Background Information on the Protection Requirements in IEEE Std 1547-2018

Rasel Mahmud and Michael Ingram

National Renewable Energy Laboratory

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Preface

The revised Institute of Electrical and Electronics Engineers 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018) was published in April 2018. This standard is one of the foundational documents in the United States needed for integrating distributed energy resources (DERs), including solar energy systems, and energy storage systems with the electric distribution grid.

The revised standard contains 11 chapters (clauses) and 8 annexes that comprise 136 pages. The revision is significantly different from the 2003 version, and it contains new concepts and new technical requirements. Each clause specifies information or requirements that apply to certain aspects that are important to the interconnection of DERs to the electric power system. Implementing the requirements necessitates a careful study of the underlying technical concepts and requires appropriate information to calculate relevant settings and configurations.

Various stakeholders have different roles in implementing the standard, and portions of the standard are directed toward a specific audience who must possess specialized information and technical training to use and apply the requirements.

This document **provides informative material on the requirements related to electrical protection in IEEE Std 1547-2018**, with the intent to equip the reader with basic knowledge and background information to improve understanding and use of the requirements specified.

Note that this document reflects the authors' interpretations, which in some instances might differ from one person to another; therefore, this work is intended to supplement the existing and growing body of knowledge[1] across the U.S. electric sector on the use and application of this important standard.

[1] Additional educational material can be found at https://www.nrel.gov/grid/ieee-standard-1547/.

Acknowledgments

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List of Acronyms

AGIR	Authority Governing Interconnection Requirements
DER	distributed energy resource
DOE	U.S. Department of Energy
EERE	Office of Energy Efficiency and Renewable Energy
EPS	electric power system
IEEE	Institute of Electrical and Electronics Engineers
PV	photovoltaic
SETO	Solar Energy Technologies Office

Executive Summary

As the penetration level of distributed energy resources (DERs) has increased significantly in recent years, the parameter settings and the configuration of installed DERs are directly impacting local electric distribution utilities as well as bulk power systems during normal and abnormal grid conditions. Yet all grid-connected DERs in the United States must conform to the interconnection requirements prescribed in the revised Institute of Electrical and Electronics Engineers 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018). For these reasons, it is crucial to understand the expected performance of DERs during abnormal grid conditions considering the requirements of IEEE Std 1547-2018. The aim of this document is twofold: (1) to summarize the requirements in IEEE Std 1547-2018 that have direct implications on distribution network protection and (2) to provide readers with knowledge and information that will be required for users to apply the specified requirements. Because the focus of this document is on distribution network protection in the presence of DERs, it is assumed that the readers have a basic understanding of distribution network protection as well as the working principles of DERs.

This document starts with a brief introduction on protection systems for distribution networks, followed by a discussion on the impact of DERs on the protection systems. Current practices to provide network protection in the presence of DERs are briefly discussed. The document then explores the performance requirements of DERs according to IEEE Std 1547-2018, especially those related to distribution network protection.

Section 6.1 in IEEE Std 1547-2018 provides an overview of the capabilities and control requirements for DERs under abnormal operating conditions. This section also introduces abnormal operating performance categories I, II, and III. The response of DERs to various types of faults and grid conditions, such as short-circuit faults and open-phase conditions, are discussed in Section 6.2 in the standard, and requirements for coordination with the area electric power system reclosing scheme are provided in Section 6.3. Section 6.4 in IEEE Std 1547-2018 specifies requirements for mandatory voltage tripping and ride-through requirements during low- and high-voltage disturbances, and Section 6.5 specifies similar requirements for low- and high-frequency disturbances. IEEE Std 1547-2018 requires that the conformance of the DERs to the requirements of IEEE Std 1547-2018 should be verified in accordance with IEEE Std 1547.1. There are several parameters and settings of DERs that need to be properly selected for reliable operation during abnormal grid conditions while applying the requirements of IEEE Std 1547-2018. Key decisions for the proper selection of these parameters and settings are:

1. Determination of the required DER abnormal operating performance category
2. Determination of the DER response (shall trip) to abnormal voltages
3. Determination of the DER response (shall trip) to abnormal frequencies.

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1 Introduction

This document aims to provide a high-level overview of topics related to electric distribution system protection to complement the requirements specified in Clause 6 of the revised Institute of Electrical and Electronics Engineers 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018).

Clause 6 contains capabilities and control requirements for distributed energy resources (DERs) under abnormal operating conditions, including voltage and frequency disturbances. Clause 6.2 specifies requirements on the response of DERs to various types of faults and grid conditions, such as short-circuit faults and open-phase conditions. Clause 6.3 specifies requirements for coordinating with the area electric power system (EPS) reclosing scheme. Tripping and ride-through requirements for voltage and frequency disturbances are described in two additional subclauses. Informative Annex B presents discussion and considerations for the assignment of abnormal performance categories, which is a way to group DERs according to their technical capabilities and settings under abnormal operating conditions.

Clause 6 is directed primarily to electric utilities—the area EPS operator, DER operators, DER device manufacturers,[2] testing agencies[3] and laboratories, and commissioning agencies. To determine the performance categories, the Authority Governing Interconnection Requirements (AGIR)[4] might choose to provide guidance to the are EPS operator.

IEEE Std 1547-2018 assumes that the reader possesses the appropriate training and experience necessary to understand and apply the stated requirements. This could include foundational electrical engineering knowledge; knowledge of area EPS device settings, parameters, and operational practices; and knowledge of general and specific DER capabilities relevant to the subject.

This document is intended as a supplement to material already published or in development,[5] and it is not intended as an exhaustive resource on technical implementation; rather, topics are

[2] Solar and other DER device manufacturers are inherently interested in the performance requirements in IEEE Std 1547-2018; however, this document focuses on the application of the standard rather than the manufacturing process of DER devices. Note that although DER manufacturers are a primary stakeholder, their concerns are equipment design and manufacturing. This document is intended to provide an overall summary for stakeholders involved in the application of the standard.

[3] The term *testing agency* includes entities such as nationally recognized testing laboratories.

[4] IEEE Std 1547-2018 defines the *Authority Governing Interconnection Requirements* (AGIR) as "cognizant and responsible 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 cognizant and responsible entity to the Area EPS operator or bulk power system operator. NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, Area EPS operators, DER operators, and bulk power system operator" (IEEE 2018).

[5] For example, see the expected revision to IEEE Std 1547.2 Application Guide for IEEE Std 1547.

presented at a level that is appropriate to serve individuals who require an introduction or technical refresher to the material.

2 Distribution System Protection Concepts

Power system protection serves two primary functions: protection of the plant (equipment and stable delivery of power) and protection of the public (including employees). At a basic level, protection seeks to disconnect equipment that experiences an overload or a short to ground; thus, protection schemes must be applied with a pragmatic and conservative approach to clearing system faults. The devices that are used to protect the power system from faults are called protective devices.

Operating settings for protective devices are calculated such that their response is coordinated under various fault conditions. Under fault conditions, protective functions generally operate too quickly for any effective human intervention based on monitoring or control; therefore, protective devices respond automatically based on grid conditions. DER systems, including photovoltaic (PV) and other inverter-based systems, also have an automatic response to fault conditions. The response of DERs to fault conditions varies depending on the type and capabilities of the DER.

Protective devices consist of several functions that are arranged to test the system conditions, make decisions regarding the normality of the observed variables, and take action as required (Anderson 1999). These functions are depicted in Figure 1.

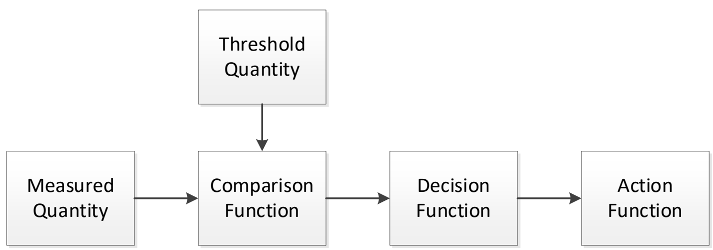


Figure 1. Protection functions

The protection system measures certain quantities, such as voltages and currents, and compares these quantities, or some combination of these quantities, against a threshold setting that is calculated by the protection engineer and set into the device. If a comparison indicates an alert condition, the decision function is triggered. The decision might involve a timing function (delay) to determine the permanence of the condition or to provide coordination among other protective devices (e.g., fuses, reclosers) on the system. Finally, if all checks are satisfied, an action function is released to operate—usually a circuit breaker is instructed to open and isolate a section of the network. Protective devices are installed with the aim of safeguarding the public, protecting assets, and ensuring the reliable supply of energy (Anderson 1999).

2.1 Electrical Faults

Electrical power systems must be designed to serve a variety of loads safely and reliably. Effective control of short-circuit current—or fault current, as it is commonly called—is a major consideration when designing coordinated power system protection. To fully understand the nature of fault current as it is applied to EPS design, it is necessary to distinguish among the various types of current available, normal and abnormal (Army Corps of Engineers 1991).

- Normal current (or load current) can be defined as the current specifically designed to be drawn by a load under normal operating conditions.
- Overload current is greater in magnitude than the current under the maximum load and flows only in the normal circuit path. It is commonly caused by overloaded equipment, single-phasing, or low-line voltage; thus, it is considered to be an abnormal current.
- Ground-fault current consists of any current that flows outside the normal circuit path. A ground-fault condition results in current flow in the equipment grounding conductor for low-voltage systems (i.e., distribution system voltages).
- When a low-impedance,[6] short-circuit path connects two or more conductors with different phases, uncontrolled and high-magnitude current can flow through the electrical system. The resulting high current is called a short-circuit current, which might range upward of thousands of amperes. The maximum value is limited by the maximum short-circuit current available on the system at the fault point. The available fault current or prospective short-circuit current depends on the fault impedance and voltage at the fault location.

Short circuits on power systems are usually disturbances of one of the following types:

- Three-phase short circuit
- Phase-to-phase short circuit
- Two-phase-to-ground short circuit
- Single-phase-to-ground short circuit.

The total current flowing to the fault depends on the type of fault and the location on the system where the fault occurs. The impedance looking back into the system varies with location, the amount of generation in service and the amount of load at the time, and the configuration of the network. All of these variations can be important in determining the range of available fault current (minimum and maximum) at a given place and time. Maximum values are necessary to determine the safe fault-interrupting ratings of devices. Both the maximum and minimum values of the available fault current are important to ensure the correct operation of the protection system.

In some cases, system configurations that are not short circuits are still considered “faults.” Single-line-open and two-line-open conditions present unbalanced current flow in the three-phase system and might require a protective response if the unbalance presents a threat to equipment. Figure 2 shows the types of faults typically observed in an electric power system.

[6] *Encyclopaedia Britannica* (Britannica n.d.) defines *impedance* as an “electrical impedance, measure of the total opposition that a circuit or a part of a circuit presents to electric current,” and according to the *Standard Handbook for Electrical Engineers* (Fowle 1933) consists of resistance and reactance, both inductive and capacitive.

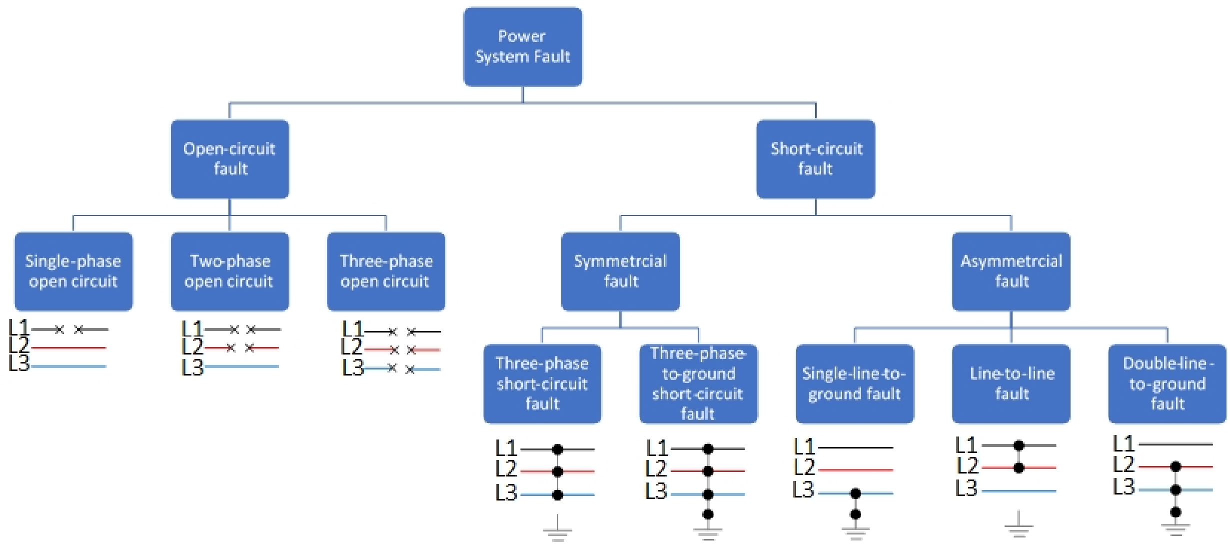
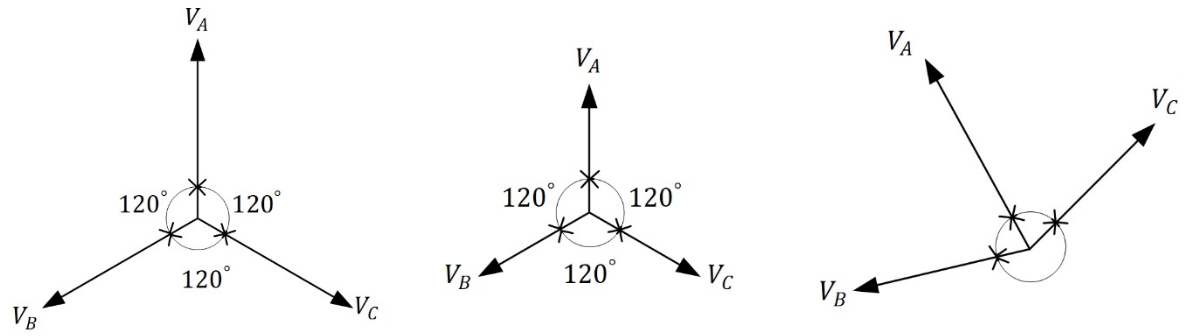


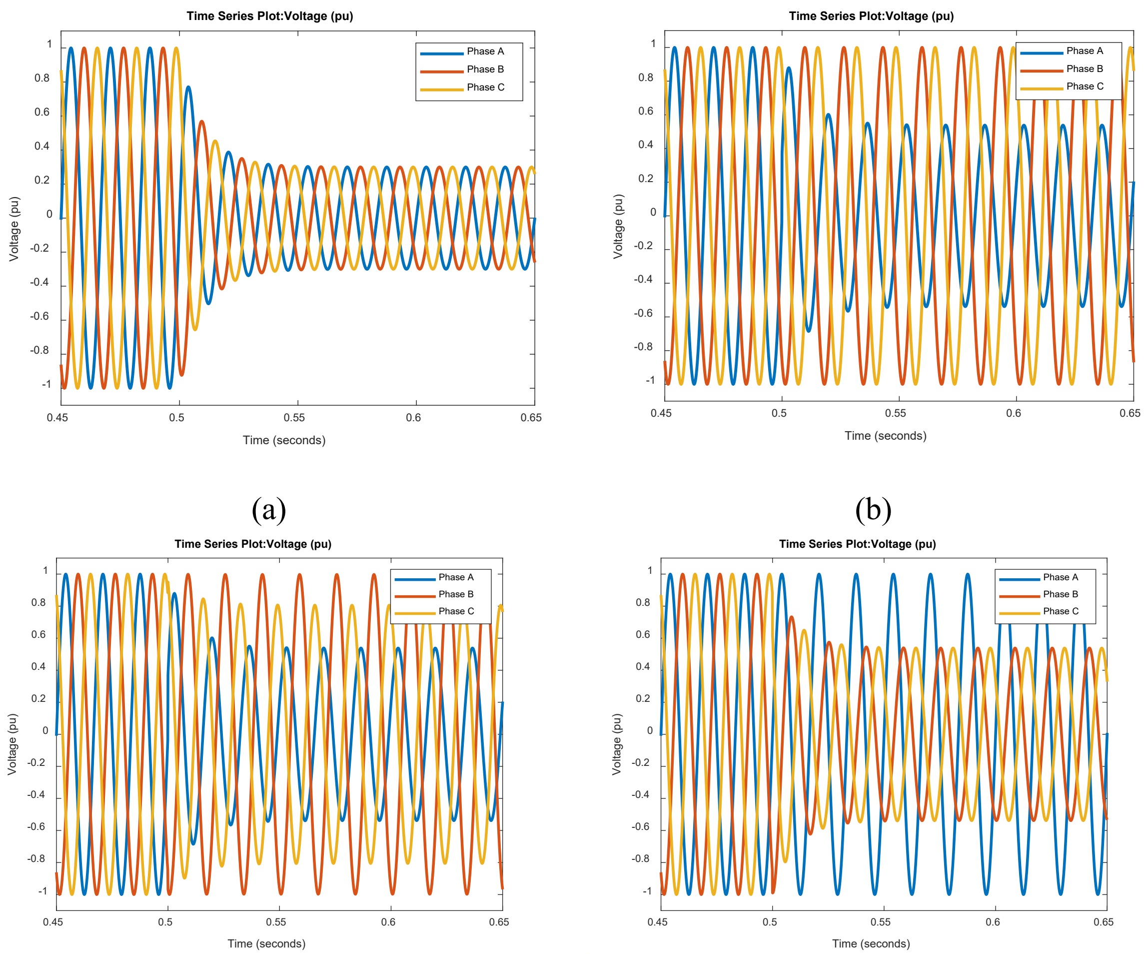
Figure 2. Types of faults in power systems

For a perfectly balanced three-phase system, the voltage magnitudes of all the phases are the same, and each phase is 120° from the other phases, as shown in Figure 3(a). But in a distribution network, the phases are not perfectly balanced, and asymmetry exists among the phase voltages and phase angles. During a symmetrical short-circuit fault, the voltage magnitudes of all the phases will have the same magnitude, albeit reduced, without any change to the relative phase angles of the phases. Figure 3(b) shows the phasor diagram of the voltage during a symmetrical three-phase short-circuit fault. An asymmetrical or unbalanced fault will result in dissimilar voltage magnitudes and phases angles for all three phases, as shown in Figure 3(c). For illustration, the Figure 5 shows the waveforms of voltages for different types of faults.



(a) (b) (c)

Figure 3. Phasor diagram of three-phase system: (a) perfectly balanced three-phase system, (b) symmetrical three-phase short-circuit fault, and (c) asymmetrical three-phase short-circuit fault



(a) (b)

(c) (d)

Figure 4. Illustrative waveform examples of different faults: (a) three-phase-to-ground fault (balanced fault), (b) single-line-to-ground fault (unbalanced fault), (c) phase-to-phase fault (unbalanced Fault), and (d) two-phase-to-ground fault (unbalanced fault)

2.2 Abnormal Conditions

Relays are one type of protective device. The function of protective relaying is to cause the prompt removal from service of any power system equipment when it suffers a short circuit or when it starts to operate in any abnormal manner that might cause damage or otherwise interfere with the effective operation of the rest of the system.

All relays used for protection operate by virtue of the current and/or voltage supplied to them by the current and voltage transformers connected in various combinations to the system equipment that is to be protected. (The system equipment could be any distribution system device, such as electrical wiring or a transformer.) Through individual or relative changes in these quantities, failures signal their presence, type, and location to the protective relays. For every type and location of failure, some distinctive differences exist among these voltage and current quantities, and various types of protective relays are available, each of which is designed to recognize a particular difference and to operate in response to it.

More possible differences exist in measured current and/or voltage than might be suspected. Differences are possible in one or more of the following:

- Magnitude
- Frequency
- Phase angle (synchronism)
- Duration
- Rate of change
- Direction or order of change
- Harmonics or wave shape.

2.3 Protective Device Coordination

Protective device coordination is the process of determining and setting the devices such that each device's automatic response is properly synchronized with the response of other devices to isolate the fault when abnormal electrical conditions occur. The goal of isolating the fault is to minimize to the greatest extent possible the number of customers that experience an outage (Mason 1956).

Protection coordination is typically accomplished through dividing the power system into protective zones (see Figure 5). If a fault occurs in a given zone, necessary actions are executed to isolate that zone from the entire system. A separate zone of protection is established around equipment. The significance of this is that any failure occurring within a given zone will "trip" (i.e., open) all circuit breakers within that zone—and only those breakers. Zone definitions account for system equipment such as generators, buses, transformers, feeders/lines, and motors. Overlapping regions are designed for redundancy to eliminate unprotected areas.

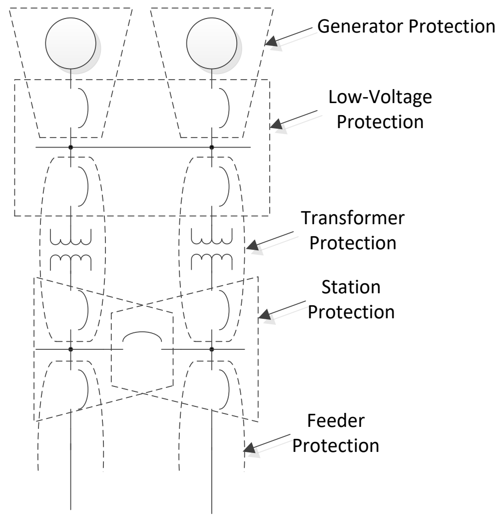


Figure 5. Zones of protection coordination. ***Illustration by NREL***

As depicted, circuit breakers[7] are generally located so that each generator, transformer, bus, line/feeder/circuit, etc., can be completely disconnected from the rest of the system. Failures might occur in each zone, such as an insulation failure, fallen or broken lines, incorrect operation of circuit breakers, short circuits, and open circuits.

[7] Note that switchgear consists of a combination of electrical disconnect switches, fuses, or circuit breakers that are used to control, protect, and isolate electrical equipment. Switches are safe to open under normal load current; protective devices are safe to open under fault current.

3 Common Concerns in the Presence of Distributed Energy Resources

This section discusses some key concepts required to design an efficient protection system in the presence of high penetrations of DERs.

3.1 Changes in Fault Current caused by Distributed Energy Resources

It is required to review the protection coordination of distribution networks because several factors associated with DERs impact the network protection and become dominant when there are high penetrations of DERs. On one hand, DERs can increase the fault current level in distribution networks. Even though a single DER might not significantly contribute to the fault current level, cumulative contributions from large numbers of DERs can alter the fault current level by enough magnitude to exceed the interruption rating of local fuses (Seguin et al. 2016).

On the other hand, the interaction of DER fault current and substation fault current on a branch can effectively reduce the fault current at the substation feeder, which will desensitize the relay. Desensitization of protection relays can interfere with the zones of protection of protective devices (Seguin et al. 2016).

Inverter-based resources have different responses than conventional synchronous generators during abnormal grid conditions. Unlike synchronous and induction generators, the fault responses of inverter-based resources are mostly software defined and designed to protect the semiconductor switches in the converter as well as to comply with the applicable standard. Experimental studies have found that the maximum steady-state fault current of inverters is on the order of 200%–300% of the nominal current (Keller et al. 2011). The actual fault current of an inverter can be less than the nominal current, depending on the control algorithm deployed within the inverter. A close examination of the requirements in IEEE Std 1547-2018 during abnormal grid conditions reveals that inverters are required to operate as a constant power source for a small range of voltage excursions around the nominal level. Beyond that narrow range of voltage excursions, inverters are allowed to operate as a constant power source or a constant current source (Mahmud, Hoke, and Narang 2020).

3.2 Reclosing Out of Synchronism

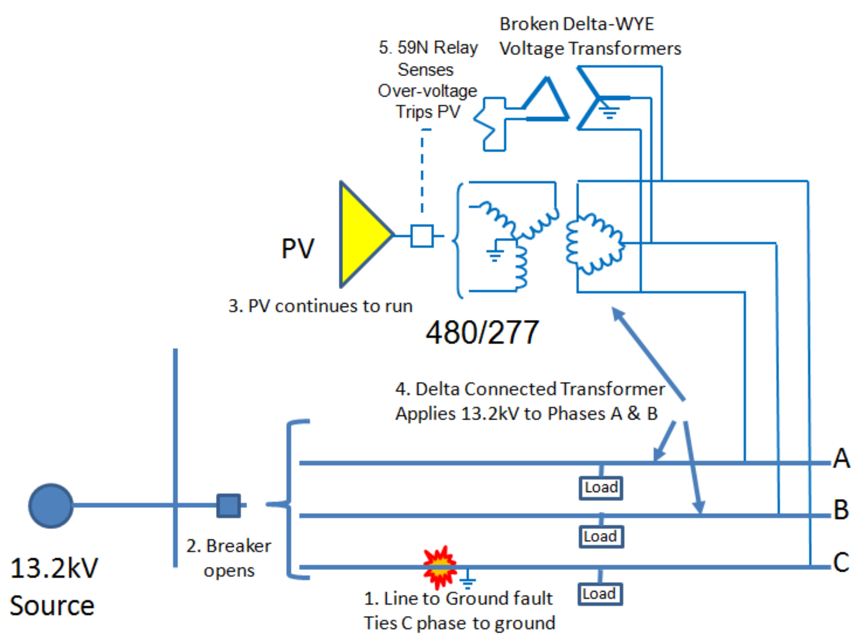
Reclosing out of synchronism is another concern for protection engineers. Out-of-synchronism reclosing might cause severe damage to the local network, equipment, and personnel. IEEE Std 1547-2018 requires DERs to detect islanding conditions within 2 seconds of the event; however, a faster reclosing attempt (faster than 2 seconds) might reclose a still-online DER that is out of synchronism (Seguin et al. 2016).

3.3 Grounding

Grounding is normally provided at the primary transformer of a utility substation for typical distribution feeders. If there are no significant penetrations DERs in the feeder, the feeder voltage rapidly collapses in the event of feeder isolation from the substation. But if there are significant penetrations of DERs, there might be a energizing source even after islanding the feeder from the rest of network. In such scenario, a ground fault in that feeder will cause an overvoltage. A supplemental grounding source at the DER installation might negatively impact the protection coordination and power quality (Whisenant 2016). Generally, inverter-based DERs act like current sources (or power sources), unlike synchronous generators, which behave as constant AC voltage sources in series with an impedance. Because of this DER characteristic, additional considerations are needed while analyzing overvoltages caused by ground faults and open phases in the presence of inverter-based DERs in distribution networks according to grounding requirements. Symmetrical component-based analysis (Clarke 1943), representing inverter-based DERs as current sources, is a powerful technique to analyze the network for grounding requirements; however, the inverter controller design, configuration, and mode of operation will play major roles in determining the efficacy of symmetrical component-based analysis (Jia et al. 2019; Camacho et al. 2018). Neutral grounding requirements for system grounding, where a significant portion of the energizing source is either current regulated or power regulated, have been defined in IEEE C62.92.6-2017 (IEEE C62.92.6 2017).

3.4 Back-Feed/Neutral Overvoltage Protection

On one hand, in cases when "the PV is connected via a delta-wye transformer, or even a wye-wye transformer in cases when the utility side of the transformer is ungrounded, then ground faults upstream of the PV may result in high voltages on the unfaulted phases" (see Figure 6) (Seguin et al. 2016).



Source: Seguin et al. 2016

Figure 6. Example of line-to-ground overvoltage caused by PV

On the other hand, distributed generation sources might cause reverse power flow through the substation power transformer if the generation exceeds the feeder load.

Distribution substations that comprise power transformers connected in a delta-wye configuration that are radially fed or tapped from a single transmission source where backfeeding is expected require special neutral overvoltage protection to reduce prolonged overvoltages from phase-to-ground faults on the delta-wye-connected transformers. If a phase-to-ground fault were to occur, it would cause an overvoltage condition on the high side of the distribution transformer. Upstream voltage-based detection will likely trip the delta-connected line, but it is also likely that no protection for such overvoltage events exists at the substation because previous assumptions of guaranteed one-way power flow would have sufficed, and clearing such faults with upstream devices would mitigate the fault; however, a significant amount of generation interconnected on the low side (wye connected) of the substation makes detecting the fault difficult because no appreciable change in the voltage on the low side of the distribution transformer is realized. Additionally, no current flows through the fault on the high-side delta-connected line, resulting in practically no perceptible change in load.[8]

3.5 Zero-Sequence Voltage

Zero-sequence voltage protection, such as 3V0 (or another high-speed detection method), on the primary side of the transformer is needed to detect overvoltage conditions and to act to protect delta-wye-connected transformers from zero-sequence voltage issues, such as overvoltage from a phase-to-ground fault, by disconnecting the generation from the substation transformer and stopping the DERs and substation transformer from contributing to the transmission-side overvoltage condition (Bower and Ropp 2002).

Known by many names—e.g., 3V0 overvoltage, neutral point shift overvoltage, ground fault overvoltage, and others—the described faulted condition of a wye-delta connected generator to an unloaded delta (e.g., three-wire) system is currently a considerable concern regarding the further deployment and integration of DERs.

Many subtransmission and transmission lines are constructed as ungrounded delta systems, and some distribution substations are served by a single three-phase, high-voltage, delta-connected power line. If an amount of DERs interconnected on the distribution feeders served by such a substation is great enough to serve (or exceed) all connected load, a potential overvoltage condition might occur on the *high side* of the distribution transformer and the delta-connected system itself. Such an overvoltage would result from a faulted phase of the delta-connected power line. As explained earlier, it is likely that there would be no upstream voltage detection-based protection for overvoltage at the substation. And with a significant amount of generation interconnected on the low side (wye connected) of the substation, the detection of the fault becomes difficult because no appreciable change in the voltage on the low side of the distribution transformer is realized. Additionally, no current flows through the fault on the high-side, delta-connected line, resulting in practically no perceptible change in load. The primary concern of these types of overvoltages is damaging the substation transformer and/or surge arrestors. Additionally, the faulted delta-connected line remains energized (downstream of the subtransmission/transmission protective device), creating a possible safety hazard to the public and utility crews until the DER-based generation trips off.

[8] For more in-depth treatment of this subject, see *Assessment of Inverter-based Distributed Generation Induced Ground Fault Overvoltage on Delta-Wye Substation Transformers* (Report R149-16) by Pterra Consulting (January 3, 2016).

Common solutions to ground fault overvoltage concerns generally revolve around adding sensing and protection of the high-voltage, delta-connected line at the substation. This type of solution is well known—many substations that are served by multiple high-voltage lines already employ such equipment for bidirectional protection. Alternative methods include the addition of dedicated, utility communications between the breakers on either side of the delta-connected line. Functionality is added that trips both ends of the line at the same time, effectively using existing sensors and protection at the upstream substation and transmitting the trip signal to the end-of-the-line substation. Unfortunately, this solution is typically expensive because of the requirement for high-quality communications links (i.e., fiber-optic cable, installed over a significant distance).

Emerging methods include protection methods focused on detecting the overvoltage on the high side of the transformer via some means requiring only actual measurements on the low side (wye-connected side). Relaying based on the detection of negative-sequence current is currently the most evolved advanced detection technique, but concerns regarding its sensitivity and selectivity remain to be addressed.

3.6 Distributed Energy Resource Impacts to the Bulk Power System

When the DER penetration level in the network is low, DER trips caused by voltage and frequency disturbances do not significantly affect the system; however, complications arise when increasing quantities of generation come from DERs. Adverse effects of DER trips on the bulk power system were evident from two recent bulk power system disturbances: Angeles Forest and Palmdale Roost (NERC 2019), both of which occurred in 2018. In both cases, faults were detected in the high-voltage transmission network (at 500 kV), and the transmission protection system cleared the fault within three cycles. Only a combined-cycle unit tripped because of the Angeles Forest disturbance, and no generating resources tripped because of the Palmdale Roost disturbance. But a substantial amount of bulk power system-connected PV resources as well as DERs tripped or went to momentary cessation. Though information on DER tripping could not be directly measured for these disturbances, anecdotal evidence and analysis of the area net load indicate that approximately 130 MW of DER resources were lost because of the Angeles Forest disturbance and 100 MW because of the Palmdale Roost disturbance. To put this in perspective, no noticeable net load changes were observed for two earlier disturbances: the Blue Cut Fire disturbance (August 16, 2016) and the Canyon 2 Fire disturbance (October 9, 2017). This implies that there was no significant DER tripping during the Blue Cut Fire disturbance and the Canyon 2 Fire disturbance, suggesting that more research is needed. Analysis on the Angeles Forest and Palmdale Roost disturbances presented in a joint North American Electric Reliability Corporation and Western Electricity Coordinating Council staff report (NERC 2019) shows that the reasons behind the tripping or momentary cessation of the PV resources include transient AC overvoltage and DC reverse current tripping, a difference between the inverter terminal and the point of interconnection voltage, and the use of momentary cessation as a method for low-voltage ride-through. Similar to voltage disturbances, DERs can trip because of frequency disturbances. Because frequency is virtually the same in each U.S. interconnection, a frequency disturbance can cause all DERs to simultaneously trip irrespective of their geographic location.

4 Current Practices to Mitigate Problems Associated with Distributed Energy Resources

Primary protection systems in distribution networks are mostly based on overcurrent protection using overcurrent relays, reclosers, and fuses. Conventional distribution network protection systems are designed assuming unidirectional power flow and a radial network. These protection systems can provide reliable protection when the penetration of DERs is low; however, as outlined in the previous section, increased penetrations of DERs on the grid introduce challenges for network protection. Protection systems in the presence of DERs can be broadly categorized into three groups: (1) network protection by reducing DER integration, (2) protection techniques embedded within the DER controller, and (3) improved network protection. Though several approaches within these protection groups have been proposed in research publications, as discussed in the following subsections, few have documented a field test on an actual network, and there is not enough publicly available information on the efficacy and reliability of these protection schemes on an actual network. The following subsections on different protection schemes are based on publicly available research and are presented as examples that might be practiced in the field.

4.1 Network Protection by Reducing Distributed Energy Resource Integration

Power from the DERs installed in distribution networks can impact distribution network protection coordination. Considering the voltage profile and short-circuit current level, a limited number of DERs can be installed in the existing distribution systems. The DER penetration level that does not interfere with the existing protective systems depends on short-circuit currents, conductor ampacity, and voltage regulation. Considering all these factors, it is possible to set the upper threshold of the DER penetration level so that the existing protection system can perform reliably without any degradation to protection coordination (Zeineldin et al. 2013).

4.2 Protection Techniques Embedded within the Distributed Energy Resource Controller

The fault response of converter-based DERs is mostly software defined; therefore, it is possible to limit the DER fault current by monitoring the voltage at the point of common coupling. Limiting the DER fault current can reduce adverse impacts on fuse-recloser coordination by reducing the DER contribution during the fault (Yazdanpanahi, Li, and Xu 2012).

4.3 Improved Network Protection

In the early stage of DER adoption on the grid, the solution approach to tackle the problem introduced by DERs toward distribution network protection systems relied on revising the relay settings whenever a new DER was installed in the network (Girgis and Brahma 2001). Multifunction reclosers/relays have been proposed to replace the fuses to address some issues of overcurrent-based protection, e.g., fuse fatigue, nuisance fuse blowing, and fuse misoperation (Funmilayo and Butler-Purry 2009); however, multifunction reclosers/relays cannot completely satisfy the requirements of distribution network protection. Distance relays and directional relays have been proposed to improve protection sensitivity and protection coordination (Sinclair et al.

2013). Similar to limiting the DER fault current embedded within the DER controller, as discussed earlier, a series fault current limiter can restore the original relay coordination by locally limiting the DER fault current during the fault (El-Khattam and Sidhu 2008). Nevertheless, these approaches are geared toward minimizing or localizing DER fault currents. Under scenarios of very high penetrations of DERs, these solutions might fail to provide robust protection to the distribution network. Adaptive protection can provide a robust solution to the challenges introduced by DERs toward distribution network protection systems by adapting relay settings and characteristics based on the prevailing condition of the network and DER generation (Wan, Li, and Wong 2010).

4.3.1 Zero-Sequence Voltage Mitigation Considerations

Pterra Consulting (Pterra 2016) made the following observations based on findings from simulations investigating the feasibility of measuring neutral-point-shift overvoltages at the DER location (i.e., on a wye-grounded circuit connected to a substation with a delta-connected transmission feed):

> While inverters can potentially cause overvoltage on the delta side of the substation transformer, some inverter designs can detect a single-line-to-ground fault condition and trip instantaneously. Time domain simulation is a potential tool for evaluating the fault detection capability of inverters for this purpose.
>
> According to ANSI/IEEE C62.92, the GFOV for an effectively grounded system is to be limited to 138%. This value can also be used to limit the overvoltage for ungrounded systems. Simulation results indicate that overvoltage on the delta side of the study substation transformer peaks at 1.38 PU as the PV/load ratio approaches 65%. At penetration levels below 65%, no overvoltage is observed. Two important notes relate to this finding:
>
> - The calculation for the load should account for those connected to the transmission side as well as the distribution side of the isolated system.
> - Though this ratio seems close to the threshold proposed by National Grid (i.e., 67%), there is possibility of under counting the load if only the distribution side load is considered.
>
> The 65% penetration limit (based on 1.38 PU overvoltage threshold) can be relaxed if:
>
> - Damage to equipment connected to delta side of the substation transformer is the reason for requiring 3V0 protection; and
> - Surge arresters connected to delta side of the substation transformer are taken into account.
>
> Simulations conducted in this study with station class surge arresters indicate that arresters can safely operate for penetration levels of up to 100%.

4.3.2 Special Case: Spot Network Protection

To maximize reliability and operational flexibility, utilities sometimes use spot and grid network systems in congested areas, such as metropolitan and suburban business districts (Behnke et al. 2005).

Unlike protection on ordinary radial feeders, de-energizing faulted feeders requires at least two (and usually more) tripping operations. *Network protectors* are used to perform this protective operation. Network protectors are defined in IEEE Std C57.12.44-2014 (IEEEC57.12.44 2014) as:

> An assembly comprising an air circuit breaker and its complete control equipment for automatically disconnecting a transformer from a secondary network in response to predetermined electrical conditions on the primary feeder or transformer, and for connecting a transformer to a secondary network either through manual control or automatic control responsive to predetermined electrical conditions on the feeder and the secondary network.

Special care with respect to locating and sizing network protectors is prescribed in Clause 9 of IEEE Std 1547-2018 when DERs are connected to secondary and spot networks.

5 Protection-Related Requirements in IEEE Std 1547-2018

5.1 Built-In Distributed Energy Resource Protection Capabilities and Test Requirements

For short-circuit faults on the area EPS circuit section to which the DER is connected, IEEE Std 1547-2018 requires the DER to *cease to energize* and trip (unless otherwise specified by the area EPS operator). According to IEEE Std 1547.1-2020, *type tests* are to be performed or overseen by a testing agency and include fault current tests to characterize the DER response to short-circuit faults on the area EPS.

5.2 Performance Requirements of Distributed Energy Resources During Abnormal Grid Conditions

IEEE Std 1547-2018 expects that the response of DERs during abnormal grid conditions will be appropriate to ensure the stability of the area EPS; the safety of the utility personnel as well as the general population; and the prevention of equipment damage, including the DERs. The rapid increase of DERs in power systems necessitates specific requirements—e.g., ride-through requirements—from DERs during abnormal voltage and frequency fluctuations to protect the security of the bulk power system and to ensure acceptable power quality.

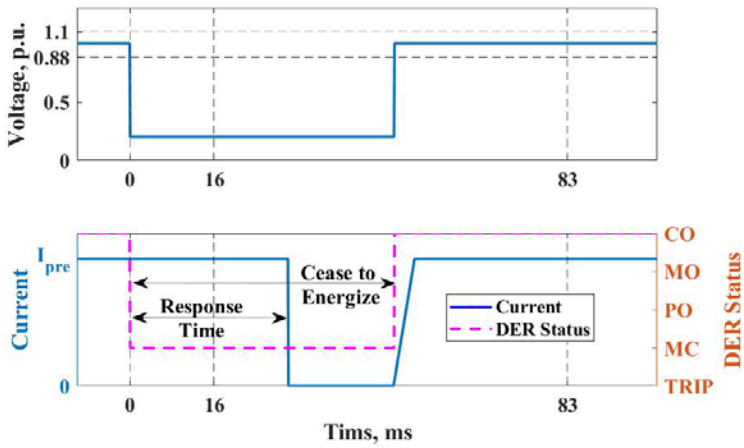
Different requirements in IEEE Std 1547-2018 are set such that no specific technology is given preference, and the standard is technology neutral. AGIRs with due consideration to technical and nontechnical issues related to the impact of DERs will assign performance-based categories to DER types and application purposes.

Three abnormal operating performance categories are defined in IEEE Std 1547-2018: Category I, Category II, and Category III. Category I DERs are required to meet minimal bulk power system reliability requirements, whereas Category III DERs are required to provide increased bulk power system security by meeting the strongest requirements disturbance ride-through. It is expected that most current DER technologies, including synchronous generators, will be able to meet the Category I requirements. These performance requirement categories are not directly tied with the capability requirement categories (Category A and Category B), and a DER can meet any combination of performance and capability requirements. The area EPS, with guidance from the AGIR, will determine the applicability of the performance category for the DER during abnormal grid conditions. Annex B of IEEE Std 1547-2018 provides a guideline to assign the abnormal performance category. The performance requirements of DERs during abnormal grid conditions are expected to not interfere with the islanding detection requirements. The availability of the primary source of energy for the DER is expected to have no impact as a result of abnormal grid conditions.

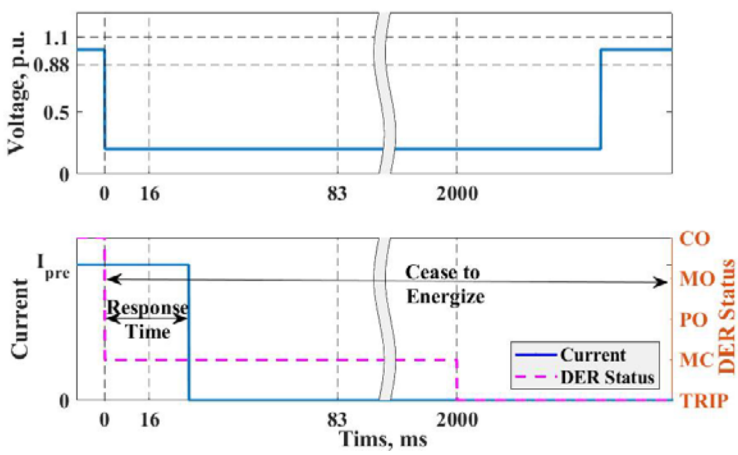
Section 6.1 of IEEE Std 1547-2018 provides an overview of the capabilities and control requirements for DERs under abnormal operating conditions, Section 6.2 outlines the requirements during area EPS faults and open-phase conditions, and Section 6.3 discusses the coordination of area EPS reclosing. The DERs must cease to energize and trip for detectable short-circuit fault and open-circuit conditions. For proper protection relay coordination of the area EPS system and fault detection time, DER interconnection parameters and area EPS protection settings might need to be updated prior to interconnecting the DERs. The area EPS might also consider the sequential tripping of DERs of relatively lower impact. Due consideration should be paid to ensure that reclosing any section of the circuit energized by DERs does not introduce unacceptable stress, e.g., out-of-synchronism reclosing. Remedial actions to avoid such reclosing might include blocking the reclosing when the circuit being reconnected with rest of the network is energized by DERs.

Section 6.4.1 of IEEE Std 1547-2018 discusses the performance requirements of DERs during abnormal voltage conditions and the circumstances for mandatory tripping, and Section 6.5.1 discusses similar requirements for frequency disturbances. IEEE Std 1547-2018 provides default settings, along with a range of allowable settings for overvoltage and undervoltage tripping and corresponding clearing times, in Table 11 for Category I, Table 12 for Category I, and Table 13 for Category III DERs. IEEE Std 1547-2018 recognizes five modes of operation for DERs during abnormal grid conditions: continuous operation, mandatory operation, permissive operation, momentary cessation, and trip. Momentary cessation and trip are grouped into cease-to-energize mode of operation, and whether the DER will trip while in cease-to-energize mode of operation depends on the fault voltage level and the duration of the fault. An illustrative example of cease-to-energize mode that covers both momentary cessation and trip is shown in Figure 7 (Mahmud, Hoke, and Narang 2020).

(a)



(b)

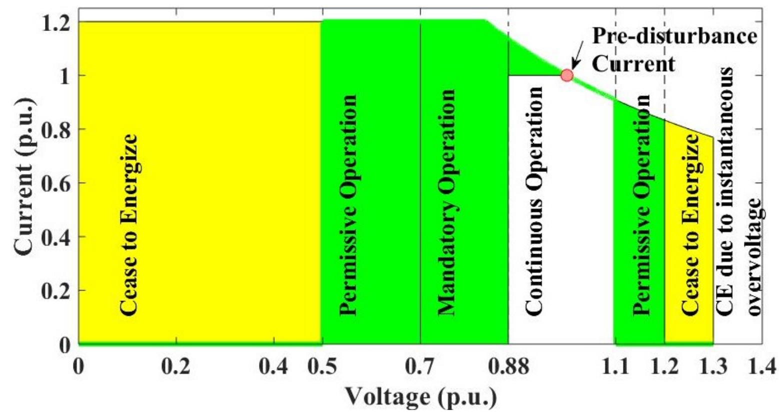


(c)

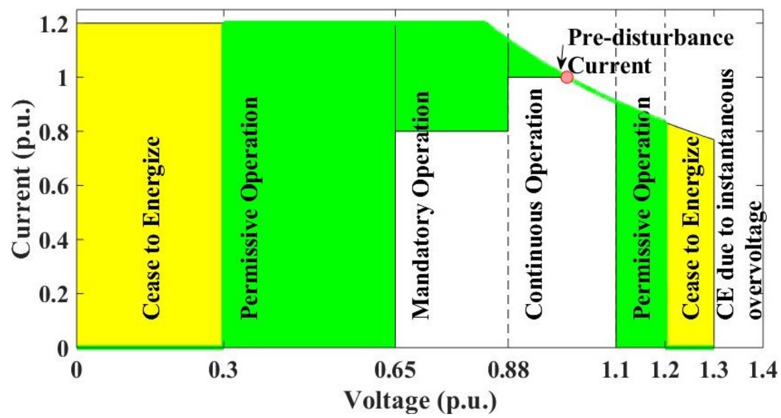
Source: Mahmud, Hoke, and Narang 2020

Figure 7. Illustrative example of cease-to-energize mode for a Category III DER, though the general principle applies to other categories of DERs too. (a) Cease-to-energize mode covers both momentary cessation and trip, (b) momentary cessation permits an immediate return to service, and (c) trip inhibits an immediate return to service.

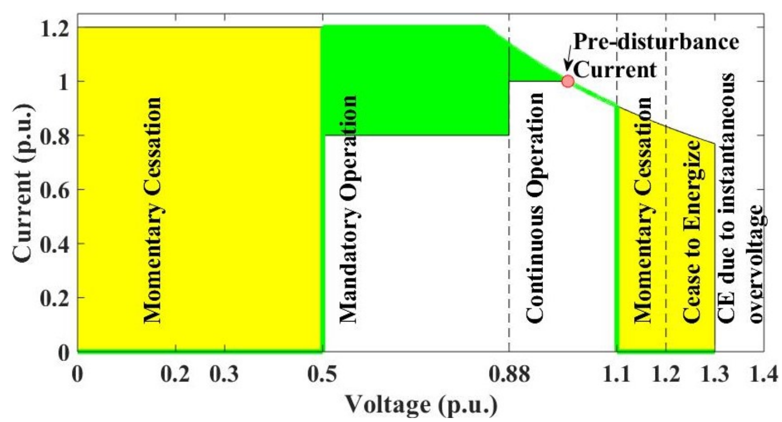
The typical fault responses of DERs show an initial spike in the current immediately after the fault, followed by a quasi-steady-state fault current before the DER goes to cease-to-energize mode of operation or returns to normal operation, depending on the severity and the duration of fault. For power electronics-based DERs, the initial current spike is normally very short-lived. The significant fault current contribution from DERs to a network fault comes from the quasi-steady-state fault current of the DERs. In addition to the fault level, the magnitude and nature of the quasi-steady-state fault current of the DERs will depend on many factors, including the DER type, power and voltage rating, primary energy source, and technology used in the power conversion. Because of the wide range of factors, obtaining a generalized fault response from DERs during a fault is very difficult; however, DERs that comply with IEEE Std 1547-2018 will demonstrate some common features during the fault. Because the responses to faults (the quasi-steady-state fault current) of inverter-based DERs are largely software defined, the fault detection time plays a crucial role in the fault response of the inverters. Example of plausible fault responses of DERs that comply with IEEE Std 1547-2018 are illustrated in Figure 8, assuming root-mean-square fault detection time (one to two cycles) and a prefault current magnitude of 1 per unit. The fault current for different fault levels will be different for the three categories of DERs defined in IEEE Std 1547-2018. Inverter-based DER fault currents could range from zero to the maximum allowed current threshold. For inverter-based DERs, this maximum allowed current threshold ranges from 1 to 1.2 times the nominal current (Keller et al. 2011; Nelson, Martin, and Hurtt 2017). For the fault voltage range where the DER is expected to be in cease-to-energize mode, a significant fault current might be observed until the fault has been detected (one to two cycles).



(a)



(b)



(c)

Source: Mahmud, Hoke, and Narang 2020

Figure 8. Allowable current ranges after a voltage disturbance according to IEEE Std 1547-2018 for a predisturbance current equal to 1 per unit: (a) Category I, (b) Category II, and (c) Category III DERs. The green and yellow shaded areas show the allowable current range after the root-mean-square voltage detection time, and the green shaded areas show the allowable current range after five line cycles. In the momentary cessation and cease-to-energize regions, the expected current is zero after the root-mean-square voltage detection time (one to two cycles).

IEEE Std 1547-2018 provides default settings, along with a range of allowable settings for overfrequency and underfrequency tripping and corresponding clearing times, in Table 18 for all categories of DERs. The area EPS operator, in collaboration with the regional reliability coordinator, will specify the underfrequency and overfrequency trip settings.

5.3 IEEE Std 1547a-2020

The IEEE Std 1547a-2020 amendment revises the ranges of allowable trip clearing time settings for DERs under the abnormal operating performance Category III to allow wider ranges (IEEE 1547a 2020).

5.4 Test and Verification Requirements with Respect to Protection

IEEE Std 1547-2018 requires that the conditions necessary for the proper and reliable operation of DERs should be verified. The verification should be done in accordance with IEEE Std 1547.1. This section discusses only the testing and verification requirements specified in IEEE Std 1547-2018 with respect to protection; however, the standard leaves room for additional verification requirements to establish confidence.

The tests should be performed to verify that the conformance to requirements is met at the applicable reference point. The periodic test requirements and the interval for interconnection-related protection functions should be prepared by the manufacturer or system integrator of the interconnection equipment and approved by the AGIR or area EPS. These tests and the frequency of the tests should be coordinated with policies of the area EPS protection system tests.

The responses of DERs to the area EPS abnormal conditions need to be tested for area EPS faults and open-phase condition as well as area EPS reclosing coordination. The responses of DERs to voltage fluctuations should be tested for three conditions: mandatory voltage tripping requirements, general requirements and exceptions, and voltage disturbances with continuous operation regions. For tests related to mandatory voltage tripping requirements and voltage disturbances with continuous operation regions, there are provisions to align the trip settings of the DER devices and the substation during the evaluation of the DERs during the design stage and to verify the correct installation settings during the evaluation of the DERs during the installation stage. Similar to voltage fluctuations, the response of DERs to frequency fluctuations should be tested for three conditions: mandatory frequency tripping requirements, general requirements and exceptions, and frequency disturbances with continuous operation regions. For tests related to mandatory frequency tripping requirements, however, there are provisions to align the trip settings of the DER devices and to verify the correct installation settings. Note that IEEE Std 1547.1 proposes different tests (type tests, interoperability tests, DER evaluations and commissioning tests, production tests, and periodic interconnection tests) to verify that the DERs comply with IEEE Std 1547-2018 at various implantation stages.

6 Considerations for the Utilization of Capabilities

Traditional protection studies of distribution networks normally model DERs as negative load. This approach works well when the penetration level of DERs in the circuit is comparatively low; however, modeling DERs as negative load fails to capture the impact of DERs on the protection system when there are significant penetrations of DERs in the distribution network. The protection of the distribution network becomes much more complex with the mandatory fault ride-through requirements. High penetrations of DERs might alter the short-circuit current level in the circuit as well as the direction of the power flow. Additional challenges associated with increasing penetrations of DERs with respect to network protection include nuisance tripping of DERs, unintentional islanding, unsynchronized reclosing, and protection system blinding. Consequences could be malfunction and/or miscoordination of the distribution network protection. Due consideration to DERs is needed to ensure an efficient protection system for the distribution network and to improve system continuity indices, e.g., minimization of consumer interruption. Distribution network protection in the presence of DERs is an active research area to find solutions to the challenges presented by DERs to distribution network protection. Key research topics in this field include better modeling of DERs and new protection schemes, e.g., adaptive protection, the application of artificial intelligence, and the application of advanced control and communications technologies. As it is important to find newer solutions for network protection in the presence of DERs, it is also important to pay attention to the standards that the DERs conform to because the requirements of the standards will have a huge impact on the response of DERs to network faults. Key decisions are outlined next.

6.1 Determination of Required Distributed Energy Resource Abnormal Operating Performance Category

The assignment of the abnormal performance category for DERs has a direct impact on the EPS protection system and the reliability of the bulk power system. For this reason, from a procedural point of view, the responsibility of assigning the DER performance category falls to the area EPS, though high-level guideline might be provided by the AGIR, e.g., the bulk power system operator or the state regulator.

IEEE Std 1547-2018 Clause 6.1 provides an overview of the capabilities and control requirements for DERs under abnormal operating conditions. Annex B (informative) presents a discussion and considerations for the performance category assignment.

IEEE Std 1547-2018 recommends assigning the majority of DERs to Category II to secure the bulk power system; however, considering the technology, application purpose, and societal benefits of the DERs, Category I and Category III can be assigned to a limited number of DERs.

6.2 Determination of Distributed Energy Resource Response (Shall Trip) to Abnormal Voltages

As in the case of the overall assignment of abnormal operating performance categories, from a procedural point of view, this is the responsibility of the area EPS operator; however, the AGIR might provide high-level direction to the area EPS operator to ensure the reliability and security of the bulk power system.

IEEE Std 1547-2018 Clause 6.4 specifies requirements for mandatory voltage tripping and ride-through requirements during low- and high-voltage disturbances. The subclause also describes the capabilities and performance requirements for dynamic voltage support. This capability is not mandatory, but it could provide improved voltage stability.

The EPS might allow trip settings outside the allowable range for DER equipment protection while ensuring that there is no conflict with voltage disturbance ride-through requirements.

6.3 Determination of Distributed Energy Resource Response (Shall Trip) to Abnormal Frequency

As in the case of the overall assignment of abnormal operating performance categories, from a procedural point of view, this is the responsibility of the area EPS operator; however, the AGIR might provide high-level direction to the area EPS operator to ensure the reliability and security of the bulk power system.

IEEE Std 1547-2018 Clause 6.5 specifies requirements for mandatory frequency tripping and ride-through requirements during frequency disturbances.

The EPS might allow trip settings outside the allowable range for DER equipment protection while ensuring that there is no conflict with frequency disturbance ride-through requirements.

AGIRs should ensure that underfrequency and overfrequency trip settings are coordinated between the area EPS operator and the regional reliability coordinator to ensure that DER trips are coordinated with wide-area underfrequency load-shedding operation, which vary across regions.

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