PDHonline Course E754 (3PDH)

Solar Inverter Standards

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Solar Inverter Standards

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Introduction

IEEE Standard 1547-2018, titled "IEEE Standard for Interconnection and interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" provides a set of criteria and requirements for the interconnection of distributed generation resources to the electric power grid. This standard significantly enhanced the performance and functional capability of DERs connecting specifically to primary and secondary distribution systems.

The purpose of IEEE Std. 1547 is to provide a uniform standard for interconnection of distributed resources with Electric Power Systems (EPS). It provides requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnection.

There are three versions of IEEE Std. 1547, namely 1547-2003, 1547-2014, and 1547-2018. This course describes the differences between previous versions of the standard to the 2018 Standard.

Background

The grid is technically and operationally complex, including complexities among regulatory compliance and mandates by the various authorities having jurisdiction over the grid. The traditional perspective of the U.S. electricity infrastructure is large central station power plants, each of which provides hundreds of megawatts or a gigawatt level of power. From there, high voltage transmission power lines transport the bulk electricity over often relatively long distances to distribution grids (known as 'area electric power systems) that then supply customers or consumers of that electricity. The power flow across the transmission grid can flow either way. The distribution system (known as area electric power system) tends to only flow one-way from transmission grid to consumers' facilities. See Figure 1.

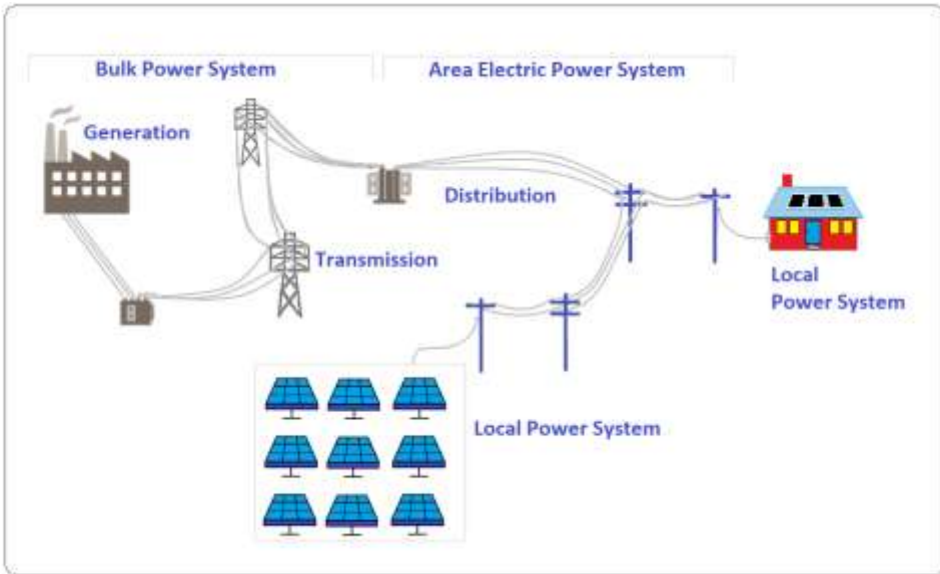

Figure 1

Historically, only monopolistic, regulated, electric utilities owned the generation, transmission, and distribution facilities. With deregulation of electricity this ownership was separated to encourage competition. Beginning in the early 1990s, distributed generation and renewable energy technologies became more cost effective for providing electricity. Consumers of electricity could thus own and install distributed generators and renewable technologies. This was a change in the structural model of the electric utility industry. This consumer-sited generation affected distribution grid circuits because some circuits experienced either two-way power flow (which the distribution system was not designed to handle) or greatly reduced one-way flow to a significantly lower level than expected.

With increasing adoption of distributed resources, the industry realized a set of standards was necessary to protect the operation of the electric power system. The utilities' concerns were system reliability, safety, and cost impacts on the electric system. Others saw the lack of national standards as a roadblock to the implementation of new distributed generation projects. The standard was intended to be universally adoptable, technology-neutral, and cover distributed resources up to 10 MVA of capacity.

The Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, first published in 2003, has been a foundational document for the interconnection of *distributed energy resources* (DER) with the electric power system. IEEE 1547 has helped to modernize the electric power systems infrastructure by providing a structure for integrating renewable energy technologies as well as other distributed generation and energy storage technologies. The Standard provides mandatory functional technical requirements and specifications, as well as flexibility and choices about equipment and operating details that comply with the standard.

As a technical standard, IEEE Std. 1547 has provided local, state, and federal regulators and policymakers a technical basis for promoting transparency, openness, and fairness in implementing DER interconnecting to the grid. However, IEEE Std. 1547 is not the only standard involved in interconnections to the electric system. Others such as IEEE Std. 1547.1, UL1741, and some articles in the National Electric Code (NEC) address the installation and interconnection of DER equipment (See Figure 2).

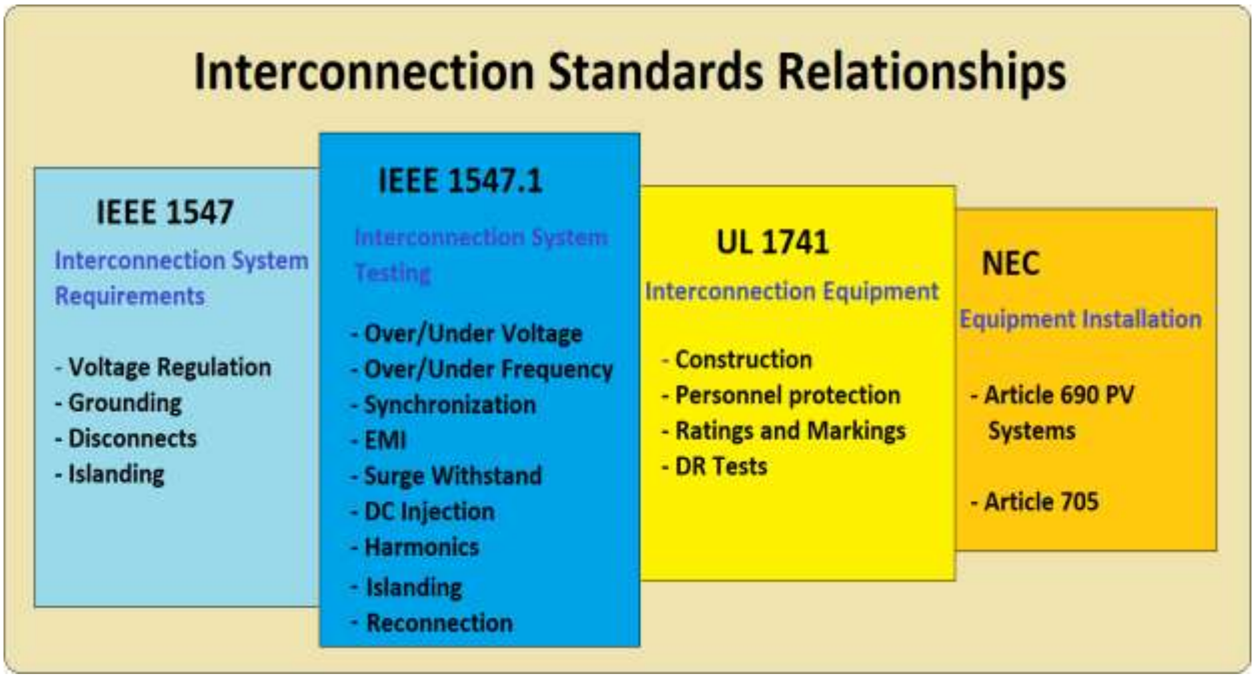

Figure 2

IEEE 1547 Series of Standards

IEEE Std. 1547 is actually a series of standards that address specific issues with interconnection of operation of DER equipment. The 1547 series of standards are shown in Table 1. Collectively these documents provide a cohesive set of requirements, recommended practices, and guidance for addressing standardized interconnection of DER.

Standard	Table 1 **IEEE 1547 Standard Series**
1547	IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.
1547.1	Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces
1547.2	Application Guide for IEEE Std. 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
1547.3	Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems.
1547.4	IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.
1547.6	IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks.
1547.7	IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection,
1547.8	Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for 4 Implementation Strategies for Expanded Use of IEEE Standard 1547.
1547.9	Guide to Using IEEE Standard 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems.

The following is a brief description of the other Standards.

IEEE Std. 1547.1
Specifies the type, production, and commissioning tests that shall be performed to demonstrate that the interconnection functions and equipment of DER conform to IEEE Standard 1547.

IEEE Std. 1547.2

Provides background on 1547 requirements, providing tips, techniques, and rules of thumb. The 1547.2 document includes rationale of 1547 requirements, and provides technical descriptions, schematics, applications guidance, and interconnection examples to enhance the use of 1547.

IEEE Std. 1547.3

Addresses guidelines for monitoring, information exchange, and control for DER interconnections. It defines an *Information Exchange Interface* and provides an *Information Exchange Agreement* template, which is a framework to capture the specification of technologies and processes needed to support communications and interoperability between equipment and implementing parties.

IEEE Std. 1547.4

Provides approaches and practices for the design, operation, and integration of microgrids, or DER island systems interconnected with the distribution grid. The 1547.4 document addresses the capability to separate from and reconnect to part of the grid while providing power to adjacent grid customers.

IEEE Std. 1547.6

Provides recommended practices that address spot and grid distribution secondary networks. IEEE Std. 1547 includes requirements for distribution secondary spot networks only —circuit topologies that are highly reliable because redundant circuits serve the customer. The IEEE Std. 1547.6 document gives an overview of distribution secondary network systems design, components, and operation; describes considerations for interconnecting DER with networks; and provides potential solutions for the interconnection of DER on network distribution systems.

IEEE Std. 1547.7

Addresses criteria, scope, and extent for engineering studies of the impact on the distribution grid by DER. The addition of DER to an *electric power system* (EPS) will change the system and its response in some manner. The methodology in IEEE Std. 1547.7 is based on a tiered approach with criteria similar to screens used by the industry— preliminary review criteria, conventional impact studies criteria, and special impact studies criteria. In 1547.7, criteria are described for determining the necessity of impact mitigation.

IEEE Std. 1547.8

IEEE Std. 1547.8 was initiated to address expanded use of IEEE Std. 1547 through the identification of innovative designs, processes, and operational procedures. IEEE Std.

1547.8 addresses advanced controls and communications for inverters supporting the grid and best practices addressing multiple inverters and microgrids, and provides state-of-the-art information for DER group behavior and interactions with grid equipment (both operational and safety related, including unintentional islanding) and interconnection system response to abnormal conditions, and provides application examples such as state-of-the-art protection practices and advanced unintentional islanding approaches.

IEEE Std. 1547.9

IEEE Std. 1547.9 provides information and examples of how to apply IEEE Std. 1547-2018 for the interconnection of *energy storage distributed energy resources* (ES-DER). The guide's scope includes ES-DER that are interfaced to an electric power system (EPS) via an inverter capable of bidirectional active and reactive power flow, and capable of exporting active power to the EPS.

IEEE Std. 1547 Version History

This section is an overview of the significant items in each version of IEEE Std. 1547. Since 2003 the Standard has progressively allowed more capabilities and interoperability with the utility grids. Figure 3 shows some of the key progressions in the Standard.

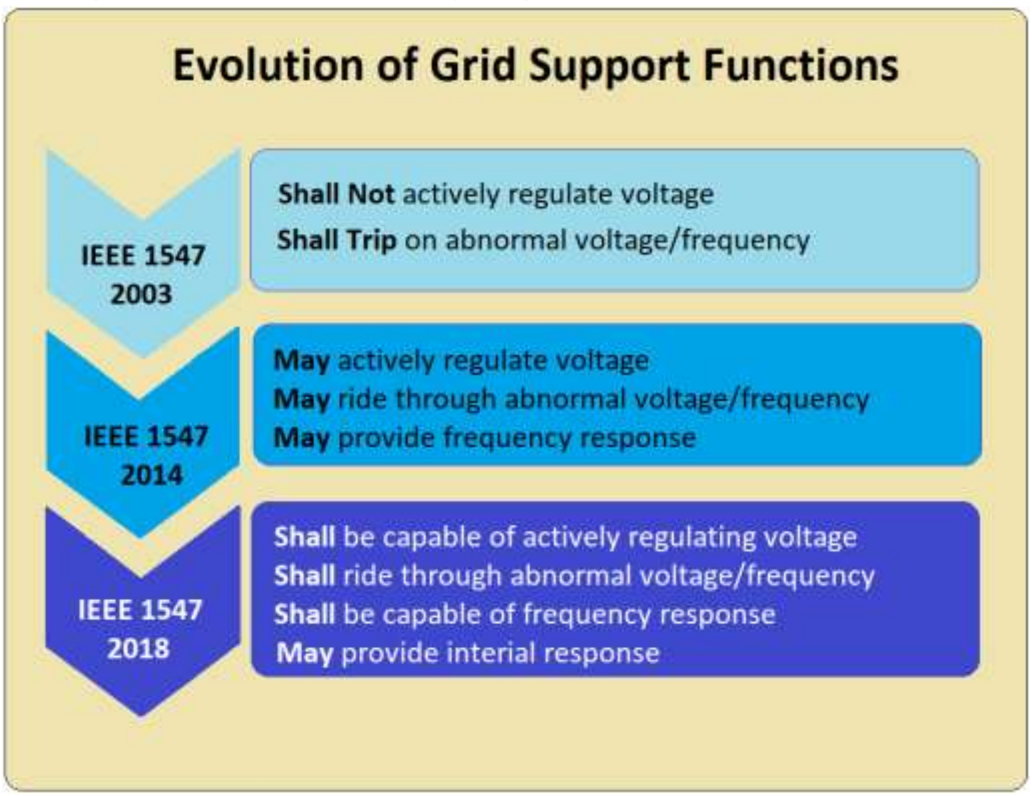

Figure 3

The following is a brief summary of the changes in the Standard from 2003 to 2018.

2003 Standard

It was apparent by the early 2000's that a standard was needed to address the growing interest in renewables and other distributed energy resources. At this point DER was only a miniscule portion of the electric generation supply and therefore, had negligible impact on the distribution system or the bulk power system.

The electric utilities were concerned that DER may interfere with voltage regulation, system relaying protection, and worker safety. As a result, the electric utility industry wanted to ensure the standard adequately address protection of the electric power system. The result was that the new standard was a brief, 26-page document, that primarily addressed how DER would respond to abnormal conditions, power quality, and islanding concerns.

IEEE Standards Board approved IEEE Std. 1547-2003 in June 2003, and received an ANSI designation in October 2003.

Some of the salient points of this new Standard included.

- Limited DER systems to less than 10 MVA of capacity.
- The DER system, defined as the local electric power system (EPS) had to be located in one contiguous site.
- Prohibited regulating voltage at the interface with the utility (known as the *Point of Common Coupling* (PCC).
- Required the DER to drop off-line if the connecting utility (i.e., area EPS) has a faulted circuit.
- Clearing times were set (and not adjustable) based on the range of voltage abnormality.
- Set specific frequency trip levels and clearing times.
- The DER was limited in the amount of DC current injection, harmonic current injection, and voltage flicker that could impact the area EPS.
- The Standard did not allow islanding; The DER must shut down if the Area EPS de-energized.
- The Standard required larger DER systems to provide certain real-time data.

2014 Standard

The implementation of DER grew rapidly in the intervening ten-year period since the development of IEEE Std. 1547-2003 and by 2014 an amendment to the Standard was approved which became IEEE Std. 1547-2004. There were three major modifications to the Standard. They are,

- Allowed some voltage regulation at the PCC, provided the Area EPS approved,
- Made slight modifications to the over/under voltage setting requirements, and
- Modified over/underfrequency settings.

2018 Standard

After the 2014 Standard, IEEE continued to work on modifications to the Standard and the result was a major re-write of IEEE 1547. The new version has grown to a 136-page document that includes eleven sections, or "clauses", with detailed operational guidelines.

Each clause specifies information or requirements that apply to certain aspects important to the interconnection of DER to the electric power system. Implementation of the requirements needs both a careful study of the underlying technical concepts and the appropriate information that might be required to calculate various settings and configurations. Implementation also requires involvement and coordination among various stakeholders. The new Standard has the following clauses,

- Clauses 1-3, Introduction, references, and definitions
- Clause 4, Summary of performance requirements
- Clause 5, Reactive power, and volage/power control
- Clause 6, Response to abnormal Area EPS conditions
- Clause 7, Power quality
- Clause 8, Islanding
- Clause 9, DER on distribution secondary
- Clause 10, Interoperability
- Clause 11, Test, and verification

Each of these clauses will be discussed in detail in the subsequent chapters.

The stakeholders who are typically concerned with the requirements specified in IEEE Std. 1547-2018 include DER device manufacturers and developers, state electric regulators, electric utilities, and BPS entities such as the National Electric Reliability Corporation (NERC), RTO's, and ISO's.

Some of the impetus for the revision was related to impacts on the bulk power supply. For instance, at low penetration levels, DERs may not pose a significant risk to BPS reliability. However, as the penetration continues to increase, the aggregate effects of DERs present both challenges and opportunities for planning, design, and operation of the BPS. NERC has expressed the following concerns:

- Impacts that DERs have by offsetting gross load, resulting in the displacement of BPS generation which are providing various *essential reliability services* (ERS),
- Impacts that DERs have on balancing generation and demand and ensuring that balancing authorities are carrying a sufficient amount of resources to meet ramping requirements,
- Ability of the BPS to have adequate voltage regulation and reactive power support with increasing penetration of DERs,
- Impacts that legacy DER ride-through and trip settings may have on BPS following large disturbances,
- Ability to model and forecast DERs for the purposes of planning and operations studies, and
- Ability to ensure BPS reliability with increasing amounts of generation that are not currently observable or dispatchable.

The new standard introduces the following key elements:

- Expanding the scope of the prior standards by considering BPS issues, such as ride-through requirements, as well as distribution system issues.
- Extending requirements from the interconnection system and the individual DER unit to the whole DER system so that all DER equipment, including ancillary equipment, will be capable of withstanding specified voltage and frequency disturbances.
- Expanding the applicability beyond individual equipment such that it can be used for plant-level verification.
- Specifying capabilities and functions necessary in a local DER communication interface.
- Enabling DERs to have the capability of providing autonomous response to voltage and frequency changes to support the grid, including voltage regulation and frequency-droop response.

The new capabilities required in IEEE Std. 1547-2018 align with the BPS reliability needs and present opportunities for maintaining or improving BPS reliability with increasing penetration of DERs. IEEE Std. 1547-2018 changes are relevant to advanced grid technologies and practices including grid-interactive microgrids. These changes include,

- VAR and Voltage Control Capabilities
- Voltage & Frequency Ride Through
- Interoperability
- Intentional Islanding

Comparison of IEEE Std. 1547 Versions

IEEE 1547-2018 is intended to apply only to DERs connected to the distribution system and is generally not suited for transmission level interconnections. Table 2 is a comparison of the 2003, 2014, and 2018 versions of the Standard.

Table 2
Comparison of IEEE 1547 Versions

Function Set	Advanced Functions Capability	2003	2014	2018
All	Adjustability in Ranges of Allowable Settings		Allowed	Required
Monitoring & Control	Ramp Rate Control			
	Communication Interface			Required
	Remote Disconnect/Reconnect			Required
	Limit Active Power			Required
	Monitor Key DER Data			Required
Scheduling	Set Active Power			
	Scheduling Power Values and Models			
Reactive Power & Voltage Support	Constant Power Factor	Allowed	Allowed	Required
	Voltage-Reactive Power (Volt-Var)	Prohibited	Allowed	Required
	Autonomously Adjustable Voltage Reference			Required
	Active Power-Reactive Power (Watt-Var)	Prohibited		Required
	Constant Reactive Power	Allowed	Allowed	Required
	Voltage-Active Power (Volt-Watt)	Prohibited	Allowed	Required

	Dynamic Voltage Support during VRT			Allowed
Bulk System Reliability	Frequency Ride-Through (FRT)			Required
	Rate-of-Change-of-Frequency Ride-Through			Required
	Voltage Ride-Through (VRT)			Required
	Voltage Phase Angle Jump Ride-Through			Required
	Frequency-Watt	Prohibited	Allowed	Required
Other	Anti-Islanding Detection and Trip			Required
	Transient Overvoltage			Required
	Remote Configurability			Required
	Return to Service			Required

Note: in this course "table" refer to tables in the Standard and "Table" refers to tables in the course. Except for the introductory clauses, each clause is covered in a chapter. The chapter numbers and clauses are not aligned. (e.g., Chapter 2 covers Clause 4, and so forth.)

Chapter 1
(Clauses 1, 2, and 3)

By the second decade in the 21st century, the deployment of DER was vastly different from the 20th century. Utilities were beginning to embrace DER and at the same time concerns were rising about the reliability impacts created by large amounts of DER. The new Standard includes protections for the Bulk Power System (BPS) concerning dynamic and transient stability issues.

Clauses one, two, and three provide an introduction, references, and definitions that are relevant to the revised Standard. This chapter will briefly cover a few of the changes in these clauses.

Clause 1

Clause 1 provides an overview of the entire standard. The subclauses provide background on general topics, scope and purpose of the standard, general remarks and limitations, and conventions for word usage and references that are required to understand and apply the standard. Key terms and concepts related to the *point of common coupling* (PCC) and *point of DER connection* (PoC) are introduced in this clause. Figure 4 shows the differences between PCC and PoC.

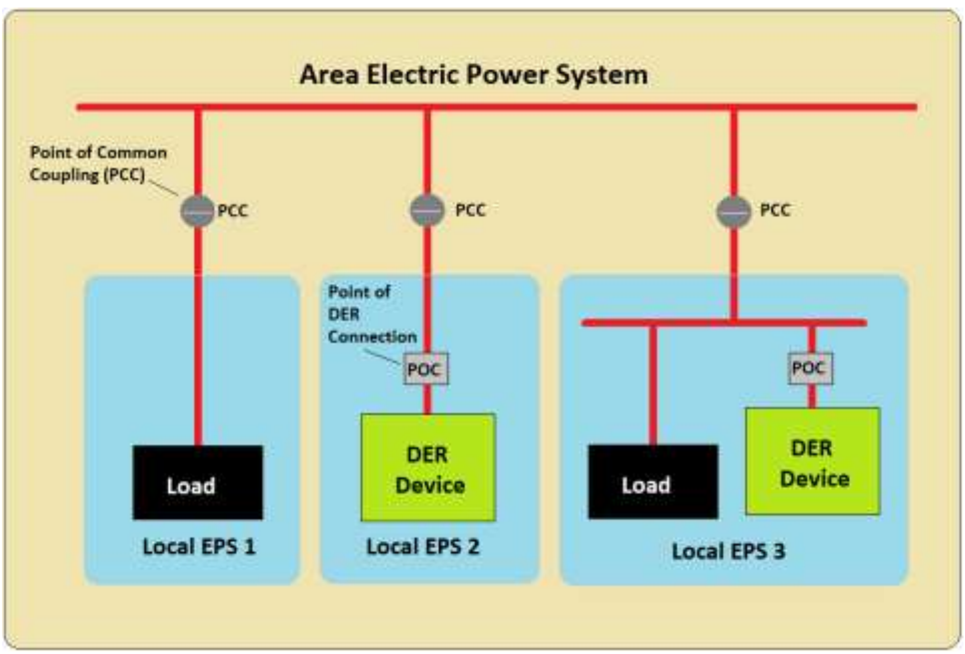

Figure 4

The PCC is the point of common coupling with the host electric utility (i.e., area electric power system) and the PoC is the point of connection of the DER or a group of DERs inside the local electric power system (i.e., non-utility side). This clause also introduces the concept of *supplemental DER device* and performance categories for normal and abnormal grid conditions.

The 2018 standard removed the 10 MVA aggregate size limitation on DER connected to the distribution grid that was in the 2003 standard.

Clause 2

Clause 2 references other documents the user must understand and apply in conjunction with the Standard. This includes other IEEE Standards as well as IEC and ANSI Standards.

Clause 3

Clause 3 provides definitions and acronyms used in the standard.

One significant new term in the Standard is the *Authority Governing Interconnection Requirements* (AGIR). IEEE standards are voluntary in nature, so state regulators, local distribution utilities, or other applicable governing bodies throughout North America must adopt them. The Standard defines these entities as the Authority Governing Interconnection Requirements (AGIR):

> "A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the area Electric Power System (EPS). This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc."

In plain language, this is the group that has the authority to set the interconnection requirements used in a particular system. This may be a public utility commission, an Independent System Operator (ISO), or other entity that has oversight of the local utility (i.e., Area EPS).

According to the Standard, the AGIR makes decisions as to whether Categories A/B or Categories I/II/III apply for a specific DER system.

Table 3 provides definitions of terms found in the Standard as well as other terms the reader may find useful.

Table 3 Definitions of Terms	
Area Electric Power System (Area EPS)	An Electric Power System (EPS) that serves local loads. This is typically the electric distribution utility.
Area Electric Power System Operator (AEPSO)	The entity responsible for designing, building, operating, and maintaining the Area EPS.
Authority Governing Interconnection Requirements (AGIR)	Entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the le entity to the Area EPS operator or bulk power system operator.
Bulk power system (BPS)	Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.
Cease to energize	Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange. This version clarifies that “cease to energize” does not require an “airgap” for isolation. Cease to energize can be achieved by any means that stops real power outflow from the DER, such as gate blocking in the inverter.
Continuous operation	Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.
DERO	The operator of the DER.

Distributed energy resource (DER)	A source of electric power that is not directly connected to a Bulk Power System. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.
Essential reliability services (ERS)	Essential reliability services (ERS) are ancillary services and generally consist of three main aspects: frequency response, balancing, and voltage control.
Energize	Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).
FIDVR	Fault-induced delayed voltage recovery (FIDVR) refers to unexpected delay in the recovery of voltage to its nominal value following the normal clearing of a fault.
Local EPS	The customer-sited portion of the system.
Mandatory operation	Required active and reactive current exchange.
Momentary cessation	Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.
Permissive operation	Operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation, in response to a disturbance of the applicable voltages or the system frequency.
Point of common coupling (PCC):	The point of connection between the Area EPS and the Local EPS.
Point of Connection (PoC)	The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.

Regional Reliability Coordinator (RRC)	Regional reliability coordinator (RRC) is the entity that maintains the real-time operating reliability of the BPS within an RC area. This is synonymous with the NERC term RC.
Reference points of applicability (RPA)	The RPA is typically either the Point of Common Coupling (PCC) or the Point of Connection (PoC) depending on the size of the system.
Restore output	DER recovery to normal output following a disturbance that does not cause a trip.
Return to service	Re-entry of DER to service following a trip
Ride-through	Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.
Trip	Cessation of output without immediate return to service; not necessarily disconnection.

Chapter 2
(Clause 4)
Technical Specifications and Performance Requirements

Clause 4 introduces key concepts and requirements that apply across the rest of the standard. Key terms and related requirements are specified in 13 subclauses.

Subclauses within Clause 4 are targeted to entities who will need to evaluate and apply the requirements of the standard. These entities include the,

1. Area EPS operator (i.e., the electric utility),
2. DER manufacturer,
3. DER operator
4. Testing agency,
5. DER developer and/or integrator, and
6. Commissioning agency.

The following are comments on the subclauses of Clause 4.

4.1 Introduction

This subclause provides an introduction with background on topics that are discussed in more detail in the following chapters.

4.2 Reference points of applicability (RPA)

This subclause specifies the characteristics of the local EPS (i.e., the customer-sited portion of the system) and the DER, which determine the specification of the *Reference points of applicability* (RPA) as the location where the requirements must be met. Annex H of the Standard provides an example of specifying the RPA.

Unless otherwise stated, the default RPA is at the *Point of Common Coupling* (PCC) which is typical at the electric utility meter. For simpler DER installations, the RPA may be at the *Point of Connection* (PoC) which is the terminals of the DER.

The location of the RPA may be changed by mutual agreement between the area EPS operator and the DER operator based on several considerations, including,

- Aggregate nameplate capacity of the DERs,
- Annual average load demand as calculated by the *area electric power system operator* (AEPSO),
- Export capability of the local EPS, and
- Evaluation of whether or not zero-sequence continuity (i.e., neutral current flow) is maintained between the PCC and PoC.

4.3 Applicable voltages

Subclause 4.3 has requirements for determining applicable voltages and the derived applicable frequency. The tables in this subclause specify requirements for the PCC located at either medium voltage or low voltage, respectively. The determination of the applicable voltage (medium voltage or low voltage) is made by the area EPS operator. Applicable voltages are based on,

- Distribution voltage configuration,
- Transformer connections,
- Location of the PCC (medium voltage or low voltage),
- Evaluation of the configuration and nominal voltage of the area eps at the PCC, or
- Evaluation of the configuration of the low-voltage winding of the Area EPS transformer between the medium-voltage system and the low-voltage system.

4.4 Measurement accuracy

This subclause specifies minimum requirements for the measurement and calculation accuracy for steady-state and transient values for RMS voltage, frequency, active power, reactive power, and measurement of time duration. The standard provides the default values are provided in table 3 of the Standard.

4.5 Cease-to-Energize Performance Requirement

Subclause 4.5 specifies requirements for active and reactive power exchange between DERs and the EPS during the cease-to-energize state.

Optional disconnection methods can be made by DER operator or the area EPS operator. Typically, DER has this capability built in. However, the DER operator may, however, choose to use alternative means to fulfill this requirement, such as a separate disconnection device.

4.6 Control capability requirements

Subclause 4.6 specifies requirements for DER capability to respond to external inputs given from either a manual DER control panel or through the local DER communications interface. This clause has requirements for capabilities to disable the permitted service setting, limit active power export, and control functional modes and parameter settings.

The area EPS operator makes the determination of whether and how to use this control capability. DERs are required to have the provision to exercise these capabilities via external commands, which could be through manual input via a DER control panel or via remote communications through the local DER communications interface. Likewise, the area EPS operator, in conjunction with the DERO makes the determination of settings for limitation of active power. And, by mutual agreement, the area EPS operator and the DER operator may choose to reduce the active power below the levels needed to support the local EPS loads.

4.7 Prioritization of DER responses

The subclause specifies the precedence of DER tripping requirements, ride through requirements, and control mode requirements specified in Clauses 5 and 6.

4.8 Isolation device

This section does not specify an isolation device. However, DERs may have this capability built in by the manufacturer. The area EPS operator can decide on the need for a separate isolation device and the Area EPS operator might also require a separate isolation device.

4.9 Inadvertent energization of the area EPS

This subclause says that DER shall not energize the area EPS when the area EPS is de-energized. Exceptions to this are at the discretion of the area EPS operator, such as for an intentional island.

The area EPS operator and DERO can decide on the need for intentional area EPS islands. The area EPS operator might require intentional islands. Utilization of intentional islanding capability is by mutual agreement between the area EPS operator and the DER operator.

4.10 Enter service

Section 4.10 specifies reference points of applicability (RPA) voltage and frequency ranges needed for,

- The DER to enter service,
- DER performance while entering service, and
- Synchronization limits for frequency, voltage, and phase angle difference.

This subclause specifically states,

> "Following a trip, or when entering service, DERs shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in table 4 and the permit service setting is set to "Enabled.""

The 'enter service' criteria might be affected by the utilization of functions specified in clauses 5, 6, and 7. For example,

- Requirements and performance of volt-volt ampere reactive (5.3.3, 5.4.2),
- Voltage trip and ride-through (6.4),
- Rate of change of frequency (6.5.2.5),
- Return to service after trip (6.6), and
- Limitation on voltage fluctuations induced by DER (7.2).

The default parameters from this subclause include,

1. The permit service setting is by default set to "Enabled".
2. Default voltage and frequency ranges are as specified in table 4 in the standard.
3. Defaults for synchronization parameter limits for frequency, voltage, and phase angle difference are as specified in table 5 in the standard.
4. The maximum active power increase of any single step during the enter service period is as specified in this section.
5. Certain types of DERs, such as large wound-rotor synchronous generators and salient pole synchronous generators, may use synchronization criteria specified in IEEE Std. 67.

Adjustments to default settings can be made by area EPS operator and DERO. The area EPS operator, in consultation with the *Regional Reliability Coordinator* (RRC) and the DER operator, may adjust settings within the ranges of allowable settings as specified in table 4 in the standard (see Table 4).

Table 4
Enter Service Criteria (all categories) DERs
(IEEE 1547-2018, table 4)

Enter Service Criteria		Objective	Foundation
Applicable Voltage within Range	Minimum Value	0.917 p.u.	0.88 p.u. to 0.95 p.u.
	Maximum Value	1.05 p.u.	1.05 p.u. to 1.06 p.u.
Frequency within Range	Minimum Value	59.5 Hz	59.0 Hz to 59.9 Hz
	Maximum Value	60.1 Hz	60.1 Hz to 61.0 Hz

The area EPS operator and RRC can decide on enter service criteria for DERs greater than 500 kVa. For instance, the area EPS operator may allow larger than the specified maximum active power step changes, based on evaluation in coordination with the RRC.

The area EPS operator may allow alternative synchronization limits. The area EPS operator may waive synchronization limits in table 5 based on consideration of whether DER-induced voltage fluctuations are within requirements in Clause 7.2.

4.11 Interconnect integrity

Subclause 4.11 describes requirements for DER protection from *electromagnetic interference* (EMI), voltage and current surge withstand, and overvoltage withstand requirements for the DER paralleling device. Defaults are as specified in this subclause and as per the following standards,

- IEEE Std. C37.90.2, EMI,
- IEC 61000-4-3, EMI,
- IEEE Std. C62.41.2, surge withstand,
- IEEE Std. C37.90.1, surge withstand,
- IEEE Std. C62.45, surge withstand, and
- IEC 61000-4-5, surge withstand.

4.12 Integration with area EPS grounding

The subclause specifies that the DER's interconnection grounding scheme must be coordinated with the ground fault protection of the area EPS. The area EPS operator can adjust the grounding scheme and the area EPS operator may specify adjustments to the grounding scheme based on area EPS requirements.

4.13 Exemptions for emergency systems and standby DERs

Subclause 4.13 specifies the exemptions granted to emergency or standby DERs. The AGIR makes the designation of DERs as an emergency or standby power source based on the intended function of the DERs and applicable industry codes. Applicable codes include,

- National Fire Protection Association (NFPA) 110 chapter on emergency or standby DERs,
- National Fire Protection Association 70 chapter on emergency or standby DERs, and
- National Electric Safety Code (NESC) chapter on emergency or standby DERs.

Chapter 3
(Clause 5)
Requirements for Reactive Power and Voltage/Power Control

This clause contains requirements for reactive power and voltage/power control capabilities of DERs. The clause is directed primarily to the area EPS operator, DER operator, DER manufacturer, testing agency, and the commissioning agency. For determination of performance categories, the authority governing interconnection requirements (AGIR) may choose to provide guidance to the area EPS operator.

This clause presents a major change from the 2003 Standard. All new DERs are now required to have certain levels of voltage regulation capability. DER is separated into two Normal Operating Performance Categories, designated A and B. See Figure 5.

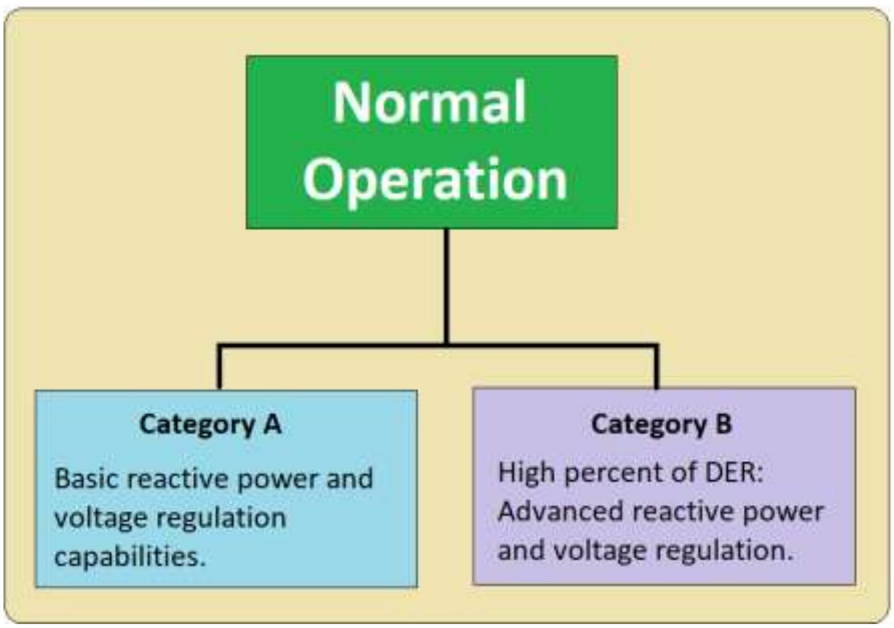

Figure 5

DER in Category A shall have a set of voltage regulation capabilities that provide the minimum required level of Area EPS voltage regulation. DERs in Category B have an extended set of voltage capabilities designed to offset the impacts of high penetrations of DER, or DER with wide time-varying outputs.

The standard defines a variety of voltage-regulating functions, such as volt-VAR and volt-watt functions and requires that all DERs have the capability to perform these functions. Use and settings of these capabilities, however, is at the discretion of the Area EPS operators, BPS operators, or the AGIR.

Key highlights of subclauses are explained below and includes notes on the implementation and configurability of the requirements and settings as well as defaults and optional configurations. The area EPS operator may choose which, if any, of these capabilities are to be used. In some jurisdictions, the AGIR may choose to provide input on these decisions.

5.1 Introduction

This subclause provides an overview of voltage and reactive power capabilities and control requirements for DERs operating under normal conditions.

The area EPS operator is responsible for specifying which performance category is required. This decision is based on several factors, including area EPS operator operational and future needs, characteristics of the current and planned future area EPS, and the intended purpose and use of the DERs. Note that this decision might include broader concepts of grid integration of DERs that fall outside the scope of the standard and might require input from the AGIR.

5.2 Reactive power capability of the DER

Subclause 5.2 specifies capability requirements for injection and absorption of reactive power that apply to both Category A and Category B distributed energy resources. The Standard describes the minimum required capabilities which state that in Category A, the DER should be able to inject up to 44% of its nameplate rating and absorb 25% of nameplate. For Category B, the values are 44% for both injection and absorption.

5.3 Voltage and reactive power control

IEEE Std. 1547-2018 requires that DERs have specified capabilities for voltage-dependent reactive power control and voltage-dependent real power control. Subclause 5.3 specifies the requirements for voltage regulation capability by use of reactive power control modes. Voltage regulation capability is mandatory for all DERs. There are two categories of voltage regulation: Category A and Category B. All DERs must be capable of three voltage regulation control modes under Category A:

1. Constant power factor mode (Default setting),
2. Voltage-reactive power mode, and
3. Constant reactive power mode.

For Category B, two additional voltage regulation capabilities are required:

1. Active power-reactive power mode, and
2. Voltage-active power mode.

The default mode is constant power factor mode at unity power factor unless the area EPS operator specifies a different mode.

Approval is needed from the area EPS operator to use voltage regulation capabilities. The decision is in part based on location-specific requirements for reactive power. In jurisdictions that use voltage regulation capabilities as part of DER grid services, input from the AGIR might also be needed based on the AGIR evaluation of policy and market goals. Other types of reactive power control are allowed by mutual agreement between the area EPS operator and the DER operator. Further requirements for voltage-reactive power mode and active power-reactive power mode can be found in sections 5.3.3 and 5.3.4, respectively.

In the Standard, tables 8 and 9 specify the default settings for voltage-reactive power and active power-reactive power. The area EPS operator may adjust these within the ranges of allowable settings shown.

DERs have an optional configuration that allows the DER to adjust its reference voltage based on measured values (as opposed to the fixed specified nominal voltage). Area EPS operator approval is required to use this capability; and if it is used, the area EPS operator will specify the associated time constant for autonomous adjustment of reference voltage.

5.4: Voltage and active power control

This subclause describes the requirements of voltage regulation capabilities by use of the active power control modes. These modes are required for Category B only and are voltage-active power modes.

The default mode is for these features is “Disabled”. The area EPS operator decides whether to use these capabilities. As noted, the AGIR might also have input depending on the AGIR’s policies and goals. Subclause 5.4.2 specifies the default and ranges of allowable settings for the relevant electrical parameters for each voltage regulation mode.

The Standard specifies default settings for the voltage-active power control mode in table 10. The area EPS operator may adjust the default values within the ranges of allowable settings shown in the table.

Chapter 4
(Clause 6)
DER Response to Area EPS Abnormal Conditions

This clause specifies requirements for DER response to abnormal conditions. For determination of abnormal operating performance categories, the AGIR and the reliability coordinator should provide guidance to the area EPS operator.

The response of aggregate DERs to abnormal voltage conditions contributes to the stability of the BPS, helps ensure utility maintenance personnel and public safety, and avoids damage to connected equipment including the DER itself. Mandatory tripping requirements in response to the Area EPS abnormal conditions was one of the key items of the original Standard (IEEE Std. 1547-2003.) These settings helped assure utilities that DERs would trip off-line when voltage and frequency were outside of normal conditions. The latest standard retains that fundamental concept of tripping DERs off-line during abnormal conditions. However, the “shall-trip” times have been lengthened and the ride-through thresholds have been widened to balance the needs of the BPS with those of the distribution system.

IEEE Std. 1547-2018 requires assigning abnormal performance categories to specific DERs and the coordination of regional voltage and frequency trip settings across the transmission and distribution interface. The specification of these regional functional settings will need to balance bulk system reliability and distribution concerns. A description of abnormal performance categories are as follows:

Category I: Essential BPS Reliability requirements

> Category I is based on minimal BPS reliability needs. The disturbance ride-through requirements for Category I acknowledge the inherent limitations that synchronous generators have compared to inverter-based systems. Category I disturbance ride-through performance, however, is not consistent with the reliability standards imposed on BPS generation resources. High penetrations of DER having only Category I capabilities could be detrimental to BPS reliability.

Category II: Complete coordination with BPS requirements

> Category II performance covers minimum BPS reliability needs, and coordinates with NERC Reliability Standard PRC-024-2, which was developed to avoid adverse tripping of BPS generators during system disturbances. These performance capabilities are attainable by inverter-based resources and possibly some other DER technologies.

Additional voltage ride-through capability was specified for DERs of Category II beyond the mandatory voltage ride-through defined by PRC-024 to account for the potential for *fault induced delayed voltage recovery* (FIDVR) on the distribution system.

Fault-induced delayed voltage recovery (FIDVR) refers to unexpected delay in the recovery of voltage to its nominal value following the normal clearing of a fault.

Category III: Ride-Through capability for both BPS and distribution provider

Category III provides the longest duration and widest bands for voltage ride-through capabilities that are attainable by inverter-based systems where there very high levels of DER penetration are expected or where momentary cessation requirements are seen as a desirable solution for coordinating with distribution system protection and safety. This category is intended to address DER integration issues like power quality and system overloads caused by DER tripping in the local Area EPS and to provide increased BPS reliability by further reducing the potential loss of DER during bulk system events.

Figure 6 shows the categories for voltage ride-through performance during abnormal operations.

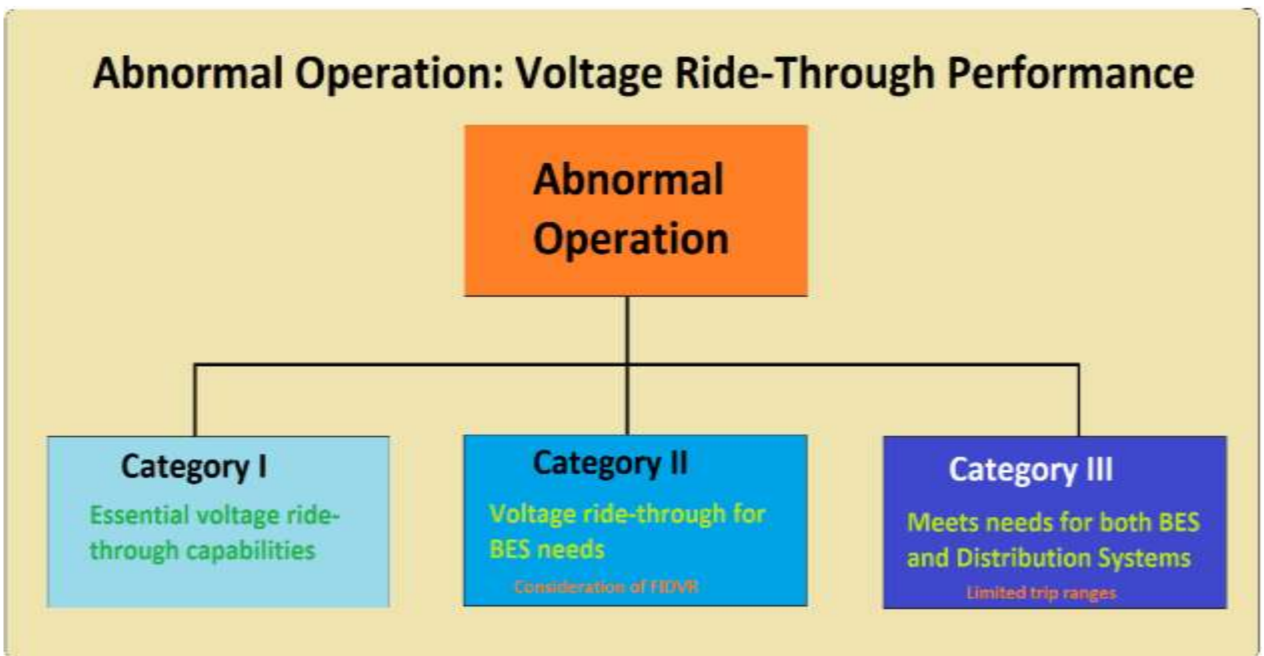

Figure 6

Subclauses of this clause are summarized below.

6.1 Introduction

This subclause provides an overview of capabilities and control requirements for DERs under abnormal operating conditions. Abnormal operating performance categories I, II, and III are introduced with some background on the rationale for using these capabilities.

The area EPS operator makes the determination of the required abnormal operating performance category. It is assumed the AGIR will provide guidance to the area EPS operator on applicability of performance categories. It is also assumed that the utilization of some of the abnormal operating performance categories related to the bulk power system, such as ride-through, requires coordination with the RRC. All DERs are required to be field-adjustable for relevant parameters in the clause. Adjustability via communications might also be required at the discretion of the area EPS operator.

6.2 Area EPS faults and open-phase conditions

Subclause 6.2 provides the requirements for the response to both short-circuit faults and open-phase conditions. Faults must be detectable by the area EPS protection systems. The DER is required to cease-to-energize and trip for short-circuit faults on the EPS circuit section.

For open phases, the DER is required to detect an open phase at the *reference point of applicability* (RPA) and cease to energize within two seconds. There is no requirement in the standard that a DER be able to detect an open phase at any other location on the Area EPS.

> The RPA which is typically either the *Point of Common Coupling* (PCC) or the *Point of Connection* (PoC) depending on the size of the system.

The area EPS operator has the right to modify DER parameters based on an evaluation of the DER fault current contribution, requirements for appropriate fault detection time, and protective relay coordination.

6.3 Area EPS reclosing coordination

The subclause says that appropriate measures must be taken to ensure the DER is coordinated with the area EPS reclosing scheme. The intent is to avoid automatically reclosing onto a circuit that is energized by DERs.

The area EPS operator decision for ensuring this requirement might include considerations for several factors, including DER type and penetration, existing area EPS protection schemes and requirements for protective relay coordination, reclosing timing, area EPS operator evaluation of reclose blocking, and transfer trip.

Additional consideration might be given to requirements for enter service (Clause 4.10) and voltage ride-through requirements for consecutive temporary voltage disturbances caused by a reclosing sequence (Clause 6.4.2.5).

The area EPS operator must provide requirements for coordinating the restore output behavior with the area EPS reclosing timing.

6.4 Voltage

Subclause 6.4 describes requirements for mandatory voltage tripping, ride-through requirements during low- and high-voltage disturbances, and performance requirements for dynamic voltage support. Dynamic voltage support is not mandatory but might provide improved voltage stability.

The Standard has default settings for under- and overvoltage tripping thresholds and clearing times (tables 11-13) for categories I, II, and III DERs. These functions are mandatory which means the DERs must trip on the default settings unless otherwise specified by the area EPS operator.

Voltage ride-through requirements for all categories of DERs are specified in the Standard (tables 14-16). Requirements for ride-through of consecutive voltage disturbances are given in Clause 6.4.2.5.

The area EPS operator may specify alternatives to the default trip and clearing times within the ranges of allowable settings based on a number of factors, including the area EPS protection schemes and requirements for protective relay coordination and coordination with voltage trip settings specified by the RRC (e.g., NERC PRC-024-2). Settings might need to be temporarily set outside the given ranges by the area EPS operator because of needs such as maintenance.

Even though DERs are not required to provide dynamic voltage support, they can be used by mutual agreement between the area EPS operator and the DER operator.

Subclause 6.4.2.7.3 allows the area EPS to adjust the transition threshold between momentary cessation and mandatory or continuous operation for Category III DERs.

Clause 6.4.1: Mandatory Voltage Tripping Requirements

Clause 6.4.1 states the following pertaining to mandatory voltage trip settings:

"When any applicable voltage is less than an undervoltage threshold, or greater than an overvoltage threshold, as defined in this subclause, the DER shall cease to energize the Area EPS and trip within the respective clearing time as indicated. Under and overvoltage tripping thresholds and clearing times shall be adjustable over the ranges of allowable settings…Unless specified otherwise by the Area EPS operator, default settings shall be used."

Table 5 shows the mandatory trip setting default values and ranges of adjustability for Categories I, II, and III.

Table 5
Shall-Trip Voltage Settings
(IEEE 1547-2018, tables 11-13)

Shall-Trip Function	Default Settings		Ranges of Allowable Settings	
	Voltage (p.u. of nominal)	Clearing Time (sec)	Voltage (p.u. of nominal)	Clearing Time (sec)
Category I Shall-Trip Voltage Settings				
OV2	1.20	0.16	1.20	0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.70	2.0	0.0–0.88	2.0–21.0
UV2	0.45	0.16	0.0–0.50	0.16–2.0
Category II Shall-Trip Voltage Settings				
OV2	1.20	0.16	1.20	0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.70	10.0	0.0–0.88	2.0–21.0
UV2	0.45	0.16	0.0–0.50	0.16–2.0
Category III Shall-Trip Voltage Settings				
OV2	1.20	0.16	1.20	0.16

OV1	1.10	13.0	1.10–1.20	1.0–13.0
UV1	0.88	21.0	0.0–0.88	2.0–50.0
UV2	0.50	2.0	0.0–0.50	0.16–21.0

The overvoltage thresholds shown in Table 5 are the same for all three Categories as they were in the 2003 standard, but the clearing times are longer. For undervoltage, Category I changes are relatively small; the undervoltage thresholds are lower, but the clearing times are the same as they were in the previous Standard. For Categories II and III, the clearing times are significantly longer than they were in the previous Standard.

Although the default settings for voltage trip and the default voltage threshold for ride-through operation in momentary cessation are generally applicable for most DER interconnections, there may exist specific distribution circuits where protection schemes differ from the general protection approaches assumed in the Standard. Distribution protection methods and overall philosophy can vary considerably from entity to entity, requiring consideration of the Standard may affect existing distribution protection practices.

Clause 6.4.2: Voltage Disturbance Ride-Through Requirements

Clause 6.4.2 defines the abnormal voltage ride-through requirements for Category I, II, and III resources in tables 14-16 of IEEE Std. 1547-2018, respectively. Figure 7 is a graphical representation of the data in the Standard.

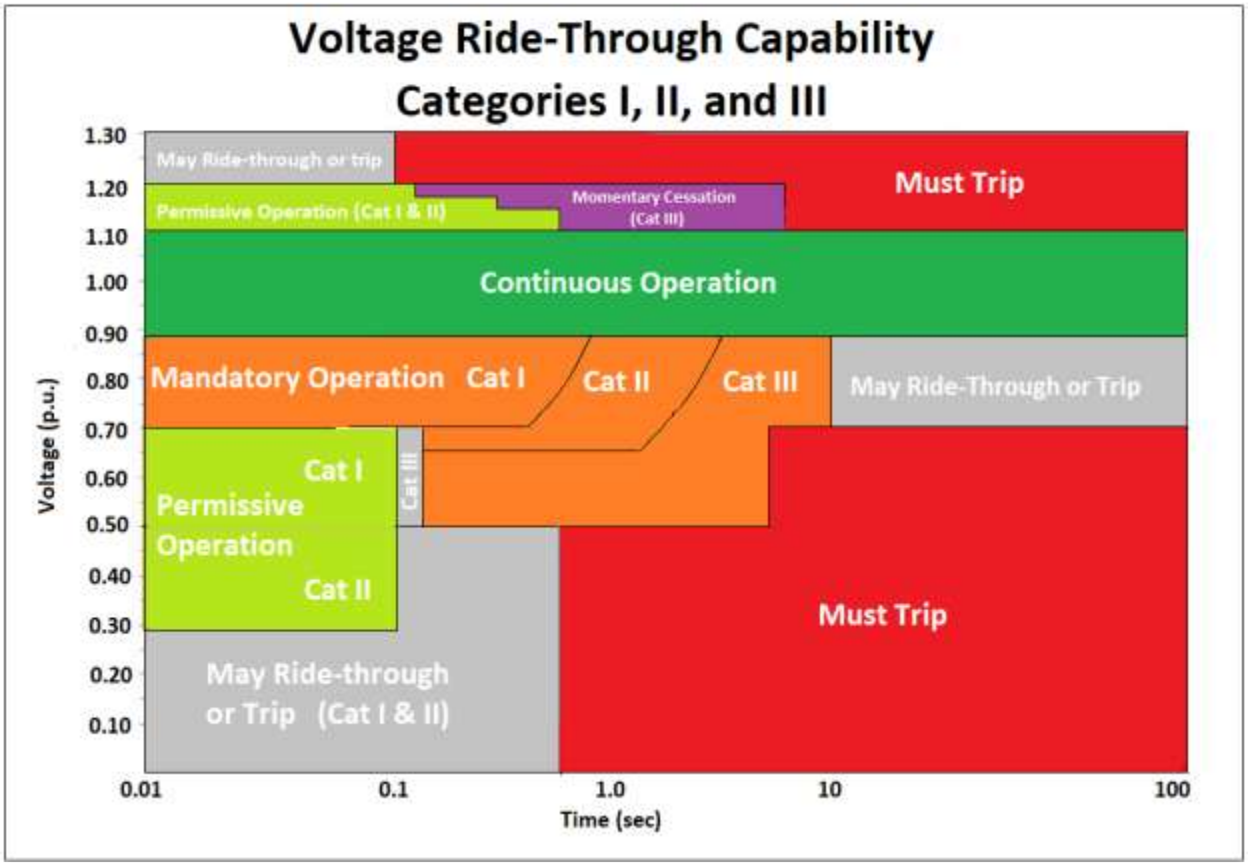

Figure 7

Limits for mandatory voltage tripping effectively define the window for "ride-through" since these settings override all other functions. For example, for both Category I and II DERs, the default values for UV2 shown in Table 5 state that, if voltage at the DER reference point drops below 0.45 p.u. for 0.16 seconds, the DER must cease to energize, regardless of ride-through capabilities. New criteria regarding voltage-sensing accuracy are also included in the Standard to better support equipment capability in meeting both mandatory tripping and ride-through requirements.

The following notes are useful perspectives to consider when implementing IEEE 1547-2018 based on the Clause 6.4.2 requirements:

- The Area EPS Operator specifies the Category (either I, II, or III) for its system. AGIRs should ensure that appropriate categories are selected for existing and future penetration levels of DERs.
- For voltage perturbations within the continuous operation region of the ride-through curves, DERs must remain in operation and continue delivering available active power of magnitude at least as great as its pre-disturbance level and prorated by the per-unit voltage of the least phase voltage if that voltage is less than nominal.

- During temporary voltage disturbances when voltage falls outside the continuous operation region, DERs must be able to ride-through, maintain synchronism, not trip, and restore output as per the Standard. This does not require DERs to continue injecting current in this region of the ride-through curves.
- Within the mandatory operation region, the DER must maintain synchronism, continue to exchange current, and not cease to energize nor trip. Category II and III DERs cannot reduce its' total apparent current below 80% of the pre-disturbance value or of the corresponding active current level subject to the available active power, whichever is less.
- During temporary voltage disturbances where voltage falls within the permissive operation region, DERs must maintain synchronism, not trip, and may either continue to exchange current or cease to energize. If the DER does cease to energize it must restore output as specified in the Standard.

Permissive operation of DERs as defined in the Standard is an "operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation". Therefore, the DER may either provide current injection or may use momentary cessation. Widespread cessation of current injection with delayed recovery of current to pre-disturbance levels can have a negative impact on BPS reliability and stability during BPS fault events. All applicable entities should seek to establish requirements for DERs to provide grid-supportive response to BPS disturbances. For Category III DERs, a momentary cessation operation region exists for specified low-voltage conditions.

A subclause in this section, 6.4.2.5, defines performance during consecutive voltage disturbances. This subclauses states that the requirements for continued operation (ride-through) or restore output shall apply to multiple consecutive voltage disturbances within a ride-through operating region, for which the voltage range and corresponding cumulative durations are specified in tables 14-16 of the Standard for Category I, II, and III DERs, respectively. These requirements are subject to the provisions specified in table 17 of the Standard (see Table 6 below) for which a DER may trip.

Table 6
Voltage ride-through requirements for consecutive temporary voltage disturbances
(IEEE Std. 1547-2018, table 17)

Category	Maximum number of ride-through disturbance sets	Minimum time between successive disturbance sets (sec)	Time window for new count of disturbance sets (min)
I	2	20.0	60

II	2	10.0	60
III	3	5.0	20

Clause 6.4.2.6 Dynamic Voltage Support

This section allows DER to provide dynamic voltage support to assist with low-voltage ride-through and high-voltage ride-through operation. The dynamic voltage support cannot cause the DER to cease to energize in situations where the DER would not cease to energize without the dynamic voltage support.

Clause 6.4.2.7: Restore Output

This subclause defines the restore output with voltage ride-through requirements. These requirements define how DERs shall operate when the applicable voltage returns to within the continuous operation region following it entering the mandatory or permissive operation regions. In all cases, DER shall maintain synchronism with the Area EPS. Performance is then based on whether or not the DER is providing dynamic voltage support:

- If the DER is not providing dynamic voltage support, then it must restore output of active current to at least 80% of pre-disturbance active current level within 0.4 seconds. Active and reactive current oscillations in the post disturbance period that are positively damped are acceptable.

- If the DER is providing dynamic voltage support, then it must continue to.
    1. Provide dynamic voltage support up to five seconds after the applicable voltage surpasses the lower value of the continuous operation region and restore output of active current to at least 80% of pre-disturbance active current level or to the available active current subject to reactive current priority, whichever is less, within 0.4 seconds.
    2. Discontinue providing dynamic voltage support five seconds after the applicable voltage surpasses the lower value of the continuous operation region and resume reactive power functionality for normal conditions.

Note that areas with any delayed voltage recovery concerns, such as those caused fault-induced delayed voltage recovery (FIDVR), may need to consider whether this type of dynamic voltage support being retracted after five seconds could impact BPS reliability.

6.5 Frequency

In addition to the voltage mandatory tripping and ride-through requirements, the Standard also includes mandatory frequency tripping and ride-through requirements during under- and over-frequency disturbances. These requirements help ensure that DERs are able to ride-through frequency disturbance events on the BPS and support BPS stability during abnormal contingency events. The requirements for ride-through only apply while DER frequency and voltage are within the "shall-trip" limits. New criteria regarding frequency-sensing accuracy are also included in the Standard to better support equipment capability in meeting both mandatory tripping and ride through requirements.

Under- and over-frequency trip settings must be coordinated between the area EPS operator and the RRC and may be adjusted within the ranges of allowable settings based on several factors, including consideration of regional underfrequency load-shedding programs and requirements for frequency restoration time.

The area EPS operator, in coordination with the RRC, may specify alternate settings for frequency-droop within the ranges of allowable settings specified in table 24. This decision is based in part on consideration of dynamic oscillatory behavior.

Utilization of inertial response by DERs with this capability is by mutual agreement between the DER operator and the area EPS operator in consultation and coordination with the RRC.

Clause 6.5.1: Mandatory Frequency Tripping Requirements

This subclause states the following pertaining to mandatory frequency trip settings:

> *"When the system frequency is in a range given below, and the fundamental-frequency component of voltage on any phase is greater than 30% of nominal, the DER shall cease to energize the Area EPS and trip within a clearing time as indicated…The underfrequency and over-frequency trip settings shall be specified by the Area EPS operator in coordination with the requirements of the regional reliability coordinator. If the Area EPS operator does not specify any settings, the default settings shall be used."*

Default settings for under- and over-frequency tripping thresholds and clearing times are specified in table 18 in the standard (see Table 7 below). These functions are mandatory which means the DERs must trip on the default settings unless otherwise specified by the area EPS operator.

Table 7
Frequency Trip Settings
(IEEE 1547-2018, table 18)

Shall-Trip Function	Default Settings		Ranges of Allowable Settings	
	Frequency (Hz)	Clearing Time (sec)	Frequency (Hz)	Clearing Time (sec)
OF2	62.0	0.16	61.8 – 66.0	0.16 – 1,000.0
OF1	61.2	300	61.0 – 66.0	180.0 – 1,000.0
UF1	58.5	300	50.0 – 59.0	180.0 – 1,000.0
UF2	56.5	0.16	50.0 – 57.0	0.16 – 1,000.0

Similar to the voltage-related trip settings, the frequency-related shall-trip settings have been coordinated with the reliability needs of the BPS and are well aligned with similar requirements for BPS-connected generating resources. The Standard uses a 0.16 second trip setting as the fastest frequency-related trip threshold, further supporting the ability of DERs to support the grid during grid disturbances.

Clause 6.5.2: Frequency Disturbance Ride-Through Requirements

DER are required to ride-through *Rate-of-Change-of-Frequency* (ROCOF) and voltage phase angle changes in order to support BPS stability. These ride-through functions cannot be disabled or field-adjusted. The frequency droop functions are also mandatory and cannot be disabled.

This subclause defines the abnormal frequency ride-through requirements for Category I, II, and III resources in table 19 of the Standard. All three categories have the same frequency requirement. See Figure 8.

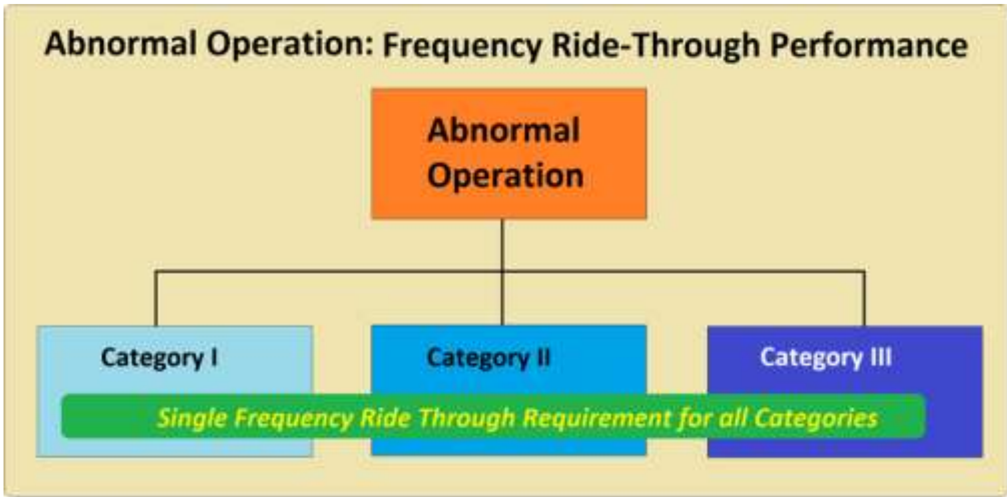

Figure 8

The frequency clearing times are much longer in the 2018 Standard compared to the previous Standard. Figure 9 is a graphical representation of this data. Notice how close the areas are between Mandatory Operation (orange), May Ride-Through (gray), and Must Trip (Red).

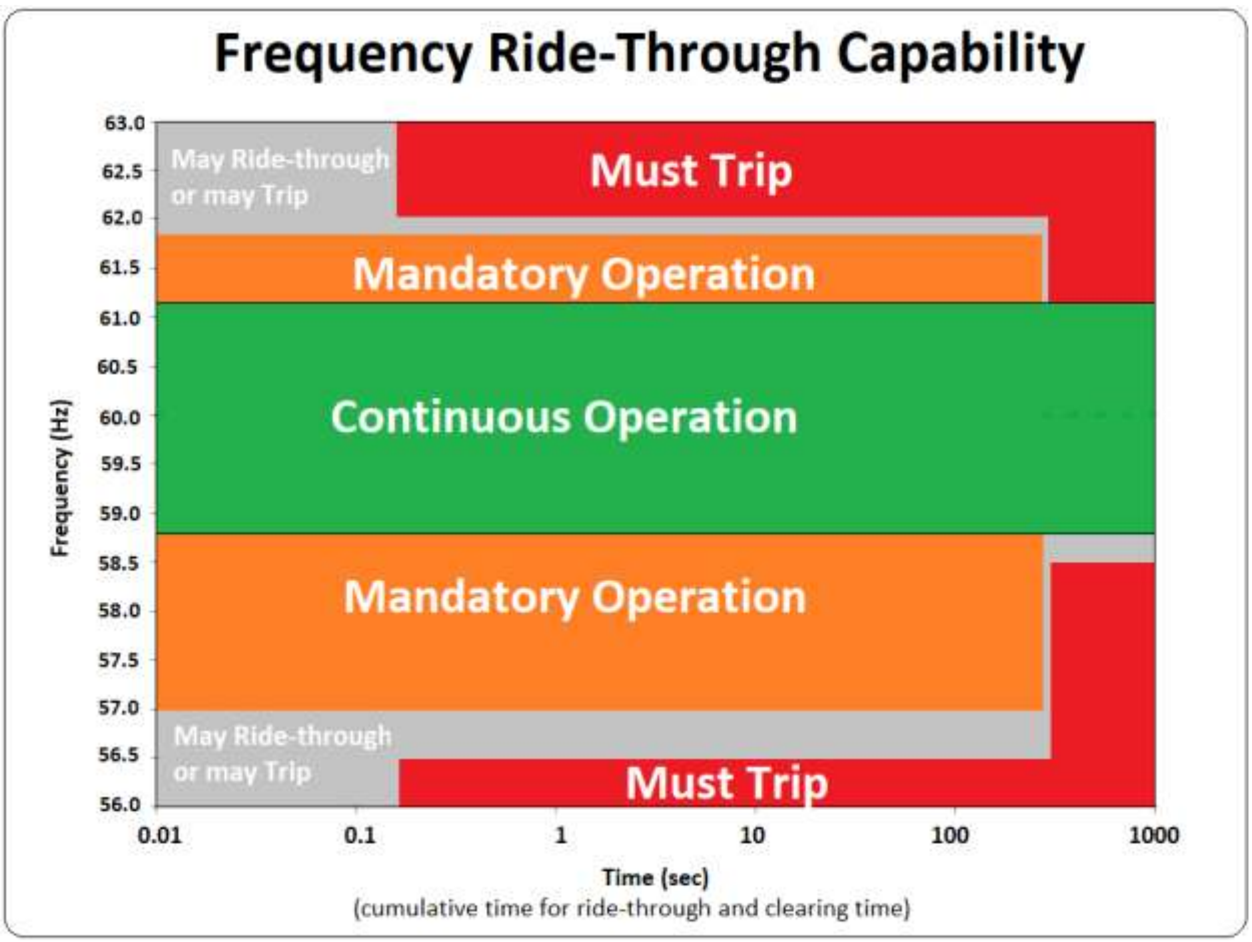

Figure 9

The following notes are useful perspectives to consider when implementing the frequency requirements:

- The ride-through requirements are just within the limits of the shall-trip criteria, in many cases.

- DERs will be designed to provide frequency disturbance ride-through capability without exceeding DER capabilities.

- Frequency disturbances of any duration for which system frequency remains between 58.8 Hz and 61.2 Hz and the per-unit ratio of voltage to frequency is less than or equal to 1.1, shall not cause the DER to trip. The DER shall remain in operation during any such disturbance and shall be able to continue to exchange active power at least as great as its pre-disturbance level of power.

- During temporary frequency disturbances, the DER shall be capable of riding through and maintaining synchronism with the Area EPS. In the Standard, tables 20 and 22 define DER performance based on the DER category selected.

  - For temporary low-frequency disturbances within the mandatory operation region, Category II and III DERs shall maintain synchronism, have active power output capability equal to pre-disturbance values, and modulate active power per table 22 of the Standard.
  - For temporary high-frequency disturbances, DERs shall maintain synchronism with the Area EPS, shall continue to exchange current with the Area EPS and shall neither cease to energize nor trip, and shall modulate active power to mitigate the over-frequency conditions per table 22 of the Standard.

- Within the continuous operation region and ride-through operating regions, DERs shall not trip for frequency excursions having a magnitude of Rate-of-Change-of-Frequency (ROCOF) that is less than or equal to the values specified in Table 8 (table 21 of the Standard).

Table 8 Rate-of-Change-of-Frequency (ROCOF) Ride-Through Requirements (IEEE 1547-2018, table 21)		
Category I	**Category II**	**Category III**
0.5 Hz/s	2.0 Hz/s	3.0 Hz/sec

Subclause 6.5.2 has eight subsections, and they are,

- 6.5.2.1 General requirements and exceptions
- 6.5.2.2 Frequency disturbances within continuous operation region
- 6.5.2.3 Low-frequency ride-through
- 6.5.2.4 High-frequency ride-through
- 6.5.2.5 Rate of change of frequency (ROCOF) ride-through
- 6.5.2.6 Voltage Phase Angle Changes Ride-Through
- 6.5.2.7 Frequency-Droop
- 6.5.2.8 Inertial Response

Only subsections 6.5.2.6, 6.5.2.7, and 6.5.2.8 are covered in this course.

Clause 6.5.2.6: Voltage Phase Angle Changes Ride-Through

Subclause 6.5.2.6, describes the ride-through performance requirements for single-phase and multi-phase DER for sub-cycle-to-cycle phase angle changes, (i.e., "phase jump"), often caused by fault events or line switching operations on the distribution system or BPS:

> *"Multi-phase DER shall ride through for positive-sequence phase angle changes within a sub-cycle-to-cycle timeframe of the applicable voltage of less than or equal to 20 electrical degrees. In addition, multi-phase DER shall remain in operation for change in the phase angle of individual phases less than 60 electrical degrees, provided that the positive sequence angle change does not exceed the forestated criterion. Single-phase DER shall remain in operation for phase angle changes within a sub-cycle-to-cycle time frame of the applicable voltage of less than or equal to 60 electrical degrees. Active and reactive current oscillations in the post-disturbance period that are positively damped or momentary cessation of the DER having a maximum duration of 0.5 seconds shall be acceptable in response to phase angle changes."*

The ability of inverter-based resources and DERs connected to the BPS to ride through changes in voltage phase angle is critical to reliable operation of the BPS. Multiple grid events have identified that phase jump

> A recent line switching event in the Western Interconnection tripped a BPS-connected solar PV facility off-line due to the large change in phase angle when the line was re-energized and resumed power flow.

issues at the distribution system and on the BPS have caused these resources to trip off-line when using legacy settings not aligned with the requirement mentioned above.

Clause 6.5.2.7: Frequency-Droop

As more DERs displace generating resources on the BPS, changes to analysis techniques and planning practices are needed to identify issues related to frequency control and balancing generation and demand. Frequency response is an *essential response service* (ERS) for BPS reliability, and the Standard requires the technical capability for DERs to provide active power frequency functionality similar to BPS-connected generating resources.

The 2018 standard requires that DERs have the capability to increase output when frequency drops and to decrease output when frequency increases in order to support the BPS. Frequency-droop operation is mandatory and default settings are included in the Standard. Some adjustment is possible, but it is expected and recommended that the default values be used unless otherwise directed by the AGIR.

The use of active power-frequency controls should be coordinated with any unintentional islanding settings. Concerns about the potential impact on unintentional islanding run-on times should not lead to wider dead-band settings for frequency-droop control since that can effectively desensitizes the function's impact.

A proportional response from DERs to high-frequency conditions beyond a dead-band can help support BPS frequency control during abnormal frequency conditions, particularly during interconnection-wide system separation events. The tendency of distribution providers to disable this function for Category I DERs bears a potential risk that should be considered. Use of Category II for DERs helps minimize this risk. Coordination between the DER operator and the responsible transmission entities is essential to ensuring that active power-related settings for the frequency-droop functions coordinate reliably with BPS practices.

Clause 6.5.2.7.1: Frequency-Droop Capability

The 2018 standard requires that DERs have the capability to increase output when frequency drops and to decrease output when frequency increases in order to support the BPS. Frequency-droop operation is mandatory and default settings are included in the Standard. Some adjustment is possible, but it is expected and recommended that the default values be used unless otherwise directed by the AGIR.

This subsection includes requirements for some DERs to have the capability to provide active power-frequency control that operates on a droop characteristic. The clause states the following:

> *"Depending on the DER abnormal operating performance category as described in Clause 4, the DER shall have the capability of mandatory operation with frequency-droop (frequency-power) during low-frequency ride-through and high-frequency ride-through as specified below."*

Table 9 below is an excerpt from table 22 in the Standard.

Table 9

Frequency Droop Requirements

(IEEE 1547-2018, table 22)

Category	Operation for Low-Frequency Conditions	Operation for High-Frequency Conditions
I	Optional (may)	Mandatory (shall)
II	Mandatory (shall)	Mandatory (shall)
III	Mandatory (shall)	Mandatory (shall)

The ability of DERs to support interconnection-wide frequency control for both underfrequency and over-frequency conditions in the future provides a significant reliability benefit. As more resources are able to provide support to grid frequency perturbations, each individual resource will need to provide less magnitude of response. It is well understood that the majority of DERs will operate at maximum available power and be unable to provide upward support for underfrequency conditions. However, having the capability to provide that support enables future grid services should the need arise for DERs to provide frequency responsive reserves and underfrequency response. By having visibility of DER status and capabilities, an operator or aggregator can provide frequency regulation, demand response, or other services.

Clause 6.5.2.7.2: Frequency-Droop Operation

This subclause specifies the active power-frequency performance of DER for frequency excursion events. It states the following:

> *"During temporary frequency disturbances, for which the system frequency is outside the adjustable dead-band, db_{OF} and db_{UF}, as specified in table 24, but still between the trip settings in table 18, the DER shall adjust its active power output from the pre-disturbance levels, according to the formulas in table 23."*

The Standard provides the formula for frequency-droop operation for underfrequency and over-frequency conditions and the parameters of these equations for each Category of DER, respectively. This information is provided in Table 10 Below, which shows the parameter values described in table 24 of the Standard. Terms in this table include,

db_{OF}: Single-sided dead band value for high-frequency, Hz.
db_{UF}: Single-sided dead band value for low-frequency, Hz.
k_{OF}: per unit high-frequency change corresponding to one per-unit power output change, unitless.
k_{UF}: per unit low-frequency change corresponding to one per-unit power output change, unitless.
$T_{response}$: Open loop response time, seconds.

The Standard provides more detail about these parameters.

Table 10
Parameters of Frequency-Droop Operation
(IEEE 1547-2018, table 24)

Parameter	Default Setting[1]			Ranges of Allowable Settings[2]		
	Cat I	Cat II	Cat III	Cat I	Cat II	Cat III
db_{OF}, db_{UF} (Hz)	0.036	0.036	0.036	0.017[3] –1.0	0.017[3] – 1.0	0.017[3] – 1.0
k_{OF}, k_{UF}	0.05	0.05	0.05	0.03 – 0.05	0.03 – 0.05	0.02 – 0.05
$T_{response}$ (Small Signal) (sec)	5	5	5	1–10	1–10	0.2–10

1. Adjustments shall be permitted in coordination with the Area EPS operator.

3. For the single-sided dead-band values (db_{OF}, db_{UF}) ranges, both the lower value and the upper value is a minimum requirement. For the frequency droop values (k_{OF}, k_{UF}) ranges, the lower value is a limiting requirement, and the upper value is a minimum requirement. For the open-loop response time, $T_{response}$ (small-signal), the upper value is a limiting requirement, and the lower value is a minimum requirement. Any settings different from the default settings in table 24 shall be approved by the regional reliability coordinator with due consideration of system dynamic oscillatory behavior.

3. A Dead band of less than 0.017 Hz shall be permitted.

Clause 6.5.2.8: Inertial Response

This subclause says:

> *"Inertial response, in which the DER active power is varied in proportion to the rate of change of frequency, is not required but is permitted."*

The Standard does not include requirements for resources to provide specific performance for the injection of active power with respect to fast-changing frequency, specifically in response to measured ROCOF. While this feature is not required, the ability of DERs to respond to rapidly changing frequency supports BPS reliability, particularly for systems with low system inertia that experience high ROCOF conditions. DERs with the capability and operational functionality to provide inertial response, might be able to provide essential response services (ERS).

6.6 Return to service after trip

The default *Return to Service* setting is unchanged at a 300-second delay, so this results in an even greater increase in the net load at re-energization that persists until the DER resumes pre-disturbance output. Therefore, for areas with high DER penetration, the demand may be significantly higher relative to demand prior to the outage. Table 11 below is a copy of Table 4 shown in Clause 4 (Chapter 2).

Table 11
Return to Service Criteria (all categories) DERs
(IEEE 1547-2018, table 4)

Enter Service Criteria		Objective	Foundation
Applicable Voltage within Range	Minimum Value	0.917 p.u.	0.88 p.u. to 0.95 p.u.
	Maximum Value	1.05 p.u.	1.05 p.u. to 1.06 p.u.
Frequency within Range	Minimum Value	59.5 Hz	59.0 Hz to 59.9 Hz
	Maximum Value	60.1 Hz	60.1 Hz to 61.0 Hz

Legacy DERs will return to service after steady-state frequency and voltage are restored and after a time delay of up to five minutes. At that point, most legacy DERs will resume operation nearly simultaneously, causing a significant shift in the net demand on any given feeder with DER penetration. This tends to destabilize wide area blackstart restoration efforts, where it is critical to maintain balance between load and generation while system inertia is still relatively low. Increasing penetration of DERs compliant with the new Standard reduces this potential impact by requiring that DERs to be capable of ramping up their power output over a prescribed period with a default of five minutes. Small DERs are allowed the option of utilizing a random delay, achieving the same behavior as a ramp-up in the aggregate of many small DER units.

These settings should help avoid adverse impacts to the operation of the BPS during large-scale restoration activities.

Chapter 5
(Clause 7)
Requirements for Power Quality

Clause 7 specifies DER compliance requirements for power quality-related phenomena. The clause is directed primarily to the DER manufacturer and the testing agency. In general, specified requirements are for qualities built into the DERs by manufacturers, and for most interconnections, no decisions are required.

The 2008 version of the Standard provides guidance on inter-harmonic limits and on DER contributions to flicker and rapid voltage changes. The temporary overvoltage section is essentially unchanged, but the transient overvoltage section is new and includes a transient overvoltage acceptance curve. Subclauses are summarized below.

7.1 Limitation of DC injection

This subclause has requirements for DER limitations on DC current injection.

7.2 Limitation of voltage fluctuations induced by the DERs

Subclause 7.2 describes requirements to limit voltage fluctuations induced by DERs. There are two subclauses that specify requirements for rapid voltage changes and flicker.

Alternate rapid voltage change limits require approval of the area EPS operator based on consideration of other rapid voltage change sources in the area EPS. Alternate flicker limits require approval of the area EPS operator based on consideration of other flicker sources in the area EPS.

7.3 Limitation of current distortion

Subclause 7.3 has limitations on harmonic current distortion, inter-harmonic current distortion, and total rated-current distortion. IEEE Std. 1547-2018 defines a new term, *total rated-current distortion*, which is used instead of total demand distortion. The IEEE harmonics standard (IEEE Std. 519) methodology is used to measure harmonic and inter-harmonic values; however, limits specified in IEEE Std. 1547-2018 refer to total rated-current distortion rather than the term total demand distortion used in IEEE Std. 519.

The area EPS operator may vary from the requirements depending on the intended use of the DERs, such as when the DER is used as an active filtering device.

7.4 Limitation of overvoltage contribution

This subclause describes limitations on the DER's contribution to instantaneous or fundamental frequency overvoltage. There are two subclauses that specify requirements for overvoltage over one fundamental frequency period and cumulative instantaneous overvoltage.

Chapter 6
(Clause 8)
Requirements for Islanding

Clause 8 specifies requirements for intentional and unintentional islanding. *Unintentional islanding* was addressed in the 2003 standard and the 2018 version provides more guidance and leeway in settings. *Intentional islanding* was not allowed in the 2003 version. The 2018 version includes an all-new section on intentional islands.

The clause is directed primarily to the DER manufacturer, the area EPS operator, the DER operator, the testing agency, and the commissioning agency. For the utilization of blackstart-capable intentional islands, additional stakeholders might include the bulk power system operator and the regional reliability coordinator. It may be assumed the DER owner is the same entity as the DER operator; however, this might not always be the case. The subclauses are summarized below.

8.1 Unintentional islanding

Subclause 8.1 specifies requirements for the prevention of unintentional islanding. There are three subclauses that specify requirements for island detection and options for modifying island detection time for protection coordination. If an unintentional island occurs, the DERs must detect the unintentional island and must cease to energize and trip within two seconds.

The EPS operator, in conjunction with the DER operator, may increase clearing time up to five seconds. This determination is based on area EPS-specific requirements and practices for protection coordination and mitigation of unintentional islanding as well as requirements and practices for area EPS auto-reclose times. There are numerous sections in the Standard they need to be considered for increasing clearing time. The following sections are relevant to this decision,

- Evaluation of continuous operation range, ranges of allowable settings, trip conditions (Clause 6),
- Exception conditions (subclauses 6.2.2.1, 6.5.2.1),
- Operating ranges (subclause 7.2.2),
- Island detection (subclause 8.1),
- Conditions for reconnection (subclauses 4.10, 4.10.4),
- Mandatory voltage trip, range of allowable settings (subclause 6.4.1), and
- Mandatory frequency trip (subclause 6.5.1).

For an unintentional island in which the DER energizes a portion of the Area EPS through the point of common coupling, Clause 8.1.1 requires the DER to detect the island, cease to energize the Area EPS, and trip within two seconds of the formation of an island. The same clause clarifies the important requirement that false detection of an unintentional island that does not actually exist shall not justify noncompliance with ride-through requirements as specified in Clause 6 of the standard. Despite this clear and strong language on unintentional islanding detection requirements in IEEE 1547-2018, Category I and II default settings are intended to address distribution utility concerns to ensure that unintentional islanding of isolated parts of the distribution grid with DERs is reliably prevented.

8.2 Intentional islanding

This subclause specifies requirements for intentional islanding. Intentional islanding refers to a planned electrical island capable of being energized by one or more Local EPSs that have one or more DERs and load. Clause 8.2 and its various sub-clauses describe intentional islanding, which may be either an island of the DER and the Local EPS or may include parts of the Area EPS; however, such an island is intentionally disconnected from other parts of the distribution system and the larger BPS.

The sub-clauses cover the creation of intentional islands, the transition to and from these islanded conditions, and how DERs should operate when connected in this manner (which may include modifications to settings when they are connected to the Area EPS that is then connected to the BPS). There are eight subclauses that specify requirements for related topics. These include general requirements, scheduled and unscheduled intentional islands, conditions for transition from grid-connected to island mode, adjustments to DER settings when operating in intentional area EPS island mode, and DER categories for intentional islands. Intentional islands can be either area EPS islands or local EPS islands. The area EPS island must be designed and operated in coordination with the area EPS operator.

Determination of intentional island application and use is made by the DERO and the area EPS operator. Considerations include use under normal and abnormal grid conditions. The DER operator must designate the category of intentional islanding. This decision requires approval and coordination with the area EPS operator. The categories are listed in Clause 8.2.8 and include these islands,

- Intentional island-capable,
- Black-start-capable,
- Isochronous capable, and
- Uncategorized.

The DER operator and the area EPS operator must determine the conditions for scheduled and unscheduled transitions to island mode as well as adjustments to DER operating settings for DERs that operate in an intentional area EPS island configuration.

Chapter 7
(Clause 9)
Requirements for DER on Distribution Secondary Networks

This clause specifies requirements for DERs on distribution secondary grid, area, or street networks and spot networks. The clause is directed primarily to the area EPS operator, the DER operator, and the DER manufacturer. Subclauses are summarized below.

9.1 Network protectors and automatic transfer scheme

This subclause specifies requirements on the use of network protectors on feeders with DERs. The Standard says network protectors are not to be used to isolate a network or network primary feeder that contains DERs.

Network protectors that are rated and tested for use with DERs according to applicable standards such as IEEE Std. C57.12.44 may be used. The area EPS operator may make decisions based on various considerations, including:

- Area EPS feeder configuration,
- Automatic transfer schemes,
- Type and rating of network protectors,
- Reverse power relaying,
- Minimum import relaying,
- Dynamically controlled inverter functions,
- Prevention of reverse power flow through network protectors,
- Fault-interrupting capability of network protectors deployed, and
- Operation of network protectors pre- and post-installation of DERs.

On a network with automatic transfer schemes and power flow the area EPS operator might allow certain configuration options that differ from the default of positive power flow from the area EPS to the load and the DERs. For DERs on grid or spot networks, the area EPS operator will determine the minimum import level at the PCC.

9.2 Distribution secondary grid networks

This subclause covers requirements on the use of DERs on secondary grid networks. Specifically, interconnected DERs must be coordinated with network protector relay functions and must be evaluated by the area EPS operator.

9.3 Distribution secondary spot networks

In addition to requirements in subclause 9.1, this subclause provides other requirements on the use of DERs on secondary spot networks, say DER is permitted only if the area EPS network bus is already energized by more than 50% of the installed network protectors.

Chapter 8
(Clause 10)
Requirements for Interoperability

Clause 10 is a new clause. The term *interoperability* is defined by IEEE as,

> *"The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively."*

This clause contains requirements for DER mandatory capabilities that the manufacturer must ensure. However, utilization of interoperability capabilities and methods for implementation are decisions for local jurisdictions. Emergency and standby DERs are exempt from the interoperability requirements specified in this clause.

Clause 10 clause provides a standardization of the local DER communications interface and protocols but does not require any specific external communication channel to be utilized. A standard local DER communication interface makes it easier, if allowed, for distribution providers or other third parties to perform monitoring and management or control of DERs.

Transmission and distribution entities, as well as regulatory entities (e.g., AGIRs), will need to provide appropriate guidance on policies for accommodating these needs. Specific policies, protocols, and mediums of communication should be established by these entities in a coordinated manner. Relevant topics include, but are not limited to, the following:

- The expected timeline for when a communication and control system may be needed.
- The technology and required performance level of the communication system to support specific use cases.
- The communication networks and architecture standards needed.
- The types and size of DERs necessary to be integrated into this standardized communication interface.
- The specific owners and operators of each level and type of communication integration system.
- Clear regulatory policies that ensure consumer protections for utilization of control functions, with different requirement standards for when control is required.

The subclauses are summarized below.

10.1 Interoperability requirements

This subclause describes requirements for overall DER interoperability. All DERs must have provision for a local DER communications interface that supports interoperability for all applicable DER functions.

The area EPS operator may determine whether to use the local DER communications interface or to deploy a separate communications system. This decision is made based on utility requirements for the utilization and interoperability capabilities. Considerations might include the integration of DERs into utility distribution operations and planning, DER situational awareness and modeling, and utility programs and services for customers. Figure 10 illustrates than in addition to the power interface between the area EPS and DER there also needs to be a communications interface.

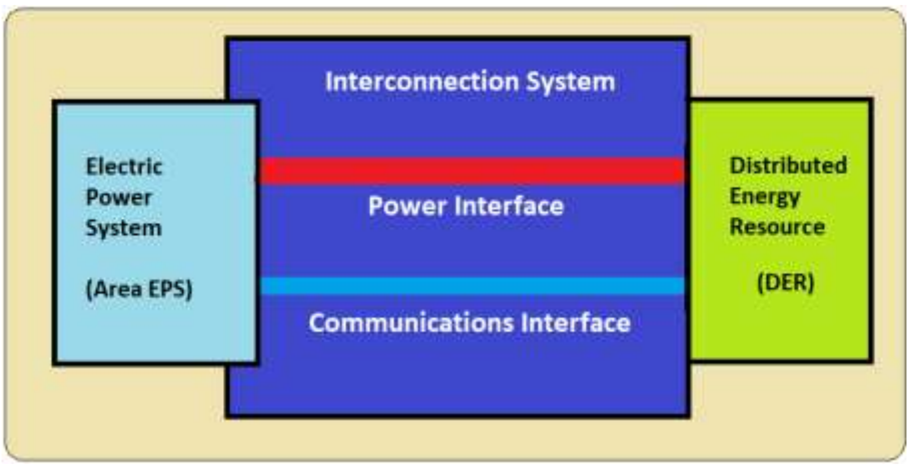

Figure 10

The standard allows for additional communications capabilities under mutual agreement between the area EPS operator and the DER operator.

10.2 Monitoring, control, and information exchange requirements

Subclause 10.2 introduces the background and intent of interoperability in the standard, and it specifies the four types of information the DER must provide through the local DER communications interface:

- Nameplate,
- Configuration,
- Monitoring, and
- Management.

10.3 Nameplate information

This subclause describes the minimum requirements for DER nameplate information that must be available through a local DER communications interface. Nameplate information is intended to describe the as-built characteristics of the DERs and is read-only. Section 10.3 contains the minimum required list of nameplate parameters. Nameplate information is preprogrammed by the DER manufacturer. These are the required items,

- Active power rating at unity power factor
- Active power rating at specified over-excited and under-excited power factor
- Specified over-excited and under-excited power factor
- Apparent power maximum rating
- Normal and abnormal operating performance category
- Reactive power injected/absorbed maximum rating
- Active and apparent power charge maximum rating
- AC voltage nominal, maximum, and minimum, rating
- Supported control mode functions
- Reactive susceptance remaining connected to the Area EPS in cease-to-energize and trip state
- Manufacturer, Model and Serial number.

10.4 Configuration information

This subclause specifies the requirement for DERs to provide configuration information through the local DER communications interface and specifies usage of configuration information and settings. Configuration information is intended to describe the DERs present capability and ability to perform functions. Configuration information can be considered optional alternatives to nameplate information (i.e., the configuration information supersedes the nameplate information). Each nameplate value has a corresponding configuration value. Configuration information is read/write.

The configuration information values are the same as nameplate values. Changes to configuration information values are by mutual agreement between the area EPS operator and the DER operator.

10.5 Monitoring information

Subclause 10.5 specifies requirements for the DER provision to provide monitoring information through the local DER communications interface. Monitoring information is intended to describe the DERs present measured operating conditions and is read-only.

The standard contains the minimum required list of monitoring parameters. These parameters are measured by the DERs and accessed via the local DER communications interface. These include,

- Active Power
- Reactive Power
- Voltage
- Frequency
- Operational State
- Connection Status
- Alarm Status
- Operational State of Charge

10.6 Management information

This subclause describes requirements for DER management information, which is used to update the functional and mode settings of the DERs. Management information is read/write through the local DER communications interface. Subclauses 10.6.2 through 10.6.12 specify descriptions and definitions for the range of settings for each management information parameter. Specific parameters and ranges for specific DER functions, including parameters for active and reactive power control, voltage and frequency trip, frequency droop, enter service ramp rates, enabling and disabling permit service, and limiting active power are provided in tables 30 through 40 of the Standard.

10.7 Communications protocol requirements

Specifies requirements for support of communications protocols that apply at the local DER communications interface. All DERs must support at least one of the following communications protocols:

- IEEE Std. 2030.5 (SEP2),
- IEEE Std. 1815 (DNP3), or
- SunSpec Modbus.

This capability is built in to the DERs by the manufacturer. Note that the scope of this subclause is only the local DER communications interface. DER internal communications and communications to the utility, customer, or third party are out of scope.

The protocol to be used is specified in the standard as chosen by area EPS operator. By mutual agreement between the area EPS operator and the DER operator, a different protocol, including a proprietary protocol, may be used.

10.8 Communications performance

This subclause specifies requirements for DER communications performance, which include the availability of communications and information read response time. The standard contains requirements that are built in by the DER manufacturer. Specifically, when DER is operational the local DER communication interface shall be active and responsive whenever the DER is operating and in a continuous operation region or mandatory operation region. The information read response time is 30 seconds or less.

10.9 Cyber security requirements

This subclause states that cybersecurity is recognized as critically important; however, no specific requirements are specified in the current standard. Although the area EPS operator might choose to not use the remote communications capabilities specified in this standard, if these capabilities are used by an external party—such as a DER aggregator, DER manufacturer, or even the DER operator—the AGIR and the area EPS operator might want to consider a cybersecurity risk evaluation of those communications paths.

Chapter 9
(Clause 11)
Requirements for Test and Verification

This clause specifies requirements for testing and verification to ensure that DERs meet the performance requirements of IEEE Std. 1547-2018. This clause also specifies at which stage in the interconnection process testing and verification shall be performed. The target audience is primarily DER manufacturers, testing agencies, commissioning agencies, the area EPS operator, the DER operator, and in some cases the DER owner. The subclauses are summarized below.

11.1 Introduction

This subclause provides background and context for the testing and verification requirements needed for each DER functional capability specified in the previous clauses. Test and verification results are to be formally documented according to IEEE Std. 1547.1.

11.2 Definition of test and verification methods

This subclause specifies the different types and applicable timing of verification methods for demonstrating DER compliance. There are six subclauses within this section that describe testing and verification and they are described as,

11.2.1 Intended use and requirements
11.2.2 Reporting for type tests
11.2.3 Production tests
11.2.4 DER evaluation
11.2.5 Commissioning tests
11.2.6 Periodic tests and verifications

The Standard allows the DER manufacturer to decide whether to perform type testing on one device (DER unit) or a combination of devices (DER system). The type testing can be performed at the factory, or in the field. Field-testing is allowed by mutual agreement between the area EPS operator and the DER operator.

Production testing occurs on every DER unit and interconnected equipment to verify correct operation of the equipment. Production testing typically occurs after type testing has confirmed that the equipment meets the performance requirements in the standard. Production testing can be performed at the factory or as part of DER evaluation or commissioning test. Field-testing is allowed by mutual agreement between the area EPS operator and the DER operator.

DER evaluations include engineering verification of components and could also include modeling and simulation of the DER system.

Periodic testing criteria must be furnished by the DER manufacturer or DER system integrator. Reverification is based on events such as changes to functional software or firmware, field modifications or replacement of DER hardware with non-substitutive components, or changes in protection settings or functions. Field demonstration of compliance needs to be mutually agreed by the area EPS operator and DER operator.

This clause requires the development of a verification plan, reports, and logs for documenting results from commissioning and testing approval by area EPS operator

11.3 Full and partial conformance testing and verification

This subclause outlines test and verification requirements for full and partial conformance DER. There are three subclauses that provide information and specify requirements for DER compliance either at the PCC and the PoC depending on the RPA determination. These requirements are presented in great detail in the standard and provide the traceability of a given requirement and the method of verification. This format is termed a *test requirement matrix* in Clause 11.3.

Test and verification requirements are given in great detail in table 43 and table 44 in the Standard. These tables are applicable to DER that meet requirements at the PCC (Section 11.3.2), and DER that meet requirements at the PoC (Section 11.3.3). IEEE 1547.1 contains test procedures and must be referenced. Fulfilling the requirements of this Clause requires development of a verification plan, reports, and logs that are mutually agreed upon by the DER operator and area EPS operator.

Development of compliance testing procedures requires decisions by DER manufacturer and approval by the area EPS operator or the AGIR. The procedures based on:

- Compliance verification process, steps, and timing,
- Verification procedure and considerations as outlined in IEEE Std. 1547.1,
- Determination of applicable RPA based on Clause 4.2, including impedance between PoC and PCC,
- The required operating modes, protection settings, and operating parameters enabled on the DER,
- Additional area EPS-specific requirements on interconnection process, test, and verification,

- For a DER system, understanding how the DER and supplemental devices are designed together and achieving compliance with the IEEE Std. 1547-2018,
- Field tests require an understanding of DER and field conditions to determine feasibility and how to perform compliance and commissioning testing in the field,
- For any potential periodic test, understanding and agreement on the events and changes made to the DER, that would trigger the type of field tests, and
- If DERs or components of DERs are substituted in the field, an evaluation on the compliance validity shall be performed and any field demonstration of compliance shall be mutually agreed upon with the EPS and DER operators.

11.4 Fault current characterization

This subclause specifies documentation requirements of parameters characterizing DER current contribution to area EPS faults.

For DERs based on doubly fed induction generators and electronically coupled rated capacity of 500 kVA or greater, the DER operator must furnish voltage and current oscillograph data to the area EPS operator. For DERs based on synchronous and induction generators, the DER operator must furnish the nameplate KVA rating and various impedance data to the area EPS operator.

Summary

IEEE Std. 1547-2018 is a significant step forward in integrating distributed energy resources into the U.S. electric grid. The new standard gives DER owners more flexibility in how their DER is utilized and also requires more accountability for working with the area electric power systems to ensure grid stability and reliability.

Allowing intentional islanding may provide more security for some DER operations such as hospitals and other critical facilities. With more high inertia generating plants being retired, it is essential that DER be able to provide reactive support to the grid. This standard is a good step in achieving these objectives.

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