Interconnection of Distributed Energy Resources in the Indian Context: IEEE 1547-2018 Adaptation for Locally-Appropriate Grid Code Development

Erik Pohl, Killian McKenna

National Renewable Energy Laboratory

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List of Acronyms

AC	alternating current
ANSI	American National Standards Institute
BIS	Bureau of Indian Standards
BPS	bulk power system
BTM	behind the meter
CEA	Central Electric Authority
CERC	Central Electricity Regulatory Commission
CPF	constant power factor
CPUC	California Public Utilities Commission
DC	direct current
DER	distributed energy resource
DISCOM	distribution company
DG	distributed generation
FERC	Federal Energy Regulatory Commission
FIDVR	fault-induced delayed voltage recovery
FRT	frequency ride through
GW	gigawatt
HECO	Hawaiian Electric Company
HVRT	high-voltage ride through
Hz	hertz
IBR	inverter-based resource
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IS	Indian Standard
kV	kilovolt
kVA	kilovolt-ampere
LV	low voltage
LTC	load tap changer
LVRT	low-voltage ride through
MHz	megahertz
MNRE	Ministry of New and Renewable Energy
MV	medium voltage
MVA	megavolt-ampere
MW	megawatt
MVAr	megavolt-ampere reactive
NEC	National Electric Code
NESC	National Electric Safety Code
NREL	National Renewable Energy Laboratory
NERC	North American Electric Reliability Corporation
OEM	original equipment manufacturer
OF	overfrequency
OLTC	on-load tap changer
PCC	point of common coupling
PF	power factor

PG&E	Pacific Gas and Electric Company
PV	photovoltaic
p.u.	per unit
ROCOF	rate of change of frequency
SERC	State Electricity Regulatory Commission
SGIA	small generator interconnection agreement
SGIP	small generator interconnection procedures
SLDC	state load dispatch center
UF	underfrequency
UL	Underwriters Laboratory
V	volt
VAR	volt ampere reactive
VRT	voltage ride through

Executive Summary

The ambitious renewable energy targets set out by the Indian government have led to a massive increase in wind and solar generation capacity. Of critical importance is how distributed generation—i.e., small-scale wind and solar generation connected to the distribution system—responds to and supports the Indian power grid. The National Renewable Energy Laboratory (NREL) has conducted analysis on state-of-the-art distributed energy resource (DER) interconnection standards and how those might apply in the Indian context. This report focuses on the Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 standard, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" (IEEE 2018).

NREL, throughout this work, has provided support to the Bureau of Indian Standards (BIS), which formally adopted the IEEE 1547-2018 standard in 2023. Although BIS adoption of this standard is a significant step toward implementation, the requirements of this standard have, as of the publishing of this report, not yet been incorporated into India's grid codes. This report outlines technical guidance and analysis on the adoption and adaptation of DERs interconnection standards in the Indian context. This analysis should be useful to the Central Electric Authority (CEA), the Ministry for New and Renewable Energy (MNRE), state load dispatch centers (SLDCs), and Indian distribution companies (DISCOMs) in their consideration of adopting and adapting the standard. This report includes a comparative analysis of existing Indian grid codes and IEEE 1547-2018 DER functionalities and settings. It examines key considerations for the adoption and adaptation of IEEE 1547-2018 for the Indian context. Lastly, it performs distribution modeling analysis of IEEE 1547-2018 default settings on Indian power system models.

By the end of the third quarter of 2023, India had installed close to 10.1 gigawatts (GW) of rooftop solar capacity (Arjun Joshi 2023) and has future targets to achieve 40 GW of rooftop solar (Press Information Bureau Government of India [PIB] 2022). From rooftop solar alone, India could reach levels of more than 20% of online instantaneous electricity generation being supplied by DERs. Adding distributed wind, storage, and other DERs will only increase this level. As such, future DER behavior and responses to system events may significantly impact bulk power system performance, reliability, and stability, highlighting the critical need for well-designed, locally appropriate interconnection standards.

Standards can provide baseline requirements around the performance, operation, testing, safety, and maintenance of DERs. Standardization across jurisdictions can improve the overall interconnection processes by reducing confusion for stakeholders and inefficiencies in manufacturing and testing. The United States (U.S.) has multiple relevant codes and standards that guide DER interconnection, though adoption of these standards by individual utilities can vary widely—key of which is IEEE 1547-2018. The standard has evolved from earlier editions that prescribed a more passive do nothing or do no harm approach from DERs to now *requiring* active grid support to maintain system stability. Trip settings have evolved to include wider mandatory trip thresholds and critical ride-through functionality for frequency and voltage support. In addition, DERs are now required to at least have the *capability* to provide active regulation of both voltage and frequency. Comparisons of functionality in 1547-2018 and CEA and MNRE draft requirements are presented in Table ES-1.

Table ES-1. Comparison of Key Grid Support Functions Present in IEEE 1547-2018, CEA Technical Standard for Distributed Generation, and the MNRE Draft Photovoltaics Inverter Requirement

Grid Support Function	IEEE 1547-2018	CEA Technical Standard for DG	MNRE Draft PV Inverter Requirement
Voltage Mandatory Trip	X	X	X
Frequency Mandatory Trip	X	X	X
Voltage Ride Through[1]	X		X
Frequency Ride Through	X		
Frequency Droop Control	X		X
Steady-State Voltage Regulation	X		
Dynamic Voltage Regulation	X		

IEEE 1547-2018 is a fundamentally U.S.-centric standard, designed around a 60-hertz (Hz) system and typical operating conditions of U.S. power systems. As such, this standard must be adapted for the Indian power system, which operates at 50 Hz, and potentially different operating conditions. In addition, inverter settings and implementation in the Indian context must be informed by India-specific grid operating conditions. Note also that IEEE 1547 is appropriate only for *distribution-connected* resources; larger resources connected to transmission or subtransmission are covered by other standards, for example, IEEE 2800-2022 for photovoltaics (PV), wind, battery energy storage, and other inverter-based resources (IBRs).

In our analysis, we find the following:

- IEEE 1547-2018 has multiple grid support functions not currently present in CEA's *Technical Standards for Connectivity of the Distributed Generation Resources* or in the MNRE Draft *Technical requirements for Photovoltaic Grid Tie Inverters to be connected to the Utility Grid in India*, including voltage ride through, frequency ride through, steady-state voltage regulation, and dynamic voltage support.

- The IEEE 1547-2018 standard's frequency-related grid support functions would need to be adapted for a 50-Hz system and could provide critical benefits to the power system at high adoption levels of DERs. Frequency ride through, at high DER levels, will be critical to the stability of the Indian power system.

- The voltage ride-through and voltage regulation settings will need to be adapted for both the prescribed voltage operating bounds and the *actual* operating conditions of voltages for Indian DISCOMs.

[1] 1547-2018 includes voltage ride-through requirements for both changes in voltage magnitude (clause 6.4) as well as changes in voltage phase angle (clause 6.5.2.6), though only the former is analyzed in this report.

  - Inappropriate adoption of 1547-2018 requirements and settings for voltage trip, ride through, and regulation could result in frequent nuisance tripping[2] of DERs as well as potential system instability.

- Although some of the settings in 1547-2018 are U.S.-centric, Indian entities can readily adopt the requirements for DERs to provide the capabilities in the standard while work continues to develop locally appropriate settings and grid support categories in the Indian context.

- The early adoption of technically sound interconnection standards and careful considerations of current and future power system characteristics are critical steps for utilities, regulators, and other involved stakeholders to take to avoid costly mistakes and retroactive changes to DER installations.

Overall, increased study using real-world Indian power system data is critical to the successful design of Indian-specific grid support functions. Consulting with DER developers and installers, DISCOMs, SLDCs, and other key power system and DER entities will be critical to the successful revision of Indian grid codes for DERs. The industry will need to strive toward a collective understanding of interconnection requirements, identify any knowledge gaps, and ensure the provision of proper support channels from inverter manufacturers or utilities. DER standards should strive to be locally appropriate, and standards agencies should strive to harmonize settings across their jurisdiction to reduce confusion for involved stakeholders and prevent interconnection delays from failed screens.

Implementing DER standards will require the cooperation of all levels of regulatory bodies in India because more central functions in 1547-2018 (i.e., those related to frequency response) may be best analyzed and set by a central agency such as CEA, while more local functions (i.e., those related to voltage response) may be best analyzed and set by state electricity regulatory commissions (SERCs) or individual DISCOMs. Lastly, engaging inverter testing laboratories can help ensure consistency and standardization across the industry—mitigating issues around improperly configured inverters, software retention of key settings,[3] and testing/commissioning procedures and creating pathways for equipment certifications.

[2] Frequent nuisance tripping of DERs can occur on systems with existing poor power quality. Poor power quality may be more frequent on systems without active voltage regulation such as on-load tap changers, regulators, or switched capacitor banks, as is the case on many Indian distribution systems.

[3] The ubiquity of advanced inverters in today's industry—which can include wireless communications and enable remote read-write access of device settings, nameplate information, and performance data—presents a clear cybersecurity risk for future power systems if left unaddressed. Cybersecurity is, however, not addressed in IEEE 1547-2018 or in this report.

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1 Distributed Energy Resources in India, Grid Code Development, and U.S. Codes and Standards

The operation and response of distributed energy resources (DERs) to grid conditions is becoming paramount to the stability and reliability of both the distribution and bulk power systems. Increasingly, DER standards, DER interconnection guidelines and agreements, and grid codes are requesting more functionality of DERs to more actively respond to and support the broader power system. This report examines leading grid codes and standards being adopted in the U.S. and within the Indian context.

The adoption and implementation of DER grid support functions and capabilities depend on the development of new interconnection standards, testing and procedures for standards certification, standards adoption and adaptation by regulators, and inclusion in utility interconnection rules and agreements. Table 1 lists key U.S. and international leading interconnection standards, grid codes, and utility interconnection guidelines related to DERs.

Table 1. Key U.S. and International Standards, Grid Codes, and Interconnection Guidelines Related to Distributed Energy Resources

U.S. Codes and Standards	Application
Institute of Electrical and Electronics Engineers (IEEE) 1547-2018	Interconnection requirements for DER performance, operation, testing, safety, and maintenance. The standard has undergone multiple revisions from 2003 to the present, incorporating additional functional requirements of DERs as interconnection technologies and solutions evolve.
IEEE 1547.1-2020	Accompanying standard to 1547 outlining the type, production, interoperability, commissioning, and periodic tests to ensure that interconnecting DERs are compliant with 1547-2018.
California Rule 21	Tariff rule issued by the California Public Utilities Commission (CPUC) outlining procedures for interconnection, operation, and metering of generation facilities connected to distribution systems of utilities under CPUC jurisdiction.
Hawaiian Electric Company (HECO) Rule 14H	HECO’s tariff rule outlining interconnection requirements for DERs, specifying select changes to prescribed settings in 1547-2018 adapting DER performance to the unique operating conditions of Hawaii’s power systems.
Underwriters Laboratory (UL) 1741	UL standard 1741 is harmonized with 1547 and 1547.1. Inverters certified under this standard (labeled with a UL 1741 stamp) are manufactured, programmed, and tested to comply with 1547.
National Electric Code (NEC)/National Electric Safety Code (NESC)	NEC/NESC to which DERs and electrical systems are designed. UL 1741 requires compliance with NEC National Fire Protection Association 70 for certification.
American National Standards Institute (ANSI) C84.1	ANSI standard C84.1 establishes nominal voltage ratings and operating tolerances for 60-hertz (Hz) electric power systems above 100 volts (V). Most U.S. utilities strive to maintain an operating threshold of ±5% at the point of service (i.e., the customer meter).

U.S. Codes and Standards	Application
EN-50549	European standard including the required capabilities of generators interconnecting with distribution grids, divided into two parts based on the interconnecting voltage levels (medium vs. low voltage).
Federal Energy Regulatory Commission (FERC) small generator interconnection agreement (SGIA) and small generator interconnection procedures (SGIP)	FERC's SGIA and SGIP outlining the contractual agreements and technical screening procedures necessary for interconnecting generators under 20 megawatts (MW).

In India, multiple agencies are involved in the development and implementation of DER interconnection standards. The Bureau of Indian Standards (BIS) is responsible for assessing and adopting international standards and adopted IEEE 1547-2018 in July 2023 (BIS 2023). The Central Electric Authority (CEA) is responsible for establishing technical standards for India's power systems, including requirements for distributed generation connected at or below 33 kilovolts (kV) prescribed in its 2013 standard *Technical Standards for Connectivity of the Distributed Generation Resources* (CEA 2013). Indian Test Laboratories could provide testing and certification to manufacturers (particularly inverter manufacturers) on the capability of equipment to meet new requirements described in the adopted standards. Lastly, Indian distribution companies (DISCOMs) would need to include DER grid support requirements in their interconnection rules and agreements and verify that installed equipment is certified—and programmed correctly—to meet both grid code and interconnection agreement requirements. A broad outline of how IEEE 1547-2018 may be adopted and adapted in India is presented in Figure 1.

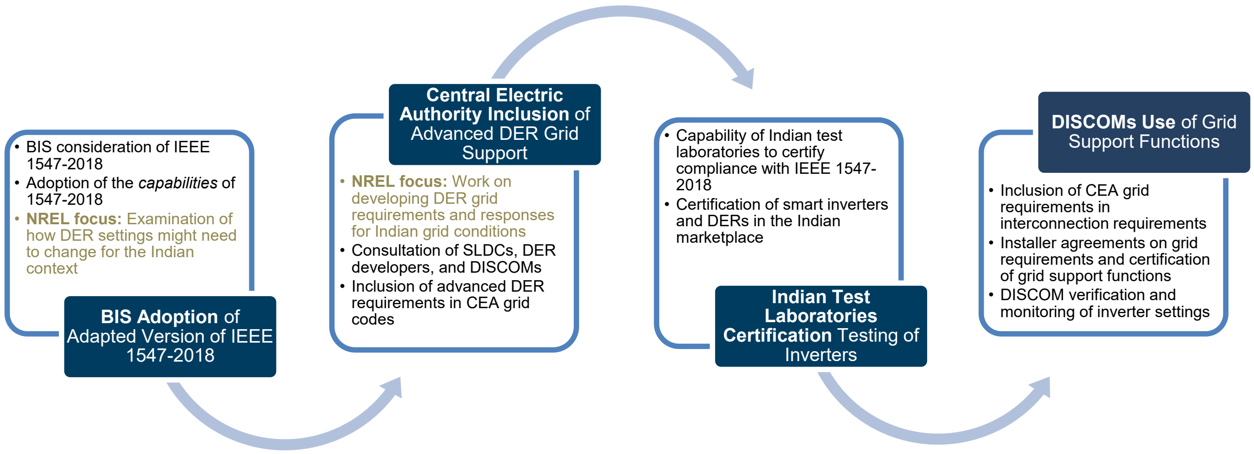

Figure 1. Overview of roles of BIS, CEA, test laboratories, and DISCOMs in the adoption, adaptation, and implementation of IEEE 1547-2018

NREL = National Renewable Energy Laboratory

Key grid codes and standards in India are outlined in Table 2 along with key revisions and amendment years. CEA has technical standards specific to generation connected at voltages both above and below 33 kV. In addition, there are also Indian standards (IS)—set by the Bureau of Indian Standards—including IS 12360, which sets acceptable voltage bounds for Indian power systems and is discussed later in this report. CEA states, "In case the Bureau of Indian Standards has not issued relevant standard, IEC standard or British Standards or standard issued by American National Standards Institute (ANSI) or any other equivalent International Standard shall be followed in that order" (CEA 2013).

Table 2. Key Indian Grid Codes and Standards Pertaining to Distributed Energy Resources

Standard Title	Voltage Class	Applies to Interconnection Class	Revisions/ Amendments
CEA Technical Standards for Connectivity to the Grid, 2007	Interconnections to the grid (at or above 33 kV)	Including load and generation interconnects	2012, 2019, 2023
CEA Technical Standards for Connectivity of the Distributed Generation Resources, 2013	Interconnections of distributed generation at or below 33 kV	Photovoltaics (PV), storage, electric vehicles/prosumers	2019
IS 12360, Voltage Bands for Electrical Installations Including Preferred Voltages and Frequency	Indian distribution and transmission systems	N/A	N/A
MNRE Draft Standard, Technical Requirements for Photovoltaic Grid Tie Inverters To Be Connected to the Utility Grid in India	Interconnections of distributed generation to the low-voltage and medium-voltage utility distribution system	Inverter-based generation	N/A

2 Considerations for Adopting and Applying IEEE 1547-2018 Functions in the Indian Context

This section examines IEEE 1547-2018 in the Indian context, considering the adoption and application of the standard. We examine the functionality in 1547-2018 that is not present in grid codes in India as well as potential country-specific changes needed to the standard.

DERs are interconnecting to distribution systems in India with increasing frequency. As DERs supplant increasing volumes of bulk power system (BPS) generation capacity, the way in which DERs respond to grid conditions becomes increasingly critical to provide sufficient grid support and avoid exacerbating grid contingencies.

Key Considerations for Adopting and Applying IEEE 1547-2018 in the Indian Context

- **IEEE 1547-2018 capabilities:** IEEE 1547-2018 contains new capabilities for DERs not present in existing Indian grid codes—specifically requirements around voltage and frequency ride through, voltage regulation, frequency support, and DER interoperability and communications. These capabilities provide additional grid support and system reliability that will be required at high DER adoption levels.

- **Current CEA and Ministry of New and Renewable Energy (MNRE) standards:** Existing CEA grid codes pertaining to DERs have requirements in terms of mandatory trip settings, and draft MNRE inverter requirements have additional preliminary requirements on ride-through and frequency droop control. The lack of robust voltage and frequency ride-through requirements for DERs presents a major risk to the stability of any power system with high levels of DER. IEEE 1547-2018 has expanded capabilities on frequency ride through and voltage regulation not present in either CEA or MNRE draft requirements. Following is a high-level functionality comparison:

Grid Support Function	IEEE 1547-2018	CEA Technical Standard for Distributed Generation	MNRE Draft PV Inverter Requirement
Voltage Mandatory Trip	X	X	X
Frequency Mandatory Trip	X	X	X
Voltage Ride Through	X		X
Frequency Ride Through	X		
Frequency Droop Control	X		X
Steady-State Voltage Regulation	X		
Dynamic Voltage Support	X		

- **Adopting IEEE 1547-2018 capabilities rather than settings:** DER grid support functions and capabilities outlined in IEEE 1547-2018 will be required for future safe and reliable operation of the Indian power system. Although some of the settings in the standard are, in some ways, U.S.-centric, Indian entities can adopt the requirements for DERs to provide the capabilities in 1547-2018 while work continues to develop locally appropriate settings and categories that are needed for the Indian context.

- **Need for establishing settings in the Indian context:** The IEEE 1547-2018 standard was formulated based on 60-Hz alternating current (AC) power system, U.S. power system grid codes, and typical U.S. operational characteristics. As such, the standard may need to be adjusted for Indian power system grid codes and actual system operating conditions. Tailoring settings to measured frequency operating regions, frequency response protocols, measured voltage operating regions, protection systems, and other locally specific grid conditions would need to be done carefully to meet Indian power system requirements.

- **Steps needed for implementation:** Widespread multistakeholder collaboration will be paramount in implementing advanced DER interconnection guidelines. Standards agencies and grid code authors must engage with DISCOMs, BPS operators, original equipment manufacturers (OEMs), DER owners and installers, and other involved third-party groups to build industry consensus on required DER capabilities and settings to maintain system stability on Indian power grids. This will require detailed modeling efforts, in-field pilot studies, and continuous monitoring of DER growth and operations.

2.1 IEEE 1547: Evolution and Underlying Assumptions

DERs are undergoing rapid changes in the rules and regulations for how they are required to respond to grid conditions. Early interconnection standards provisioned that DERs should trip or cease to energize for any voltage or frequency excursion outside expected continuous operating ranges, as is prescribed in IEEE 1547-2003 (IEEE 2003). This legacy standard and general approach to DER interconnection are still in use today by some U.S. utilities. As DER growth has accelerated, representing a growing source of distributed generation and connected capacity, new standards have emerged that require additional capabilities and support. Innovations in inverter control and capabilities along with concern about the growing aggregated capacity of DERs have led to additional requests for DER grid support capabilities.

The evolution of DER interconnection standards is illustrated in Figure 2. Initial standards provisioned that DERs should not actively participate in grid regulation. These initial standards specified conditions for tripping offline for any disturbance outside of continuous operating ranges (1547-2003). An important consideration is that without any minimum ride-through requirements for voltage and frequency events, DERs may trip *anywhere* “inside-the-lines” (i.e., at any time or any voltage/frequency threshold within those set in the standard). This can lead to unnecessarily tight trip thresholds, frequent nuisance tripping, and no guarantees that DERs remain online for any length of time during a voltage or frequency event. The nascent existence of DER monitoring in the industry adds difficulty in determining the level of operating reserves needed to maintain system stability following a loss of DERs. This legacy approach was generally sufficient for low levels of DERs for which the loss of their aggregate generation would be inconsequential for the BPS. However, when aggregate DER generation reaches a significant portion of overall system generation, the sudden and widespread loss of DERs may exacerbate grid disturbances and lead to system instability. As such, ride-through provisions are an essential component of DER interconnection standards.

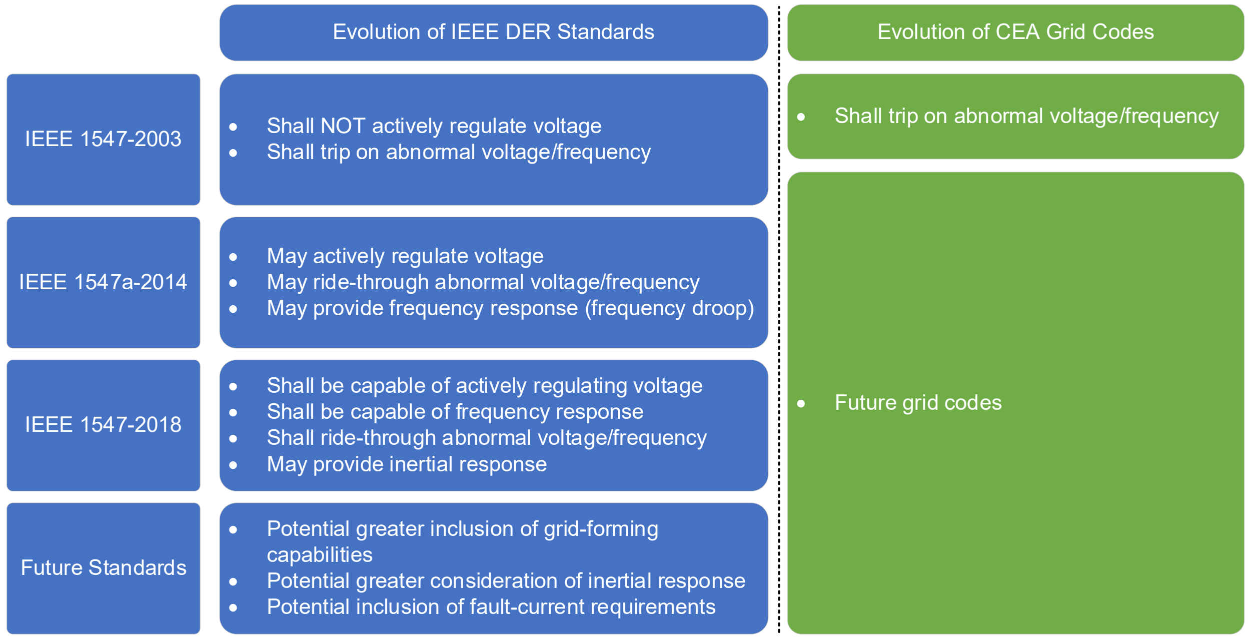

Figure 2. Evolution of IEEE 1547 DER standards and evolution of CEA/MNRE grid codes for DERs

Subsequent revisions to IEEE 1547 started to include provisions for DERs to participate in voltage regulation and event ride through—though not mandating these capabilities—while also widening must-trip thresholds (IEEE 1547a-2014) (IEEE 2014). Today's standards have provisions that DERs *must* be capable of providing active regulation and ride-through functionality (1547-2018) (IEEE 2018). Figure 3 and Figure 4 show how mandatory trip settings for DERs have widened between the first revision of 1547 and the most recent. Wider mandatory trip thresholds allow for the inclusion of ride-through requirements and prevent DERs from tripping on typical contingency events and system faults. These new revisions aim to prevent DERs from compounding transmission contingencies or leading to sympathetic tripping of large amounts of distributed generation. The standard is evolving, and subsequent revisions are expected to include more provisions on inertia-type and grid-forming capabilities.

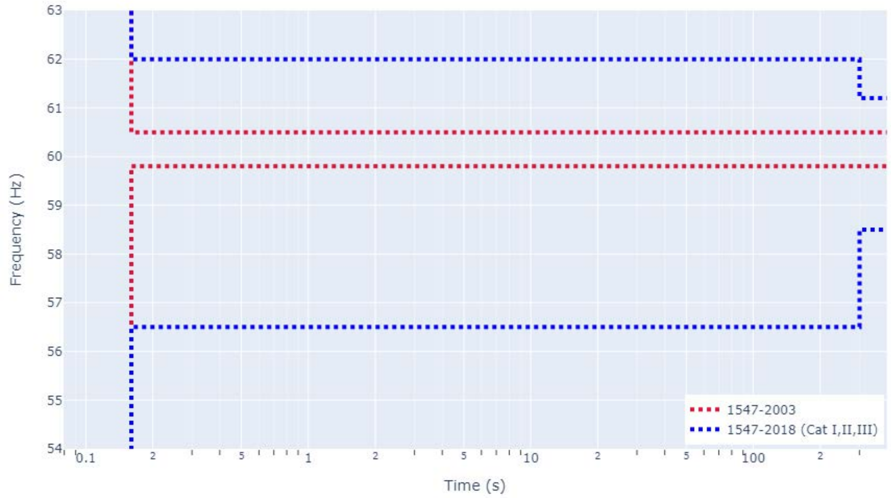

Figure 3. Evolution of frequency trip thresholds in 1547-2003 and 1547-2018[4]

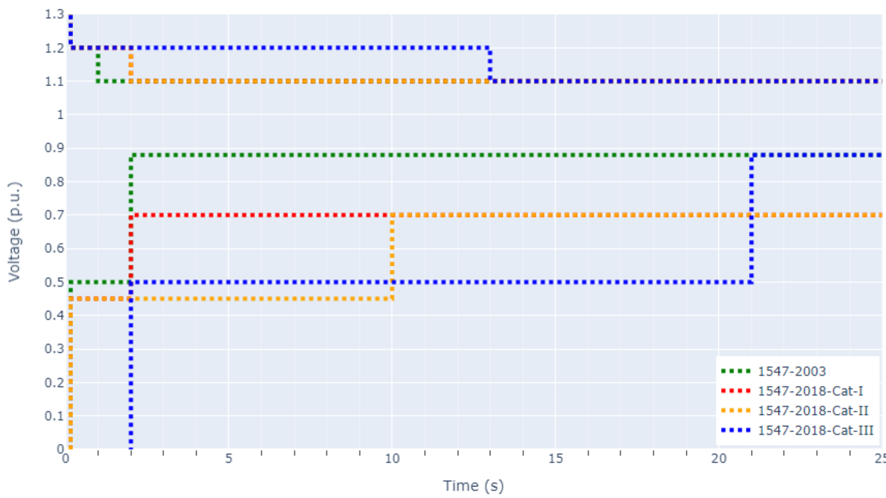

Figure 4. Evolution of voltage trip thresholds (default settings) in 1547-2003 and 1547-2018

IEEE 1547-2018 provides a way for utilities to adopt grid support and advanced functionality from DERs. The standard was developed by a working group of primarily North America–based utilities, inverter manufacturers, national laboratories, nonprofit research institutions, universities, and DER developers. Utilities in the United States are generally grouped into investor-owned utilities (IOUs), municipal utilities, and cooperative utilities. IOUs are regulated by state public utility commissions, which can require enforcement of DER standards. Municipals are owned and/or operated by city and county local government, and cooperatives answer to—and are owned by—their customers. To date, the legacy provisions in IEEE-1547-2003 have been adopted by many states in some form or another, and a growing number of states

[4] The 1547-2003 frequency trip values and associated clearing times represent the most stringent settings allowable by the standard for DERs >30 kW. The 1547-2018 values and associated clearing times represent the default settings in the standard.

are gradually adopting IEEE 1547-2018 at least in part (i.e., some clauses and not others) (Lisa Schwartz and Natalie Mims Frick 2022). The provisions in 1547-2018 can be useful in high-DER scenarios to provide additional grid support, though more work is needed to fully assess the impacts of such support functions on aspects of local power systems—including distribution voltage regulation, event ride through, frequency response, and system protection. A further concern that current standards are attempting to address is a way to verify DER settings to prevent issues related to inconsistent or misconfigured DER settings.

IEEE 1547-2018 contains required DER capabilities, accompanied by suggested default settings and ranges of allowable settings. As mentioned, these settings may be somewhat U.S.-centric, relating to both a 60-Hz system and typical U.S. frequency and voltage operating bounds. The standard includes a note to readers specifying a 60-Hz assumption and describing the need for appropriate adjustments for other frequencies;[5] however, it does not explicitly mention some of the other more nuanced assumptions regarding proposed default settings throughout the standard.

The standard notes the potential for a simple proportional adjustment of the frequency values using the per unit (p.u.) equivalent frequency values on a 50-Hz base. Although this approach may work in many cases, users of the standard should carefully consider the unique operating characteristics of the local system, including frequency operating ranges, characteristics of contingency events, and BPS frequency response. This approach extends beyond frequency thresholds specified in the standard, including voltage operating bounds, system fault characteristics, system protection schemes, size of the transmission system, generation portfolio mix, feeder topology, and levels of current and forecasted DER and IBR adoption. Even within the U.S., distribution systems across states and utilities are widely heterogenous and adaptations to 1547 are made for locally appropriate adoption (HECO 2020; Pacific Gas and Electric Company [PG&E] and CPUC n.d.).

DER interconnection standards should be designed to ensure the safe and reliable operation of distributed generation. Without due considerations of unique characteristics of different power systems, there is a risk of compromising individual DER operation, distribution system reliability, or BPS stability. Individual DERs tripping offline excessively—because of settings that are not locally appropriate—challenge the viability of DERs for developers, owners, and operators. In evolving renewable energy markets, poor performance of initial DER installations may discourage further investments in DERs or more broadly, renewable energy, hindering global decarbonization efforts. If the design of mandatory trip, ride through, and droop responses of DERs are not well studied and/or coordinated with BPS operations, DERs can increase the risk of cascading events and blackouts from frequency and voltage contingencies. Protection surrounding DER operation should be designed so that DERs do not trip offline unless necessary to clear a fault, prevent equipment damage, maintain system stability, or ensure worker/public safety.

[5] "This standard has been written assuming a 60-Hz nominal system frequency. If the standard is used with other nominal frequency values, all frequency values in the standard should be adjusted appropriately. This may require proportional adjustment of the frequency values in coordination with the regional reliability coordinator." (IEEE 1547-2018)

2.2 Distributed Energy Resource Interconnection Standards in India Today

The current landscape of interconnection standards in India is led by the Central Electric Authority (CEA), a national entity that specifies technical and safety standards for Indian power systems at all voltage levels. Of the existing standards that govern interconnections (both distribution and transmission level), CEA has issued a technical standard for interconnecting distributed generators (at voltages below 33 kV; CEA 2013) and a similar standard for interconnection to the BPS (at voltages at or above 33 kV; CEA 2007). Although the latter contains provisions surrounding voltage ride through, dynamic voltage support functionalities, and frequency droop for inverter-based resources (IBRs) connected at the BPS level, these advanced functionalities are not included in their DER-specific standard. It is worth noting that India's Ministry for New and Renewable Energy (MNRE) has published a draft standard, *Technical Requirements for Photovoltaic Grid Tie Inverters to be Connected to the Utility Grid in India* (MNRE 2020) which, although not formally issued, includes some preliminary revisions of CEA's distributed generation (DG) standard to include advanced functionalities. As such, we have included these pending draft revisions in this report to illustrate the ongoing evolution of Indian grid standards. Table 3 shows the applicable voltage classes, generation technologies, and generation sizes comparing IEEE 1547-2018, CEA, and the MNRE standards and regulations. Table 4 compares functionalities present across the three standards.

Table 3. Applicability of Relevant DER Interconnection Standards

DER Characteristics	IEEE 1547-2018	CEA Technical Standard for DG	MNRE Draft PV Inverter Requirement
Applicable Voltage Classes	Primary/secondary distribution voltages	<=33 kV	Low- and medium-voltage distribution systems
Applicable Generator Type	Technology neutral	Technology neutral	PV only
Applicable Generator Size	Any distribution-connected generation[6]	Unspecified	Unspecified

Table 4. Key Grid Support Functions Defined in Relevant DER Interconnection Standards

Grid Support Function	IEEE 1547-2018	CEA Technical Standard for DG	MNRE Draft PV Inverter Requirement
Voltage Mandatory Trip	X	X	X
Frequency Mandatory Trip	X	X	X
Voltage Ride Through	X		X
Frequency Ride Through	X		
Frequency Droop Control	X		X
Active Voltage Regulation	X		
Dynamic Voltage Regulation	X		

In addition to the CEA and MNRE standards described previously, MNRE's order "Quality Control Solar Photovoltaics Systems, Devices and Component Goods Order 2017" also provides a way for the central government to enforce compliance with several key standards related to solar PV and DER interconnection and safety. Table 5 provides the applicable Indian or international standards for each technology (MNRE 2017). In addition, standards from BIS and International Electrotechnical Commission (IEC) such as IEC 62109 (-1, -2, and -3) (inverter safety), IS 16169/IEC 62116 (anti-islanding), and IEC 61683 (measuring efficiency) provide test procedures for inverters and solar PV systems to ensure compliance.

[6] IEEE 1547-2018 is not applicable to individual synchronous generators rated at or above 10 megavolt-amperes (MVA).

Table 5. Applicable Inverter Standards required in MNRE Order "Quality Control Solar Photovoltaics Systems, Devices and Component Goods Order 2017"

Product	Indian Standard Number	Title of Indian Standard
Crystalline silicon terrestrial PV modules (Si wafer based)	IS 14286	Crystalline Silicon Terrestrial Photovoltaic (PV) modules - Design Qualification and Type Approval
Thin-film terrestrial PV modules (a-Si, CiGs, and CdTe)	IS 16077	Thin-Film Terrestrial Photovoltaic (PV) Modules - Design Qualification and Type Approval
PV module (silicon wafer and thin film)	IS/IEC 61730 (Part 1) IS/IEC 61730 (Part 2)	Photovoltaic (PV) Module Safety Qualification Part 1 - Requirements for Construction Photovoltaic (PV) Module Safety Qualification Part 2 - Requirements for Testing
Power converters for use in photovoltaic power system	IS 16221 (Part 1) IS 16221 (Part 2)	Safety of Power Converters for Use in Photovoltaic Power Systems Part 1 - General Requirements Safety of Power Converters for Use in Photovoltaic Power Systems Part 2 - Particular Requirements for Inverters
Utility-interconnected PV inverters	IS 16169	Test Procedure of Islanding Prevention Measures for Utility-Interconnected Photovoltaic Inverters
Storage battery	IS 16270	Secondary Cells and Batteries for Solar Photovoltaic Application

2.3 Character of Service

Key differences exist between Indian and U.S. power systems related to values for nominal frequency and voltage, normal voltage operating bounds, voltage regulation, frequency operating bounds, and grid topologies. These differences should be noted and should inform any adoption and adaptation of any international DER standards. Abnormal operating conditions and the local system response—including typical fault characteristics, fault propagation from the BPS to distribution, system protection, size of the transmission system, and generation portfolio mix—should also be considered. DER response should be coordinated with local system protection schemes, frequency load shedding programs, BPS droop control, and local voltage regulation. In the following subsections, we examine the unique characteristics of Indian power systems and how these differ from those in much of the United States.

2.3.1 Voltage Operating Bounds

U.S. distribution systems generally operate around the standard low-voltage operating voltage (120 V for residential applications) and within the voltage bounds set in the ANSI standard C84.1 (American National Standards Institute, Inc. 2016). ANSI C84.1 Range A voltage thresholds, which are defined at the point of service (typically the customer meter), should remain within a ±5% window, with only limited, short-duration excursions being acceptable. Range B defines slightly wider bounds, for which excursions from Range A into Range B should be limited in extent, frequency, and duration. In contrast, India—and much of the world—

operates on wider voltage bounds, defined in IEC 60038, of ±10%, with a base voltage of 230 V (IEC 2021). Voltage thresholds for both standards are provided in Table 6.

Table 6. Service Voltage Bounds for U.S. and India Voltages in Per Unit Terms

	ANSI C84.1 Range A[7] (American National Standards Institute, Inc. 2016)			IS 12360 (BIS 1988)/IEC 60038 (50 Hz) (IEC 2021)[8]		
Voltage Bound	Under Voltage	Nominal Voltage	Over Voltage	Under Voltage	Nominal Voltage	Over Voltage
Character of Service	114 (0.95 p.u.)	120 (1.00 p.u.)	126 (1.05 p.u.)	207 (0.9 p.u.)	230 (1.00 p.u.)	254 (1.10 p.u.)
	ANSI C84.1 Range B[9]					
	110 (0.917 p.u.)	120 (1.00 p.u.)	127 (1.058 p.u.)			

2.3.2 Voltage Regulation

Distribution system voltage regulation ensures that service voltages stay within specified bounds. Principal voltage control assets are substation on-load tap-changing transformers, which are supported with pole-mounted voltage regulators and capacitor banks distributed along distribution circuits. On-load tap changers (OLTCs) and voltage regulators operate based on setpoints with defined dead bands that govern when to initiate a tap change to boost (raise) or buck (lower) the load-side voltage. Switched capacitor banks use similar settings to determine when to open or close to provide reactive power support.

Overall, there is an underinvestment in active voltage regulation on Indian distribution systems, and where it exists it may take the form of a manual tap changer on a substation transformer that is operated by field personnel a few times a year as demand changes seasonally. Primary distribution transformers (66 kV:33 kV) are generally the last form of active voltage regulation, whereas secondary distribution transformers (33 kV:11 kV) may have only a manual tap changer (Deutsche Gesellschaft fur Internationale Zusammenarbeit [GIZ] 2017). As a result, voltages outside of service voltage bounds may be more frequent for customers. DER voltage thresholds should be designed not only with regulated voltage bounds but also *actual measured* voltage operating ranges for a given distribution system.

2.3.3 Frequency Bounds

In the United States, bulk system generation assets primarily control system frequency, with emerging requirements in interconnection standards for DERs to provide some level of support or regulation. Generator governor controls are typically programmed with a dead band of up to ±36 megahertz (MHz), with a droop control of 4 or 5% (North American Electric Reliability

[7] This refers to Range A - Service voltage as defined by ANSI. Electric supply systems shall be designed and operated so that most service voltages remain within Range A limits, with only infrequent excursions.
[8] BIS IS 12360 notes an alignment of Indian Standard Nominal system voltages with IEC recommendations, migrating to nominal voltages of 230/400 with a tolerance of ±10%.
[9] This refers to Range B - Service voltage as defined by ANSI. Voltages in this range should be limited in extent, frequency, and duration.

Corporation [NERC] 2019). Underfrequency load shedding will typically begin between 59.3 and 59.5 Hz (NERC 2017). Under normal conditions, the system frequency varies between 59.95 Hz (0.999 p.u.) and 60.05 Hz (1.001 p.u.) (Boemer, Brooks, and Key 2015). In contrast, under normal operating conditions, the India Electric Grid Code states, "All the constituents of the Power System shall make all possible efforts to ensure that the grid frequency remains within the bandwidth of 49.5–50.2 Hz" (0.99–1.004 p.u.) (CEA 2010), representing a wider p.u. operating range. CEA dictates that all generators greater than 10 MW connected at 33 kV and above shall have frequency control with a droop of 3–6% and a dead band not exceeding ±30 MHz (CEA 2019).

Defining frequency bounds for DERs for trip or ride through becomes increasingly critical as DER adoption levels increase to a nontrivial amount compared to system load and bulk generation. Should a frequency event trip off large amounts of DER at once, the masked load and sudden loss of generation could damage equipment, impact system protection, affect load performance, or lead to a BPS frequency collapse.

Rapid PV adoption in Germany provides valuable lessons learned regarding frequency trip settings and planning for future PV adoption levels. In 2007, Germany had over 3 gigawatts (GW) of distributed PV interconnected, which exceeded the primary reserve amount on the European interconnected system, and installed DERs were set with a tight overfrequency bound of 50.2 Hz (1.002). Should the system frequency have exceeded this value on a high solar production day, there would be a massive loss of generation—causing a European-wide contingency (GIZ 2017). During a 2006 event, portions of Europe experienced frequencies that *did* exceed this threshold, bringing to light the system risk of having such tight must-trip thresholds for DERs (Mass et al. 2016). The retrofit of DERs to a wider threshold was a lengthy and costly process and involved going back to the entire population of solar inverters to change the overfrequency trip setting or in some cases install new inverters (GIZ 2017). Germany's current DER interconnection standard from Bundesverband der Energie- und Wasserwirtschaft (BDEW) has increased the must-trip setting to 51.5 Hz (1.03 p.u.) with an added frequency droop control for frequency above 50.2 Hz and below 51.5 Hz, requiring DERs to reduce their power output by 40% per Hz in this range (BDEW 2008). Prior revisions of 1547 had a similar flaw, initially requiring a must-trip threshold outside of 60.5 Hz (1.008 p.u.) and 59.3 Hz in 0.16 seconds (IEEE 2003). Within the Western Interconnection in the United States, it was shown that contingency events could cause system frequency to occasionally exceed these thresholds. These requirements were made at a time when DERs were not forecasted to play a substantial role in U.S. energy systems and therefore have a negligible effect on BPS stability. These initial settings were motivated largely by safety and coordination of protection and controls on distribution systems, with little consideration of the BPS implications (Patel et al. 2013).

The size of the transmission system, generation portfolio size and makeup, and existing primary frequency response programs all can affect nominal and abnormal frequency conditions. In the United States, the state of Hawaii is a prime example of a low-inertia, high-inverter-based system, with a peak of between 70% and 90% (depending on the island) of total generation coming from renewables in 2022 (HECO 2023). Because of wider normal and abnormal frequency operating ranges, Rule 14H—applicable on the islands—includes significantly wider trip and ride-through thresholds than 1547 does and allows for more aggressive droop control from IBRs. These comparisons with 1547 are illustrated in Figure 5 and listed in Table 7 and Table 8 (HECO 2020).

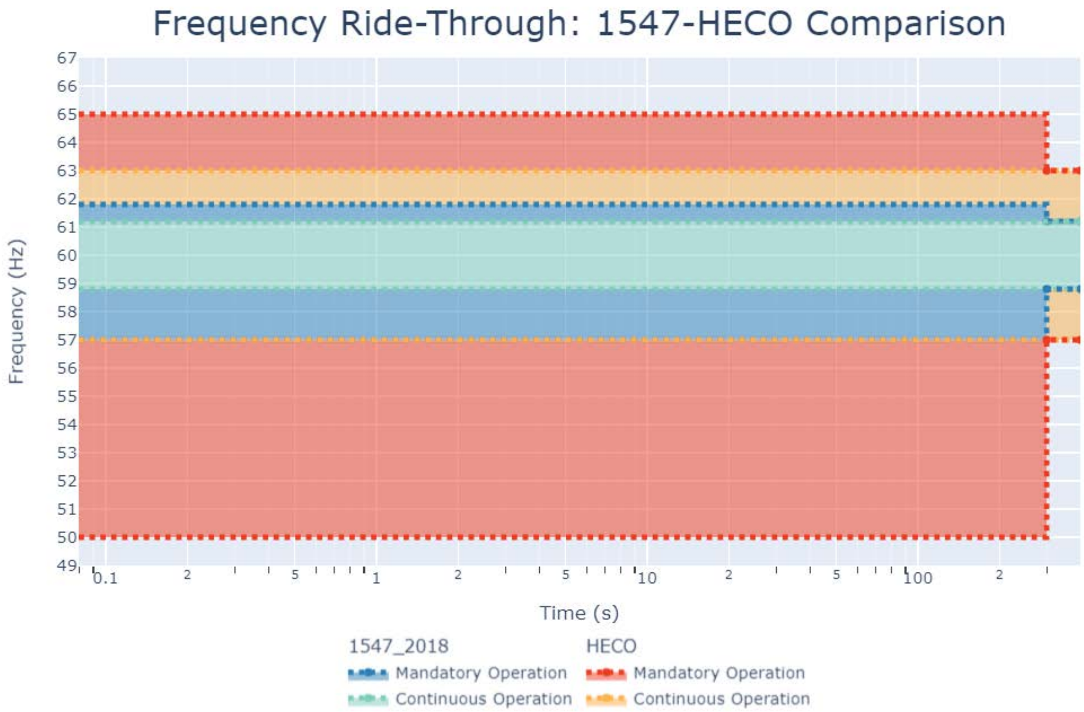

Figure 5. Comparison of frequency ride-through settings in HECO's Rule 14H and 1547-2018

Table 7. Frequency Ride-Through Requirements for DER of Abnormal Operating Performance Category III Compared with Hawaiian Electric Company (HECO 2020)

Frequency Range		**Operating Mode**	**Minimum Time (s)**
1547-2018	HECO (SRD V2.0)		
f > 62.0	f > 65.0	No ride-through requirements apply to this range	
61.2 < f ≤ 61.8	63.0 < f ≤ 65.0	Mandatory	299
58.8 ≤ f ≤ 61.2	57.0 ≤ f ≤ 63.0	Continuous operation	Infinite
57.0 ≤ f < 58.8	50.0 ≤ f < 57.0	Mandatory operation	299
f < 57.0	f < 50.0	No ride-through requirements apply to this range	

Table 8. Parameters of Frequency-Droop (Frequency-Power) Operation for DER of Abnormal Operating Performance Category III Compared with Hawaiian Electric Company (HECO 2020)

Parameter	Range of Allowable Settings	
	1547-2018	HECO (SRD V2.0)
db_{OF}, db_{UF} (Hz)	0.017[10]–1.0	
k_{OF}, k_{UF}	0.02–0.05	0.02–0.07
$T_{Response}$ (s)	0.2–10	

Where db_{of} *is the single-sided overfrequency deadband,* db_{uf} *is the single-sided underfrequency deadband,* k_{of} *is the overfrequency droop,* k_{uf} *is the underfrequency droop, and* $T_{response}$ *is the open-loop response time.*

2.3.4 *Grid Topologies*

Nuances of local grid topologies and design characteristics should be considered when implementing DER interconnection standards. Indian distribution systems are separated into primary distribution and secondary distribution. Primary distribution operates at 33–66 kV, referred to as extra-high-tension, and serves distribution transformers and large industrial loads. Secondary distribution operates at 11 kV, referred to as high-tension, served from distribution transformers up to 20 MVA. High-tension feeders are generally radial, up to 20 kilometers in length (rural areas) and designed for one-directional power flow. The low-tension network operates at 230/400 V and can stretch a few hundred meters, and distribution transformers can range from 100 kilovolt-amperes (kVA) (largest rural) to 1,250 kVA (largest urban) (GIZ 2017). There exists a wide variety of grid topologies across the United States, varying in voltage class, line kilometers, overhead vs. underground construction, radial vs. looped vs. networked, system impedances, customer types, load characteristics, and more. Figure 6 shows some of the key differences in low-voltage network topologies between the United States and India. Although the United States predominantly uses split-phase transformers trapped off a single medium-voltage phase for residential services, other countries may instead use a three-phase transformer and low-voltage network with single-phase services tapped off a shared secondary main.

[10] In 1547-2018, a deadband of less than 0.017 Hz shall be permitted.

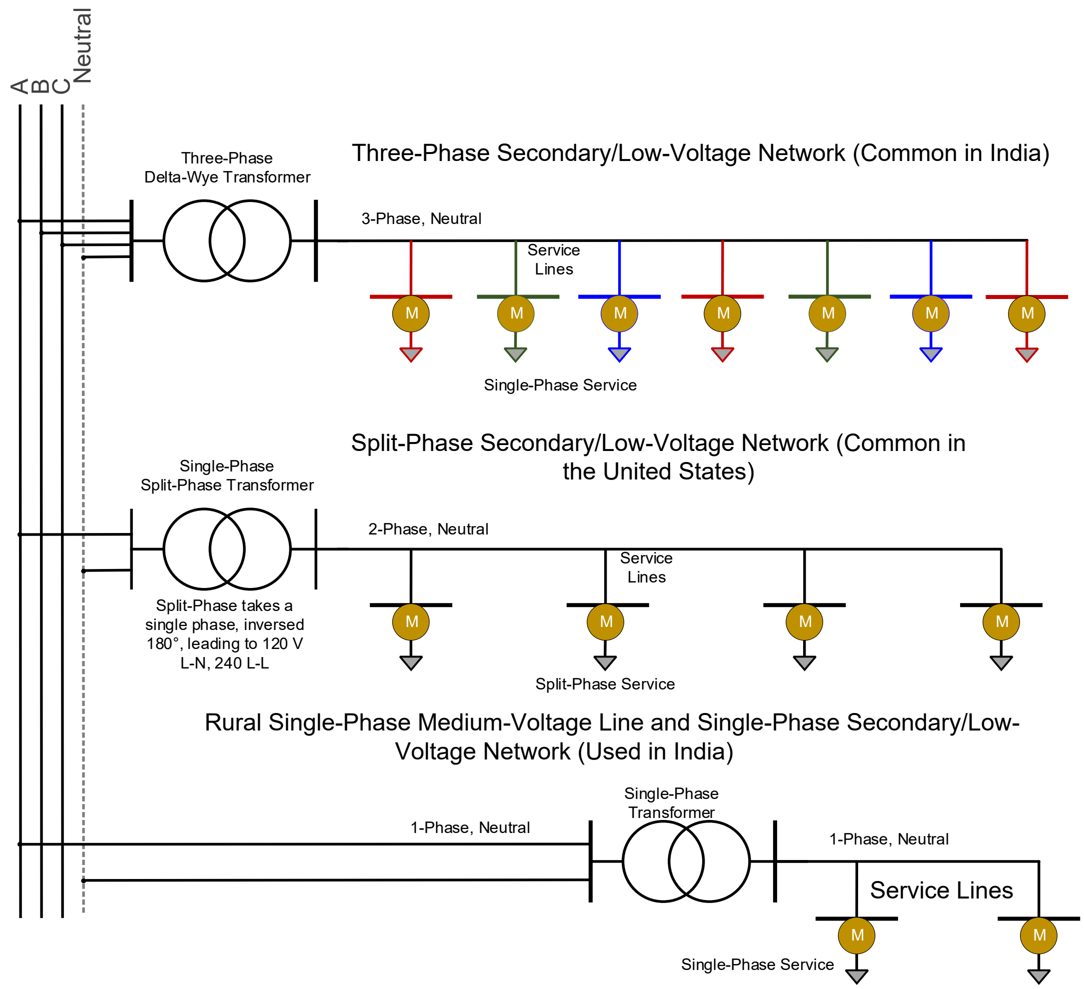

Figure 6. Different grid architectures for low-voltage/secondary circuits

U.S. systems use split-phase transformers tapping off a single phase, whereas Indian systems use three-phase low-voltage networks

2.4 Considerations for Frequency Ride Through and Frequency Support

Frequency ride through and trip settings are designed predominantly with BPS operating characteristics in mind to prevent underfrequency load shedding or a systemwide frequency collapse from the inadvertent loss of a large amount of DERs following a contingency event. The sudden loss of a large, centralized generation asset will often result in an underfrequency event, whereas the sudden loss of a large load or load area may result in an overfrequency event. During an underfrequency event, the widescale tripping of DERs may further lower the nadir, hindering the BPS's primary frequency response attempting to arrest the frequency drop and recovery. Cascading failures of generation or triggering of load shedding may result.

The lessons learned from German- and U.S.-based widespread IBR adoption provide insight on the consequences of improper frequency ride-through settings or lack of field verification. Utilities and DISCOMs in areas with emerging DER markets may benefit from an early, proactive anticipation of large-scale DER adoption when designing interconnection standards. Retroactively changing inverters or their settings can be a costly and lengthy process.

BPS stability with high amounts of IBRs generally favors wider trip thresholds and more robust ride-through capabilities. Analysis of local system historical frequency data and event recordings, although not a comprehensive study, make up critical components of designing appropriate frequency trip and ride-through thresholds. The typical depth, duration, and rate of change of frequency (ROCOF) of recorded events should inform standards. Instantaneous trip settings close to normal operating conditions should be avoided. There should also be minimum ride-through requirements so that DERs do not trip offline because of internal (i.e., behind-the-meter [BTM]) protection operations (Boemer, Brooks, and Key 2015). Table 9 lists the frequency trip and ride-through (or lack thereof) provisions across the three standards, which are also illustrated in Figure 7.

Table 9. Frequency Ride-Through Requirements for IEEE 1547-2018 and CEA and MNRE Regulations

	IEEE 1547-2018 Category I/II/III		CEA Technical Standard for DG		MNRE Draft PV Inverter Requirement	
Ride-Through Component	**Under Frequency**	**Over Frequency**	**Under Frequency**	**Over Frequency**	**Under Frequency**	**Over Frequency**
Continuous Operation	58.8 Hz (0.98 p.u.)	61.2 Hz (1.033 p.u.)	f>47.5 Hz (0.95 p.u.)	f<50.5 Hz (1.01 p.u.)	f>47.5 Hz (0.95 p.u.)	f<52 Hz (1.04 p.u.)
Mandatory Operation	57.0-58.8 Hz (0.95-0.98 p.u.) for 299 s	61.2-61.8 Hz (1.02-1.03 p.u.) for 299 s	N/A	N/A	N/A	N/A
Permissive Operation	N/A	N/A	N/A	N/A	N/A	N/A
Shall Trip	UF1: 58.5 Hz (0.975 p.u.) in 300 s UF2: 56.5 Hz (0.942 p.u.) in 0.16 s	OF1: 61.2 Hz (1.02 p.u.) in 300 s OF2: 62.0 Hz (1.033 p.u.) in 0.16 s	f<47.5 Hz (0.95 p.u.) in 0.2 s	f>50.5 Hz (1.01 p.u.) in 0.2 s	f<47.5 Hz (0.95 p.u.) in 0.2 s	f>52 Hz (1.04 p.u.) in 0.2 s

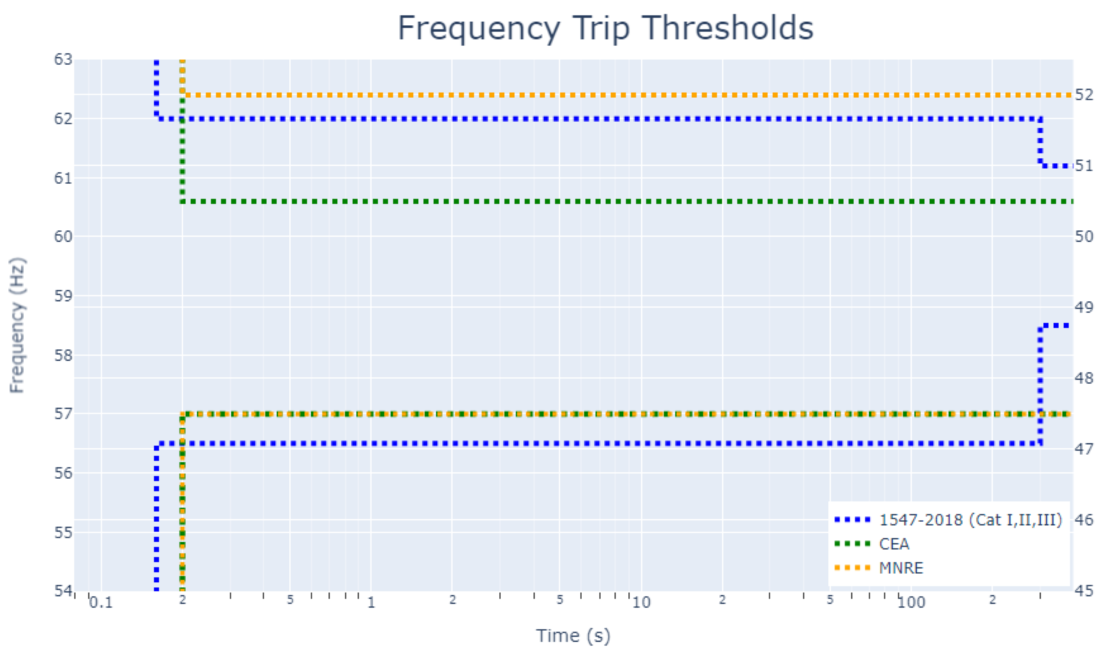

Figure 7. Frequency trip thresholds for IEEE 1547-2018, CEA, and MNRE regulations

When designing frequency trip and ride-through settings, adequate time should be given following a contingency event for large-scale generation to provide primary frequency response or for underfrequency load shedding programs to activate before tripping any DERs. With fewer traditional generating resources providing system inertia (i.e., replacing synchronous machines with IBRs), the ROCOF in the event of system contingencies might increase. Similarly, higher ROCOF may be seen if a section of the BPS is isolated and there is less inertia present to slow the frequency decline. As such, minimum ROCOF ride through and trip should also be requirements so that DERs do not trip offline for high ROCOF scenarios (Boemer, Brooks, and Key 2015). CEA and MNRE standards do not include any ROCOF ride-through provisions. The prescribed values in 1547 are listed in Table 10.

Table 10. ROCOF Ride-Through Requirements for DERs for IEEE 1547-2018

Category I[11]	Category II	Category III
0.5 Hz/s	2.0 Hz/s	3.0 Hz/s

Following a contingency event, frequency restoration time can also vary depending on the size and generation mix of the grid. Larger power systems, such as the three large U.S. interconnections, can range into 100–300 s for full restoration (Boemer, Brooks, and Key 2015). Long restoration times create the need for longer trip and ride-through time for DERs, as seen in 1547 and listed in 9, ensuring that the BPS has the chance to recover *before* DERs trip and

[11] See Annex B in 1547 for information on when and for what type of DERs to use Category I.

potentially exacerbate the problem. The UF2 and OF2 thresholds of 1547 are designed to trip DERs instantaneously to prevent equipment damage for extreme excursions.

CEA's DG standard currently sets overfrequency trip thresholds at 50.5 Hz (1.01 p.u.), a tighter threshold than 1547 despite frequency operating bands similar to those in the United States, potentially creating similar issues previously seen in Germany. This comparison is illustrated in Figure 7. In addition, CEA sets trip times to 0.2 s, not requiring any ride-through capabilities. In MNRE's draft standard, this setting is raised to 52 Hz, a wider trip value, possibly preventing inadvertent trips from DERs—though the trip time remains instantaneous at 0.2 s. CEA's underfrequency threshold more closely aligns with 1547's UF2 threshold (0.95 p.u. vs. 0.942 p.u.). Neither CEA nor MNRE's draft standard includes any ride-through requirements given the relatively narrow, instantaneous trip values.

Following a contingency event on the BPS, DERs may provide dynamic frequency response in the form of power frequency droop control to arrest a frequency sag by increasing real power output during an underfrequency event or reducing real power output in response to an overfrequency event (i.e., frequency-watt). The former support function may have cost implications for the DER owner/operator because of the necessary curtailment below the inverter's maximum output, providing a reserve margin. If a distributed generator is paired with an energy storage system, curtailment of the distributed generator would not be necessary because the discharging storage could provide the necessary frequency response for an underfrequency event, or, for an overfrequency event, the storage could charge from the shed generator output, reducing any curtailment. Extreme care must be taken when assigning appropriate settings for dynamic frequency support from DERs because inappropriate droop parameters could result in oscillatory behavior on the bulk system, unnecessary curtailment of a generator, or damage to synchronous turbine generators (IEEE 2022). CEA does not include any type of frequency support, whereas MNRE has provisions for support in overfrequency events—but not for underfrequency. These requirements are listed alongside the 1547-2018 default values in Table 11.

Table 11. Frequency Droop Requirements for IEEE 1547-2018 and CEA and MNRE Regulations

	IEEE 1547-2018 Category I/II/III	CEA Technical Standard for DG	MNRE Draft PV Inverter Requirement
Underfrequency dynamic support	$p = \min\limits_{f<60-db_{UF}} \left\{ p_{pre} + \frac{(60 - db_{UF}) - f}{60 * k_{UF}} ; p_{avl} \right\}$	N/A	N/A
Overfrequency dynamic support	$p = \max\limits_{f>60+db_{OF}} \{ p_{pre} + \frac{f - (60 + db_{OF})}{60 * k_{OF}} ; p_{min} \}$	N/A	>50.6 Hz (default) reduced by at least 40% per Hz[12]

[12] Applies to DER with >25 kVA installed capacity.

Key Takeaways

- The widespread loss of DERs, because of tripping during a BPS fault or contingency event, could exacerbate a frequency contingency and cause cascading failures, underfrequency load shedding, and widespread blackouts.
- Appropriately wide frequency trip and ride-through settings should be applied to DERs to mitigate system risks. Settings should be based on local system frequency data and event recordings (among other system studies) characterizing normal operating conditions and the typical depth (nadir), duration, and ROCOF of large contingency events. This analysis should be accompanied by considerations and modeling of potential future system conditions because the increased adoption of inverter-based resources may lead to higher-ROCOF, lower-nadir events in the future.
- Trip and ride-through settings should be coordinated with BPS resource frequency response and underfrequency load shedding programs, allowing for system recovery *before* tripping DERs.
- Proactive consideration of BPS impacts from aggregated DER capacity can prevent costly retroactive inverter changes.

2.5 Voltage Ride Through

Fault type, voltage sag propagation from BPS to distribution systems, system protection schemes, and fault proximity to the DER all contribute to the voltage ultimately seen at the DER's point of common coupling (PCC) during an event and should inform voltage ride through (VRT) and trip settings. Voltage sags are often the result of a fault on the BPS or distribution system, whereas voltage swells may result from the sudden loss of load, capacitor bank operations, or a regulator malfunction (i.e., tap changer hunting) because of faulty equipment or improper settings.

The propagation of a voltage sag across the BPS and distribution system depends on various characteristics of the subtransmission and distribution system, including fault type, load composition, DER adoption levels and controls, and system impedances. The duration of a voltage sag is typically a function of system protection clearing times. Low VRT settings should consider the maximum clearing times for BPS protection and distribution protection (including backup protection clearing times), allowing the system to clear a fault, *before* tripping DERs. DERs should be capable of multiple consecutive ride-through operations to account for reclosing intervals on the BPS and distribution (Boemer, Brooks, and Key 2015).

The presence of inductive motor loads, such as air conditioners, on a distribution system can produce prolonged undervoltages following a fault, known as fault-induced delayed voltage recovery (FIDVR), which can last anywhere from 5 to 30 s and therefore must be considered for low-voltage ride through (LVRT) and trip settings. The use of passive (cease-to-energize) LVRT during a long FIDVR event affecting a wide area could lead to BPS stability issues at the loss of

DER active power injection. Active ride through (DER continuing to inject active power) may reduce the extent of a FIDVR but has implications for system protection schemes (e.g., relay desensitization, sympathetic tripping, device miscoordination etc.) because of short-circuit contributions of DERs (Boemer, Brooks, and Key 2015; McDermott et al. 2019). Conducting system studies that allow for a rough distinction between typical BPS fault characteristics and typical distribution-level faults can help inform the type of ride-through behaviors needed for different voltage levels during an event.

One must also consider post-fault conditions following a VRT event. If a significant amount of system load was lost and is not yet back online, or switched capacitor banks or line regulators have adjusted during a FIDVR, the system may experience temporary overvoltages in the post-fault period until it readjusts. High-voltage ride through (HVRT) should be required for DERs to avoid causing cascading DER loss following a ride-through event. For exceedingly high voltages, however, DERs should be limited in their contributions to temporary and transient overvoltages,[13] and clearing times must be kept short to prevent equipment damage (Boemer, Brooks, and Key 2015).

CEA's DER standard does not currently support any voltage ride-through functionality, though there are some provisions in its equivalent BPS-level interconnection standard and MNRE's draft standard shown in Table 12 and Figure 8.

Table 12. Voltage Ride-Through Requirements for IEEE 1547-2018 and CEA and MNRE Regulations

	IEEE 1547-2018 Category III[14]		CEA Technical Standard for DG		MNRE Draft PV Inverter Requirement	
IEEE Definition	Under Voltage	Over Voltage	Under Voltage	Over Voltage	Under Voltage	Over Voltage
Continuous Operation	0.88	1.10	V>=0.8	V<=1.1	0.85	1.1
Mandatory Operation	0.7–0.88 for 20 s 0.5–0.7 for 10 s	N/A	N/A	N/A	<0.5 for 1.7 s 0.5–0.85 for 3 s	1.1–1.2 for 2 s 1.2–1.3 for 0.2 s
Momentary Cessation	<0.5 for 1 s	1.10–1.20 for 12 s	N/A	N/A	N/A	N/A
Shall Trip or Cease to Energize	0.5–0.88 in 21 s <0.5 in 2 s	1.1–1.2 in 13 s >1.2 in 0.16 s	V<0.8 in 2.0 s	V>1.1 in 2.0 s	0.5–0.85 in 3.1 s <0.5 in 1.8 s	1.1–1.2 in 2.1 s 1.2–1.3 in 0.3 s >1.3 in 0.05 s

[13] See 1547-2018 clause 7.4 for requirements limiting contributions to temporary and transient overvoltages.
[14] 1547a-2020 includes a minor amendment to the allowable range of clearing times for Category III DER responses to abnormal voltages to allow greater flexibility in implementing 1547-2018 (IEEE 2020b).

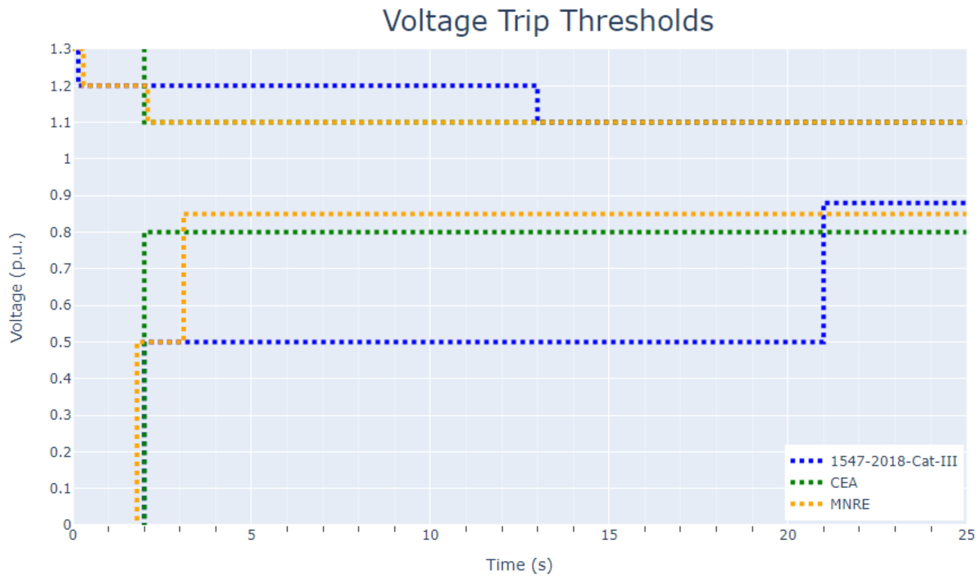

Figure 8. Voltage trip thresholds for IEEE 1547-2018, CEA, and MNRE regulations

Key Takeaways:

- Voltage ride-through functionalities can provide important support for the BPS during contingency events and faults, though they may create challenges for distribution system protection schemes. When systemwide levels of DERs become high (or may become high during the lifetime of DERs), it is necessary to prioritize voltage ride through to preserve bulk system stability.
- Ride-through times should consider maximum clearing times for BPS protection and distribution protection so that DERs do not trip offline before the fault is cleared.
- FIDVR can create extended undervoltage events, requiring longer undervoltage ride-through times. The presence of inductive motor loads—specifically single-phase heating, ventilating, and air conditioning systems—can increase the likelihood of a FIDVR.
- Distinguishing typical fault characteristics for the BPS and distribution system can inform different ride-through behaviors for BPS vs. distribution-level faults.
- HVRT settings should be designed so that post-fault overvoltages do not trip DERs.

2.6 Voltage Support Functions

Inverters complying with 1547-2018 have functionalities to provide active regulation of quasi-steady-state voltage within the normal operating region, autonomously, at the DER point of common coupling. These advanced functionalities can be seen as a way to reduce or mitigate the adverse effects of distributed generation on a distribution circuit or as a way to provide additional voltage control benefits. The distinction largely depends on the existing conditions of the feeder before adding DERs, though studies have shown that inverter voltage support functions can improve the voltage constraints of a feeder's hosting capacity (Ding, Mather, and Gotseff 2016). As with many functions in 1547, local grid operating conditions should inform the voltage regulating strategy and inverter setpoints used.

Listed in Table 13 and Table 14, 1547-2018 includes specific requirements for DER volt ampere reactive (VAR) contribution capabilities and specific DER operating modes so that DERs can participate in voltage regulation on the distribution system. MNRE includes VAR contribution requirements, with higher contribution requirements from DERs than in 1547 (60% of nameplate absorption and injection vs. 44% in 1547). Because the standard does not include any functionalities for active voltage regulation, CEA does not specify VAR requirements for DERs, and neither MNRE nor CEA specifies any required operating modes other than fixed power factor.

Table 13. DER Reactive Power Injection/Absorption Requirements for IEEE 1547-2018, CEA, and MNRE Regulations

	IEEE 1547-2018 Category B		CEA Technical Standard for DG		MNRE Draft PV Inverter Requirement	
	Injection	Absorption	Injection	Absorption	Injection	Absorption
Inverter reactive power injection/absorption capabilities	44%	44%	N/A	N/A	60%	60%

Table 14. Voltage Regulation Requirements for IEEE 1547-2018, CEA, and MNRE Regulations

	IEEE 1547-2018 Category B (Capability)	CEA Technical Standard for DG	MNRE Draft PV Inverter Requirement
Fixed power factor	Mandatory	Mandatory	Mandatory
Voltage-reactive power	Mandatory	N/A	N/A
Active power-reactive power	Mandatory	N/A	N/A
Constant reactive power	Mandatory	N/A	N/A
Voltage-active power mode	Mandatory	N/A	N/A

Constant Power Factor

Constant power factor (CPF) mode operates at a fixed power factor (i.e., a fixed ratio between reactive power and apparent power), typically set to unity or slightly inductive (i.e., leading PF) to counteract the voltage rise caused by active power injection. An important benefit of this strategy is its inherent simplicity, allowing ease of verification and simplicity for commissioning and for DER developers. A drawback of CPF is that the voltage control is independent of grid conditions (i.e., if system voltages are already low, a leading power factor will be disadvantageous). CPF with a unity power factor is the default operating mode in 1547, CEA, and MNRE standards.

Volt-VAR

Volt-VAR control functions inject or absorb reactive power as a function of voltage measured at the inverter terminals following a user-configured volt-VAR droop function with dead bands and saturation points. The inverter operates at an inductive power factor to lower high voltages (e.g., during periods of low load and high active power generation) and at a capacitive power factor to raise low voltages (e.g., during periods of high load and low active power generation). Depending on the priority setting of the inverter (watt-priority vs. VAR-priority) and inverter size, activating volt-VAR may curtail active power production. NREL studies have shown that the potential curtailment from these functions is low (<1%) for systems in which the utility keeps voltages within character of service bounds (Giraldez Miner et al. 2017). The magnitude of curtailment depends on the size of the inverter compared to the peak active power production (or "headroom," e.g., size of the solar panel direct current [DC] capacity vs. inverter AC capacity). Using watt-priority will ensure that active power is not curtailed for the sake of VAR production but may result in grid support functions being unavailable when active power production is at or near the inverter's apparent power capacity. Conversely, VAR-priority will reduce active power production if needed for the sake of reactive power support, resulting in slightly less revenue for the DER owner. VAR priority is required by 1547-2018. An option for developers to limit active power curtailment in VAR priority is to purposefully oversize inverters for the connected solar modules. Both California's Rule 21 and Hawaii's Rule 14H require volt-VAR as the default mode set to VAR priority (Enayati et al. 2020; CPUC 2018).

Volt-Watt

Volt-watt may be activated to curtail active power when voltage exceeds a defined threshold or in conjunction with volt-VAR to function as a backstop when additional grid support is needed (e.g., if absorbing 44% reactive power is not sufficient to bring overvoltages within bounds). For DERs with active power *absorption* capabilities (e.g., battery energy storage systems), absorbing active power can be used to further reduce system voltages during overvoltage events. Volt-watt provides similar benefits to volt-VAR in reducing the level of overvoltages occurring from DER adoption. Volt-watt cannot, however, *raise* voltages in response to an undervoltage event.

Dynamic Voltage Support

Dynamic voltage support can provide additional grid support and stability during a voltage sag or swell outside the normal operating region by providing rapid reactive power exchanges from DERs. IEEE 1547-2018 does not *require* this functionality or define how it would be provided, but it notes that it *may* be used upon agreement of the local power system operator. When voltages are outside of the continuous operating region but within mandatory or permissive operating regions, dynamic voltage support may be provided. Though provided as an option in 1547-2018, it is not currently a requirement because there may be challenges associated with coordinating this support function with distribution protection schemes (Enayati et al. 2020).

Curves

Individual states and DISCOMs must consider what level of voltage support they prefer to come from locally controlled inverters and assign the appropriate values within the inverter control curve capabilities. The volt-VAR default curves in 1547 are shown in Figure 9, overlaid with the ANSI and IS/IEC voltage bounds as well as the curves adopted in California as part of Rule 21. Adjusting setpoints of volt-VAR and volt-watt curves will impact how often inverters are providing support and, in some cases, how much active power production is curtailed. This is analyzed further for the Indian context in Section 3.

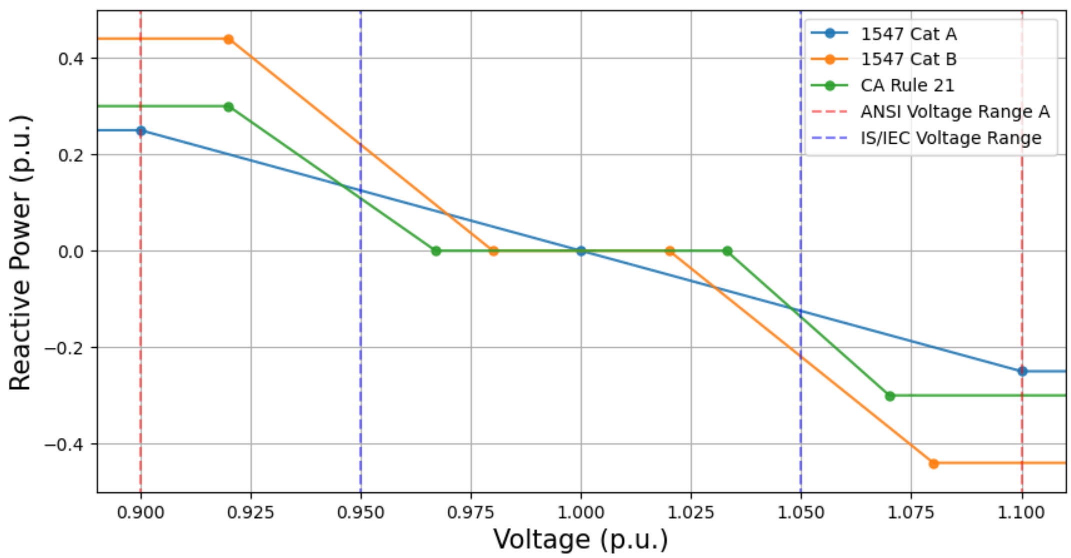

Figure 9. Volt-VAR curves for 1547 (Category A and Category B) and California Rule 21

The main differences between Category A and Category B are the presence of a dead band and the maximum reactive power contribution requirements. Using Category A will essentially result in continuous intervention from inverters, even when voltages are within allowable boundaries. The purpose of the dead band has been to allow utility primary assets to perform voltage control for a specified range around unity voltage, making sure that inverter voltage control does not interact with primary voltage control assets. Category B allows inverters to operate at unity power factor while voltages are within a ±2% range. California Rule 21 further widened this dead band, which would further limit inverter intervention in voltage regulation. Rule 21 also reduces the maximum VAR contribution from 44% to 30% (PG&E and CPUC n.d.).

When selecting a volt-VAR curve for inverters, one should avoid excessively steep slopes or short response times because these may lead to system instability (Li, Smith, and Rylander n.d.). Ensuring consistency in inverter configurations is also critical to ensure system stability and accurate system modeling and to coordinate DER support with conventional voltage regulating equipment.

DER-Utility Coordination of Voltage Regulation

It is important that inverter-based voltage support be designed with the operation of existing utility-owned equipment in mind to avoid reducing the effectiveness of existing equipment, causing system instability, or leading to excessive operations of electromechanical devices. As DER adoption increases on a feeder, existing voltage regulating devices will likely need to be reevaluated. At a minimum, regulator settings should be modified to accommodate reverse power flow to avoid incorrect tap changes causing voltage violations. A small number of DERs will have a relatively minor role on feeder-wide voltage management, but as adoption increases, inverter-based voltage management may even take precedence over conventional utility-owned voltage management strategies.

With an increase in variable distributed generation on a distribution system, existing, utility-owned voltage regulators or load tap changers (LTCs) may operate more frequently to counteract the sag and swells caused by the variable injection of real power from DERs throughout the day. In electromechanical devices, increased daily operations could reduce the lifespans of that equipment because of wear and tear on moving components and electrical contacts. Power-electronic-based inverters used today can regulate voltage on a much quicker timescale, reducing DER-caused voltage variability and removing some of the burden from slower-to-act electromechanical devices. Volt-VAR functionalities may have minor impacts on inverter lifespan because of an increase of apparent power supplied by the inverter when operating at a nonunity power factor, increasing inverter temperatures and reducing overall lifespan by a small percentage (Thiagarajan et al. 2019).

For systems with few active voltage regulation assets, as is common in India, inverter voltage support functions may be an opportunity for improved power quality through a low-cost alternative to conventional voltage management. CEA and MNRE do not yet include these functionalities.

Key Takeaways:

- Inverter voltage support functions can reduce adverse impacts from DERs or provide additional grid benefits.
- Volt-VAR functionality can effectively regulate system voltage with minimal impacts on active-power production.
- Inverter voltage support can be coordinated with and provide benefits to existing utility-owned voltage regulation.
- Volt-VAR or volt-watt curves should be appropriately designed to provide the desired amount of support from inverter-based resources, based on the operating conditions of the local power system. This may, for example, require the widening of dead bands or the adjusting of saturation points on the default 1547 curves.

2.7 Faults and Enter-Service Criteria

An unintentional island can occur when the aggregate distributed generation and load on an isolated feeder section are relatively well balanced, allowing the DER to continue to energize the line section. Unintentional islands pose serious safety risks for line workers and equipment. Load rejection overvoltage occurs when a portion of the feeder with a DER-to-load ratio of ≥1 becomes islanded. Until anti-islanding detection trips inverters, there can be a brief period in which distributed generation feeds the islanded loads, potentially leading to transient overvoltage conditions (though laboratory testing has shown these events to last on the order of micro- or milliseconds; Nelson et al. 2015). Inverters generally detect an islanded system by either passively sensing a change in voltage or frequency or by actively trying to alter a system's state by outputting frequency perturbations and measuring the resulting change in the system frequency. IEEE 1547-2018 requires that inverters be able to reliably detect the formation of an unintentional island and trip offline within 2 s. As mentioned previously, UL 1741 certification of inverters is a requirement by many utilities in the United States and includes tests to assess the capabilities of inverter anti-islanding detection methods.

Reclosing onto an energized, out-of-sync circuit can also damage both utility and customer-owned equipment because of an unintentional island forming. As a mitigation, many reclosing devices must now be equipped with voltage-supervisory reclosing, measuring the load-side voltage and restricting reclosing if the line is still energized. Ensuring that reclosing intervals are not shorter than the 2-s clearing times for DERs is also important in preventing out-of-sync reclosing. There are provisions for intentional islanding applications of DERs in 1547-2018 as well; however, these are not discussed in this report. Each of the three interconnection standards analyzed in this report contains the same requirement for anti-islanding: trip within 2 s of island formation, shown in Table 15.

Table 15. Anti-Islanding Requirements for IEEE 1547-2018, CEA, and MNRE Regulations

	IEEE 1547-2018 Category I/II/III	CEA	MNRE (Draft Standard)
Anti-Island	Trip within 2 s of island formation	Cease to energize within 2 s of island formation	Cease to energize within 2 s of island formation

Following a contingency event, the BPS may still be in a semi-vulnerable state once frequency and voltage have recovered. As such, it is important that the automatic, uncontrolled reconnection of DERs does not create additional issues for BPS generation. Historically, BPS operators have been able to control all generation assets. Having many uncoordinated distributed generation assets may complicate this restoration process. For example, the automatic rapid reconnection of a large number of DERs could result in overfrequency or overvoltage events, which could then lead to additional generation tripping, equipment damage, or system collapse. Without the need for widespread communication networks to manage DERs, randomized restoration delays for DERs as well as maximum ramp rates may mitigate issues resulting from rapid step changes and overvoltage from distributed generation coming back online too quickly (Boemer, Brooks, and Key 2015). In addition, to prevent excessive transmission backfeed, a delayed reconnection and ramp rate allows loads lost during an outage to restart. Implementing a maximum ramp rate prevents any sharp changes in generation possibly leading to large voltage step changes. Each of the three standards analyzed in this report has provisions for a required delay capability, though 1547 has the longest delay requirement of the three standards. Only 1547 and MNRE contain required ramp rates for reenergization, all listed in Table 16.

Table 16. Entering Service Requirements for IEEE 1547-2018, CEA, and MNRE Regulations

	IEEE 1547-2018 Category I/II/III	CEA Technical Standard for DG	MNRE Draft PV Inverter Requirement
Frequency	f>=59.5 f<=60.1	f>47.5 f<50.5[15]	f>49.5 f<50.5
Voltage	V>=0.917 V<=1.05	V>0.8 V<1.10[16]	V>0.85 V<1.10
Delayed Enter Service	Capable of delaying 0–600 s with 300 s (5 min) as default; <500 kVA should have a random time delay interval of 300 s	Capable of delay for at least 60 s	Capable of delay between 20 and 300 s
Ramp Rate	<=20% of active power step change (for >500-kVA DERs)	N/A	10% per min

Key Takeaways:

- Unintentional islanding of DERs poses serious safety risks for line workers and equipment. IEEE 1547-compliant inverters must detect islands and trip offline.
- The automatic, uncontrolled reconnection of DERs following a grid event could cause additional challenges for the area electric power system such as momentary overvoltages, reverse power flow, or sharp step changes in voltage and net load.
- To prevent further damage to BPS assets following a contingency event, random delays and maximum ramp rates for DERs may provide a smoother transition back to normal operating conditions.

[15] No specific frequency enter-service criteria given. Trip thresholds are listed in place.
[16] No specific voltage enter-service criteria given. Trip thresholds are listed in place.

2.8 Additional Context-Specific DER Integration Challenges

Although disparities in frequency and voltage bounds are a focus of this report and subsequent modeling sections, other key challenges with DER integration may still require consideration of local power systems, institutions, and design/operating procedures—all of which may differ across utility, state, or country borders.

2.8.1 Verification

Verification of inverter settings remains a major challenge with utilities without a well-defined way to verify whether inverter settings are correctly configured in the field and whether the settings remain correctly configured for the life of the DER. With accelerating growth of DERs, performing in-person witness tests for each new installation becomes intractable. Ensuring consistency and accuracy in device configurations is a critical step in reliably integrating higher levels of IBRs. NERC issued an industry recommendation in March 2023, describing multiple large-scale disturbances on the BPS that resulted in widespread loss of IBRs, mostly BPS-interconnected solar PV; distribution-connected resources, wind energy plants, synchronous generators, and battery energy storage plants have also been identified in recent NERC reports as having tripped or reduced generation when they should not have done so. The investigation determined that solar PV resources had systemic event ride-through deficiencies, causing them to incorrectly trip offline during grid disturbances when they should have remained connected and injecting current. NERC observed that inverter control settings implemented in the field frequently did not match those required by the regional transmission operator/independent system operator (RTO/ISO) and studied in the interconnection screening process. For BPS-connected resources, NERC advised wider trip thresholds based on maximum equipment thresholds for maximum ride-through capability, minimal or no use of instantaneous tripping elements, improved coordination between generator operators and inverter manufacturers regarding inadvertent tripping causes and mitigation measures, and not limiting dynamic reactive support from IBRs (NERC 2023). This serves as a lesson to the industry that IBRs and advanced inverter functionalities can be reliable only if configured correctly upon installation and not altered later.

In some cases, it may be prudent to design default inverter settings that are preconfigured as an industry default upon interconnection as a backstop to prevent installer error from adversely affecting the power systems. This may also suggest that simpler settings and fewer DER advanced functionalities may be preferable to more complex ones, given the need for additional installer training and additional room for human error upon installation. Once again, these choices should be made while remaining cognizant of the current state of the industry within the country in question. If DERs are relatively nascent in the country and DER developers and installers are few and far between, simpler settings may be warranted.

2.8.2 Testing and Certification

Implementing the new requirements in 1547-2018 represents a marked increase in overall complexity for DER integration, interconnection, and, importantly, testing and certification of new devices and DERs. The number of parameters that must be set, tested, and commissioned increases as utilities adopt the advanced functionalities listed in 1547-2018. In addition, understanding the real-world capabilities and limitations of DERs through rigorous testing procedures is critical to ensure sound interconnections.

IEEE 1547.1-2020 (IEEE 2020a) is a supplemental standard to 1547-2018 that outlines the various testing procedures for DERs to verify their compliance with the technical requirements in 1547-2018. The testing standard differentiates between the various components and combinations of electrical and mechanical devices that make up a DER, allowing precise application of the testing and verification requirements at the various levels of a DER. These key definitions are presented in Table 17. The bulk of this standard includes multiple test procedures, manufacturer requirements, reporting requirements, data structure and naming conventions, measurement requirements, and other best practices to be completed at various stages of DER implementation detailed in Table 18.

Table 17. IEEE 1547.1-2020 Key Terms and Definitions

Equipment under test (EUT)	A DER-type-neutral term used to refer to the devices or combination of devices subject to the tests in the standard. The EUT may be a DER unit, DER system, DER composite, individual DER component, or supplemental DER device.
DER	“A source of electric power that is not directly connected to a BPS, as defined in IEEE Std 1547-2018. 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” (IEEE 2020a).
DER unit	“A fully compliant DER that does not require supplemental DER devices to meet the requirements of IEEE Std 1547” (IEEE 2020a).
DER system	“A system that consists of DER unit(s) and supplemental DER device(s) that is type tested as a system and installed in accordance with the DER manufacturer’s instructions and that, as a whole, is fully compliant with IEEE Std 1547” (IEEE 2020a).
DER composite	“A system that consists of partially compliant DER components and supplemental DER device(s), and requires detailed design evaluation, installation evaluation, and commissioning tests to determine full compliance to IEEE Std 1547 requirements” (IEEE 2020a).
Supplemental DER device	“Any equipment that is used to obtain compliance with some or all of the interconnection requirements of this standard” (e.g., capacitor banks, static synchronous compensators, harmonic filters not part of a DER unit, protection devices, and plant controllers) (IEEE 2020a).

Table 18. IEEE 1547.1-2020 Testing Categories

General Requirements	Requirements for test result accuracy, manufacturer product information, testing equipment, test reporting formats, and the order of tests to be conducted. Facilitates the efficient and accurate exchange of information across involved parties, enables automation in DER screening, and provides traceability to the respective testing agencies or responsible party.
Type Tests (Clause 5)	Testing of the manufactured devices to verify that they can meet the technical requirements and functionalities included in 1547-2018, including responses to grid disturbances and faults, voltage and frequency support, and priority of responses. Tests conducted or overseen by a testing agency on one or more representative DER units. Test results may be transferrable to other DER units that are part of the same product family or design.
Interoperability Tests (Clause 6)	Testing of the local DER communication interface to verify that communication criteria are met and all pieces of information associated with DER interoperability are exchanged and acted on properly. Includes both communication-protocol-agnostic test procedures as well as protocol-specific considerations.
Production Tests (Clause 7)	Testing conducted by the equipment manufacturer on every unit of DER equipment prior to shipment, though this may be combined with or substituted for type tests or interoperability tests not completed separately. Includes tests for response to abnormal voltage/frequency as well as documentation verifying key equipment specifications and test results.
DER Evaluations (Clause 8)	Design evaluation or “desk study” to occur during the interconnection process to verify that the designs of the DER system or DER composite meets 1547-2018 requirements. As-built/on-site installation evaluation, occurring at the time of commissioning, to verify correct installation and settings of the designed DER according to previously reviewed documentation. The verification requirements for a given DER unit, system, or composite; may change depending on the location of the reference point of applicability. These reference-point-of-applicability-specific requirements are outlined in 1547-2018.
Commissioning Tests (Clause 8)	Depending on the type of DER, location of the reference point of applicability, and previously established conformance, either a basic or detailed commissioning test is needed at the time of DER commissioning. Testing requirements may include visual inspections of components and connections, several tests of key functions (i.e., operability of the isolation device), or more series of tests to verify that the combination of devices can together meet 1547-2018 requirements.
Periodic Interconnection Tests (Clause 9)	Periodic tests to verify that the DER still meets the requirements of 1547-2018. These may be required after key changes are made to the DER such as changes in software, hardware, protection functions, or operating modes or following operational or performance issues.

Inverter certifications play a critical role in ensuring that installed IBRs can meet prescribed interconnection requirements in 1547. U.S. inverters are certified by UL 1741, which is harmonized with 1547. UL 1741 outlines specific safety requirements and, for grid interconnection functionality, refers to the tests described in 1547.1, outlined previously.

Interconnection standards should not contain requirements that exceed the capabilities of regionally available inverters or protection equipment. In cases where new inverter capabilities are required, sufficient time should be provided for development and testing of those capabilities. Interconnection standards should clearly describe the capabilities that new inverters should be designed with along with any required certification or testing requirements so that inverter manufacturers can comply. For the adoption of 1547 in the Indian context, certification and testing standards and testing laboratories should be established to ensure that implemented DER equipment can meet the requirements set out in new grid codes.

2.8.3 Regulatory Structure

The organizational structure of utility regulatory bodies may differ across countries, states, or utilities. As explained in Section 2.1, different regulatory bodies govern different utility types in the United States (IOUs, municipal utilities, and cooperatives). Similarly, additional requirements may be imposed on a distribution utility from the transmission system operators or balancing authority, and not all regulations are solely for the benefit of the distribution network. For example, state regulators in California and Hawaii require frequency support from DERs to support the bulk system (as provisioned in California Rule 21 and Hawaii Rule 14H). For a regulatory structure such as that in India—with central-, state-, and DISCOM-level regulation in place—different grid support functions may be best prescribed by different entities. For example, frequency-related functionalities, which must be coordinated across the entire bulk system, may be better set by a central authority such as CEA, whereas more local functions such as voltage support and VRT may be better set by the SERCs or individual DISCOMs, adapted to their specific grid conditions and local-level regulatory requirements. As further explained in the following section, this highlights the broad stakeholder collaboration necessary to properly adopt DER interconnection standards.

2.8.4 Stakeholder Collaboration

Widespread integration of DERs represents a fundamental shift in how utilities have operated and engaged with industry and its ratepayers. Historically, external stakeholders have had minimal to no engagement with day-to-day utility operations or system design because the utility has been the sole provider of system reliability. Because more third-party-owned and -operated devices are connected to the grid and relied upon for critical grid reliability services, utilities and regulators must approach broad, continuous stakeholder engagement as a fundamental piece of system design and reliability. When designing interconnection standards, many parties should inform the process—including inverter manufacturers, system operators, BPS generation operators, DISCOMs, DER developers, DER installers, inverter testing laboratories, research institutions, consumer advocate organizations, and regulators. Achieving consensus across these stakeholder groups is a critical step in designing effective and reliable interconnection standards.

In collaboration with utilities, detailed simulation-based studies as well as field pilots should be conducted, using real-world data, to assess the performance of proposed standards on real-world systems. Consulting with local developers and installers of DERs can help ensure collective understanding of interconnection requirements, identify any knowledge gaps, and ensure that the proper support channels from inverter manufacturers or utilities are provided. Although DER standards should strive to be locally appropriate, standards agencies should also strive to harmonize settings across their jurisdiction to reduce confusion for involved stakeholders and prevent interconnection delays from failed screens. Lastly, engaging inverter testing laboratories can help ensure consistency and standardization across the industry—mitigating issues around improperly configured inverters, firmware updates wiping settings, and testing/commissioning procedures and creating pathways for certifications (i.e., UL 1741-certified inverters).

3 Performance of IEEE 1547-2018 Functions Under Indian Grid Conditions and Implications for Distributed Energy Resources

A key objective of this report is to highlight the location- and circuit-specific nature of many of the 1547-2018 support functions detailed in previous sections above. The specific analysis of power system characteristics that are representative of service areas seeking to adopt these settings is a critical step to inform the proper settings and function adoption.

In some of the following subsections, we perform an example analysis on a load flow model of a real-world Indian distribution circuit using OpenDSS. Only analysis results are shown to protect asset location information. Going forward, this feeder model will be referred to as the “Indian test feeder” and has the high-level attributes listed in Table 19.

Table 19. Feeder Technical Attributes (Indian Test Feeder)

Voltage Class (Medium Voltage [MV], Low Voltage [LV])	Total Line Kilometers	Total Load Count (0.9 PF	Total DER Count (Solar PV)	Peak Load (Without Solar)	Aggregate DER Generation Capacity
11 kV (MV), 0.44/0.23 kV (LV)	186,145	6,243	1,248	3.333 MW 2.025 MVAr	1,555 MW

3.1 Voltage Trip and Ride Through

As outlined previously, the inadvertent tripping of DERs on voltage excursions because of faults, switching events, or even steady-state conditions can result in dissatisfied DER owners, exacerbated grid issues, voltage instability, or the cascading tripping of other resources. If trip settings are inappropriately narrow, repeated poor performance from DERs might disincentivize future DER investment.

Modeling a distribution feeder or using field measurements can provide valuable insights to ensure that voltage trip and ride-through settings are adequately wide to allow for reliable DER operation on each unique power system. In the following example, we analyze our Indian test feeder looking at both steady-state conditions and a simulated voltage profile of a FIDVR event. Both CEA and 1547-2018 trip and ride-through settings are analyzed, applying the same settings to all 1,248 DERs listed in Table 20. It is important to note that while implementing IEEE 1547 trip and ride-through settings, some choices can affect the behaviors of the DERs. When voltages are within the “permissive operation region,” the DER may continue to exchange current with the area EPS, or it may cease to energize. In our models, we elected to maintain current exchange and operate in a current-limited output. OpenDSS Generator Model 7 is used in this region with the Vminpu parameter equal to the upper threshold for this region. In addition, when voltages are within the “may ride through or may trip” region, we have elected to trip our DERs, representing a more conservative ride-through capability—though still compliant with 1547-2018.

Our scenarios are labeled in the accompanying plots as described in Table 20. All simulations are compared with a baseline run in which DERs will not trip off at all.

Table 20. Scenario Descriptions for Trip and Ride-Through Scenarios Analyzed

Scenario Name	Baseline No Trip	No Voltage Ride Through (NO_VRT)	Voltage Ride Through for 1547-2018 Category I (VRT_CAT_I), Category II (VRT_CAT_II), and Category III (VRT_CAT_III)
Applicable DER settings	DERs always on, using OpenDSS Generator Model 7 with Vminpu = 0.88.	No voltage ride-through capabilities enabled. DERs will trip instantaneously at CEA voltage thresholds.	VRT enabled using 1547-2018 ride-through and trip thresholds for each performance category.

The following steady-state simulations represent a peak load day without the use of a substation LTC or any voltage regulation from DERs. This represents a potential worst-case scenario, particularly for undervoltages measured at the PCC. Simulations are run with a 15-minute temporal resolution. Although this is a relatively coarse resolution given the timescales that DERs will trip on voltage violations, it can still be used to approximate DERs tripping and reentering service because of steady-state conditions.

Figure 10a shows the voltages (minimum phase voltage used for three-phase DERs) at the PCC of each DER. Immediately, one can notice the wide range of voltages experienced by the various DERs, depending on location, generation capacity, and upstream impedance. The range includes voltages well below the 0.9 threshold listed in IEC 60038. For a small subset of DERs, the minimum voltage drops below 0.8 p.u. around the 21-hour mark. As a result, in Figure 10b, seven DERs trip offline during this time—resulting in a relatively minor loss of only 13 kW in total. Once voltages rise above 0.8 for these generators, they reconnect, with a delay time of 300 s (or one timestep at 15-minute [min] resolution).

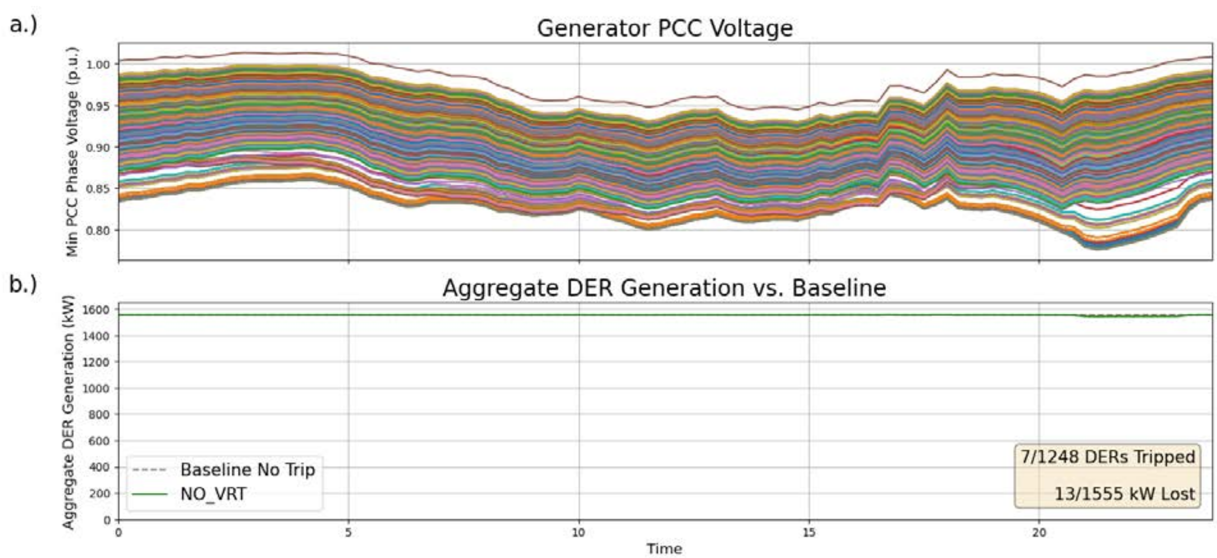

Figure 10. Steady-state voltage simulation results (no voltage ride through), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

Replacing CEA trip values with 1547-2018 Categories I, II, and III ride-through settings, we actually see a *higher* amount of lost generation on our feeder, totaling 314 DERs tripped offline at the worst point around 12 hours. This performance result is repeated for all three categories of ride-through settings in Figure 11, Figure 12, and Figure 13. We may notice some differences across these three categories if they are modeled at a finer time resolution, but at 15-min resolution, the DERs trip as they exceed the maximum time in the “mandatory operation” region, which at its longest (Category III) ends at 20 s.

Initially, several DERs trip offline in the first few timesteps of the simulation, as voltages for some generators are below the 0.88 p.u. threshold for continuous operation at the beginning of the simulation. Below this threshold (and above 0.65 p.u.), DERs will trip offline in 2–20 s. At this timestep, we see a coinciding drop in PCC voltages, illustrating the possibility of cascading effects from losing distributed generation. As a result, the PCC voltages for these generators reach an even lower point throughout the day than in the NO_VRT case, resulting in even more DERs tripping later. As DERs reconnect, the PCC voltages begin to rise again (also a result of load decreasing in the evening). One should remember that the default values from 1547-2018 are used in this analysis, with the “may ride through or may trip” region set to trip. As such, the results shown in the figures would change if the proper adjustments were made prior to implementation. In addition, should the Indian DISCOM implement other means of voltage regulation (i.e. OLTC, switched capacitors, or voltage regulators), this could alleviate the preexisting undervoltages.

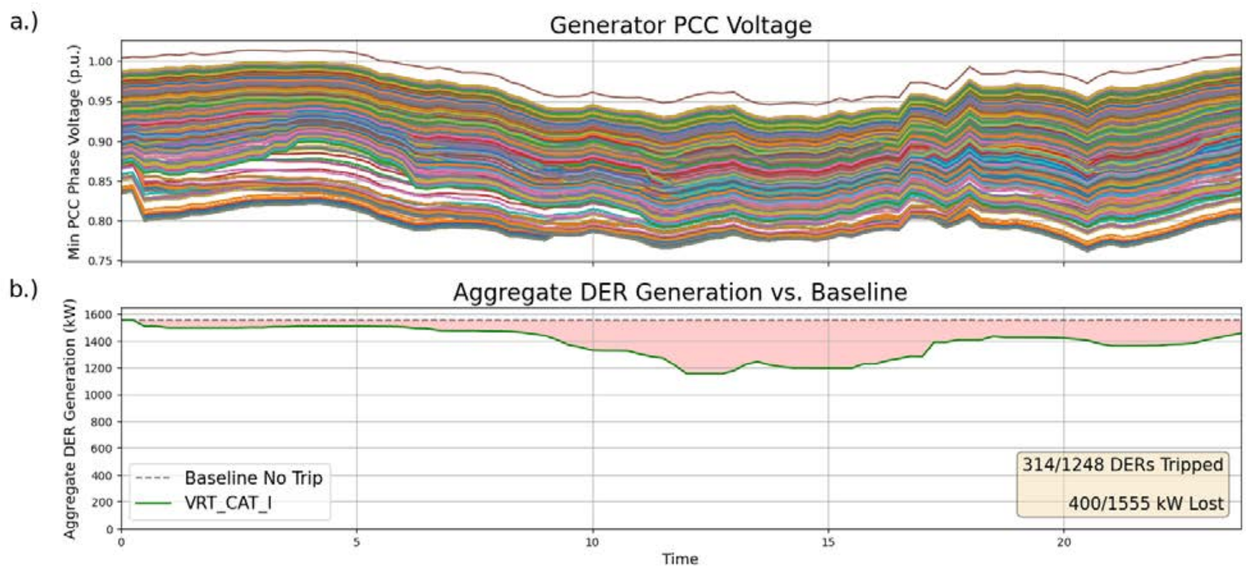

Figure 11. Steady-state voltage simulation results (1547-2018 Category I), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

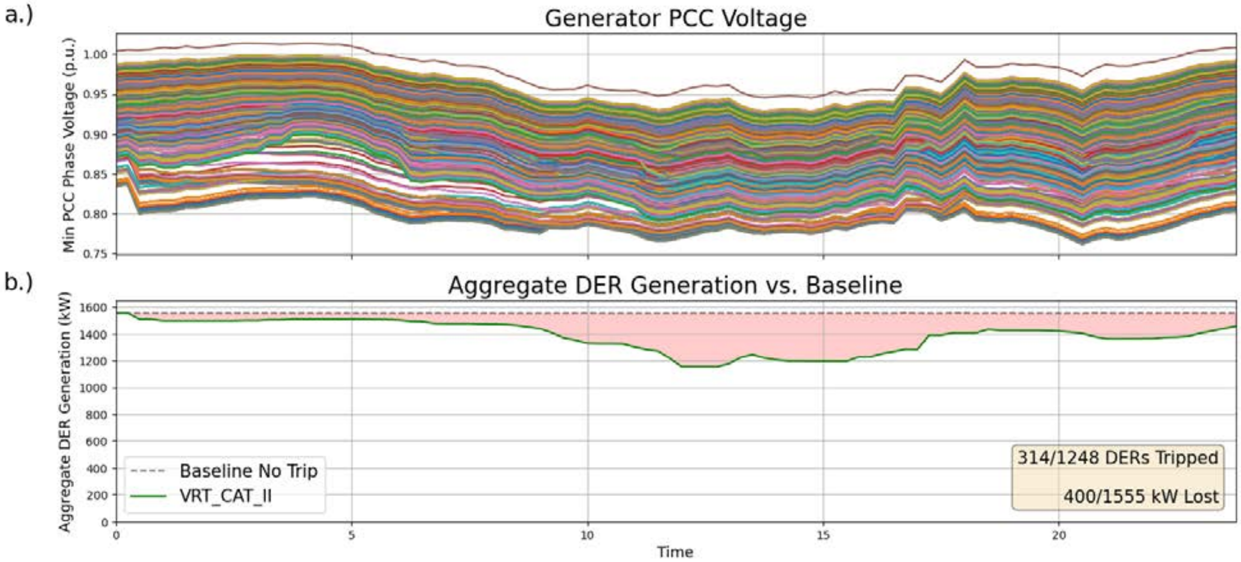

Figure 12. Steady-state voltage simulation results (1547-2018 Category II), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

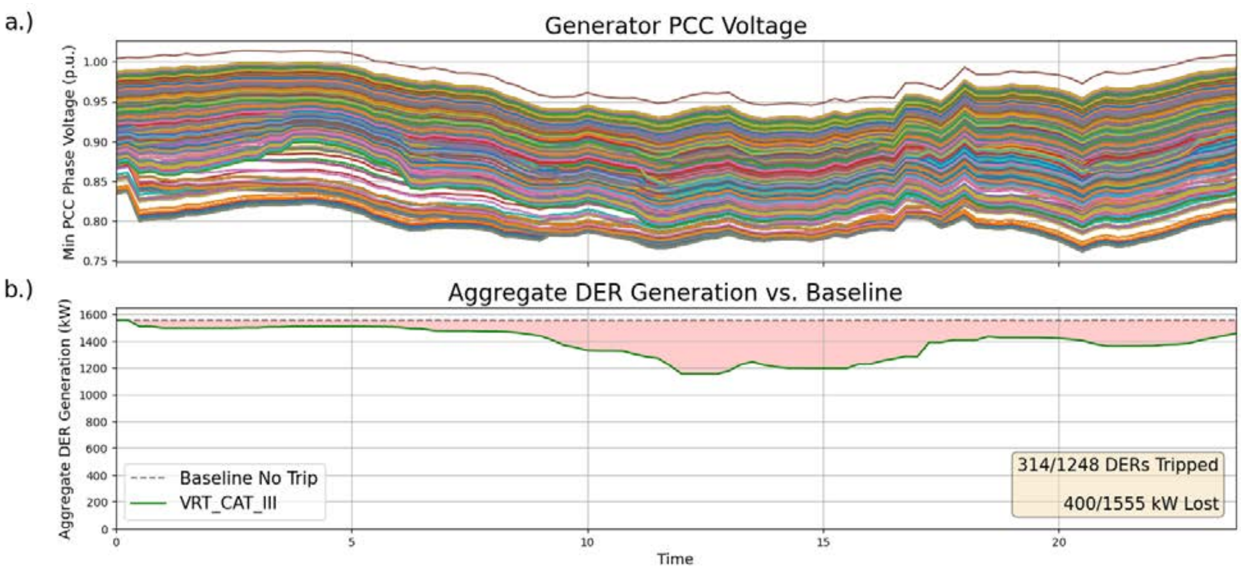

Figure 13. Steady-state voltage simulation results (1547-2018 Category III), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

Although this steady-state analysis shows that even during normal operating conditions, DERs may trip offline because of voltage violations, the primary goal of ride-through capabilities is to ensure that DERs do not trip offline for transient events accompanied by a voltage sag or swell. As such, we studied how these same ride-through settings in Table 20 would perform for a FIDVR event, triggered by a transmission or subtransmission fault. Using a simplified analysis, the simulations shown in the following figures use a voltage profile (applied at the substation) that represents the initial drop and slow recovery of the system voltage. This profile was produced using a transmission and distribution cosimulation with a load controller to simulate the stalling of motors. Simply using a voltage profile has one shortcoming: It does not accurately represent the progressive loss of inductive loads as stalled motors trip off because of thermal protection or overload. This phenomenon could produce overvoltages following the initial recovery of voltage because capacitor banks (if in use) that were previously providing reactive power support are now overcompensating and driving the voltage higher, until they switch offline. However, this approach does still accurately represent the undervoltages experienced in such an event. The following simulations are performed at a 0.025-s temporal resolution to capture the short-duration initial voltage dip resulting from a fault and subsequently cleared by a protective device on the transmission or subtransmission system.

Once again, we initially assume no LTC or any voltage regulation from DERs, though the former would likely not have an effect on an event of this duration given that typical operating delays used in the industry are on the order or 10–120 s to limit excessive tap changes and premature failure from wear (Gonen 2014). As such, this 12-s event would likely not initiate any tap changes. That said, we assume a 1.05 p.u. prefault steady-state voltage at the substation, which somewhat simulates the prefault conditions that might exist in the presence of an LTC regulating to 1.05 p.u.

Figure 14 shows the results of our FIDVR simulation for our no voltage ride-through (NO_VRT) scenario. In Figure 14a, we see that PCC voltages initially drop to between 0.4 and 0.55 p.u. because of a system fault. Stalling induction motor loads result in a lengthy recovery and PCC voltages below 0.9 for several seconds. Without any ride-through provisions for DERs, every generator trips offline immediately when voltages dip below CEA's 0.8 p.u. undervoltage threshold in the NO_VRT scenario. As a result, the full 1.555 MW of distributed generation is lost almost instantaneously. This generation does not reenter service within the simulation's short time frame of 13 s.

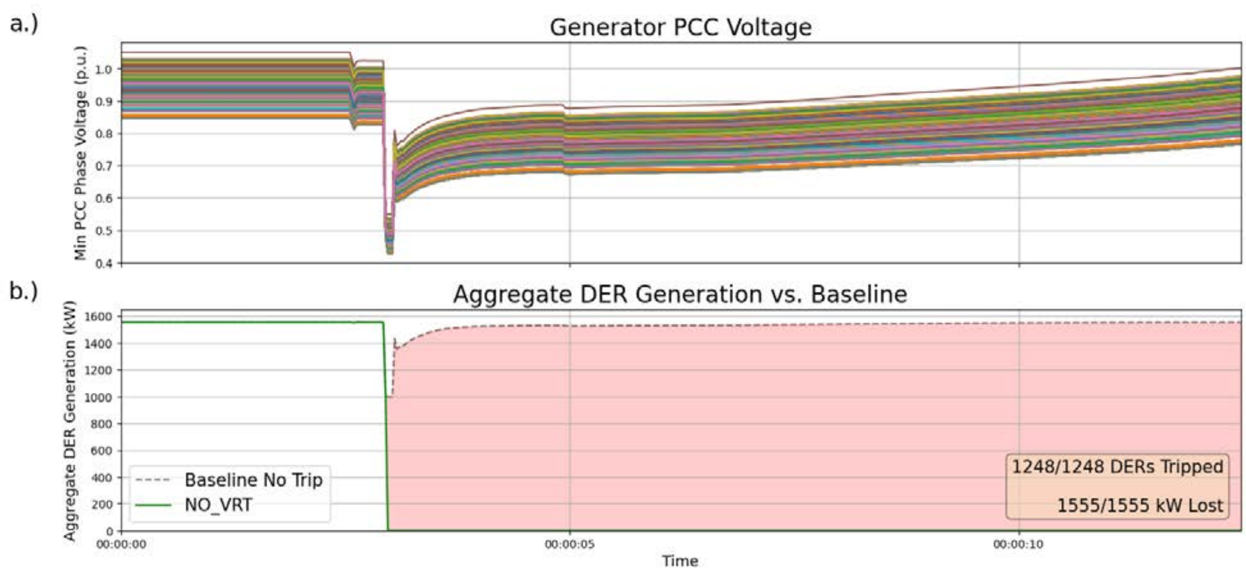

Figure 14. FIDVR simulation results (no voltage ride through), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

Adding ride-through provisions using 1547-2018 Category I settings, we see a similar result in Figure 15 with a few key differences. That is, we again see the loss of all 1,248 DERs; however, this occurs in stages—separated by time delays—rather than all at once. A handful of DERs trip offline *before* the fault. Because of existing steady-state low voltages for several DERs (below 0.88 p.u.), these DERs will trip once the mandatory operation capability region is exceeded (between 0.7 and 1.42 s). One can see the accompanying voltage drop when these generators trip. Although this is not a result of the FIDVR event, it is still indicative of inadequate ride-through settings for the given distribution circuit. Following the initiation of the FIDVR event, we again see several more DERs trip within a short time frame. Additional DERs trip immediately when PCC voltages drop below 0.5 p.u., whereas additional DERs trip after 0.16 s after the permissive operation region is exceeded. Once the voltage has begun to recover, the remainder of the DERs trip after exceeding the mandatory operation region. These DERs will all trip between 0.7 and 1.42 s, and so we see a rapid reduction in distributed generation within that time frame.

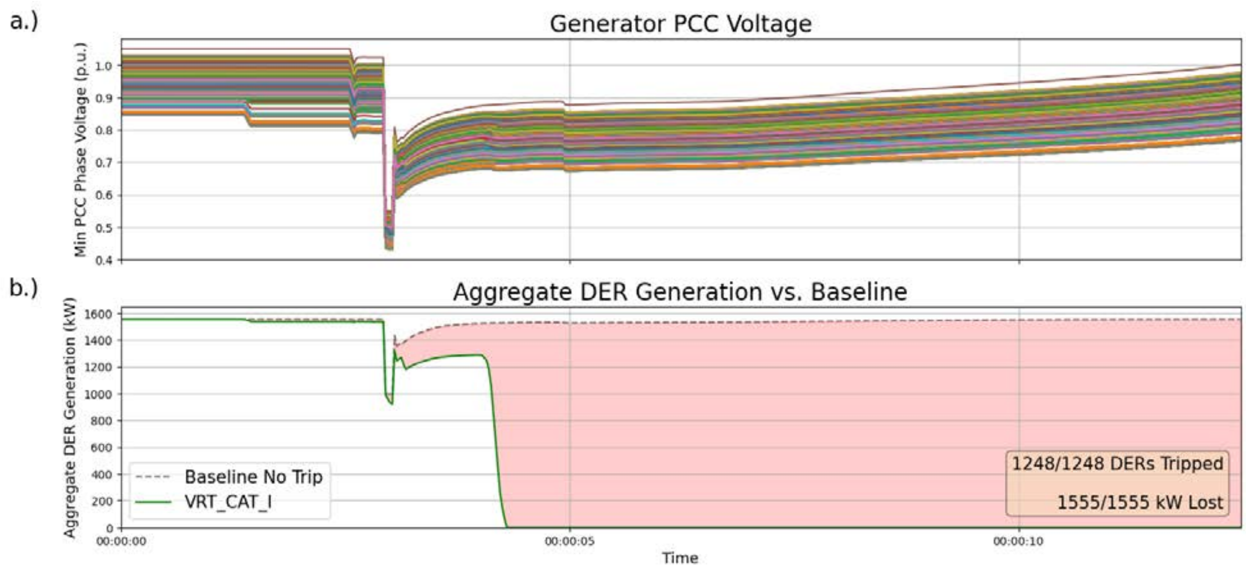

Figure 15. FIDVR simulation results (1547-2018 Category I), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

IEEE 1547-2018 Category II settings once again result in all generation being lost from the simulated FIDVR as shown in Figure 16. However, given the longer-duration mandatory operation region, we no longer see any DERs trip *before* the FIDVR—though these generators with low steady-state voltages do seem to trip shortly after the FIDVR event begins. Because of a lower bottom threshold for our permissive operation region, we do not see as many DERs trip from the initial fault-induced voltage sag because it does not drop below the 0.3 p.u. lower threshold. Instead, we see most DERs remain online until their mandatory operating region is exceeded between 3 and 5 s after the event began. After this time, we see a sharp loss of generation. It is still worth highlighting that most DERs successfully rode through the initial voltage sag from the fault. Had that not triggered a FIDVR—or had the voltage recovered more quickly—the loss of generation from this event might have been minimal.

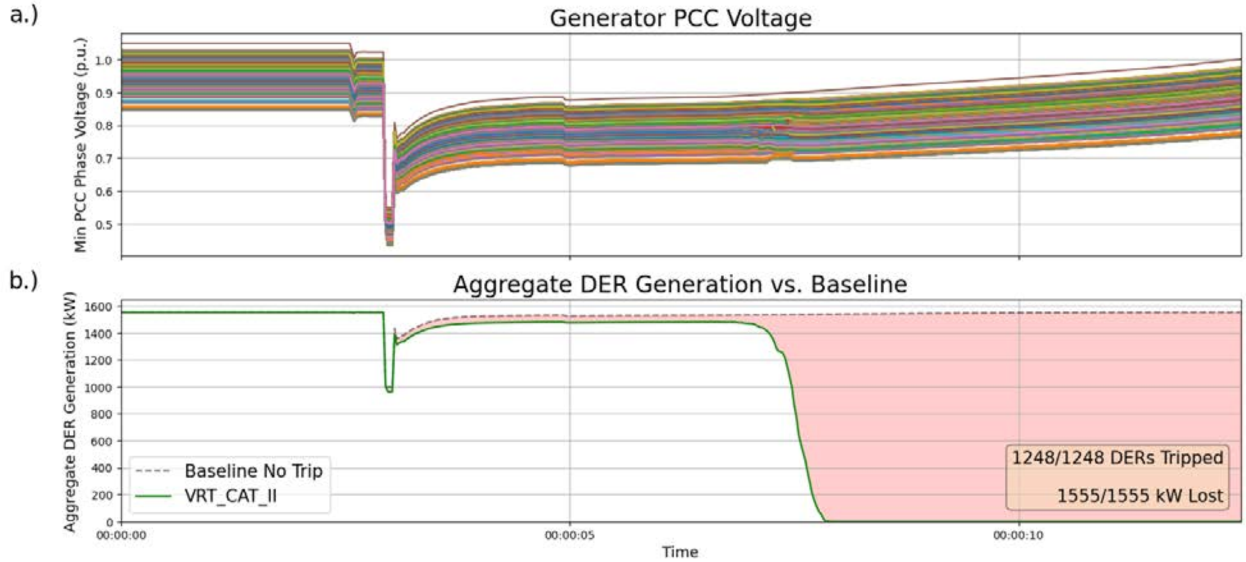

Figure 16. FIDVR simulation results (1547-2018 Category II), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

Lastly, using Category III settings from 1547-2018 results in far fewer DERs tripping offline as shown in Figure 17. The initial fault-induced voltage sag results in more DERs tripping than Category II settings because of the addition of the momentary cessation period below 0.5 p.u. However, given the longer (10–20 s) mandatory operation region, 1,155 DERs successfully rode through the entirety of this event. Once again, although even the most robust *default* settings in 1547 resulted in some lost generation, appropriately adjusting these settings prior to implementation could likely prevent this—illustrating the importance of analyzing local grid conditions.

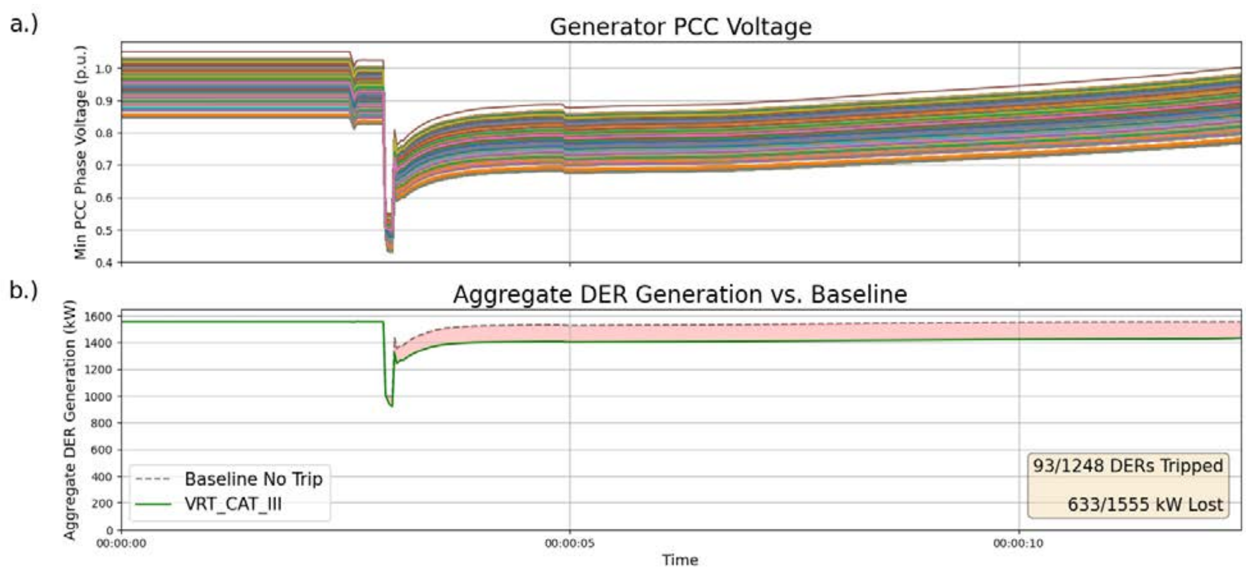

Figure 17. FIDVR simulation results (1547-2018 Category III), showing a.) DER PCC voltage profiles and b.) aggregate generation from all DERs

A DER's location on a given circuit could change the effectiveness of both voltage ride-through and voltage support functions, the latter of which is analyzed further in Section 3.3. Typical distribution design principles lead utilities to regulate voltage at the feeder head to a setpoint higher than 1.0 p.u. to keep end-of-line voltages within acceptable bounds. As a result, customers close to a substation or distribution transformer may be more likely to see overvoltages as opposed to undervoltages seen nearer the end of the feeder. For example, Figure 18 shows annual voltage measurements at 30-min resolution from a distribution transformer on an Indian distribution circuit. This is overlaid with DER trip status using 1547-2018 Category III trip settings and assuming no voltage impacts from DERs disconnecting because this analysis does not perform any load flow. Over the course of the year, DERs located close to this transformer could, at worst, trip up to 181 times—losing over 6% of their daytime operating hours. This may represent the conditions seen only by a small subset of the DERs on a feeder, but for owners operating DERs close to a substation or distribution transformer, this can have substantial impacts on the profitability of their generators.

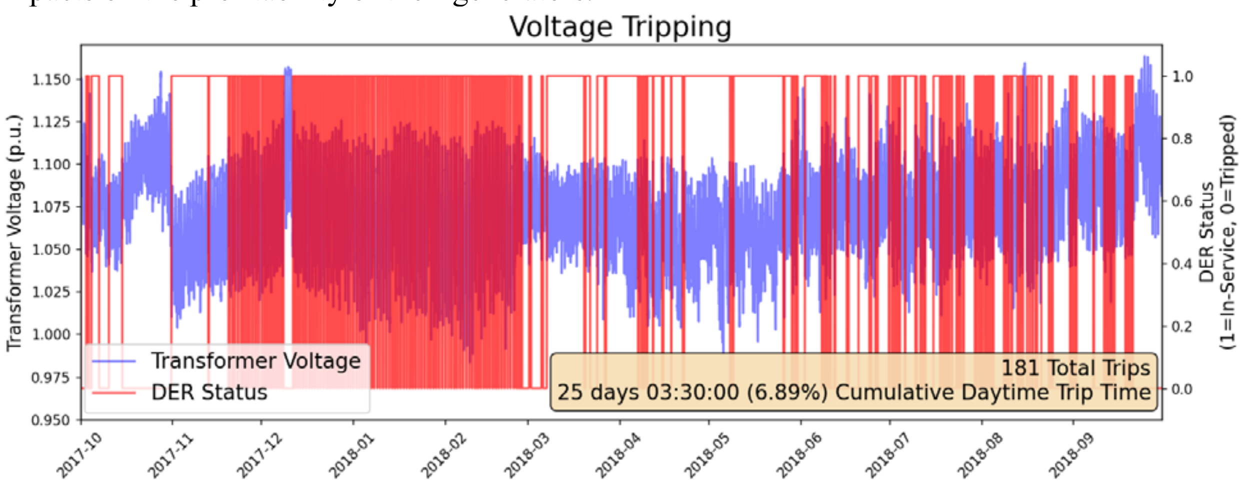

Figure 18. Measured voltage from a distribution transformer on an Indian feeder and DER trip status using 1547-2018 Category III settings

3.2 Frequency Ride Through

One of the key issues described in Section 2.1.3 is what became known as the "50.2-Hz Problem," resulting from implementing overly stringent frequency trip thresholds on a system with operating frequencies that could very feasibly exceed those thresholds. A similar analysis as in Section 3.1 can be performed to ensure that values chosen for frequency ride-through and trip settings are adequate for the system in question. This analysis is relatively simplistic because we did not perform any load flow analysis or simulate the effects on frequency from the loss of additional distributed generation. Instead, we simply identify any time the system frequency exceeds DER trip thresholds, flagging these instances in red in the following figures.

Once again, we can analyze both the steady-state conditions as well as transient events. The first set of plots shows how DERs would perform for a full year, using 5-min average frequency data (Grid-India n.d.). To illustrate poor performance, Figure 19 shows system frequency overlaid with DER trip status, using previous and excessively tight German trip thresholds (i.e., the 50.2-Hz Problem). One can see that any time the system frequency exceeds 50.2 Hz or drops below

47.5, DERs trip offline—totaling 129 trip events for a total of 1 day, 11 hours, and 30 minutes of downtime during daylight hours (between 7 a.m. and 7 p.m.).

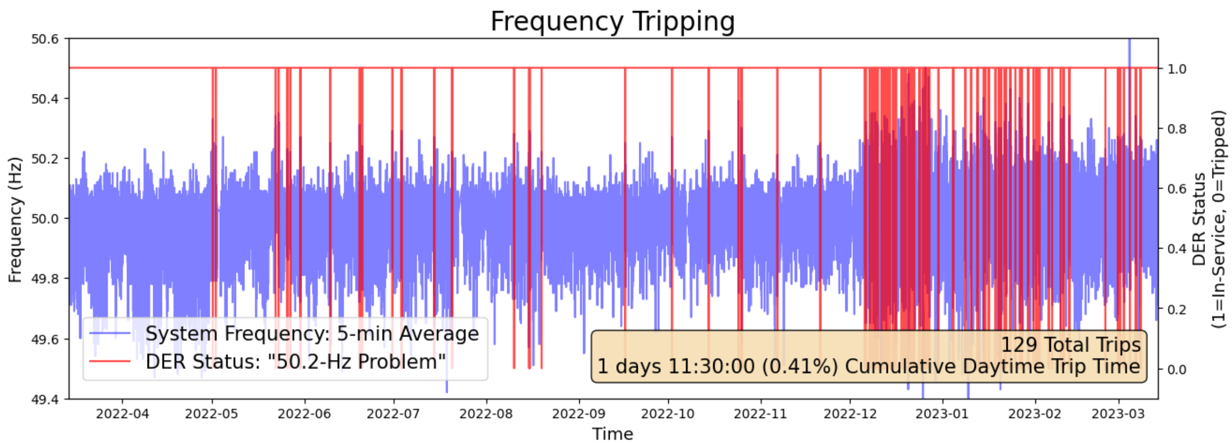

Figure 19. System frequency from station in Delhi and DER status for a trip setting of 50.2 Hz

Figure 20 shows an analogous simulation using settings currently implemented in CEA's *Technical Standards for Connectivity of Distributed Generation Resources*, which includes wider bounds (50.5 Hz and 47.5 Hz). As a result, we see no trips during the same period. Given the wider trip thresholds prescribed in 50-Hz-adjusted 1547-2018 settings (with may-ride-through or may-trip region set to trip), we see the same behavior using those settings as well as shown in Figure 21. This simple analysis shows that 1547-2018 default settings for frequency ride through and trip are likely sufficient, given the steady-state data used. This, however, does not address any transient events that may still pull system frequency outside the allowable thresholds and cause DERs to trip.

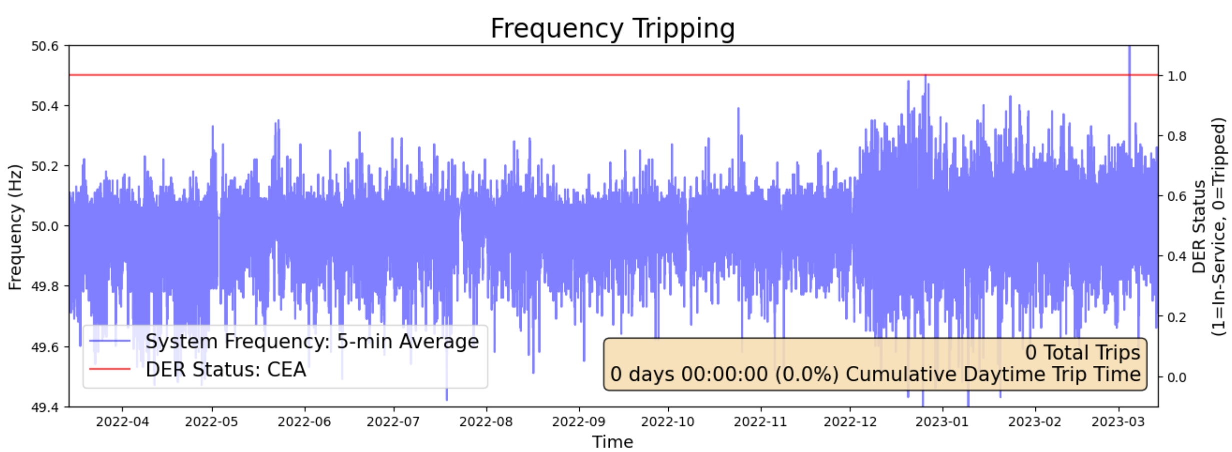

Figure 20. System frequency from station in Delhi and DER status for CEA trip settings

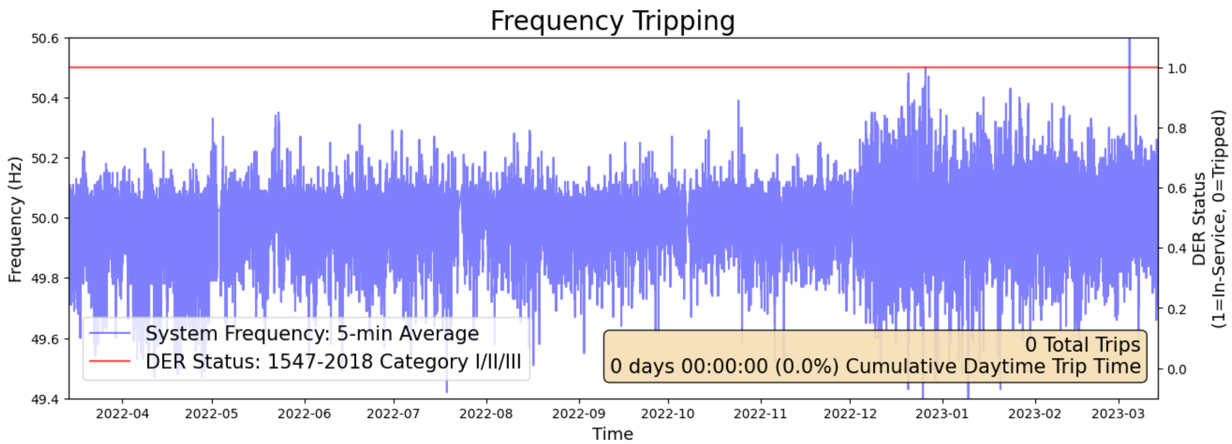

Figure 21. System frequency from station in Delhi and DER status for 1547 Category I/II/III trip settings

If more granular data are available, a similar approach as that described previously can be used to study the transient behaviors of the system frequency because these are more likely to affect DER operations than the steady state. A 2022 report from Grid-India (POSOCO and Indian Institute of Technology Bombay 2022) (formerly known as Power System Operation Corporation Limited [POSOCO]) details the system's worst contingency events and their associated impacts on the system frequency. As of November 2021, the largest contingency on Indian power systems occurred on May 28, 2020, when 5.3 GW of generation was lost because of inclement weather tripping multiple 765-kV transmission lines, resulting in an observed nadir of 49.54 Hz (a drop of 0.48 Hz from pre-event frequency). Although a nadir of 49.54 Hz is well within the 50-Hz-adjusted 1547 frequency ride-through and trip settings (UF2 of 47.5 Hz), one should also consider the possibility of this same contingency event occurring during a time of low, steady-state frequency. The lowest steady-state value within our 5-min average data set is 49.4 Hz. Assuming a loss of 5.3 GW of generation at this time would result in an equivalent 0.48 Hz drop as it did in May 2020; this would bring our nadir down to 48.92 Hz. This, too, should not have resulted in DER's tripping on underfrequency.

It is also critical to consider future grid conditions, such as reductions in system inertia following the widespread adoption of IBRs, which may affect the characteristics of frequency events. Similarly, the consideration and modeling of a large contingency event when system inertia is lower (i.e., when IBR generation is peaking during peak wind or solar hours) can further inform DER settings. As mentioned in Section 2, a reduction in system inertia could create higher-ROCOF, lower-nadir events, which might change the desired settings for DERs. Advanced modeling efforts can help inform what potential contingency events might look like on Indian power systems.

3.3 Voltage Support Functions

The voltage support functions outlined in Section 2.6 provide grid support by measuring grid conditions at the PCC and dynamically adjusting DER power quantities. As such, preexisting grid conditions will influence the behaviors of these inverter functions and DER interactions with utility-owned distribution voltage control. Utilities may elect to assign a larger or smaller burden to DERs providing voltage regulation services, based on a variety of factors. Regardless of the utility's intent, to achieve the intended support level from DERs, one must first accurately characterize PCC voltages across the distribution network.

A distribution system with wider voltage operating ranges (as measured at the PCC) will prompt more-frequent or larger-magnitude voltage response from DERs. Distribution systems without preexisting active voltage regulation, such as substation-located OLTCs (as is common among some Indian distribution systems [GIZ 2017]), line regulators, or switched capacitor banks, are likely to operate at a wider range of voltages and therefore elicit higher inverter activation. In the following examples, we calculate inverter activation as a measurement of the reactive power support provided by DERs across our modeling time frame.

An "acceptable" level of inverter activation must ultimately be determined by individual utility operators, considering impacts on inverter lifespan (albeit likely small [Thiagarajan et al. 2019]), active power curtailment for DER owners, reactive power flows on distribution networks, interactions with present or planned utility-owned voltage regulation devices, or the overall level of reliance placed on independently owned and operated distributed resources to provide critical grid functionalities.

3.3.1 Scenarios

The following examples analyze our Indian test feeder under a variety of scenarios. We model PCC voltages and inverter contributions during the peak load day in June when end-of-line voltages are likely lowest and during a day in February when the ratio of DER generation to load is the highest. These two scenarios are denoted as "Peak Load" and "High-DER-to-Load." The impacts of utility-owned voltage regulation in the form of a substation-located OLTC are also shown—denoted by "LTC" and "No-LTC" in the scenario names—along with the voltage impacts of inverters programmed with 1547-2018 default volt-VAR curves, which are divided into Category A and Category B and further divided into watt- and VAR-priority.

3.3.2 PCC Voltage

A duration curve provides an understanding of the amount of time PCC voltages operate outside a specified dead band. The following examples show the nodal voltages at every node on our test circuit that also contains loads (i.e., the PCC), where we may also expect customers to potentially interconnect solar PV in the future. The examples provide sample curves with acceptable threshold markers corresponding to ±10% of nominal voltage according to the IEC 60038 standard. It can be helpful for utility planners to characterize PCC voltages under multiple scenarios, including seasonal load changes, year-over-year load growth, with and without utility-owned active voltage regulation, or high building or vehicle electrification.

The impacts of adding an LTC are made clear in Figure 22 and Figure 23 because the addition significantly reduces the duration of PCC voltage violations for our test feeder and therefore the amount of support requested from DERs. In other words, the magnitude of PCC voltage impacts from IBDERs generally increases as the preexisting grid conditions worsen. In our LTC scenarios, we see almost no impacts from volt-VAR, indicating that inverter support is rarely activated. Conversely, we see a more substantial impact from volt-VAR activation on our No-LTC scenario. Utilities may wish to use this relationship to conduct cost-benefit analyses and decide whether volt-VAR functionalities are worthwhile to implement.

In the case of our Indian test feeder, customers are affected by preexisting undervoltages, which are, to some extent, improved by solar and the addition of volt-VAR functionalities. As a result, we see the worst PCC voltages on our peak day—during which demand is higher and subsequently end-of-line voltages are lower—and very few violations in our high-DER-to-load day. As is often the case on U.S. distribution systems (Giraldez Miner et al. 2017), the additional distributed generation leads to overvoltages at PCCs, and the worst-case scenarios may instead be the High-DER-to-Load scenario, highlighting the fact that preexisting grid conditions dictate how IBDERs with advanced functionalities will operate.

The differences in voltage while using Category A default values vs. Category B default values are minor on this feeder. However, should this analysis be expanded to a larger set of distribution circuits or higher PV adoption scenarios, one may find a more pronounced difference. Shown in the figures that follow, operating in VAR-priority, as is prescribed in 1547-2018, provides slightly better voltage improvements than operating in watt-priority, which may limit the inverters' ability to regulate PCC voltages. However, the effectiveness of volt-VAR can vary depending on the type of preexisting voltage violations (over- vs. undervoltage), PV location on the circuit, utility voltage-management devices (such as capacitor banks), and circuit X/R ratio, highlighting the importance of performing this type of analysis.

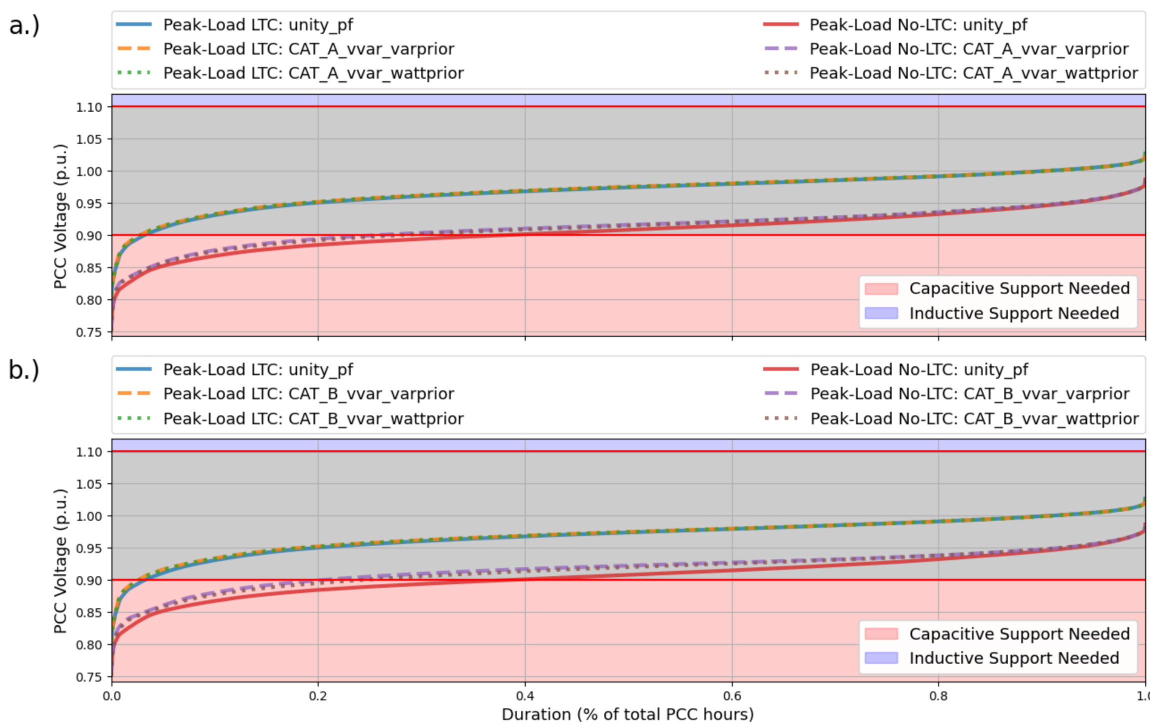

Figure 22. Peak-Load scenario PCC voltage duration curves with and without a substation LTC and with and without inverter volt-VAR functionality: a) 1547 Category A default settings; b) 1547 Category B default settings

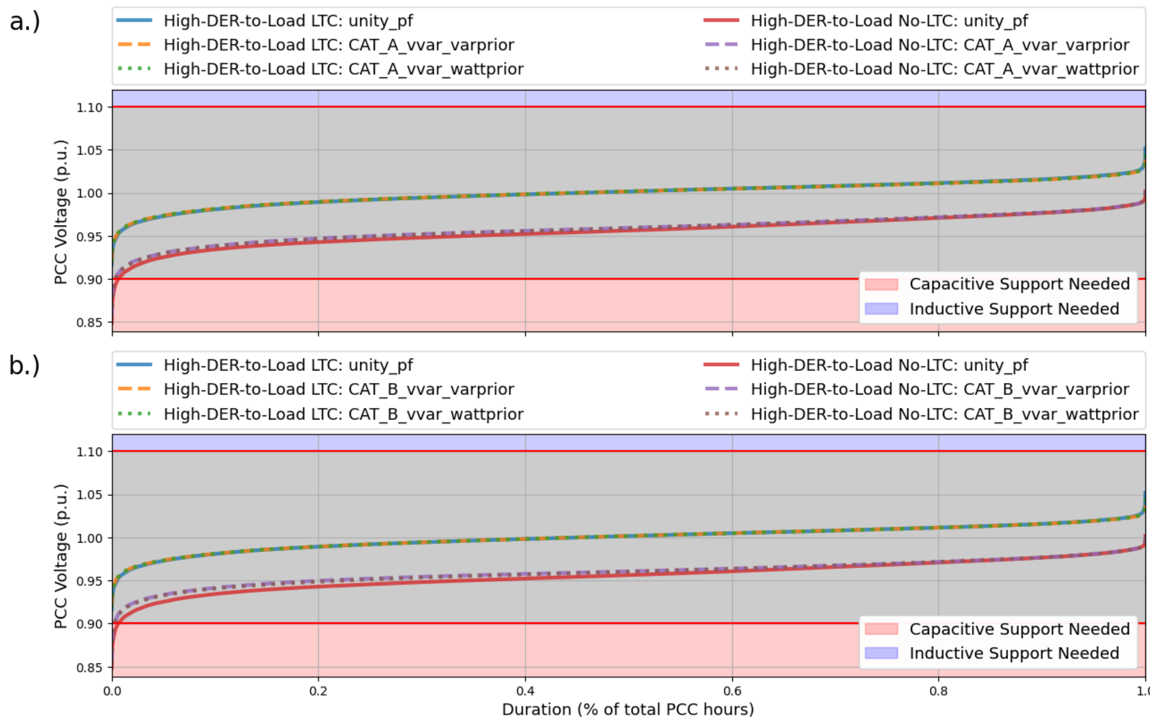

Figure 23 High-DER-to-Load scenario PCC voltage duration curves with and without a substation LTC and with and without inverter volt-VAR functionality: a) 1547 Category A default settings; b) 1547 Category B default settings

3.3.3 Inverter Activation

Quantifying inverter activation—or how often and to what magnitude inverters are providing voltage support—can further inform utility decisions on adopting active voltage regulation functionalities. In the following figures, we show the kVAR contributions from inverters as a percentage of their kVA nameplate capacity. We calculate inverter activation simply as the area between the duration curves and the zero line using a middle Riemann sum. Although we highlight PCC voltages that extend beyond the ±10% IEC 60038 thresholds, one should note that 1547-2018 Category A volt-VAR default values contains no dead band, whereas Category B default values contain a ±2% dead band. As such, even within the allowable PCC voltage thresholds in ANSI C84.1 or IEC 60038, inverters following these default curves would still be providing voltage support in the form of reactive power injection or absorption.

Although high levels of PV adoption can have a significant impact on systemwide voltages, at lower adoption levels, systemwide voltages will be relatively unaffected. In our scenarios, we see in Figure 22 and Figure 23 the relatively small systemwide voltage impacts from PV volt-VAR functionality. As such, one must consider that these early adopters of DERs may bear a disproportionally large burden of regulating system voltage in the absence of utility-owned voltage regulation. Given that our largest voltage violations occur during our Peak-Load scenario, we see in Figure 24 and Figure 25 inverters operating at their peak reactive power output (44% or 25% for Category A and Category B, respectively) for a longer duration than we see during our High-DER-to-Load scenario. We see in the following examples that in all cases, the inverter activation is slightly smaller under watt-priority than in VAR-priority; in the previous PCC voltage plots, we see a slightly better voltage improvement under VAR-priority than under watt-priority.

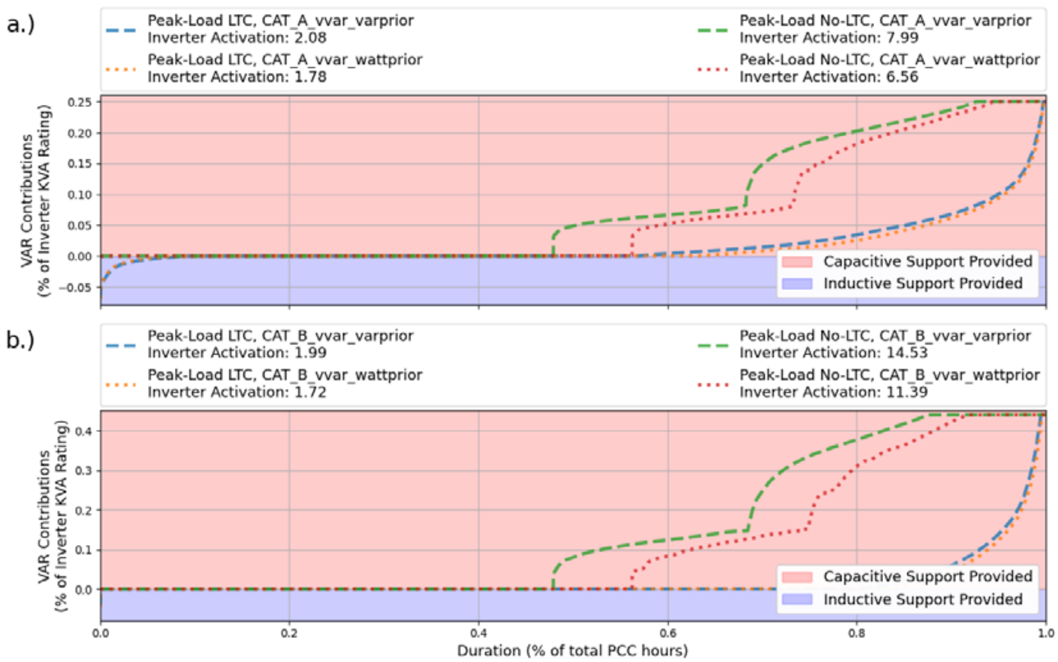

Figure 24 Peak-Load scenario inverter activation duration curves with and without a substation LTC and with and without inverter volt-VAR functionality: a) 1547 Category A default settings; b) 1547 Category B default settings

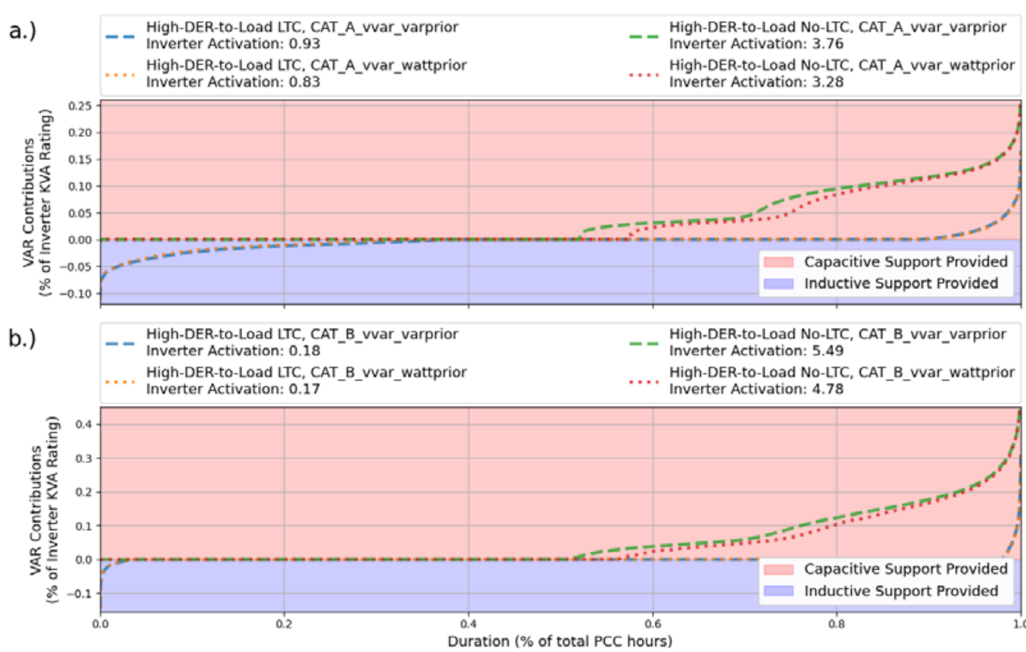

Figure 25 High-DER-to-Load scenario inverter activation duration curves with and without a substation LTC and with and without inverter volt-VAR functionality: a) 1547 Category A default settings; b) 1547 Category B default settings

3.3.4 Inverter Curtailment

A greater reliance on IBDERs for voltage regulation may increase the likelihood of curtailing active power production, subject to inverter priority settings (watt- vs. VAR-priority) and inverter sizing. In our test scenario, we sized all inverters at a 0.9 AC/DC ratio, and we calculated the difference in active power generation between our unity-PF scenario and each volt-VAR scenario. Figure 26 illustrates the concepts discussed previously—that there can be a loss of real power generation when operating inverters in VAR-priority, especially in the presence of significant preexisting voltage violations, as is the case for our No-LTC scenarios. Although watt-priority removes any curtailment because of inverter voltage regulation, the small amounts of curtailment seen while operating in watt-priority are because a current-fixed device—such as an inverter—will typically generate more power when operating at a higher voltage. In the case of the High-DER-to-Load, LTC, Category A scenario, we saw in the previous section that these inverters are more often providing inductive reactive power support, slightly lowering the PCC voltage (compared with unity PF) and therefore generating slightly less active power. This shows that even under the worst case (Peak Load, No-LTC, Category B, VAR-priority), we see only minimal curtailment.

As detailed previously, the Indian test feeder used here mainly experiences undervoltages. Other feeders, especially at high penetrations of distributed generation, may instead experience overvoltages. Similarly, as mentioned previously and shown in Figure 18, DERs located close to the substation or distribution transformer may experience higher voltages because of the setpoint used by the utility. In this case, a utility may consider adding volt-watt as a backup to volt-VAR so that at higher voltages, if an inverter is operating at maximum VAR absorption but continues to see voltages above its bandwidth, the inverter would begin to curtail real power production following a user-defined volt-watt curve. On a feeder with systemic overvoltages at the PCC, this approach could lead to more significant PV curtailment than volt-VAR alone.

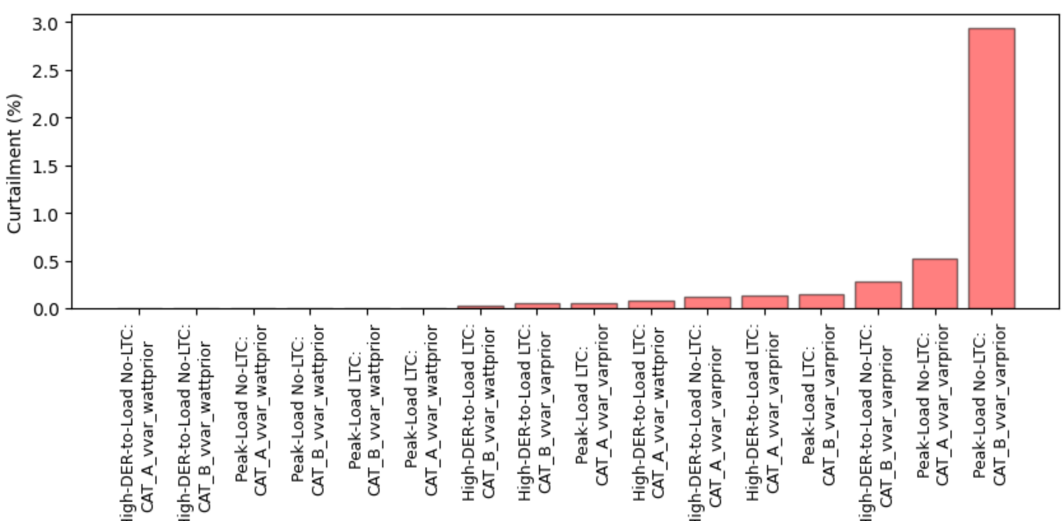

Figure 26. Inverter curtailment (as a percent of total generation) while using different voltage support settings across modeling scenarios

4 Conclusions and Future Work

Substantial growth in wind and solar generation capacity in India are creating a need for more robust grid codes, particularly addressing the unique functionalities and operating characteristics of IBRs—both at the bulk system level and those connected at the grid edge. Although some advanced functionalities such as voltage ride through are already prescribed in CEA's bulk system grid codes, distributed generation interconnection lacks critical provisions for ensuring bulk system stability and reliability at high DER adoption levels. IEEE 1547-2018 provides a foundational basis for adopting such advanced functionalities. As explained throughout this report, this standard must be examined carefully—within the Indian context—to ensure a appropriate interconnection of DERs on Indian power systems, which in some ways are different from those on which the standard is largely based. Although the standard provides flexibility for adjusting default settings, these settings must be adjusted in an informed way and proactive action taken to avoid costly retrofits or risks to system reliability. The considerations listed throughout this report provide a basis for beginning this context-specific analysis; however, we have addressed only a select few clauses. The entirety of the standard should be reviewed carefully, addressing similar needs for locally appropriate adoption.

In our analysis, we find the following:

- IEEE 1547-2018 has multiple grid support functions not present in CEA's *Technical Standards for Connectivity of the Distributed Generation Resources* or in the MNRE Draft *Technical requirements for Photovoltaic Grid Tie Inverters to be connected to the Utility Grid in India*, including voltage ride through, frequency ride through, steady-state voltage regulation, and dynamic voltage support.

- IEEE 1547-2018 standard frequency-related grid support functions would need to be adapted for a 50-Hz system and could provide critical benefits to the power system at high adoption levels of DERs. Frequency ride through, at high DER levels, will be critical to the stability of the Indian power system.

- The voltage ride-through and voltage regulation settings will need to be adapted for both the prescribed voltage operating bounds and the *actual* operating conditions of voltages for Indian DISCOMs.

    - Inappropriate adoption of 1547-2018 requirements and settings for voltage trip, ride through, and regulation could result in frequent nuisance tripping of DERs as well as potential system instability.

- Although some of the settings in 1547-2018 are U.S.-centric, Indian entities can readily adopt the requirements for DERs to provide the capabilities in the standard while work continues to develop locally appropriate settings and grid support categories in the Indian context.

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- The early adoption of technically sound interconnection standards and careful considerations of current and future power system characteristics are critical steps for utilities, regulators, and other involved stakeholders to take to avoid costly mistakes and retroactive changes to DER installations.

Overall, increased study using real-world Indian power quality data in conjunction with advanced system modeling efforts is critical to the successful design of Indian-specific grid support functions. Consulting with DER developers and installers of DERs, DISCOMs, SLDCs, and other key power system and DER entities will be critical to the successful revision of Indian grid codes for DERs. The industry will need to strive toward a collective understanding of interconnection requirements, identify any knowledge gaps, and ensure that the proper support channels from inverter manufacturers or utilities are provided. DER standards should be locally appropriate, and standards agencies should harmonize settings across their jurisdiction to reduce confusion for involved stakeholders and prevent interconnection delays from failed screens. Cooperation across all levels of regulators (central, state, and DISCOM level) will be required to fully analyze and implement advanced functionalities for DERs. Lastly, engaging inverter testing laboratories can help ensure consistency and standardization across the industry—mitigating issues around improperly configured inverters, software retention of key settings, and testing/commissioning procedures and creating pathways for certifications.

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