

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Reliability Guideline

Bulk Power System Reliability Perspectives on  
the Adoption of IEEE 1547-2018

March 2020

**RELIABILITY | RESILIENCE | SECURITY**



3353 Peachtree Road NE  
Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

# Table of Contents

---

Preface .....	iii
Preamble .....	iv
Executive Summary.....	v
Introduction .....	vii
Potential Impacts of DERs on BPS Reliability.....	vii
Background of IEEE 1547-2018 .....	viii
Implementation of IEEE 1547-2018.....	viii
Coordination between Distribution and Transmission Entities.....	xi
Chapter 1: BPS Perspectives on IEEE 1547-2018 Clauses .....	1
Clause 1.4: General Remarks.....	1
Clauses 6.4.1 and 6.4.2: Voltage Mandatory Tripping and Ride-Through .....	3
Clause 6.4.1: Mandatory Voltage Tripping Requirements .....	4
Clause 6.4.2: Voltage Disturbance Ride-Through Requirements .....	5
Clauses 6.5.1 and 6.5.2: Frequency Mandatory Tripping and Ride-Through.....	7
Clause 6.5.1: Mandatory Frequency Tripping Requirements .....	7
Clause 6.5.2: Frequency Disturbance Ride-Through Requirements.....	8
Clause 6.4.2.7: Restore Output .....	9
Clause 6.5.2.7: Frequency-Droop .....	10
Clause 6.5.2.7.1: Frequency-Droop Capability .....	11
Clause 6.5.2.7.2: Frequency-Droop Operation .....	12
Clause 6.5.2.8: Inertial Response.....	13
Clause 6.5.2.6: Voltage Phase Angle Changes Ride-Through .....	13
Clause 4.10 and Clause 6.6: Enter Service and Return to Service .....	14
Clause 8.1: Unintentional Islanding.....	15
Clause 8.2: Intentional Islanding .....	16
Clause 10: Interoperability, Information Exchange, and Protocols.....	16
Appendix A: References.....	18
Appendix B: Ride-Through Requirements in IEEE 1547-2018.....	20
Appendix C: Definitions used in IEEE 1547-2018 .....	22
Contributors .....	24

## Preface

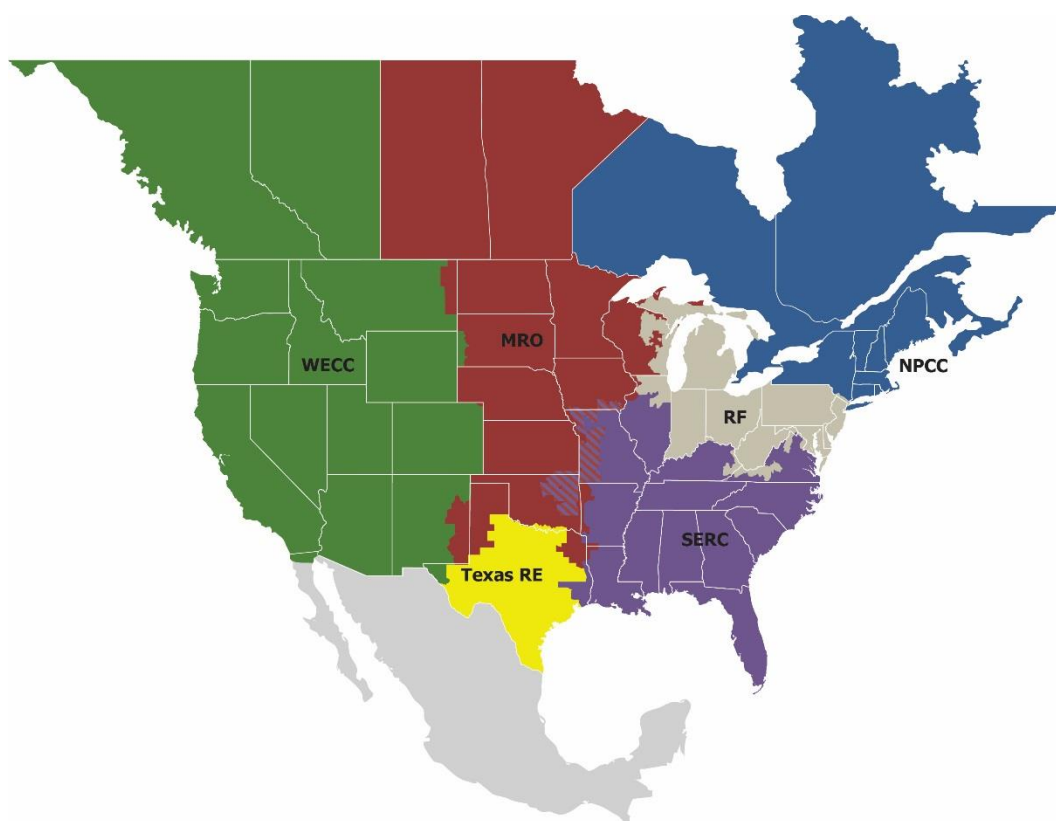
---

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

*Because nearly 400 million citizens in North America are counting on us*

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



<b>MRO</b>	Midwest Reliability Organization
<b>NPCC</b>	Northeast Power Coordinating Council
<b>RF</b>	ReliabilityFirst
<b>SERC</b>	SERC Reliability Corporation
<b>Texas RE</b>	Texas Reliability Entity
<b>WECC</b>	Western Electricity Coordinating Council

# Preamble

---

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees (the Operating Committee (OC), the Planning Committee, and the Critical Infrastructure Protection Committee (CIPC)) are authorized<sup>1</sup> by the NERC Board of Trustees (Board) to develop reliability (OC and Planning Committee) and security guidelines (CIPC) per their charters. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

NERC, as the Federal Energy Regulatory Commission (FERC) certified ERO,<sup>2</sup> is responsible for the reliability of the BES and has a suite of tools to fulfill this responsibility, including (but not limited to) lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis Program, the Compliance Monitoring and Enforcement Program, and mandatory standards. Each entity—as registered in the NERC compliance registry—is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

---

<sup>1</sup> [http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20\(Clean\).pdf](http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf)  
[http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20\(2\)%20with%20BOT%20approval%20footer.pdf](http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf)  
<http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf>

<sup>2</sup> <http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf>

## Executive Summary

---

NERC has focused on ensuring the reliable operation of the BPS under increasing penetrations of BPS-connected inverter-based resources as well as distributed energy resources (DERs).<sup>3</sup> The NERC Integrating Variable Generation Task Force (IVGTF)<sup>4</sup> also stated that large amounts of DERs<sup>5</sup> connected to the grid could have significant effects on the reliability of the BPS. Of main concern was the lack of disturbance ride-through capability.<sup>6</sup> The NERC Distributed Energy Resources Task Force (DERTF) report<sup>7</sup> further characterized the impacts that DERs may have on BPS reliability. Recent BPS disturbances have illustrated the need for fault ride-through capability,<sup>8</sup> particularly the need for voltage phase angle jump ride-through and rate-of-change-of-frequency ride-through capability.<sup>9</sup> Lastly, the NERC Load Modeling Task Force (LMTF) developed a modeling framework and recommended adopting practices for studying the aggregate impacts that DERs may have on the BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) is further analyzing these impacts and developing recommended practices and industry guidance.

IEEE Standard 1547-2018 *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* (referred to herein as “IEEE 1547-2018”) was published in April 2018 and significantly enhanced the performance and functional capability of DERs connecting specifically to primary and secondary distribution systems. IEEE 1547-2018 is intended to apply only to DERs connected to the distribution system and is generally not suited for other interconnection levels (i.e., resources connecting to the subtransmission or transmission systems). These new capabilities align with the BPS reliability needs and present opportunities for maintaining or improving BPS reliability with increasing penetration of DERs. The IEEE P1547.1 working group expects equipment certified to this new standard to become available in the 2021 time frame. This reliability guideline discusses the adoption of IEEE 1547-2018 and considerations that should be made during its adoption that reflect BPS reliability perspectives.

The timely adoption and implementation of IEEE 1547-2018 for DERs connected to the distribution system across North America is strongly encouraged. The specifications for DERs in IEEE 1547-2018 include performance capability categories and allowable ranges of functional settings that provide flexibility to align with specific system needs. However, these flexibilities require coordination between distribution and transmission entities for effective adoption. The adoption of IEEE 1547-2018 requires the authority governing interconnection requirements (AGIR)<sup>10</sup> and various stakeholders to get involved at a deeper technical level than in the past.<sup>11</sup> Due to the required amount of coordination in IEEE 1547-2018, it is expected that AGIRs may need around two years to develop an effective implementation plan for the standard. Further, DERs compliant with IEEE 1547-2018 are expected to become readily available in 2021, a key incentive for AGIRs to begin the coordination activities for adoption and implementation of the standard.

---

<sup>3</sup> NERC Summary of Activities: BPS-Connected Inverter-Based Resources and Distributed Energy Resources (September 2019):

[https://www.nerc.com/comm/PC/Documents/Summary\\_of\\_Activities\\_BPS-Connected\\_IBR\\_and\\_DER.pdf](https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf).

<sup>4</sup> NERC IVGTF, “Summary and Recommendations of 12 Tasks,” June 2015:

[https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%2011/IVGTF%20Summary%20and%20Recommendation%20Report\\_Final.pdf](https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%2011/IVGTF%20Summary%20and%20Recommendation%20Report_Final.pdf)

<sup>5</sup> Refer to the definition of DER provided in IEEE 1547-2018. Also refer to the NERC DERTF definition of a DER that is defined as “any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the BES.” Note, however, that generating resources connected to the sub-transmission system should generally be classified as BPS-connected and not as a DER. This applies in this paper.

<sup>6</sup> This entails voltage ride-through (VRT) and frequency ride-through (FRT) capability.

<sup>7</sup> [https://www.nerc.com/comm/Other/essntlrbltysrvcskfrCDL/Distributed\\_Energy\\_Resources\\_Report.pdf](https://www.nerc.com/comm/Other/essntlrbltysrvcskfrCDL/Distributed_Energy_Resources_Report.pdf)

<sup>8</sup> <https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx>

<sup>9</sup> <https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report>

<sup>10</sup> Per IEEE 1547-2018, the AGIR may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc.

<sup>11</sup> IEEE 1547-2003 contained a set of “one-size-fits-all” requirements that did not allow for flexibility of DER settings nor required much coordination between transmission and distribution system entities: <https://standards.ieee.org/standard/1547-2003.html>.

This reliability guideline provides high-level guidance<sup>12</sup> and BPS reliability perspectives that should be considered during the adoption and implementation of IEEE 1547-2018. Specifically, this guideline focuses on issues that pertain to DERs that have been identified by NERC SPIDERWG as potentially having an impact on the BPS. The guidance provided herein is intended to support state regulators' adoption and implementation of IEEE 1547-2018 as regulators are the entity most likely to fill the role of the AGIR in many cases.<sup>13</sup> The materials presented will also likely aid AGIRs in coordinating with Distribution Providers (DPs), Balancing Authorities (BAs), Reliability Coordinators (RCs), and other entities navigating adoption of IEEE 1547-2018 and its requirements. Each of the capability requirements and functional settings require coordination with the RC for their area.<sup>14</sup> This reliability guideline will address key clauses in IEEE 1547-2018 in detail to ensure that BPS reliability perspectives and recommended considerations are made clear. These include, but are not limited, the following: voltage and frequency mandatory trip settings, ride-through capability, DER enter service and return to service operation, DER controls configuration, and interoperability and local DER communication interface considerations.

---

<sup>12</sup> Readers are encouraged to become familiar with IEEE 1547-2018, which goes beyond BPS-related issues. Be aware that IEEE 1547 is subject to change. For example, since IEEE 1547-2018 was approved, the IEEE Standards Association has issued an errata for IEEE 1547-2018 in June 2018 and has also approved a Project Authorization Request in September 2019 for an amendment to the standard.

<sup>13</sup> The term "authority governing interconnection requirements" is introduced in IEEE 1547-2018 and in most cases is likely the state regulatory utility commission.

<sup>14</sup> IEEE 1547-2018 specifies the term "regional reliability coordinator" as the functional entity that maintains the real-time operating reliability of the BPS within an RC area. This is synonymous with the term RC as defined in the NERC Functional Model. Refer to the NERC website for a map of RC footprints: <https://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx>.

# Introduction

---

This guideline provides BPS perspectives that should be considered during the adoption and implementation of IEEE 1547-2018.<sup>15</sup> It does not cover every specific clause of IEEE 1547-2018; however, it addresses general benefits of the standard and specific clauses related to BPS reliability. This guideline is not intended to suffice as engagement or coordination among RCs and other stakeholders nor intended to address regionally-specific consideration; rather, it is intended to serve as a useful reference in these coordination activities. Note that the use of terminology generally mirrors the definitions of IEEE 1547-2018; refer to [Appendix C](#) for definitions of terms used.

## Potential Impacts of DERs on BPS Reliability

At low penetration levels, DERs may not pose a significant risk to BPS reliability. However, as the penetration continues to increase across many parts of North America, the aggregate effects of DERs present both challenges and opportunities for planning, design, and operation of the BPS. NERC has been analyzing the impacts that DERs can have on the BPS, including key findings and recommendations from the NERC IVGTF report<sup>16</sup> and the NERC DERTF report.<sup>17</sup> These efforts and the ongoing work by the NERC SPIDERWG are focusing on the aggregate impact that DERs can have on BPS reliable operation. Of particular focus are the following areas:

- The impacts that DERs have by offsetting gross load, resulting in the displacement of BPS generation which are providing various essential reliability services (ERSs)
- The impacts that DERs have on balancing generation and demand, and ensuring that BAs are carrying a sufficient amount of resources to meet ramping requirements
- The ability of the BPS to have adequate levels of voltage regulation and reactive power support with increasing penetration of DERs
- The impacts that legacy DER ride-through and trip settings may have on BPS performance following large disturbances
- The ability to model and forecast DERs for the purposes of planning and operations studies
- The ability to ensure BPS reliability with increasing amounts of generation that are not currently observable<sup>18</sup> or dispatchable

The aggregate effect of many DERs distributed across the interconnected BPS is already having an impact on BPS planning and operations. For example, the California Energy Commission Integrated Energy Policy Report forecasts approximately 6,845 MW of DERs within the California Independent System Operator footprint.<sup>19</sup> In response to their concerns about DERs, the California Public Utility Commission adopted CA rule 21,<sup>20</sup> which identified and implemented many of the functional capabilities that are now included in IEEE 1547-2018 and mandated that all solar PV DERs installed (starting September 9, 2017) use “smart inverters” to provide grid support and help address the issues described above. Thousands of MWs of DERs have been installed in California since that time with smart inverter functionality mandated by CA Rule 21. However, much of the installed equipment (i.e., legacy equipment)

---

<sup>15</sup> <https://standards.ieee.org/findstds/standard/1547-2018.html>.

<sup>16</sup> NERC IVGTF, Integration of Variable Generation Task Force Report: Summary and Recommendations of 12 Tasks, June 2015: [https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF%20Summary%20and%20Recommendation%20Report\\_Final.pdf](https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF%20Summary%20and%20Recommendation%20Report_Final.pdf)

<sup>17</sup> NERC DERTF, Distributed Energy Resources: Connection Modeling and Reliability Considerations, February 2017: [https://www.nerc.com/comm/Other/essntlrbltysrvcskfrDL/Distributed\\_Energy\\_Resources\\_Report.pdf](https://www.nerc.com/comm/Other/essntlrbltysrvcskfrDL/Distributed_Energy_Resources_Report.pdf)

<sup>18</sup> The inability for BPS grid planners and operators to understand the DER location, equipment standardization, on-line performance and behavior to grid events may pose significant challenges in both planning and operational time horizons and will increase in severity as the penetration of DERs continues to increase.

<sup>19</sup> [https://ww2.energy.ca.gov/2019\\_energy\\_policy/](https://ww2.energy.ca.gov/2019_energy_policy/)

<sup>20</sup> <https://www.cpuc.ca.gov/Rule21/>



that could trip rather than ride through disturbances (those that predate the update to CA Rule 21) will likely remain for decades.

## Background of IEEE 1547-2018

IEEE 1547-2018 is a newly published IEEE standard that specifies minimum technical interconnection and interoperability requirements for DERs connected to the distribution system.<sup>21</sup> Changes in the -2018 version of the standard address issues in the original -2003 version that required updating due to technology developments and recent learnings.<sup>22</sup> At a high level, the new standard introduces the following key elements:

- Expanding the scope of the prior IEEE 1547 standard by considering BPS issues, such as ride-through requirements, as well as distribution system issues<sup>23</sup>
- Extending requirements from the interconnection system and the individual DER unit to the whole DER facility (i.e., DER system) (For example, DER auxiliary equipment will now 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 (e.g. interoperability considerations) in addition to the electrical performance of the DER at its connection point<sup>24</sup>
- 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

Other new requirements include prioritization of DER functions, measurement accuracy requirements, and power quality requirements. The Interstate Renewable Energy Council (IREC) published a review of changes in the -2018 version for state regulators<sup>25</sup> and the National Rural Electric Cooperative Association (NRECA) published a guide for cooperative utility engineers.<sup>26</sup> The Electric Power Research Institute (EPRI) reviewed experience with the standard's implementation to date<sup>27</sup> and has published materials related to BPS issues as well.<sup>28</sup>

## Implementation of IEEE 1547-2018

IEEE 1547-2018 is intended to apply only to DERs connected to the distribution system and is generally not suited for other interconnection levels (i.e., resources connecting to the subtransmission or transmission systems).<sup>29</sup> BPS-connected inverter-based resources should follow the recommendations set forth by NERC,<sup>30</sup> are required to meet

<sup>21</sup> <https://standards.ieee.org/findstds/standard/1547-2018.html>.

<sup>22</sup> <http://sites.ieee.org/sagroups-scc21/standards/1547rev/>.

<sup>23</sup> For example, lack of ride-through capability can have a negative impact on BPS reliability. This was observed in the Palmdale Roost and Angeles Forest disturbances in North America and in the August 2019 disturbance that occurred in the United Kingdom:

<https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx>

<https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report>.

<sup>24</sup> Once communications networks are deployed, utilities or aggregators can communicate with this interface to monitor, control, and exchange information with DERs.

<sup>25</sup> <https://irecusa.org/publications/making-the-grid-smarter-state-primer-on-adopting-the-new-ieee-standard-1547-2018-for-distributed-energy-resources/>.

<sup>26</sup> <https://www.cooperative.com/programs-services/bts/Documents/Reports/NRECA-Guide-to-IEEE-1547-2018-March-2019.pdf>.

<sup>27</sup> [http://eprijournal.com/wp-content/uploads/2019/04/2019.03-F2\\_TemplateIntegratedGrid.pdf](http://eprijournal.com/wp-content/uploads/2019/04/2019.03-F2_TemplateIntegratedGrid.pdf).

<sup>28</sup> <https://www.epri.com/#/pages/product/000000003002014545/>.

<https://www.epri.com/#/pages/product/000000003002014546/>.

<https://www.epri.com/#/pages/product/000000003002014547/>.

<sup>29</sup> The NERC Inverter-Based Resource Performance Task Force (IRPTF) identified misapplication of IEEE 1547 for BPS-connected inverter-based resources due to its linkage with UL 1741 Standard: [https://www.nerc.com/comm/PC\\_Reliability\\_Guidelines\\_DL/Inverter-Based\\_Resource\\_Performance\\_Guideline.pdf](https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf).

<sup>30</sup> [https://www.nerc.com/comm/PC\\_Reliability\\_Guidelines\\_DL/Inverter-Based\\_Resource\\_Performance\\_Guideline.pdf](https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf)



local utility interconnection requirements,<sup>31</sup> and are expected to be required to meet the future requirements being developed by IEEE P2800 (which is the transmission counterpart to IEEE 1547).<sup>32</sup> IEEE 1547-2018 is technology-neutral and was vetted by a large group of industry stakeholders that range from DER manufacturers to distribution and transmission utilities. The goal of IEEE 1547-2018 implementation is to harmonize technical interconnection performance capability requirements and functional specifications for the growing installations of DERs.<sup>33</sup> Development of IEEE 1547-2018 considered different regional- and utility-specific situations as well as the current and anticipated future capabilities of the technology to safely and reliably interconnect DERs to the grid.

Entities will need to ensure that updates to interconnection requirements and the implementation of IEEE 1547-2018 align with the rollout of equipment compliant with the standard.<sup>34</sup>

## Authority Governing Interconnection Requirements

IEEE standards are voluntary in nature, so state regulators, local distribution utilities, or other applicable governing bodies throughout North America must adopt them. The FERC Small Generator Interconnection Procedures and Energy Policy Act of 2005 reference IEEE 1547 and any updates to the standard, so DERs whose interconnections are subject to FERC jurisdiction are likely subject to the requirements of IEEE 1547-2018. Similarly, AGIRs should ensure appropriate adoption and implementation of IEEE 1547-2018 in interconnection requirements for all other DERs not subject to FERC jurisdiction. In many cases, interconnection requirements for DERs may need to be modified to accommodate the new standard.

In February 2020, the National Association of Regulatory Utility Commissioners (NARUC) approved a resolution that recommended state utility commissions adopt and implement IEEE 1547-2018.<sup>35</sup> The resolution grants flexibility for state commissions, recognizing the unique procedures, priorities, and needs for each state while also considering best practices identified by technical experts. The resolution also recognizes IEEE 1547-2018 for convening a stakeholder process, utilizing existing research and experience to make evidence-based decisions, and aligning the implementation of the standard with the availability of certified equipment.

IEEE 1547-2018 includes performance categories and functional settings that allow significant flexibility; however, selecting the appropriate settings requires stakeholder involvement. The standard introduces the concept of the AGIR, which is defined in IEEE 1547-2018 as follows:<sup>36</sup>

**“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. 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.”<sup>37</sup>

As stated, an AGIR can be a state regulator or a municipal or cooperative governing board. DPs should be aware that a high degree of technical involvement is necessary for successfully implementing IEEE 1547-2018. Additionally,

---

<sup>31</sup> [https://www.nerc.com/comm/PC\\_Reliability\\_Guidelines\\_DL/Reliability\\_Guideline\\_IBR\\_Interconnection\\_Requirements\\_Improvements.pdf](https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf).

<sup>32</sup> <https://standards.ieee.org/project/2800.html>.

<sup>33</sup> Including distributed generation and energy storage systems.

<sup>34</sup> <https://site.ieee.org/sagroups-scc21/standards/1547rev/>

<sup>35</sup> <https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7>

<sup>36</sup> <https://standards.ieee.org/findstds/standard/1547-2018.html>.

<sup>37</sup> IEEE 1547-2018 also states: “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.”

coordination across many stakeholders is also necessary. RCs, Planning Coordinators (PCs), Transmission Planners (TPs), Transmission Owners (TOs), Transmission Operators (TOPs), BAs, state regulatory agencies, manufacturers, and developers will likely all have a stake in how IEEE 1547-2018 is implemented for each local jurisdiction. Collaboration at the state-level and regional-level are encouraged to engage all necessary stakeholders. The goal is that involvement from all interested stakeholders will lead the state regulatory entities and DPs to successful selection of appropriate settings within IEEE 1547-2018 and appropriate enforcement of the standard across all DERs connecting to their grid.

It is expected that the collaboration process of reaching consensus between all interested parties regarding assigning voltage and frequency ride-through performance categories and determining regional voltage and frequency trip<sup>38</sup> setting (thresholds and clearing times) could take around two years. Utilizing DER communication and interoperability capabilities will also require a significant amount of coordination and updates to technical interconnection and interoperability requirements to address customer privacy and contractual concerns. Relevant entities, including state regulatory entities, are encouraged to support early implementation of IEEE 1547-2018 and begin engaging with necessary stakeholders. DERs that are fully certified<sup>39</sup> to comply with IEEE 1547-2018 are expected to be widely available to commercial markets in 2021. AGIRs should initiate the stakeholder process early such that full implementation can align with the availability of certified equipment. AGIRs with an existing high penetration of DERs may consider earlier interim implementation dates similar to what areas such as California (Rule 21),<sup>40</sup> Hawai'i (Rule 14h),<sup>41</sup> and others have done; however, note such interim implementation requires specific considerations to ensure eventual alignment with IEEE 1547-2018. **Figure I.1** presents a summarized comparison of the different requirements between California Rule 21, Hawai'i Rule 14h, and the new IEEE 1547-2018.

The IEEE P1547.2 Working Group is drafting an application guide for IEEE 1547-2018 that will include additional information for effective implementation of IEEE 1547-2018. The IEEE application guide is expected to be published in the 2021–2022 time frame. EPRI is also working with its members on a project titled “Navigating DER Interconnection Standards and Practices” to develop guidance on the adoption of IEEE 1547-2018.<sup>42</sup>

---

<sup>38</sup> Definition of trip in IEEE 1547-2018: “Inhibition of immediate return to service, which may involve disconnection. Note: Trip executes or is subsequent to cessation of energization.”

<sup>39</sup> [https://standardscatalog.ul.com/standards/en/standard\\_1741\\_2](https://standardscatalog.ul.com/standards/en/standard_1741_2)

<sup>40</sup> <https://www.cpuc.ca.gov/Rule21/>

<sup>41</sup> <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaii-electric-light-rules>

<sup>42</sup> EPRI, “Navigating DER Interconnection Standards and Practices: Supplemental Project Notification,” 3002012048, 2017: <https://www.epri.com/#/pages/product/000000003002012048/>.

Standards for DER		Listing/Certification			Interconnection Standards			State/PUC/Utility Rules	
Function Set	Advanced Functions Capability	UL 1741	UL 1741(SA) 2016	IEEE 1547.1 -2017*	IEEE 1547-2003	IEEE 1547a-2014	IEEE 1547-2018	CA Rule 21 (Phases)	HI/HECO Rule 14H & UL SRDv1.1
All	Adjustability in Ranges of Allowable Settings			Δ		√	‡		
Monitoring & Control	Ramp Rate Control		Δ					‡ (P1)	‡
	Communication Interface			Δ			‡	‡ (P2)	‡
	Disable Permit Service (Remote Shut-Off, Remote Disconnect/Reconnect)			Δ			‡	‡ (P3)	‡
	Limit Active Power			Δ			‡	‡ (P3)	
	Monitor Key DER Data			Δ			‡	‡ (P3)	
Scheduling	Set Active Power							[ ‡ (P3) ]	
	Scheduling Power Values and Models							‡ (P3)	
Reactive Power & Voltage Support	Constant Power Factor	√	Δ	Δ	√	√	‡	‡ (P1)	X
	Voltage-Reactive Power (Volt-Var)		Δ	Δ	X	√	‡	‡ (P1)	‡
	Autonomously Adjustable Voltage Reference			Δ			‡	!!!	!!!
	Active Power-Reactive Power (Watt-Var)			Δ	X		‡		‡
	Constant Reactive Power	√		Δ	√	√	‡		
	Voltage-Active Power (Volt-Watt)		Δ	Δ	X	√	‡	‡ (P3)	‡
Bulk System Reliability & Frequency Support	Dynamic Voltage Support during VRT						√	[ ‡ (P3) ]	
	Frequency Ride-Through (FRT)		Δ	Δ			‡	‡ (P1)	‡
	Rate-of-Change-of-Frequency Ride-Through			Δ			‡	!!!	!!!
	Voltage Ride-Through (VRT)		Δ	Δ			‡	‡ (P1)	‡
	Voltage Phase Angle Jump Ride-Through			Δ			‡	!!!	!!!
Other Advanced DER Functions	Frequency-Watt		Δ	Δ	X	√	‡	‡ (P3)	‡
	Anti-Islanding Detection and Trip			Δ			‡	‡ (P1)	‡
	Transient Overvoltage						‡		‡
	Remote Configurability						‡	‡ (P2)	‡
	Return to Service (Enter Service)						‡	‡ (P1)	‡

Legend: X Prohibited, √ Allowed by Mutual Agreement, ‡ Capability Required, Δ Test and Verification Defined  
 [ ... ] Subject to clarification of the technical requirements and use cases, !!! Important Gap

Source: EPRI

**Figure I.1: Comparison between IEEE 1547 and other DER Interconnection Standards**  
**[Source: EPRI]**

## Coordination between Distribution and Transmission Entities

IEEE 1547-2018 addresses the natural diverging objectives between transmission and distribution system operation by requiring coordination among DPs and RCs. While both the DPs and RCs have the same overall goal of reliable, safe, and cost-effective power system operation, they have different operational responsibilities. RCs are focused on regional and system-wide reliability where objectives include longer DER trip times, capability of DERs to ride-through specified voltage and frequency excursions (and continue injecting active and reactive current, when possible), and ride through large deviations in phase angle.<sup>43</sup> DPs are focused on shorter DER trip times and the utilization of momentary cessation<sup>44</sup> over a wider range of voltages due to safety concerns for line workers and the public with regard to unintentional islanding and protection coordination. Many DPs are concerned that limited testing and certifications for DERs may not reflect actual performance during a wide variety of real-world conditions. These conflicting objectives are illustrated in **Figure I.2** and can be addressed if the AGIR initiates a stakeholder process to coordinate ride-through capability requirements, regional voltage and frequency trip settings, and other advanced<sup>45</sup> features. Examples of these stakeholder processes include PJM,<sup>46</sup> MISO,<sup>47</sup> and the Massachusetts Technical Standard Review Group.<sup>48</sup>

<sup>43</sup> <https://www.epri.com/#/pages/product/000000003002006203/>

<sup>44</sup> Momentary cessation definition in IEEE 1547-2018: “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.”

<sup>45</sup> Other advanced features may include, but are not limited to, automatic voltage (volt-var) control, frequency-droop (frequency-power) control, or phase jump ride-through.

<sup>46</sup> <https://www.pjm.com/committees-and-groups/task-forces/derrttf.aspx>.

<https://www.pjm.com/-/media/committees-groups/task-forces/derrttf/20190913/20190913-pjm-guideline-for-ride-through-performance-rev1.ashx>.

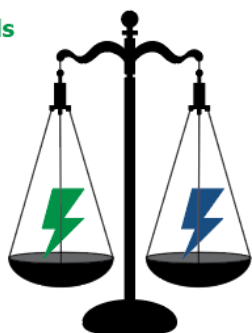
<sup>47</sup> <https://www.misoenergy.org/planning/generator-interconnection/ieee-1547/>.

<https://www.misoenergy.org/planning/generator-interconnection/ieee-1547/>.

<sup>48</sup> <https://sites.google.com/site/massdgc/home/interconnection/technical-standards-review-group>.

**Distribution System Needs**

- Short trip times
- Ride-through with momentary cessation
- Voltage rise concerns
- Islanding concerns
- Protection coordination
- Line worker safety

**Bulk Power System Needs**

- Long trip times
- Ride-through with constrained momentary cessation
- Reactive power demands
- Dynamic voltage support
- Frequency support

**The need for transmission and distribution coordination is increasing.**

**Figure I.2: Transmission and Distribution System Needs – Drivers for Coordination**  
[Source: Adapted from EPRI]

Adoption of IEEE 1547-2018 requires entities to make decisions regarding how to implement the standard. Learnings from ongoing regional adoption suggest including selection of the following:

- Normal operating condition reactive power-voltage regulation (IEEE 1547-2018, Clause 5)
- Abnormal voltage and frequency ride-through performance categories (IEEE 1547-2018, Clause 6)
- Voltage and frequency regulation settings (IEEE 1547-2018, Clauses 5 and 6)
- Selection of standardized communication protocols (IEEE 1547-2018, Clause 10)

It is difficult to retrofit new capabilities into DER equipment once installed in the field. It is critical that these decisions be made early to ensure that newly interconnecting DERs have the capability and appropriate settings to meet the functional specifications laid out in IEEE 1547-2018 (even if some of these capabilities may not yet be utilized until they become necessary at a future date).

IEEE 1547-2018 provides default values for many functional settings for DER performance during normal and abnormal voltage and frequency conditions. Without further specification of functional settings beyond the specification of particular performance categories, adoption of IEEE 1547-2018 would require all jurisdictional DERs, and associated interconnection equipment, to utilize the category-specific default values; including whether the functionality is enabled or disabled. However, the standard also provides flexibility for the settings to be altered from default values as needed. During the AGIR-initiated stakeholder process and by using the default values as a starting point, entities should consider whether these settings are appropriate based on DER technology, size, etc.

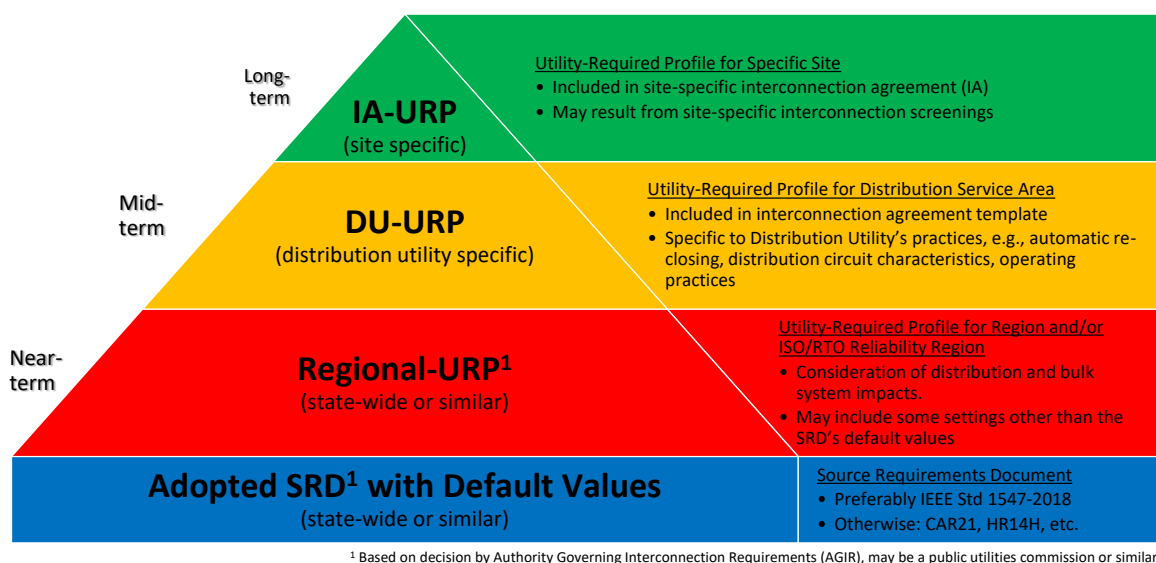
Ranges of adjustability and different performance category levels are provided in the standard such that regional or utility-specific settings<sup>49</sup> can be established for specific Area EPS needs, Local EPS needs, and to address the capabilities of different DER technologies. Decisions relating to abnormal performance category assignment and specification of regional settings for any active power-related functions (e.g., frequency-droop and other functions not covered in this guideline such as voltage-active power) should be coordinated with the RC. Ideally, regional or minimum settings should be chosen based on regional BPS reliability studies using latest aggregate DER modeling practices.<sup>50</sup> If DPs need to divert from regional category assignments and settings, the RC should be informed about

<sup>49</sup> These may be called “utility-required profiles (URPs)” and may be implemented via “manufacturer-automated profiles (MAPs)”.

<sup>50</sup> <https://www.epri.com/#/pages/product/00000003002013503/>.

<https://pjm.com/-/media/committees-groups/task-forces/dertrf/20190730-workshop/20190730-item-18-implementing-ride-through-from-distributed-energy-resources.ashx>.

these utility-specific settings to ensure the DERs are accurately modeled in reliability studies. **Figure I.3** illustrates the various levels of DER functional settings with regional settings expected in the near term and site-specific settings in the long term.



**Figure I.3: Levels of DER Interconnection Requirements and Settings [Source: EPRI]**

Management of the increasing diversity of DER functional settings can become a challenge. Even once DPs and RCs successfully coordinated DER functional settings, the reliable application of these settings to DERs in the field may not be ensured. Many DER manufacturers currently use so-called manufacturer-automated profiles (MAPs) that pre-set certain functional parameters to the values specified in applicable rules (e.g., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these MAPs are not validated by any third party, and verification by utility engineers is often limited to the review of a photo taken by a DER installer of the selected MAP on the DER's general user interface at the time of commissioning. Given the criticality of DER trip and other settings for the BPS, more sophisticated verification methods are desired. One approach being explored by EPRI is developing a central database to store DER settings where authorized users can write settings, and all other users can read these settings to help exchange information among all applicable entities.<sup>51</sup>

### BPS Perspectives and Recommendations

Key issues to address through coordination with the RCs include reactive power-voltage regulation during normal operations, abnormal voltage and frequency ride-through performance categories, regional voltage and frequency regulation settings, and communication protocols. Decisions relating to abnormal performance category assignment and the specification of regional settings for any active power-related functions (e.g., frequency-droop and voltage-active power) should be coordinated with the RC. If DPs need to divert from regional category assignments and settings, the RC should be informed about these utility-specific settings to ensure the DERs are accurately modeled in reliability studies. Reliable application and verification of DER functional settings are of increasing importance. A central database is one of various options to facilitate efficient data exchange among the DP, RC, and DER installer.

<sup>51</sup> EPRI is launching a public, web-based DER Performance Capability and Functional Settings Database in 2020: <https://dersettings.epri.com>.

# Chapter 1: BPS Perspectives on IEEE 1547-2018 Clauses

---

This chapter discusses the sections and clauses in IEEE 1547-2018 relevant to reliable operation of the BPS, and provides BPS perspectives that should be used by AGIRs and RCs while coordinating to determine regionally-appropriate implementation of IEEE 1547-2018.

## Clause 1.4: General Remarks

Clause 1.4, Clause 6.4.2, and Annex B of IEEE 1547-2018 describe and utilize the ride-through performance category assignment of DERs. Adoption of IEEE 1547-2018 requires assigning abnormal performance categories to specific (groups of) DERs and the coordination of regional voltage and frequency trip settings across the transmission and distribution (T&D) interface. The specification of these regional functional settings will need to balance bulk system reliability and distribution concerns. Per language in IEEE 1547-2018, DPs and AGIRs “should not determine these regional settings without coordination with the appropriate (RC).” A description of abnormal performance categories are as follows:

- **Category I:**<sup>52</sup> “Category I is based on minimal BPS reliability needs and is reasonably attainable by all DER technologies that are in common usage today. The disturbance ride-through requirements for Category I acknowledge the inherent limitations that synchronous generators have compared to inverter based systems, and are derived from the German Association of Energy and Water Industries (BDEW) guideline of 2008<sup>53</sup> for medium voltage synchronous generators that is one of the most widely applied standards in Europe.<sup>54</sup> Many synchronous generator manufacturers are currently designing products to meet the requirements of this standard. 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, but limited penetration of this category would not have a material negative impact. It should be noted that penetration, with regard to BPS reliability impacts, should be measured on a regional or bulk system-wide<sup>55</sup> basis, and local distribution system penetration levels are not typically of particular relevance.”
- **Category II:** Category II performance covers minimum BPS reliability needs, and coordinates with NERC Reliability Standard PRC-024-2,<sup>56</sup> 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.<sup>57</sup> Additional voltage ride-through capability was specified for DERs of Category II beyond the mandatory voltage ride-through defined by PRC-024-2 to account for the potential for fault-induced delayed voltage recovery (FIDVR) on the distribution system.<sup>58</sup>[12] IEEE 1547-2018 working group members expected that Category II might be adopted by the majority of the AGIRs for inverter-based DERs,

---

<sup>52</sup> As described in the informative appendix of IEEE 1547-2018.

<sup>53</sup> BDEW German Association of Energy and Water Industries (2008): Technical Guideline Generating Plants Connected to the Medium-Voltage Network. Guideline for generating plants’ connection to and parallel operation with the medium-voltage network), published June 2008, revised January 2013: <https://www.vde.com/de/fnn/dokumente/archiv-technische-richtlinien>.

<sup>54</sup> The BDEW guideline has since been superseded by the VDE Application Guide VDE-AR-N 4110, “Technical requirements for the connection and operation of customer installations to the medium voltage network (TAR Medium Voltage)”: <https://www.vde.com/en/fnn/topics/technical-connection-rules/>.

<sup>55</sup> Synchronous Interconnections, such as the Eastern Interconnection, ERCOT, WECC, are examples of bulk systems in this context.

<sup>56</sup> <https://www.nerc.com/ layouts/15/PrintStandard.aspx?standardnumber=PRC-024-2&title=Generator%20Frequency%20and%20Voltage%20Protective%20Relay%20Settings&jurisdiction=United States>

<sup>57</sup> Synchronous generator based DER would have to be significantly redesigned to meet Category II ride-through capabilities.

<sup>58</sup> <https://www.epri.com/#/pages/product/000000003002006203/>  
[http://www.nerc.com/docs/pc/tis/fidvr\\_tech\\_ref%20v1-2\\_pc\\_approved.pdf](http://www.nerc.com/docs/pc/tis/fidvr_tech_ref%20v1-2_pc_approved.pdf).  
<http://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/2015%20FIDVR%20Workshop%20Takeaways.pdf>.



but an amendment to IEEE 1547-2018 has been initiated to provide more flexibility to adopt Category III (see below) based on experience from stakeholder processes in PJM, MISO, and ISO NE.

- **Category III:**<sup>59</sup> 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<sup>60</sup> 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. Prior to the initiation of an amendment to IEEE 1547-2018, Category III requirements were expected to be applied to high penetration DER systems; however, with the amendment, this may no longer be the case.<sup>61,62</sup>

Table 1.1 shows the three categories for ride-through performance capability.

Table 1.1: Ride-Through Capability Abnormal Performance Categories		
Category	Objective	Foundation
I	Essential BPS reliability needs; reasonably achievable by all current state-of-the-art DER technologies	German grid code for synchronous DER <sup>63</sup>
II	Full coordination with BPS needs	Based on NERC Reliability Standard PRC-024-2, adjusted for distribution voltage differences (delayed voltage recovery)
III	Ride-through designed for distribution support as well as BPS needs	Based on California Rule 21 <sup>64</sup> and Hawai'i Rule 14H <sup>65</sup>

<sup>59</sup> An amendment to IEEE 1547-2018 is drafted by the IEEE SA to widen the allowable ranges for voltage trip clearing times of Category III that provides more flexibility to adopt Category III. The amendment would harmonize the low value of the range of allowable trip clearing time settings for UV1 and UV2 in Category III with the values specified in Category I and II, effectively allowing to terminate DER ride-through operation by trip clearing times inside the Category III voltage ride-through capability regions. With the successful ballot and likely publication of an amendment by May 2020, Category III with modified voltage trip settings is expected to become the most common requirements for inverter-based DER.

<sup>60</sup> There is no generally accepted definition or threshold that quantifies “very high levels” of DER penetration. The concept of “high penetration” of DER penetration should not be directly linked to distribution system backflow. Penetration of DER not exceeding load can be of significant impact on BPS performance. Also, regional or interconnection-wide penetration levels are more relevant to BPS performance.

<sup>61</sup> Category III is similar to smart inverter requirements required in California (Rule 21) and Hawai'i (Rule 14H).

<sup>62</sup> Allowable undervoltage trip times in Category III of not shorter than 21 seconds for shallow (UV1) and 2 seconds for deep (UV2) voltage dips were regarded as too long by many distribution protection engineers. The amendment is expected to be published in spring 2020 along with the publication of IEEE P1547.1.

<sup>63</sup> BDEW German Association of Energy and Water Industries (2008): Technical Guideline Generating Plants Connected to the Medium-Voltage Network. Guideline for generating plants' connection to and parallel operation with the medium-voltage network), published June 2008, revised January 2013: <https://www.vde.com/de/fnn/dokumente/archiv-technische-richtlinien>.

<sup>64</sup> <https://www.cpuc.ca.gov/Rule21/>

<sup>65</sup> <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rules>



### BPS Perspectives and Recommendations

- Decisions related to ride-through capability and trip settings should be addressed in the near-term because the aggregate impact from undesired choices will accumulate over time, and large-scale reconfiguration or retrofit of DERs could be challenging and costly.
- Default settings have been chosen to “do no harm” for BPS reliability. However, each of these default settings should be reviewed and coordinated between the DP and RC to ensure that they do not have any conflicts with BPS, regional, and distribution system reliability and safety criteria.
- Any modifications to the default settings should consider the range of allowable settings as specified in IEEE 1547-2018, and the AGIR (in coordination with all stakeholders, particularly the RC) should make appropriate modifications within the ranges of adjustability that best suits each jurisdiction. The RC should be informed of settings that differ from established defaults to ensure the DERs are accurately modeled in reliability studies.

### Clauses 6.4.1 and 6.4.2: Voltage Mandatory Tripping and Ride-Through

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. Developing performance requirements for DER voltage mandatory tripping and ride-through should consider the needs of the distribution system as well as the BPS. Mandatory tripping requirements in response to the Area EPS abnormal conditions was one of the key items of the original IEEE 1547-2003. These settings helped assure utilities that DERs would trip off-line when voltage and frequency were outside of normal conditions to help ensure worker safety. IEEE 1547-2018 retains that fundamental concept of tripping DERs off-line during abnormal conditions. However, the “shall-trip”<sup>66</sup> 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. 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 1.2](#) state that, if voltage at the DER reference point drops below 0.45 pu for 0.16 seconds, the DER must cease to energize,<sup>67</sup> regardless of ride-through capabilities.<sup>68</sup> New criteria regarding voltage-sensing accuracy are also included in IEEE 1547-2018 to better support equipment capability in meeting both mandatory tripping and ride-through requirements.

<sup>66</sup> Definition of trip in IEEE 1547-2018: “Inhibition of immediate return to service, which may involve disconnection.” Refer to the notes identified in the definition in the standard.

<sup>67</sup> Definition of cease to energize in IEEE 1547-2018: “Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.” Refer to the notes identified in the definition in the standard and appendix B of this document for an illustrative figure and further explanation of responses to abnormal conditions like cease to energize, momentary cessation, and trip.

<sup>68</sup> Because the standard allows for a ride-through exemption “buffer” of 0.16 second prior to the trip time, this may result in zero “effective ride-through” for voltage before 0.45 p.u.

## BPS Perspectives and Recommendations

- The mandatory tripping requirements in IEEE 1547-2018 are well understood to support worker and general public safety, and equipment integrity. The “shall-trip” allowable clearing time ranges have been increased significantly in IEEE 1547-2018 to enable DERs to utilize their capability to ride through abnormal voltage and frequency conditions on the distribution system, typically encountered during BPS contingency events.
- The RC and the Area EPS operator should mutually agree on shall-trip settings in IEEE 1547-2018 to ensure both distribution system and BPS reliability needs are met. Ideally, “shall-trip” settings should be chosen based on regional BPS reliability studies.

### 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 1.2** shows the Category I, II, and III mandatory trip setting default values and ranges of adjustability as defined in Tables 11–13 in IEEE 1547-2018.

Table 1.2: Shall-Trip Voltage Settings				
Shall-Trip Function	Default Settings		Ranges of Allowable Settings	
	Voltage [pu of nominal voltage]	Clearing Time [sec]	Voltage [pu of nominal voltage]	Clearing Time [sec]
<b>Category I Shall-Trip Voltage Settings</b>				
OV2	1.20	0.16	Fixed at 1.20	Fixed at 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*
<b>Category II Shall-Trip Voltage Settings</b>				
OV2	1.20	0.16	Fixed at 1.20	Fixed at 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
<b>Category III Shall-Trip Voltage Settings</b>				

Table 1.2: Shall-Trip Voltage Settings				
Shall-Trip Function	Default Settings		Ranges of Allowable Settings	
	Voltage [pu of nominal voltage]	Clearing Time [sec]	Voltage [pu of nominal voltage]	Clearing Time [sec]
OV2	1.20	0.16	Fixed at 1.20	Fixed at 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*

\* Updated to show ranges based on expected amendment to IEEE 1547-2018

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 developing the IEEE 1547-2018 requirements. AGIRs should consider these local distribution system protection practices when implementing IEEE 1547-2018. Distribution protection methods and overall philosophy can vary considerably from entity to entity, requiring consideration of how IEEE 1547-2018 requirements may affect existing distribution protection practices.<sup>69</sup> Adjusting the momentary cessation threshold may help coordinate with existing distribution protection schemes and other safety concerns.

### BPS Perspectives and Recommendations

- AGIRs should consider local distribution system protection practices when implementing IEEE 1547-2018, and ensure that appropriate shall-trip settings are determined. From a BPS perspective, shall-trip clearing times should be set as long as possible while still ensuring distribution system coordination and public safety.
- The voltage-related shall-trip default settings of IEEE 1547-2018 are generally set to support BPS reliability, and provide sufficient robustness to expected BPS grid disturbances. The specifications of default values and ranges of allowable settings in IEEE 1547-2018 align well with similar requirements set forth for BPS-connected generating resources.

### 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 1547-2018, respectively. Figures H.7–H.9<sup>70</sup> of the standard visualize these ride-through requirements as well. [Appendix B](#) of this guideline includes the ride-through figures from IEEE 1547-2018 for reference. The following notes are useful perspectives to consider when implementing IEEE 1547-2018 based on the Clause 6.4.2 requirements:

<sup>69</sup> This is a matter of balancing customer power quality and public safety with DER interconnection restrictions, and this depends on the nature of the particular distribution system and the environment (e.g., lightning flash density) in which the system is located. These practices should not drive any protection settings that conflict with BPS security needs but may drive extra requirements for DER connection (e.g., direct transfer trip) or DER penetration limits.

<sup>70</sup> An amendment to IEEE 1547-2018 has been successfully balloted and is expected to be published by May 2020. The undervoltage range of clearing time in [Table 1.2](#) reflect this amendment.

- The Area EPS Operator, as guided by the AGIR who determines applicability of the performance categories, 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<sup>71</sup> phase voltage if that voltage is less than nominal.
- During temporary voltage disturbances when voltage falls outside the continuous operation region, DERs “shall be capable to ride-through, shall maintain synchronism with the Area EPS, shall not trip, and shall restore output as specified in Clause 6.4.2.7.” Note that this does not require DERs to continue injecting current in this region of the ride-through curves.
  - Within the mandatory operation region, the DER “shall maintain synchronism with the Area EPS, shall continue to exchange current with the Area EPS, and shall neither cease to energize nor trip.”
    - Category II and III DERs “shall, by default, not reduce its total apparent current...below 80% of the predisturbance value or of the corresponding active current level subject to the available active power, whichever is less...” subject to conditions specified.
  - During temporary voltage disturbances where voltage falls within the permissive operation region, DERs “shall maintain synchronism with the Area EPS or shall not trip, may continue to exchange current with the Area EPS or may cease to energize, and if DERs ceases to energize, shall restore output as specified in Clause 6.4.2.7.”
    - Note that permissive operation of DERs as defined in IEEE 1547-2018 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 predisturbance 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.
    - DER performance within the permissive operation region should be prescribed by the AGIR such that it is clear how DERs are being implemented in the field. It is recommended that the appropriate setting (current injection or momentary cessation) be mutually agreed upon by the Area EPS operator, DP, and RC.
    - It is critical that TPs, PCs, and RCs understand how DERs are expected to behave during these conditions such that they can be accurately modeled in reliability studies.
  - For Category III DERs, a momentary cessation operation region exists for specified low-voltage conditions.
- Clause 6.4.2.5 defines performance during consecutive voltage disturbances. It 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 IEEE 1547-2018 for Category I, II, and III DERs, respectively. These requirements are subject to the provisions that specify conditions in Table 17 of IEEE 1547-2018 for which a DER may trip. Refer to these provisions, specified in Table 17 of IEEE 1547-2018, for more details.

<sup>71</sup> For low-voltage [high-voltage] ride-through, the relevant voltage at any given time shall be the least [greatest] magnitude of the individual applicable phase-to-neutral, phase-to-ground or phase-to-phase voltage relative to the corresponding nominal system voltage.

## BPS Perspectives and Recommendations

- The voltage disturbance ride-through requirements of IEEE 1547-2018 provide significantly improved capability and performance of DERs over past versions of IEEE 1547. The ability of DERs to ride-through BPS disturbance events, particularly voltage disturbances such as transmission-level faults, becomes an important component of BPS stability as the penetration of DERs continues to increase.
- Appropriate selection of DER abnormal performance category is important, particularly since it affects the manner in which DERs ride-through abnormal voltage disturbances.
- DERs may cease to inject current during the permissive operation region of Category I and II, similar to momentary cessation which is expected to be experienced by many DERs during BPS fault events. DERs assigned to category III are required to ride-through voltage dips below 0.5 pu in momentary cessation mode.
- AGIRs should ensure that DER operation in the permissive operation and momentary cessation region is coordinated between the Area EPS operator, the DER operator, and the RC and BA to ensure appropriate performance from these resources during BPS fault events.
- Regional BPS reliability studies can help build an understanding of the impact of DER ride-through operation, including the impact of momentary cessation on the BPS.

## Clauses 6.5.1 and 6.5.2: Frequency Mandatory Tripping and Ride-Through

In addition to the voltage mandatory tripping and ride-through requirements, IEEE 1547-2018 also includes frequency-related mandatory tripping and ride-through requirements.<sup>72</sup> 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 (as explained in the previous section). New criteria regarding frequency-sensing accuracy are also included in IEEE 1547-2018 to better support equipment capability in meeting both mandatory tripping and ride-through requirements.

### Clause 6.5.1: Mandatory Frequency Tripping Requirements

Clause 6.5.1 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 overfrequency 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.”

**Table 1.3** shows the mandatory trip setting default values and ranges of adjustability as defined in Table 18 in IEEE 1547-2018.

<sup>72</sup> These Category I and II default settings were intended to address prevailing distribution utility concerns to ensure that unintentional islanding (UI) of isolated parts of the distribution grid with DERs is reliably prevented. However, research by Sandia and EPRI falsifies concerns that smart inverter ride-through performance with enabled grid support functions could extend UI run-on-times beyond 2 seconds. Independent from smart inverter grid support, run-on-times may exceed 2 s if induction motor loads are present in the isolated feeder.

<https://www.osti.gov/servlets/purl/1491604>

<https://www.epri.com/#/pages/product/000000003002012986/>

Table 1.3: Frequency Trip Settings				
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	0.16–1000.0
OF1	61.2	300	61.0–66.0	180.0–1000.0
UF1	58.5	300	50.0–59.0	180.0–1000.0
UF2	56.5	0.16	50.0–57.0	0.16–1000.0

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. AGIRs should seek feedback from RCs to ensure that underfrequency and overfrequency trip settings are coordinated because interconnection frequency response and underfrequency load shedding (UFLS) thresholds vary across RCs and interconnections. IEEE 1547-2018 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 (see subsequent sections on phase jump and rate-of-change-of frequency (ROCOF)).

### BPS Perspectives and Recommendations

- AGIRs should ensure that underfrequency and overfrequency trip settings are coordinated between the Area EPS operator and the RC to ensure that DER tripping is coordinated with wide-area UFLS operation and interconnection-wide frequency response characteristics.
- The frequency-related shall-trip settings of IEEE 1547-2018 are generally set to support BPS reliability, and provide sufficient robustness to expected BPS grid disturbances. The capabilities, and in many cases the default settings, used in IEEE 1547-2018 align well with similar requirements set forth for BPS-connected generating resources. However, the default settings should be reviewed by the AGIR for each specific system.

### Clause 6.5.2: Frequency Disturbance Ride-Through Requirements

Clause 6.5.2 defines the abnormal frequency ride-through requirements for Category I, II, and III resources in Table 19 of IEEE 1547-2018. Figure H.10 of the standard visualizes these ride-through requirements as well. [Appendix B](#) of this guideline includes the ride-through figures from IEEE 1547-2018 for reference. The following notes are useful perspectives to consider when implementing IEEE 1547-2018 based on the Clause 6.5.2 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: 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 predisturbance level of power.

- During temporary frequency disturbances, the DER shall be capable to ride through and maintain synchronism with the Area EPS. Tables 20 and 22 of IEEE 1547-2018 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 predisturbance values, and modulate active power per Table 22 of IEEE 1547-2018.
  - 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 overfrequency conditions per Table 22 of IEEE 1547-2018.
- Within the continuous operation region and ride-through operating regions, DERs shall not trip for frequency excursions having a magnitude of ROCOF that is less than or equal to the values specified in [Table 1.4](#) (Table 21 of IEEE 1547-2018).

<b>Table 1.4: ROCOF Ride-Through Requirements (Table 21 of IEEE 1547-2018)</b>		
<b>Category I</b>	<b>Category II</b>	<b>Category III</b>
0.5 Hz/s	2.0 Hz/s	3.0 Hz/sec

### BPS Perspectives and Recommendations

- The frequency disturbance ride-through requirements of IEEE 1547-2018 provide significantly improved performance of DERs over past versions of IEEE 1547. The ability of DERs to ride-through BPS disturbance events, including frequency disturbances, becomes an important component of BPS stability as the penetration of DERs continues to increase.
- Categories I, II, and III have the same frequency and voltage phase angle jump disturbance ride-through requirements and help ensure appropriate performance of DERs when part of a larger BPS.
- Improvements to ROCOF ride-through, particularly for Category II and III DERs, will greatly improve DERs ability to ride-through imbalances in generation and load that may occur on the BPS.

### Clause 6.4.2.7: Restore Output

Clause 6.4.2.7 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:<sup>73</sup>

- If the DER is not providing dynamic voltage support, then it “shall restore output of active current to at least 80% of pre-disturbance active current level within 0.4 s. 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 shall perform the following:

<sup>73</sup> This Reliability Guideline does not provide a recommendation for the use of dynamic voltage support for DER during fault events. However, fault current contribution and dynamic voltage support from DERs may help support BPS voltage recovery during and following BPS fault events. Coordination with distribution system protection practices will be critical and should be considered by AGIRs during the coordinated implementation process.



- “Continue to provide dynamic voltage support up to 5 s 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 s.”
- “Discontinue providing dynamic voltage support 5 s after the applicable voltage surpasses the lower value of the continuous operation region and resume reactive power functionality for normal conditions as defined in Clause 4.2 for the mode that has been selected.”

Note that areas with any delayed voltage recovery concerns, such as those caused FIDVR,<sup>74</sup> may need to consider whether this type of dynamic voltage support being retracted after five seconds could impact BPS reliability.

### BPS Perspectives and Recommendations

- In cases where DERs do not provide dynamic voltage support and cease injection of current to the Area EPS, active current recovery within 0.4 seconds after voltage returns to within the continuous operating range appears to reasonably support wide-area BPS stability currently. However, in the future, this may need to be revisited by TPs and PCs and should be modeled appropriately in reliability studies.
- TPs and PCs should understand if end-use load dynamics, such as motor stalling, could result in post-fault voltages remaining low such that DERs are unable to restore output for BPS fault events. This has been observed in events where single-phase induction motor stalling (common in legacy air-conditioning systems) has occurred.
- Continued current injection during abnormal grid conditions helps mitigate potential transient and voltage stability issues on the BPS. As such, DERs providing dynamic voltage support and continuing current injection to the grid during disturbance events provide useful support to the BPS during disturbance events.

## 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 ERS for BPS reliability, and IEEE 1547-2018 requires the technical capability for DERs to provide active power-frequency (i.e., frequency-power or frequency-droop) functionality similar to BPS-connected generating resources.<sup>75</sup> Utilization of this feature with appropriate functional settings should be considered in the near-term to support BPS operation. AGIRs should coordinate with RCs and BAs to ensure appropriate settings are selected to support interconnection-wide power balancing.

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 deadband settings for frequency-droop control since that can effectively desensitizes the function’s impact.<sup>76</sup> A proportional response<sup>77</sup> from DERs to high-frequency conditions beyond a deadband can help support BPS frequency control during abnormal frequency conditions, particularly during interconnection-wide system separation events. The tendency of DPs to

<sup>74</sup> <https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/Dynamic%20Load%20Modeling%20Tech%20Ref%202016-11-14%20-%20FINAL.PDF>

<sup>75</sup> Note that IEEE 1547-2018 does not allow for this function to be disabled.

<sup>76</sup> Wider deadbands may cause delayed response from DERs to frequency disturbances that will adversely impact BPS frequency control by prolonging the frequency recovery period. A reasonable maximum deadband should be considered in a coordinated manner between the DPs, TPs, and RCs.

<sup>77</sup> Reduction of active power above a certain frequency threshold.

disable this function for Category I DERs bears a potential risk that should be considered by each AGIR. Use of Category II for DERs helps minimize this risk.

Coordination between the DER operator and the responsible transmission entities (e.g., RC, BA) is essential to ensuring that active power-related settings for the frequency-droop (frequency-power) functions coordinate reliably with BPS practices.

### BPS Perspectives and Recommendations

- As more DERs displace generating resources on the BPS, concerns about frequency control and balancing generation and demand are growing.
- DERs providing frequency response with appropriate settings can provide BPS reliability benefits to balancing and frequency control.
- DERs expected to operate at maximum available power can still support BPS frequency for overfrequency conditions.
- Future DER management systems and controls may enable DERs to provide upward support for underfrequency conditions when DERs are curtailed. This could provide another ERS to the BPS in the future if needed. However, this would need to be coordinated with the distribution and transmission system operators to ensure that the frequency-related response is not exacerbating any reliability issues that led to the DER curtailment.

### Clause 6.5.2.7.1: Frequency-Droop Capability

Clause 6.5.2.7.1 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 1.5: Frequency Droop Requirements (Table 22 of IEEE 1547-2018)**

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 overfrequency 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. DER management systems may also unlock the capabilities to provide these services to the BA. By having visibility of DER status and capabilities, an operator or aggregator can provide frequency regulation, demand response, or other services.

## BPS Perspectives and Recommendations

- IEEE 1547-2018 requires newly interconnecting DERs to have the capability to provide active-power frequency control in the upward and downward directions for underfrequency and overfrequency conditions, respectively (except for Category I). DERs supporting interconnection-wide frequency control in the future provides BPS reliability benefit.

### Clause 6.5.2.7.2: Frequency-Droop Operation

Clause 6.5.2.7.2 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 deadband  $db_{OF}$  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.”

Tables 23 and 24 of IEEE 1547-2018 provide the formula for frequency-droop operation for underfrequency and overfrequency conditions and the parameters of these equations for each Category of DER, respectively. **Table 1.6** shows the parameter values described in Table 24 of IEEE 1547-2018. Refer to IEEE 1547-2018 for details regarding each parameter value.

<b>Table 1.6: Parameters of Frequency-Droop Operation (Table 24 of IEEE 1547-2018)</b>						
Parameter	Default Setting <sup>a</sup>			Ranges of Allowable Settings <sup>b</sup>		
	Category I	Category II	Category III	Category I	Category II	Category III
$db_{OF}, db_{UF}$ [Hz]	0.036	0.036	0.036	0.017 <sup>c</sup> –1.0	0.017 <sup>c</sup> –1.0	0.017 <sup>c</sup> –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

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

b. For the single-sided deadband values ( $db_{OF}$ ,  $db_{UF}$ ) ranges, both the lower value and the upper value is a minimum requirement (wider settings shall be allowed). For the frequency droop values ( $k_{OF}$ ,  $k_{UF}$ ) ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set to greater values). For the open-loop response time,  $T_{response}$  (small-signal), the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values). 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.

c. A Deadband of less than 0.017 Hz shall be permitted.

AGIRs should coordinate with all relevant parties, including the BA and RC, to ensure that appropriate settings and capabilities are enabled for active power-frequency control from DER. AGIRs should ensure that any requirements in place at the BA level be met by appropriate DER settings. This applies to current system needs as well as future penetration levels of DER. For example, individual or groups of DERs potentially participating in future frequency responsive reserve requirements or markets may need to meet specific performance capabilities. Further, dispatch capability and visibility of these resources may also be needed to ensure operational ability (i.e., frequency responsive headroom). The ranges of allowable settings enable different types of DERs to be accommodated with slight changes in droop, deadband settings, and response times.

### BPS Perspectives and Recommendations

- The default and ranges of allowable settings in Table 24 of IEEE 1547-2018 are aligned with current and future needs of the BPS in terms of frequency control.
- AGIRs should coordinate with applicable BAs and RCs to ensure that DERs have the capability and operational ability, as needed, to meet any requirements at the BPS. This is particularly applicable for DERs providing ERSs to the BPS through ancillary service markets or other BA requirements.

### Clause 6.5.2.8: Inertial Response

Clause 6.5.2.8 states the following related to “inertial response”:

“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.”

IEEE 1547-2018 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. Note that IEEE 1547-2018 uses the term “inertial response”; however, this term in IEEE 1547-2018 is more effectively named “fast frequency response (FFR)” in this document to avoid confusion. Further, changing active power in response to measured ROCOF is only one means of providing FFR.

While this feature is not required, the ability of DERs to respond to rapidly changing frequency does support BPS reliability, particularly for systems with low system inertia that experience high ROCOF conditions. While not necessary, DERs with the capability and operational functionality to provide FFR could provide a BPS ERS.

### BPS Perspectives and Recommendations

- While not required, DERs with the ability to provide FFR (termed “inertial response” in IEEE 1547-2018) could provide an ERS to the BPS. This is particularly valuable for low inertia systems with high ROCOF.

### Clause 6.5.2.6: Voltage Phase Angle Changes Ride-Through

Clause 6.5.2.6 of IEEE 1547-2018, provided below, describes the ride-through performance requirements for single-phase and multi-phase DER for sub-cycle-to-cycle phase angle changes (referred to as “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 time frame 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 s 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 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. A BPS line switching event (no fault) 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. In August 2019, a large disturbance in the UK that resulted in operation of UFLS involved about 150 MW of DER tripping on “Vector Shift protection” that exceeded six degrees.<sup>78</sup>

### BPS Perspectives and Recommendations

- With increased DER penetrations, the ability of DERs to ride through large changes in voltage phase angle becomes increasingly important for reliable operation of the BPS. Large changes in voltage phase angle can occur during normally cleared fault events or line switching on the BPS. Widespread DER tripping during these events could cause adverse impacts to BPS reliability. Therefore, from the BPS perspective, voltage phase angle ride-through capability and performance is strongly recommended for all DERs.

## Clause 4.10 and Clause 6.6: Enter Service and Return to Service

From a BPS perspective, there are minimal concerns with connecting individual DER units; however, a significant penetration of DERs can pose challenges when unexpectedly entering service or returning to service following a trip event. When an electric distribution circuit is energized, the end-use loads will instantly resume consuming energy. Thermostatically-controlled loads, including HVAC, water heaters, ovens, etc., lose their diversity and may simultaneously be in the “on” state at re-energization, resulting in an increase in load often referred to as “cold load pickup.” The default “Return to Service” setting on both legacy IEEE 1547-2003 and newer IEEE 1547-2018 DERs is a 300-second delay, so this results in an even greater increase in the net load at re-energization that persists until the DER resume predisturbance output. Therefore, for areas with high DER penetration, the demand may be significantly higher relative to demand prior to the outage. In addition, substation load tap changers, regulators, and capacitors are all in the position appropriate for DER operation, which may cause challenges upon restoration.

Clause 4.10.2 defines the requirements for DERs entering on-line operation (enter service). Clause 6.6 references the requirements of Clause 4.10.2 related specifically to return to service after a trip condition. Clause 4.10.2 states as follows:

“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 and the permit service setting is set to “Enabled.””

**Table 1.7** shows the return to service following trip and enter service criteria for Category I, II, and III DERs.

<sup>78</sup> A six-degree phase jump is not uncommon for BPS fault events. UK disturbance report can be found here:

<https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report>

<b>Table 1.7: Enter Service Criteria for Category I, I, and III DERs (Table 4 in IEEE 1547-2018)</b>			
<b>Enter Service Criteria</b>		<b>Objective</b>	<b>Foundation</b>
Applicable Voltage within Range	Minimum Value	$\geq 0.917 \text{ pu}^a$	0.88 pu to 0.95 pu
	Maximum Value	$\leq 1.05 \text{ pu}$	1.05 pu to 1.06 pu
Frequency within Range	Minimum Value	$\geq 59.5 \text{ Hz}$	59.0 Hz to 59.9 Hz
	Maximum Value	$\leq 60.1 \text{ Hz}$	60.1 Hz to 61.0 Hz

<sup>a</sup> Corresponds to Range B of ANSI C84.1, Table 1, column for service voltage of 120–600 V.

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 (and should be coordinated with the BA), where it is critical to maintain balance between load and generation while system inertia is still relatively low. Increasing penetration of DERs compliant with IEEE 1547-2018 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. AGIRs and DPs should review the settings to determine appropriate schemes that should be coordinated with wide-area blackstart activities.

### **BPS Perspectives and Recommendations**

- Unexpected or large changes in DER output may adversely impact BA and RC restoration activities following wide-area disturbances. BAs and RCs need to understand expected load pickup behavior following outage conditions, including the response of DERs.
- AGIRs should ensure that return to service and enter service settings are coordinated among DPs, BAs, and RCs. Appropriate voltage and frequency limits, in addition to return to service time, should be coordinated with all entities.

## **Clause 8.1: Unintentional Islanding**

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 “[f]alse 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. The latest draft of IEEE P1547.1 requires that DER anti-islanding performance be demonstrated in type-testing with the widest voltage and frequency tripping set points and with grid support functionality (voltage regulation and frequency droop) enabled. However, limited testing on actual systems with many parallel inverters (and end-use loads) has been performed in the field, so AGIRs should understand that continuous monitoring and feedback may be needed in this area.

Despite this clear and strong language on unintentional islanding detection requirements in IEEE 1547-2018 and in the forthcoming IEEE 1547.1 testing and verification standard, the Category I and II default settings were intended to address prevailing distribution utility concerns to ensure that unintentional islanding of isolated parts of the



distribution grid with DERs is reliably prevented. However, latest research by Sandia<sup>79</sup> and EPRI<sup>80</sup> indicates that smart inverter ride-through performance with enabled grid support functions does not extend UI run-on-times beyond two seconds.<sup>81,82</sup> Ongoing industry research is needed to determine appropriate islanding detection sensitivities in cases of high penetration of DERs.

## Clause 8.2: 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 (e.g., a planned island that independently energizes a local or wider-area network during a BPS outage). 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). Clause 8.2.8 describes categorizations of DERs based on their performance in these islands: uncategorized, intentional island-capable, black start-capable, and isochronous-capable.

### BPS Perspectives and Recommendations

- The settings and performance of DERs related to intentional islanding is outside the scope of consideration by SPIDERWG and recommendations provided by NERC.

## Clause 10: Interoperability, Information Exchange, and Protocols

Clause 10 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 DPs or other third-parties to perform monitoring and management or control (changing settings) of DERs. Such interoperability may be a critical need for managing systems with high penetration levels of DERs in the future. This communication may also be a future requirement by BAs in order to have adequate visibility and control of DERs that are participating in either wholesale energy or ancillary service markets.

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

<sup>79</sup> <https://www.osti.gov/servlets/purl/1491604>

<https://energy.sandia.gov/download/43576/>

<sup>80</sup> <https://www.epri.com/#/pages/product/000000003002012986/>

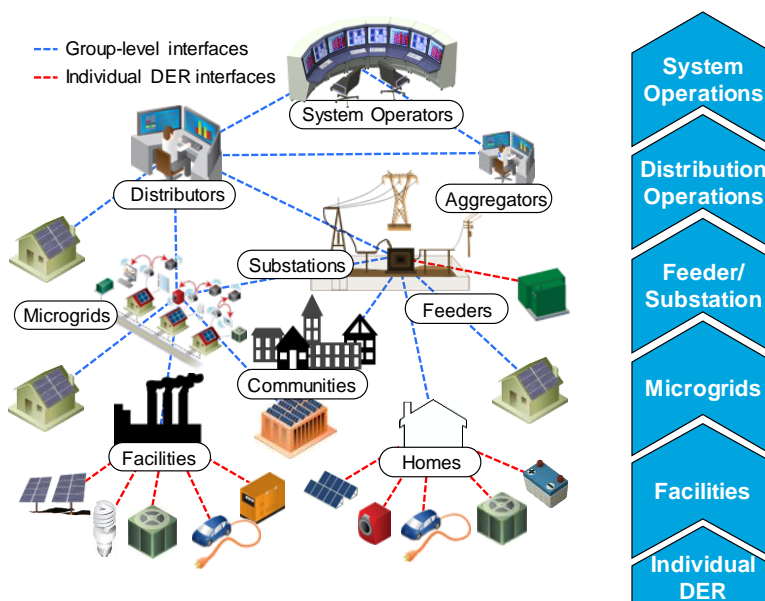
<sup>81</sup> Testing by Sandia National Lab showed that DERs conforming to IEEE 1547 with grid support functions enabled showed roughly a 3x factor for UI run-on-times; however, none exceeded two seconds. Further research by Sandia found potential failures to detect islands when varying islanding detection methods were applied by different DERs as well as when synchronous machines were present.

<sup>82</sup> Independent from grid support functions, run-on-times may exceed two seconds when dissimilarities from the standard test circuits are present in the distribution feeder. Clause 8.1.2 allows the clearing time for UI prevention to be extended from two seconds to as much as five seconds upon mutual agreement between the Area EPS operator and the DER operator. However, many utilities do not consider this a suitable practice.



- The types and size of DERs necessary to be integrated into this standardized communication interface<sup>83</sup>
- The specific owners and operators of each level and type of communication integration system (e.g., the local distribution entity or other third party)
- Clear regulatory policies that ensure consumer protections for utilization of control functions, with different requirement standards for when control is required

**Figure 1.1** illustrates one of many communications interface models that could be utilized and that should be considered by each AGIR as needed.<sup>84</sup> The industry is currently working towards specifying the messages that may be exchanged between BPS operators, DPs, and DER owners.<sup>85</sup>



**Figure 1.1: Example of Possible Architecture for DER Management and Control**  
[Source: EPRI]

### BPS Perspectives and Recommendations

- A standardized local DER communication interface would allow authorized entities (e.g., DPs or others) to perform monitoring and management or control (e.g., changing settings) of DERs that may be a critical need for managing systems with high penetration levels of DERs in the future.
- DERs should be installed with communications capabilities defined in IEEE 1547-2018 as the visibility and control of DER operation may become necessary for BAs and other entities as DER penetration increases.
- AGIRs should consider whether specific policies, protocols, and mediums of communication should be established for DERs. This should consider potential future penetration levels of DERs.

<sup>83</sup> A comprehensive DER integration strategy likely would involve a staged approach.

<sup>84</sup> <https://www.epri.com/#/pages/product/000000003002016712/>

<sup>85</sup> <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008215>

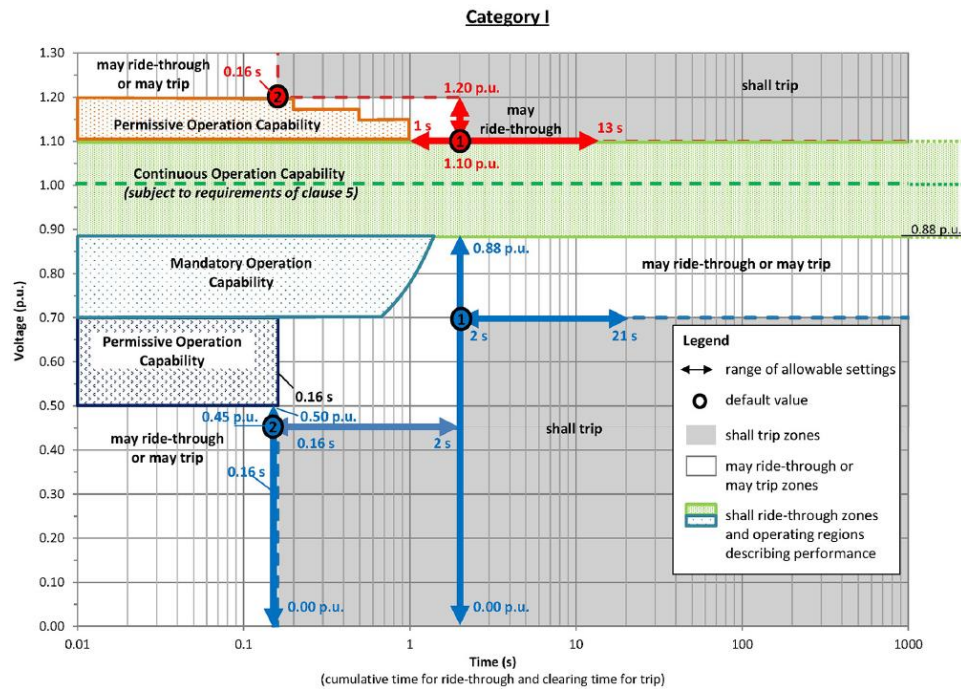
## Appendix A: References

---

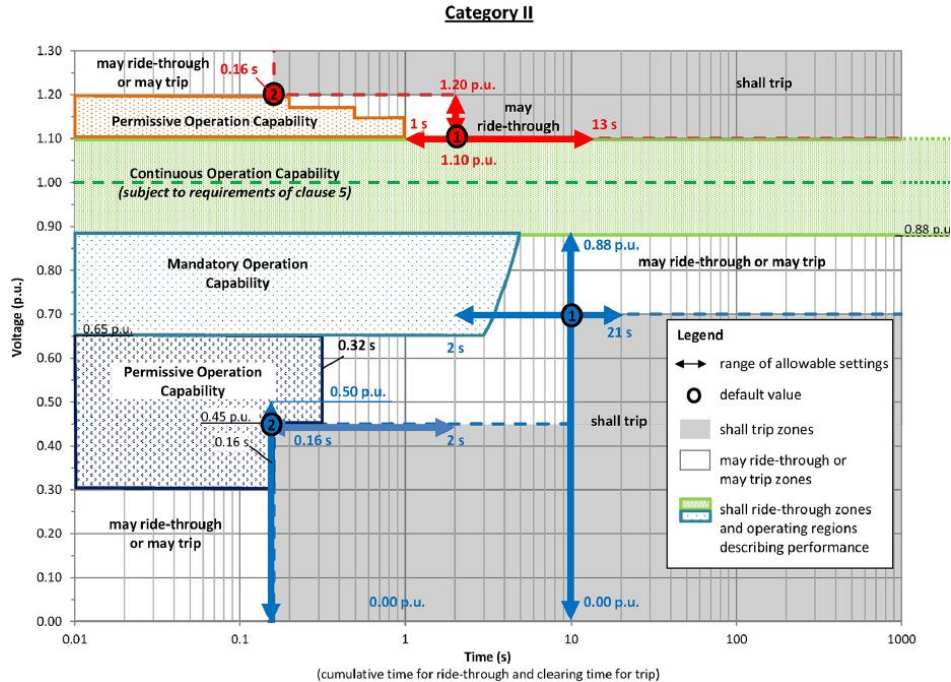
- [1] IEEE, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. IEEE 1547-2018," April 2018: <https://site.ieee.org/sagroups-scc21/standards/1547rev/>.
- [2] SCC21 (2019): IEEE 1547™-2018 (Revision of IEEE 1547-2003). IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. Sponsor Website. IEEE Standards Coordinating Committee 21 (SCC21): <http://sites.ieee.org/sagroups-scc21/standards/1547rev/>.
- [3] NERC, "Performance of Distributed Energy Resources During and After System Disturbance: Voltage and Frequency Ride-Through Requirements," 2013: [http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF17\\_PC\\_FinalDraft\\_December\\_clean.pdf](http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF17_PC_FinalDraft_December_clean.pdf).
- [4] NERC, "Distributed Energy Resources: Connection, Modeling, and Reliability Considerations," 2017: [http://www.nerc.com/comm/Other/essntlrbltysrvctskfrcdL/Distributed\\_Energy\\_Resources\\_Report.pdf](http://www.nerc.com/comm/Other/essntlrbltysrvctskfrcdL/Distributed_Energy_Resources_Report.pdf).
- [5] IREC, "Making the Grid Smarter. Primer on Adopting the New IEEE 1547-2018 Standard for Distributed Energy Resources," 2019: <https://irecusa.org/publications/making-the-grid-smarter-state-primer-on-adopting-the-new-ieee-standard-1547-2018-for-distributed-energy-resources/>.
- [6] NRECA, "Guide to the IEEE 1547-2018 Standard and its Impacts on Cooperatives," March 2019: <https://www.cooperative.com/programs-services/bts/Documents/Reports/NRECA-Guide-to-IEEE-1547-2018-March-2019.pdf>
- [7] C. Sweet, "A new Template for the Integrated Grid. How a Revised National Standard for Distributed Energy Resources Could Change the Power System," EPRI Journal, March/April 2019: [http://eprijournal.com/wp-content/uploads/2019/04/2019.03-F2\\_TemplateIntegratedGrid.pdf](http://eprijournal.com/wp-content/uploads/2019/04/2019.03-F2_TemplateIntegratedGrid.pdf).
- [8] EPRI, "Training Module. Overview on IEEE 1547-2018. 3002014545," October 2018: <https://www.epri.com/#/pages/product/000000003002014545/>.
- [9] EPRI, "Training Module. DER Ride-through Performance Categories and Trip Settings. 3002014546," November 2018: <https://www.epri.com/#/pages/product/000000003002014546/>.
- [10] EPRI, "Training Module. T+D Coordination for DER Ride-Through and Trip Requirements," 3002014547: <https://www.epri.com/#/pages/product/000000003002014547/>.
- [11] EPRI, "Navigating DER Interconnection Standards and Practices: Supplemental Project Notification," 3002012048, 2017: <https://www.epri.com/#/pages/product/000000003002012048/>.
- [12] EPRI, "Recommended Settings for Voltage and Frequency Ride-Through of Distributed Energy Resources. Minimum and Advanced Requirements and Settings for the Performance of Distributed Energy Resources During and After System Disturbances to Support Bulk Power System Reliability and Their Respective Technical Implications on Industry Stakeholders," 3002006203, 2015: <https://www.epri.com/#/pages/product/000000003002006203/>.
- [13] PJM Interconnection, "DER Ride Through Task Force," <https://www.pjm.com/committees-and-groups/task-forces/derrttf.aspx>.
- [14] PJM, "PJM Guideline for Ride Through Performance of Distribution-Connected Generators," 2019: <https://www.pjm.com/-/media/committees-groups/task-forces/derrttf/20190913/20190913-pjm-guideline-for-ride-through-performance-rev1.ashx>.
- [15] MISO, "IEEE 1547 - Distribution Interconnection Coordination," <https://www.misoenergy.org/planning/generator-interconnection/ieee-1547/>.

- [16] MISO, "MISO Guideline for IEEE 1547-2018 Implementation,":  
<https://www.misoenergy.org/planning/generator-interconnection/ieee-1547/>.
- [17] MA TSRG, "Massachusetts Technical Standards Review Group,":  
<https://sites.google.com/site/massdgc/home/interconnection/technical-standards-review-group>.
- [18] EPRI, "Distributed Energy Resources Performance and Settings Database," Pre-Software, 2018:  
<https://dersettings.epri.com>.
- [19] BDEW German Association of Energy and Water Industries (2008): Technical Guideline Generating Plants Connected to the Medium-Voltage Network. Guideline for generating plants' connection to and parallel operation with the medium-voltage network), published June 2008, revised January 2013:  
<https://www.vde.com/de/fnn/dokumente/archiv-technische-richtlinien>.
- [20] VDE Application Guide VDE-AR-N 4110, "Technical requirements for the connection and operation of customer installations to the medium voltage network (TAR medium voltage)":  
<https://www.vde.com/en/fnn/topics/technical-connection-rules/>.
- [21] NERC, "A Technical Reference Paper Fault-Induced Delayed Voltage Recovery: White Paper," 2009:  
[http://www.nerc.com/docs/pc/tis/fidvr\\_tech\\_ref%20v1-2\\_pc\\_approved.pdf](http://www.nerc.com/docs/pc/tis/fidvr_tech_ref%20v1-2_pc_approved.pdf).
- [22] NERC, "Fault-Induced Delayed Voltage Recovery (FIDVR) & Dynamic Load Modeling," U.S. DOE-NERC Workshop, September 2015:  
<http://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/2015%20FIDVR%20Workshop%20Takeaways.pdf>.
- [23] EPRI, "Understanding Smart Inverter Functions' Impact on Islanding Detection. Technical Update. 3002012986," December 2018: <https://www.epri.com/#/pages/product/000000003002012986/>.
- [24] Sandia National Laboratory, "Evaluation of Multi-Inverter Anti-Islanding with Grid Support and Ride-Through and Investigation of Island Detection Alternatives. SAND2019-0499," January 2019:  
<https://www.osti.gov/servlets/purl/1491604>.
- [25] EPRI, "DER Modeling Guidelines for Transmission Planning Studies: 2018 Summary. Technical Update," 3002013503: <https://www.epri.com/#/pages/product/000000003002013503/>.
- [26] A. Levitt, "Implementing Ride Through from Distributed Energy Resources.," PJM DER Ride Through Task Force, PJM Interconnection, 2019: <https://pjm.com/-/media/committees-groups/task-forces/derrttf/20190730-workshop/20190730-item-18-implementing-ride-through-from-distributed-energy-resources.ashx>.
- [27] I. S. 2030.5-2013, "Standard for Smart Energy Profile 2.0 Application Protocol," 2013.
- [28] EPRI, "Current Practices in Scheduling Distributed Energy Resources into System Operations: An Examination of Selected U.S. and International Regions," 3002009483, 2017:  
<https://www.epri.com/#/pages/product/000000003002009483/>.
- [29] EPRI, "Common Functions for DER Group Management: Third Edition," 3002008215, 2016:  
<http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008215>.
- [30] EPRI, "Transmission and Distribution Operations and Planning Coordination. TSO/DSO and Tx/Dx Planning Interaction, Processes, and Data Exchange," 3002016712:  
<https://www.epri.com/#/pages/product/000000003002016712/>.
- [31] Sandia National Laboratory, "Unintentional Islanding Detection Performance with Mixed DER Types. SAND2018-8431," July 2018: <https://energy.sandia.gov/download/43576/>.
- [32] EPRI (2019): Unintentional Islanding Detection. Impact of Grid Support Functions and Motor Loads. 3002015745. Palo Alto, CA: <https://www.epri.com/#/pages/product/000000003002015745/>.

## Appendix B: Ride-Through Requirements in IEEE 1547-2018

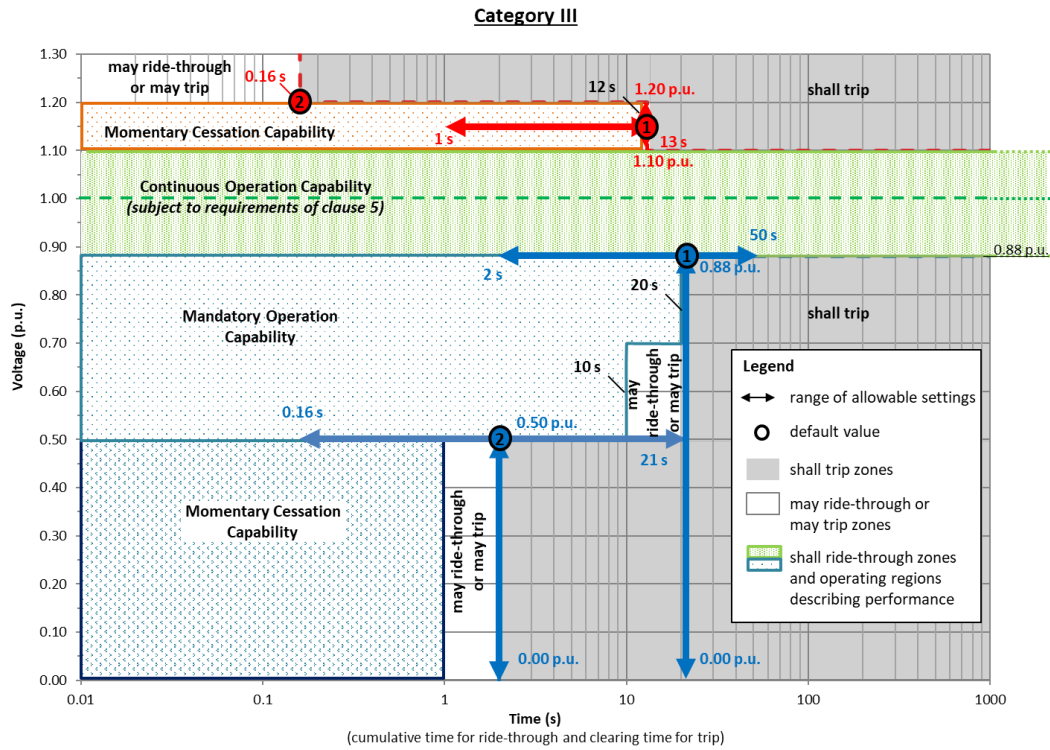


**Figure B.1: Category I Abnormal Voltage Ride-Through Requirement**  
[Source: © 2018 IEEE]

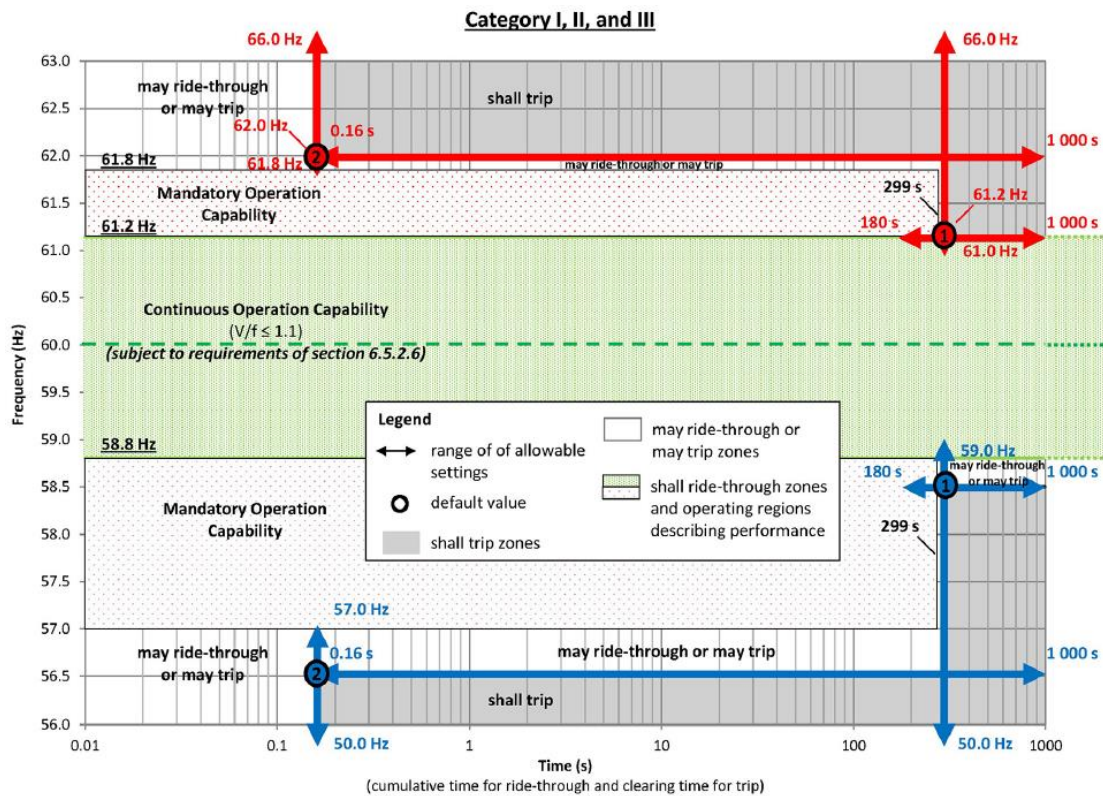


**Figure B.2: Category II Abnormal Voltage Ride-Through Requirement**  
[Source: © 2018 IEEE]





**Figure B.3: Category III Abnormal Voltage Ride-Through Requirement, as amended in 2020**  
**[Source: © 2018 IEEE]**



**Figure B.4: Category I, II, and III Abnormal Frequency Ride-Through Requirement**  
**[Source: © 2018 IEEE]**

## Appendix C: Definitions used in IEEE 1547-2018

---

The following definitions are used in IEEE 1547-2018 and are provided here as a reference.

**Area electric power system (Area EPS):** An EPS that serves local EPSs.

NOTE: Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc., and is subject to regulatory oversight.

**Area electric power system operator (Area EPS operator):** The entity responsible for designing, building, operating, and maintaining the Area EPS.

**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 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.

**Bulk power system (BPS):**<sup>86</sup> 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.

NOTE 1: This may lead to momentary cessation or trip.

NOTE 2: This does not necessarily imply, nor exclude disconnection, isolation, or a trip.

NOTE 3: Limited reactive power exchange may continue as specified, e.g., through filter banks.

NOTE 4: Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.

NOTE 5: Refer to 4.5 for additional details.

**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.

**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.

**Energize:** Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).

---

<sup>86</sup> Note that this definition of bulk power system differs from the definition in the NERC Glossary of Terms. However, it captures the general essence of the NERC definition of BPS. This document uses the NERC definition of BPS throughout.

**Mandatory operation:** Required continuance of active current and reactive current exchange of DER with Area EPS as prescribed, notwithstanding disturbances of the Area EPS voltage or frequency having magnitude and duration severity within defined limits.

**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.

NOTE 1: See Figure 2.

NOTE 2: Equivalent, in most cases, to “service point” as specified in the National Electrical Code® and the National Electrical Safety Code®.

**Point of distributed energy resource 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.

NOTE 1: See Figure 2.

NOTE 2: For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (a) device(s) in conjunction with (a) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

**Restore output:** Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

**Return to service:** Enter service following recovery from a trip.

**Ride-through:** Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

**Trip:** Inhibition of immediate return to service, which may involve disconnection.

NOTE: Trip executes or is subsequent to cessation of energization.



## Contributors

---

NERC acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC would like to acknowledge the technical contributions of EPRI for the leadership in developing this guideline.<sup>87</sup> NERC also would like to acknowledge all the contributions of the NERC SPIDERWG and IEEE P1547.2 Working Group.

Name	Entity
Jens Boemer (IEEE P1547.2 Vice Chair)	Electric Power Research Institute
Jose Cordova	Electric Power Research Institute
Mohab Elnashar	Independent Electricity System Operator
David Forrest	Aspen Tree Partners LLC
Dan Kopin	Utility Services
Bradley Marszalkowski	ISO New England
Barry Mather	National Renewable Energy Laboratory
Bill Quaintance (SPIDERWG Vice Chair)	Duke Progress
Jayanth Ramamurthy	Entergy
Das Ratan (IEEE P1547.2 Sub-Group Co-Lead)	GE Power
Steven Rymsha	SunRun
Kannan Sreenivasachar	ISO New England
Wayne Stec (IEEE P1547.2 Chair)	Distregen LLC
Clayton Stice (SPIDERWG Sub-Group Co-Lead)	Electric Reliability Council of Texas
Reigh Walling	WES Consulting LLC
Taylor Woodruff	Oncor
Jimmy Zhang (SPIDERWG Sub-Group Co-Lead)	Alberta Electric System Operator
Kun Zhu (SPIDERWG Chair)	Midcontinent Independent System Operator
Ryan Quint (SPIDERWG Coordinator)	North American Electric Reliability Corporation
John Skeath (SPIDERWG Coordinator)	North American Electric Reliability Corporation

---

<sup>87</sup> EPRI and its members are working on a project titled *Navigating DER Interconnection Standards and Practices* to develop guidance on adoption of IEEE 1547-2018. For more information, see <https://www.epri.com/#/pages/product/3002012048/>.