?

The proposed changes to IEEE 1547 bring this standard up to date to address the increasing challenges of greater DER penetration and the changing nature of DER equipment and applications. The revised standard is more definitive, and requirements placed on the DER provide the utility with new ways to help mitigate DER system impacts. Unlike the original standard (IEEE 1547-2003), the revised standard explicitly provides utilities with considerable discretion regarding utilization of DER functionality. These changes however, place an increased burden on utilities to understand the complexities of the standard in order to apply it to the maximum benefit to their systems.

What do cooperatives need to know or do about it?

Cooperatives need to understand the proposed changes to IEEE Standard 1547 because they may affect the way that co-ops design, protect, and operate their systems. Interactions between the cooperatives and DER owners or installers can become more complex. Cooperatives' distribution systems often have characteristics and constraints that differ from the suburban and urban systems dominating most of the investor-owned and public utilities. Furthermore, most cooperatives cannot afford to have engineering staff dedicated solely to DER issues and application of this standard. It is important that the standard provides adequate recognition of the special nature of the typical rural electric cooperative. As the standard's draft development is now concluding, co-op engineers are encouraged to join the ballot pool to ensure that the standard adequately addresses the needs of the cooperative community. Please see the end of this article for details on how to participate in the balloting process.

INTRODUCTION

IEEE Standard 1547™-2003 is the model distributed energy resource (DER, i.e., distributed generation or storage) interconnection standard, used widely across the U.S. and Canada. Since the time when this standard was first adopted fourteen years ago, there has been tremendous growth in DER across the continent. The standard, now undergoing major revision, is greatly increased in detail and complexity. The previous articles in this series have addressed two of the largest areas of change, voltage regulation and disturbance performance.

This article points out several other changes in the proposed standard that are expected to affect utility interconnection decisions and practices. These selected topics are introduced here with a few key takeaways. The topics addressed in this article, which are not strongly related to each other, are:

- Scope of the standard
- Unique terminology used in the standard
- Feeder island and recloser coordination
- Intentional islands, including “utility microgrids”
- Power quality
- Data communications and interoperability
- DER testing and evaluation

The revised standard is now in the final draft stage, with balloting by industry stakeholders scheduled for spring of 2017.

SCOPE OF STANDARD

The intent of the working group is for the standard to cover *all* generation and electrical energy storage that connects to that which is commonly understood to be a distribution system.

The current version of the standard, IEEE 1547-2003, limits itself to the requirements for interconnection of DER (referred to as DR, or distributed resources in the 2003 version), rated 10 MVA or less, to the grid at “typical primary or secondary distribution voltages.” During deliberations of the IEEE working group developing the revised standard (referred to as P1547 in this article[2]), it was decided that a fixed MVA limit is inadequate as a criterion to discriminate distribution-connected generation or energy storage resource from transmission-connected resources. DER facilities with aggregate ratings greater than 20 MVA have been successfully interconnected with distribution systems, particularly at the higher primary voltages (e.g., 34.5 kV). On the other hand, there are smaller DER facilities interconnected to transmission and subtransmission (e.g., 69 kV) systems. Voltage level is not considered to be a clean-cut criterion, either. For some utilities, 23 kV is a transmission voltage, and for many others 34.5 kV is used for general distribution purposes.

The intent of the working group is for the standard to cover all generation and electrical energy storage that connects to that which is commonly understood to be a distribution system: a medium-voltage system delivering power to many end-use customers, typically over a radial feeder. The difficulty is in formally defining the distinction between distribution, sub-transmission, and transmission systems. The working group opted to remove the 10 MVA limit of applicability from P1547, allowing the determination of what is and is not distribution to be defined by the users of the standard. This effectively closes the previously existing gap with FERC’s small generator interconnection procedures, etc.

Figure 1 summarizes how the scope of P1547 changed compared to IEEE 1547-2003. The current IEEE 1547-2003 limits itself to the DER “interconnection system,” thus excluding the remainder of the DER from the scope. In practice, the interconnection system to which the existing standard referred could be an inverter, if the inverter had the self-contained protective functions required by the standard, or it could be just the relay and switchgear package used to interconnect a synchronous generator. The performance of the entire DER system is relevant to the new requirements now included in P1547, such as voltage disturbance ride-through. For example, if a prime mover is intolerant of a power output disturbance caused by a fault within the fault ride-through requirements, and the prime mover trips off, then the DER is noncompliant. Therefore, the scope of P1547 is no longer limited to the DER interconnection system.

[2] The “P” designation is used by the IEEE Standards Association to designate a standard draft or revised standard draft under development.

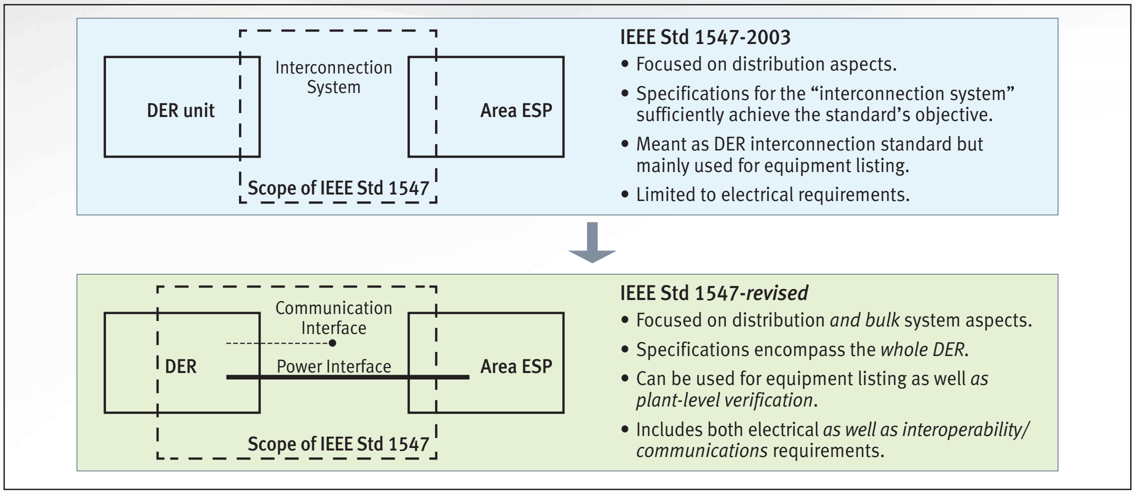

FIGURE 1: Changes in IEEE 1547's scope

The fact that IEEE 1547 is a DER interconnection standard and is not simply an equipment standard was reinforced in the new draft P1547. It has been recognized in P1547 that a DER facility may be a system of equipment that together meet the standard's requirements. Some examples where the required performance may be met by equipment other than the DER unit itself include:

- A generator combined with protective relays and switchgear to meet fault tripping requirements
- A STATCOM[3] supplementing induction generators (e.g., as sometimes used in small hydro and wind turbines) to meet variable reactive power and fault ride-through requirements
- Direct transfer trip system to achieve coordination with fast feeder breaker reclose delays and island avoidance requirements

Testing requirements in P1547 have been modified to accommodate the fact that a DER may not be self-sufficient to provide all of the required performance.

Utilities usually prefer that performance is defined at the point where the utility and customer system intersect, called the point of common coupling (PCC) in the standard. On the other hand, DER equipment manufacturers, particularly producers of small devices such as rooftop photovoltaic (PV) inverters, prefer that requirements apply at the terminals of the DER unit (e.g., inverter). The compromise reached in P1547 is that the requirements of the standard apply at the PCC for large facilities, defined as those which export at least 500 kVA to the utility system. Basically, utility-scale power generation facilities such as PV farms devoted to wholesale power sales fall into this category. Smaller DER embedded with customer load must meet requirements at the DER terminals, referred to as the point of DER Connection (PoC).

UNIQUE TERMINOLOGY

The standard uses terminology that may be unfamiliar to most utility engineers. The term "Area Electric Power System" or Area EPS is used throughout P1547 as a substitute for "utility system," and "Local Electric Power System" or Local EPS is a substitute for "customer system." These terms were used in the original standard and were introduced because some involved in the development did not want it to

[3] Static Synchronous Compensator — a power electronic device providing variable reactive power.

be tied to the current utility/customer structure. To avoid confusion, the same terms were carried forward into the P1547 draft.

Requirements in P1547 for DER to ride through certain faults and frequency disturbances introduce several unique terms, as defined below:

Cease to energize — means that the DER stops injecting active (real or kW-producing) current into the grid and any reactive current flow is limited. It is not feasible to require that the DER cease the flow of any current, including reactive current, because it is typically necessary to have small, high-frequency electromagnetic interference (EMI) filters connected on the utility side of the current interrupting devices of an inverter in order to meet FCC requirements. Also, there is always a miniscule amount of charging capacitance in any cable or conductor between the DER terminals and the point of utility system connection. Transformers may also be between the DER (or any switchgear used to isolate DER) and the point of utility system interconnection, and would cause a reactive power flow due to their exciting current.

Trip — cease to energize and inhibit immediate return to service. Tripping may involve, but does not necessarily require, physical disconnection.

Isolation or disconnect — isolation or disconnection of the DER from the grid by a switching device with a physical separation between its contacts. Normal circuit breakers, circuit switchers, contactors, etc. provide physical separation. Physical separation is in contrast to cessation of current implemented by turning off semiconductor devices, such as transistors in an inverter or thyristors in a solid-state switch.

Momentary cessation — an operational state used for severe undervoltage or overvoltage events that only applies to DER meeting the requirements of Category III ride-through performance.[4] Momentary cessation means that the DER ceases to energize the Area EPS (utility) with the capability to immediately resume operation (in less than 0.4 seconds) when the voltage recovers from the under/over voltage condition. In practice, Category III performance is likely to be obtainable only from inverter-interfaced DER, because disconnecting a synchronous generator and then re-synchronizing the generator to the grid within the allowable time would be difficult. In the case of inverters, the cessation of energization would typically be performed by stopping the gating of the transistors of the inverter, without any mechanical action.

Permissive operation — means that continued injection by the DER of current into the utility system is at the option of the DER. If the DER interrupts its output, however, it must be capable of resuming operation immediately (in less than 0.4 seconds) after the voltage recovers. Permissive operation allows DER that might be overstressed by continued operation to cease output, but also accommodates DER that may not be able to disconnect and then reconnect in less than 0.4 seconds after voltage recovery. A synchronous generator using mechanical circuit breakers for interruption and reconnection is an example of the latter.

Mandatory operation — Continued supply of active and reactive power to the utility (Area EPS) during and following voltage and frequency disturbances less severe than defined limits.

[4] P1547 specifies three levels of voltage and frequency disturbance ride-through performance, with Category III being the most stringent, intended for situations of very high DER penetration. See the previous article in this series (Part 3 IEEE 1547 Relevant to Disturbance Performance) for a discussion of ride-through performance categories.

IEEE 1547-2003 established two seconds as the maximum allowable inadvertent island duration.

The proposed standard clarifies that reclosing coordination is a mutual responsibility of the DER owner and utility.

Performance operating region — an area on a plot of voltage or frequency versus cumulative duration of the given voltage or frequency at an equal or greater deviation from the nominal value. Within the area of a performance operating region, DER must provide a defined performance (e.g., continued operation, momentary cessation, etc.)

ISLANDING AND RECLOSING COORDINATION

"Islanding" is when DER sustains energization of a portion of the utility system, such as a feeder, when the normal utility source of energization is switched off or lost. For a stable island to persist, both the active (real) and reactive power outputs of all the DER on the island must be in close balance with the active and reactive power demands. The subject of potential unintentional islanding has long been a focus of concern by utilities. IEEE 1547-2003 established two seconds as the maximum allowable inadvertent island duration. In response, the DER manufacturers have developed a wide range of protection schemes by which islands can be detected and eliminated by tripping off the DER. While the details of most anti-islanding schemes are trade secrets, it is generally known that most schemes fit into one of the following categories:

- **Schemes that attempt to destabilize an islanded system.** For example, if frequency increases, a DER response can be to cause the frequency to increase further in a type of positive-feedback until the frequency deviates sufficiently to cause tripping.
- **Schemes that measure the impedance of the system,** typically by introducing a small change in active or reactive current and measuring the response. When connected to a utility grid, the impedance is normally low, but when islanded the impedance becomes large. Detection of a high impedance results in the DER being tripped.
- **Schemes based on differences in the harmonic voltage levels** in the interconnected and islanded states.[5]

In addition to the two-second limit, IEEE 1547-2003 requires DER to be "coordinated with Area EPS (i.e., utility) reclosing practices." Reclosing into an island energized by DER, which may be out of phase with the utility voltage, can be damaging to utility and non-DER customer equipment.[6] Perhaps due to this latter requirement not being sufficiently explicit, the DER community appears to have paid less attention to it. The proposed standard clarifies that reclosing coordination is a mutual responsibility, and is not solely a responsibility of the utility, to ensure that reclosing delays are set longer than two seconds for feeders that have enough DER penetration to potentially sustain an island.

P1547 retains the same two second maximum inadvertent island duration as the original standard.[7] The original standard has footnotes proposing means by which longer-duration islands could be avoided. These recommendations have been deemed no longer appropriate and have not been carried forward into P1547. The

[5] The validity of these methods in the field, where harmonics produced by other loads may be present, even when islanded, has some uncertainty. These schemes may be much more successful in ideal laboratory tests than in actual function.

[6] Out-of-phase reclose is well known to be potentially very damaging to synchronous generators. Inverters, however, are self-protected from this scenario and this fact, along with insufficient knowledge regarding the potential impacts to other customers, may be why feeder reclosing coordination has not previously received adequate attention of the inverter manufacturers.

[7] The proposed standard also allows the DER owner and utility to mutually agree to extend the maximum allowable inadvertent island time to five seconds.

While intentional islands within customer facilities are out-of-scope for IEEE 1547, the proposed standard addresses special requirements of DER that interconnect and operate with "utility microgrids."

The proposed standard makes power quality requirements more explicit and quantitative to facilitate enforcement.

requirement to coordinate with utility feeder reclosing has been made much more explicit, clearly indicating that reclosing must not result in unacceptable stress or disturbances on the utility system. In practice, this usually means that any DER-energized island must be eliminated prior to reclosing. By way of informative footnotes, P1547 advises that direct transfer trip, voltage-supervised reclosing (i.e., hot-line blocking or under-voltage permissive), or lengthening the minimum reclosing delay greater than the island duration might be solutions when the DER penetration on the feeder might sustain an island.

INTENTIONAL AREA EPS ISLANDS (UTILITY MICROGRIDS)

Intentional islands are subsystems of DER and load that can operate isolated from the grid. In most applications, these intentional islands are within a customer (e.g., campus) facility. Because the scope of IEEE 1547 is limited to the interconnection of DER with utilities, requirements for DER inside those facility island applications are out-of-scope and are not addressed in the standard. However, there is a certain type of intentional island where a portion of the utility (Area EPS, in IEEE 1547 terminology) is included within the intentional island. Examples for such intentional Area EPS islands, sometimes also called "utility microgrids," are where an intentional island is formed around a utility substation and its feeders, or a single feeder or portion of a feeder.

In some cases, a utility may choose to implement such an intentional islanding capability, such as where the normal supply to a customer load area is prone to outages (e.g., a remote resort area fed by a single feeder that traverses a mountain range). In other areas, utilities are being required to implement such arrangements by regulators or political entities. For these limited cases, P1547 addresses the special requirements of DER (typically customer owned) that interconnect and operate with these "utility microgrids." Some of the unique DER requirements for operation in intentional islands include faster response times for voltage and frequency regulation necessary to maintain stability of the weak, low-inertia nature of such intentional islands while they are isolated from the short-circuit capacity and very large inertia of the interconnected power grid. Furthermore, wider ranges for some of the voltage and frequency trip requirements are specified. P1547 clarifies, however, that these particular responses and ranges of adjustability are only to be enabled when the intentional island is isolated from the Area EPS. Otherwise, the modified DER settings may have undesirable consequences on the operation and reliability of the interconnected Area EPS.

POWER QUALITY

Voltage Variations

Changes to the power quality requirements in P1547, relative to the original standard, generally make the requirements more explicit and quantitative, which facilitate enforcement of the requirements with less ambiguity. For example, with regard to flicker, the original standard merely states that DER "shall not create objectionable flicker for other customers." P1547, in contrast, limits the short-term flicker (P_{st}) and long-term flicker (P_{lt}) contributions of DER to specific quantitative limits based on the IEC-flickermeter algorithm, as defined in IEEE 1453.

In addition to placing quantitative limits on DER flicker contribution, which is repetitive variation of voltage, P1547 also places limits on intermittent, abrupt changes in voltage. These are termed "rapid voltage changes" (RVC), with specific limits that depend on the number of times per day such RVCs occur. RVC may occur, for example, during energization of a DER facility's transformers, or switching of capacitor banks.

Harmonic Limits

P1547 retains the basic framework of harmonic limits used in the original standard which is based on IEEE 519. The revised standard, however, deviates somewhat from IEEE 519 with regard to interharmonics and even-order harmonics in order to address issues related to modern inverters.

When the words "power quality" are spoken, many utility engineers think of harmonic distortion issues. With the modern power conversion technology used today, excessive harmonic distortion is rarely caused by DER; more often than not, harmonics are an issue that may often be perceived to be more significant than it really is. For example, when there is enough DER on a distribution circuit to largely supply the connected load, most of the 60 Hz current supplied by the utility is cancelled. The residual current flow from the utility into the feeder can be highly distorted on a percentage basis. The actual amount of harmonic current does not increase, but may appear to be large due to the decrease of the fundamental. The majority of the harmonic current in such cases is due to customer load devices.

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There have been cases where improperly designed or configured DER inverters have gone into a type of control instability, causing large oscillations in current and voltage in the harmonic frequency range. This potential for misoperation is good reason to retain harmonic distortion limits in DER interconnection standards as a justification for mandatory correction or even disconnection of offending DER if such events occur. It should be noted that such misoperation may not be evident during DER factory tests or even field commissioning tests, but may arise at some time in operation when the grid conditions of load, line, and DER interact.

Most DER installed today use voltage-source inverters (VSI) to convert the DC from PV arrays and fuel cells, or the variable frequency AC output of wind turbines and microturbines, to 60 Hz AC. These inverters use transistors switching at frequencies generally on the order of a few kHz to synthesize a 60 Hz voltage using pulse-width modulation (PWM). While the PWM process creates a distorted voltage, filters on the outputs of properly-designed inverters remove this distortion yielding a very clean signal at the inverter terminals. The amount of current distortion is a function of the impedance, at the frequency of the distortion, of the system to which it is connected. Existing voltage distortion in the grid, typically caused by other loads (e.g., consumer electronics, variable speed drives, compact fluorescent lamps, etc.), can cause harmonic currents to flow into the inverter. This complicates measurement of DER harmonic contributions in the field because it is nearly impossible to discriminate harmonic current flow caused by the DER from that caused by background distortion from other harmonic sources, including loads, in the utility system.

IEEE 519, which is the IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, is widely used in the utility industry. This standard was originally developed prior to the widespread adoption of VSI technology, and its foundations are based on older line-commutated converter technology using thyristors and diodes. Line commutated converters inject harmonic currents that are largely invariant with the grid impedance, and all injections are at discrete integer harmonics. Thus, IEEE 519 specifies limits to customer device (e.g., DER) distortion based on integer harmonic current magnitudes. This is a somewhat incongruent fit with modern VSI technology, as the latter appears more like a voltage source behind impedance at frequencies that may not all be integer harmonics. The recommended harmonic limits specified in IEEE 519 were directly incorporated into IEEE 1547-2003 as normative (mandatory) requirements.

Distortion limits specified in P1547 remain specified in terms of current. However, the limitations no longer apply to just the discrete integer harmonic orders, but also to the "interharmonic" frequencies between the integer orders.

By mutual agreement with the utility, DER can exceed the harmonic current limits if the DER is acting as an active filter, injecting harmonic currents with opposite polarity than the harmonics produced by other loads and devices in order to provide a cancellation effect beneficial to the utility system.

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IEEE 519 and IEEE 1547-2003 both specify a much reduced harmonic current limit for even-order harmonics- one-fourth of the adjacent odd harmonic limit. At the higher harmonic orders, where the odd harmonics are limited to very small magnitudes, the even harmonics limits are so low as to make measurement impractical in many cases. In general, harmonic impacts do not differ between even- and odd-order harmonics. This interaction decreases in severity with the reciprocal of the frequency, and is insignificant at the high-order harmonics where measurement of even-order harmonics at the IEEE-519 limit levels are problematic. Therefore, IEEE 1547-2003 "backs off" the even harmonic restriction as the harmonic order increases such that even and odd order harmonics have the same limits at the eighth order and above.

Overvoltage Limitations

The limitations on overvoltages caused by DER in IEEE 1547-2003 are vague and are not defined quantitatively. P1547, in contrast, imposes very specific limits on both transient (short-duration) overvoltages in the sub-cycle range that are measured by the instantaneous peak magnitudes and duration of the voltage waveform, and longer duration temporary overvoltages measured by the root-mean-square (rms) voltage magnitude. For longer durations of overvoltage, the limitations are more restrictive in order to coordinate with the withstand capabilities of customer and utility equipment, such as surge arresters.

There are two overvoltage phenomena of particular relevance to DER interconnection. One is ground fault overvoltage (GFOV) caused by inadequate grounding, and the other is termed "load rejection overvoltage" (LROV) where current-regulated DER drive into an isolated system having generation output exceeding load demand. Both of these relate to the short period of time (less than two seconds) when a utility feeder is disconnected from the substation source and the DER continues energization of the islanded feeder.

The normal source of grounding for utility distribution feeders is provided from the utility primary distribution substation. When a feeder is islanded, this ground source is no longer connected to the feeder. A ground fault on the island can cause the unfaulted phase-to-ground voltage to rise to the phase-to-phase magnitude (1.73 times normal) due to the lack of a ground source, resulting in a GFOV. The existence of the GFOV depends on the characteristics of the distribution transformer serving the DER, as well as the characteristics of the DER energizing the island. If the DERs energizing the island are synchronous generators, which provide a voltage source, a GFOV is likely unless supplemental ground sources are located on the feeder (e.g., a grounding transformer or a grounded-wye delta DER interconnection transformer). Inverters, however, generally act as controlled current sources and a GFOV might not occur. Understanding of the industry regarding this difference is increasing, and a working group of the IEEE Surge Protective Devices Committee has produced a report on this issue that is cited in

The explicitly-defined overvoltage limitations of P1547 allow the adequacy of grounding to be quantitatively evaluated considering the characteristics of the equipment involved.

The proposed standard requires DER of all ratings to have the capability of exchanging data and the data list is more extensive.

the list of references for this article. While the original standard simply stated that "the grounding scheme of the DR (i.e., DER) interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS (utility)…," the explicitly-defined overvoltage limitations of P1547 allow the adequacy of grounding to be quantitatively evaluated considering the characteristics of the equipment involved.

If a utility feeder is islanded with DER that is operating at an output level substantially exceeding load demand in the islanded system, a LROV can occur due to the constant-current nature of typical DER inverters. Overvoltages caused by this phenomenon can be quite high (they can approach twice nominal voltage) but are generally of very short duration. The original standard does not address the overvoltages produced by this phenomenon in any way. In contrast, P1547's limits provide the basis for protecting the utility and its customers.

INFORMATION INTEROPERABILITY

Interoperability pertains to the capability of a DER or DER facility to exchange defined information with an external entity, such as the utility or third-party aggregator. In the original standard, only DER facilities having an aggregate capacity of 250 kVA or more are required to be able to exchange a very limited amount of information with the utility for purposes of monitoring. These data are connection status, real and reactive power output, and voltage at the point of connection.

P1547 goes far beyond the original standard and requires DER of all ratings to have the capability of exchanging data and the data list is more extensive. The data include DER reactive power, voltage and frequency control, and ride-through capabilities and ratings, monitoring information (similar to that required in the original standard for large DER), control (e.g., voltage regulation) parameters, voltage and frequency trip thresholds, power output limitations, and parameters related to entering and exiting service. The DER is required to be capable of properly exchanging these data using one of three standard protocols (DNP3, SunSpec Modbus, and IEEE 2030.5). P1547 recognizes that the utility may futher specifiy which standard protocol is required or another protocol that is mutually agreeable to both parties. Requirements for the communication networks specifics as well as for communication inside a DER facility are outside the scope of P1547.

DER TESTING

In order to prove compliance with the IEEE 1547 interconnection standard, DER equipment and installations must be tested and verified. The revised base IEEE 1547 standard determines what is to be tested; a companion IEEE 1547.1 standard (currently being revised) defines how tests are to be performed. Test specifications in P1547.1 are intended to strike a balance between meeting utility requirements and keeping the cost of testing reasonable for DER vendors and developers. In the P1547 revision, testing and verification requirements are deferred to the IEEE 1547.1 DER testing standard.[8] Until the revised IEEE 1547.1 standard is published, application of the revised IEEE 1547 standard will remain limited.

Several factors related to the changes in DER applications and the performance requirements of P1547 make testing and verification of DER more complex than was envisioned in the original standard:

- Some DER facilities must achieve performance as measured at the point of common coupling (PCC) with the utility, and not at the

[8] The working group to revise IEEE 1547.1-2005 has already been formed, and is at the early stages of a complete revision of the IEEE1547.1 testing standard to execute the testing requirements defined in P1547.

individual DER terminals. For example, the reactive power at the PCC differs from the sum of the reactive power outputs of each DER unit within a facility, due to reactive power losses occurring in the lines, cables, and transformers, and the reactive power gains caused by cable capacitive charging and capacitor banks, within the facility. For a reactive power requirement that is applicable at the PCC (as it is specified for large dedicated generation facilities such as PV farms), tests of reactive power capability of each DER unit do not provide complete information to ensure compliance.

- DER may be supplemented by devices that are not part of the DER units themselves (e.g., capacitor banks, protective relay packages, etc.)

As a result, the test requirements defined in P1547 have been made more flexible to accommodate different paths toward conformance verification.

DER interconnection testing involves a number of different stages which apply differently if the DER is a self-contained unit and whether the DER installation must meet requirements at the DER terminals or at the PCC with the utility. These stages are:

Type tests — where the DER manufacturer tests DER of a specific design (i.e., "type" or "model"). These tests are extensive, and in the case of self-contained DER that need only meet performance requirements at its terminals, may be sufficient to fully demonstrate compliance. These type tests are normally performed at a Nationally Recognized Testing Laboratory (e.g., UL).

Production tests — where every DER unit produced is tested for operability and to verify that settings have been properly implemented. These tests would typically be performed by the manufacturer at the production facility.

DER evaluation — determines if the composite of individual partially-compliant DER, plus any supplemental devices, together meet the performance requirements of the standard at the location where the requirements are applicable. The DER evaluation consists of two parts. The first is a desk study early in the interconnection review process. This may include reviews of ratings, calculations (e.g. reactive power losses and gains between the DER units and the PCC), and possibly simulations. The second part is an as-built installation evaluation. This confirms that the DER was built according to the design evaluated during the earlier desk study. For example the nameplates of equipment, relay settings, proper connections of current transformers, etc. might be inspected. This overall DER evaluation step is generally not applicable to a small self-contained DER, such as a rooftop PV installation. It is very applicable for facilities such as PV farms and complex combinations of equipment. The DER evaluation steps would normally be performed by or on behalf of the utility.

Commissioning tests — verify as-built-performance and are often the only means to test systems of equipment. On the other hand, there are practical limitations to that which can be tested in the field. For example, few utilities are willing to stage intentional faults on their system to test ride-through performance.

Periodic tests — are performed during the life of the DER interconnection. For example, periodic tests may be performed to verify correct protective tripping settings.

The revised P1547 introduces the concepts of full and partial conformance testing. Except in the case of a fully self-sufficient DER unit that is required by the standard to comply only at its terminals, it is not possible for type testing to fully verify conformance. Therefore, type testing is combined with DER evaluation. DER evaluation must have some verified type test results in order to determine if the entire system provides conforming performance. For example, a DER unit may have limited reactive power capability and cannot alone meet the requirements of the standard. The DER installation design may combine the DER unit with capacitor banks of specified ratings in order to meet the requirements. To evaluate conformance, a partial type test of the DER is needed in order to verify its capabilities, even if not fully sufficient. This is an example of a *partial* conformance type test. In contrast, a *full* conformance type test determines if the DER device is fully sufficient to meet the required performance. P1547 includes a detailed conformance traceability matrix that links specific tests with specific performance requirements for both the situation where the DER is self-sufficient and where it will be supplemented by other devices.

FROM DRAFT TO STANDARD

As this final article in the *TechSurveillance* series on IEEE 1547 is being published, the draft P1547 is now complete and the balloting process will soon commence. As this standard will have substantial impact on cooperatives, in terms of distribution system planning, operations, and dealing with cooperative members interconnecting DER, cooperative engineers are encouraged to become involved in the standard balloting process. The details of how to become part of the balloting pool, and the process used by the IEEE Standards Association to ballot and review the draft standard are described below. ■

BALLOTING PROCESS FOR IEEE 1547
How to become a member of the balloting pool for IEEE Standards

Ballot pools for IEEE standards are distinct from the working groups that develop the standards drafts. Joining a ballot pool for a particular standard is totally separate from joining the working group.

To participate in IEEE standard balloting, you first need to join the IEEE Standards Association as a part of your IEEE membership. Currently, this costs an additional $53 in addition to your IEEE and any IEEE technical society memberships that you have. This gives you the ability to vote on an unlimited number of standards that enter the balloting process. Note that there is a process to pay a per-ballot fee without joining IEEE or the Standards Association, but that is not applicable for most of us.

When you join the Standards Association, you should develop an "Activity Profile" within the myProject™ web site (**https://development.standards.ieee.org**). This allows you to select sponsor committees, working groups, and projects in which you are interested. You will receive invitations to enroll in the ballot pools for the standards that these groups develop. For example, if you search on "distribution," you will get a number of committees, working groups, and projects that have "distribution" in their name. By selecting the sponsor level, in this case, "PE/T&D (PES Transmission and Distribution Committee)," you will receive notices of all standards coming to ballot that are sponsored by this entity. If you are specifically interested in other committees, working groups, or projects, you should check those as well.

Continued

BALLOTING PROCESS FOR IEEE 1547
How to become a member of the balloting pool for IEEE Standards (Cont.)

For IEEE 1547 specifically: you need to add SCC21 (Standards Coordinating Committee 21 — Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage) to your profile.

Any IEEE-SA member can join any ballot group during the invitation period. It is up to the individual to determine that they are technically qualified to review, comment, and vote on the standard being balloted. When you join the ballot group, you must declare an interest category (e.g. producers, users). No interest category can comprise over one-third of the balloting group. The goal is to have representation from all interested parties, but to avoid an overwhelming influence by any one of those parties. The sponsor entity can reject requests for ballot pool membership as necessary to obtain this balance. A proposed standard will pass if at least 75 percent of all ballots from a balloting group are returned, and if 75 percent of these bear a "yes" vote. For example, if ballot returns of 30 percent are abstentions, the ballot fails.

Balloters vote to approve, disapprove, or abstain. They can also approve or disapprove with comment. Balloters that disapprove are highly encouraged to provide comments of changes in the standard that will allow them to change their vote from disapprove to approve. The ballot resolution group responds to all comments whether submitted by a voter that approves or disapproves the standard. Comments are often straightforward editorial or technical changes to the standard. The standard, with changes based on the comments received, are recirculated to the balloting group. The balloting group can then make comments on the changes made and also has the opportunity to change their vote based on revised standard. The hope is that the changes will persuade balloters that previously disapproved to change to approving the standard, but there is a possibility that some that originally approved of the standard will change their ballot to “disapprove.” The process can require several rounds of balloting, revision, and recirculation. In the end, the objective is to reach a consensus that is widely accepted across the industry.

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About the Author

Reigh Walling is a utility and renewable energy industry consultant, focusing his practice on the technical issues related to DER interconnections and renewable energy integration, as well as a variety of transmission-related areas. He has long been heavily involved in standards related to interconnection of DER and transmission-scale renewable energy plants, including participation in the inner writing group of the original IEEE 1547, several of the IEEE 1547.x companion standards, NERC PRC-024, and the NERC Integration of Variable Generation Task Force, and as well as a co-facilitator in the current IEEE 1547 revision working group. Prior to establishing Walling Energy Systems Consulting in 2012, he was a key member of GE's Energy Consulting group for 32 years. While at GE, he was the program manager for the Distribution Systems Testing, Application, and Research utility consortium, of which NRECA is a long-standing member.

Questions or Comments

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BUSINESS AND TECHNOLOGY STRATEGIES
TRANSMISSION AND DISTRIBUTION STRATEGIES WORK GROUP

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